Appendix A

Letter to agencies

TREY GOWDY, SOUTH CAROLINA
CHAIRMAN

ONE HUNDRED FIFTEENTH CONGRESS

ELIJAH E. CUMMINGS, MARYLAND
RANKING MINORITY MEMBER

Congress of the United States

House of Representatives

COMMITTEE ON OVERSIGHT AND GOVERNMENT REFORM
2157 RAYBURN HOUSE OFFICE BUILDING
WASHINGTON, DC 20515-6143

MAJORITY (202) 225-5074
MINORITY (202) 225-5051

http://oversight.house.gov

December 8, 2017

The Honorable R. Alexander Acosta
Secretary
U.S. Department of Labor
200 Constitution Avenue, N.W.
Washington, D.C. 20210

Dear Mr. Secretary:

Agencies issue a wide variety of policy documents for different purposes. Generally, when a policy is intended to be binding, agencies issue a regulation.[1] Other times, agencies issue statements of policy, interpretive rules, and other guidance regarding how the agency plans to interpret laws and legislative rules.[2]

These various forms of guidance are not legally binding, but, according to the Government Accountability Office (GAO), the documents have wide-ranging effects on public and private sector behavior. In a 2015 report, GAO stated: "guidance documents can have a significant effect on regulated entities and the public, both because of agencies' reliance on large volumes of guidance documents and the fact that the guidance can prompt changes in the behavior of regulated parties and the general public."[3]

The GAO also found agencies' use of guidance varied significantly, ranging from as few as ten at some agencies to more than one hundred guidance documents each year at others.[4] The reason for this discrepancy is unclear. It is also unclear whether there are uniform practices or strategies throughout the executive branch for developing and issuing guidance documents.

To help the Committee better understand how and when federal agencies issue guidance documents, please provide a list of all guidance documents issued by your agency since January 1, 2008, including the following for each guidance document listed:

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[1] GOV'T ACCOUNTABILITY OFFICE, GAO-17-404T, REGULATORY GUIDANCE PROCESSES: SELECTED DEPARTMENTS COULD STRENGTHEN INTERNAL CONTROL AND DISSEMINATION PRACTICES 14 (April 2015), *available at* http://www.gao.gov/assets/670/669688.pdf.

[2] Agencies use a variety of names to refer to guidance documents, such as memoranda, policy statements, manuals, circulars, bulletins, advisories, or guidance. The Office of Management and Budget defines a guidance document as an agency statement of general applicability and future effect that sets forth a policy or interprets a statutory or regulatory issue. *Id.* at 7.

[3] *Id.* at 8.

[4] *Id.* at 13.

1. The title;

2. The name of the form of guidance, such as circular, guidance, frequently asked questions, bulletin, memoranda, or statement;

3. A brief description of the subject;

4. The date of issuance;

5. The issuing agency, component, office, or program;

6. An indication of whether:

    a. The guidance was considered significant;

    b. The agency submitted the guidance for review by the Office of Information and Regulatory Affairs, and if it was:

        i. The title of the guidance used in the submission; and
        ii. The date submitted;

    c. The agency submitted the guidance to Congress and GAO, and if it was:

        i. The title of the guidance used in the submission; and
        ii. The date submitted; and

    d. The Regulatory Reform Task Force has reviewed or has plans to review the guidance document, and any results of such review; and

7. To the extent applicable:

    a. The Federal Record citation;

    b. A hyperlink to a copy of the document;

    c. The Regulation Identification Number; and

    d. Any other identification number for the document.

Provide the requested documents and information as soon as possible, but no later than 5:00 p.m. on December 22, 2017. An attachment to this letter provides additional instructions for responding to the Committee's request.

Please contact Katy Rother of the majority staff at [redacted] or [redacted] with any questions about this request. Thank you for your attention to this matter.

Sincerely,

Trey Gowdy
Chairman

Mark Meadows
Chairman
Subcommittee on Government Operations

Jim Jordan
Chairman
Subcommittee on Healthcare, Benefits, and Administrative Rules

Gary J. Palmer
Chairman
Subcommittee on Intergovernmental Affairs

Blake Farenthold

Blake Farenthold
Chairman
Subcommittee on the Interior, Energy, and Environment

Enclosure

cc: The Honorable Elijah E. Cummings, Ranking Member
Committee on Oversight and Government Reform

The Honorable Gerald E. Connolly, Ranking Member
Subcommittee on Government Operations

The Honorable Raja Krishnamoorthi, Ranking Member
Subcommittee on Healthcare, Benefits, and Administrative Rules

The Honorable Val Butler Demings, Ranking Member
Subcommittee on Intergovernmental Affairs

The Honorable Stacey E. Plaskett, Ranking Member
Subcommittee on the Interior, Energy, and Environment

Responding to Committee Document Requests

1. In complying with this request, you are required to produce all responsive documents that are in your possession, custody, or control, whether held by you or your past or present agents, employees, and representatives acting on your behalf. You should also produce documents that you have a legal right to obtain, that you have a right to copy or to which you have access, as well as documents that you have placed in the temporary possession, custody, or control of any third party. Requested records, documents, data or information should not be destroyed, modified, removed, transferred or otherwise made inaccessible to the Committee.

2. In the event that any entity, organization or individual denoted in this request has been, or is also known by any other name than that herein denoted, the request shall be read also to include that alternative identification.

3. The Committee's preference is to receive documents in electronic form (i.e., CD, memory stick, or thumb drive) in lieu of paper productions.

4. Documents produced in electronic format should also be organized, identified, and indexed electronically.

5. Electronic document productions should be prepared according to the following standards:

   (a) The production should consist of single page Tagged Image File ("TIF"), files accompanied by a Concordance-format load file, an Opticon reference file, and a file defining the fields and character lengths of the load file.

   (b) Document numbers in the load file should match document Bates numbers and TIF file names.

   (c) If the production is completed through a series of multiple partial productions, field names and file order in all load files should match.

   (d) All electronic documents produced to the Committee should include the following fields of metadata specific to each document;

   BEGDOC, ENDDOC, TEXT, BEGATTACH, ENDATTACH, PAGECOUNT,CUSTODIAN, RECORDTYPE, DATE, TIME, SENTDATE, SENTTIME, BEGINDATE, BEGINTIME, ENDDATE, ENDTIME, AUTHOR, FROM, CC, TO, BCC, SUBJECT, TITLE, FILENAME, FILEEXT, FILESIZE, DATECREATED, TIMECREATED, DATELASTMOD, TIMELASTMOD, INTMSGID, INTMSGHEADER, NATIVELINK, INTFILPATH, EXCEPTION, BEGATTACH.

6. Documents produced to the Committee should include an index describing the contents of the production. To the extent more than one CD, hard drive, memory stick, thumb drive, box or folder is produced, each CD, hard drive, memory stick, thumb drive, box or folder should contain an index describing its contents.

7. Documents produced in response to this request shall be produced together with copies of file labels, dividers or identifying markers with which they were associated when the request was served.

8. When you produce documents, you should identify the paragraph in the Committee's schedule to which the documents respond.

9. It shall not be a basis for refusal to produce documents that any other person or entity also possesses non-identical or identical copies of the same documents.

10. If any of the requested information is only reasonably available in machine-readable form (such as on a computer server, hard drive, or computer backup tape), you should consult with the Committee staff to determine the appropriate format in which to produce the information.

11. If compliance with the request cannot be made in full by the specified return date, compliance shall be made to the extent possible by that date. An explanation of why full compliance is not possible shall be provided along with any partial production.

12. In the event that a document is withheld on the basis of privilege, provide a privilege log containing the following information concerning any such document: (a) the privilege asserted; (b) the type of document; (c) the general subject matter; (d) the date, author and addressee; and (e) the relationship of the author and addressee to each other.

13. If any document responsive to this request was, but no longer is, in your possession, custody, or control, identify the document (stating its date, author, subject and recipients) and explain the circumstances under which the document ceased to be in your possession, custody, or control.

14. If a date or other descriptive detail set forth in this request referring to a document is inaccurate, but the actual date or other descriptive detail is known to you or is otherwise apparent from the context of the request, you are required to produce all documents which would be responsive as if the date or other descriptive detail were correct.

15. Unless otherwise specified, the time period covered by this request is from January 1, 2009 to the present.

16. This request is continuing in nature and applies to any newly-discovered information. Any record, document, compilation of data or information, not produced because it has not been located or discovered by the return date, shall be produced immediately upon subsequent location or discovery.

17. All documents shall be Bates-stamped sequentially and produced sequentially.

18. Two sets of documents shall be delivered, one set to the Majority Staff and one set to the Minority Staff. When documents are produced to the Committee, production sets shall be delivered to the Majority Staff in Room 2157 of the Rayburn House Office Building and the Minority Staff in Room 2471 of the Rayburn House Office Building.

19. Upon completion of the document production, you should submit a written certification, signed by you or your counsel, stating that: (1) a diligent search has been completed of all documents in your possession, custody, or control which reasonably could contain responsive documents; and (2) all documents located during the search that are responsive have been produced to the Committee.

Definitions

1. The term "document" means any written, recorded, or graphic matter of any nature whatsoever, regardless of how recorded, and whether original or copy, including, but not limited to, the following: memoranda, reports, expense reports, books, manuals, instructions, financial reports, working papers, records, notes, letters, notices, confirmations, telegrams, receipts, appraisals, pamphlets, magazines, newspapers, prospectuses, inter-office and intra-office communications, electronic mail (e-mail), contracts, cables, notations of any type of conversation, telephone call, meeting or other communication, bulletins, printed matter, computer printouts, teletypes, invoices, transcripts, diaries, analyses, returns, summaries, minutes, bills, accounts, estimates, projections, comparisons, messages, correspondence, press releases, circulars, financial statements, reviews, opinions, offers, studies and investigations, questionnaires and surveys, and work sheets (and all drafts, preliminary versions, alterations, modifications, revisions, changes, and amendments of any of the foregoing, as well as any attachments or appendices thereto), and graphic or oral records or representations of any kind (including without limitation, photographs, charts, graphs, microfiche, microfilm, videotape, recordings and motion pictures), and electronic, mechanical, and electric records or representations of any kind (including, without limitation, tapes, cassettes, disks, and recordings) and other written, printed, typed, or other graphic or recorded matter of any kind or nature, however produced or reproduced, and whether preserved in writing, film, tape, disk, videotape or otherwise. A document bearing any notation not a part of the original text is to be considered a separate document. A draft or non-identical copy is a separate document within the meaning of this term.

2. The term "communication" means each manner or means of disclosure or exchange of information, regardless of means utilized, whether oral, electronic, by document or otherwise, and whether in a meeting, by telephone, facsimile, email (desktop or mobile device), text message, instant message, MMS or SMS message, regular mail, telexes, releases, or otherwise.

3. The terms "and" and "or" shall be construed broadly and either conjunctively or disjunctively to bring within the scope of this request any information which might otherwise be construed to be outside its scope. The singular includes plural number, and vice versa. The masculine includes the feminine and neuter genders.

4. The terms "person" or "persons" mean natural persons, firms, partnerships, associations, corporations, subsidiaries, divisions, departments, joint ventures, proprietorships, syndicates, or other legal, business or government entities, and all subsidiaries, affiliates, divisions, departments, branches, or other units thereof.

5. The term “identify,” when used in a question about individuals, means to provide the following information: (a) the individual's complete name and title; and (b) the individual's business address and phone number.

6. The term “referring or relating,” with respect to any given subject, means anything that constitutes, contains, embodies, reflects, identifies, states, refers to, deals with or is pertinent to that subject in any manner whatsoever.

7. The term “employee” means agent, borrowed employee, casual employee, consultant, contractor, de facto employee, independent contractor, joint adventurer, loaned employee, part-time employee, permanent employee, provisional employee, subcontractor, or any other type of service provider.

COMMITTEE ON OVERSIGHT AND GOVERNMENT REFORM
U.S. HOUSE OF REPRESENTATIVES
115TH CONGRESS

NOTICE OF APPEARANCE OF COUNSEL

Counsel submitting: ____

Bar number: ________________ **State/District of admission:** ______________

Attorney for: ____

Address: ____

Telephone: (_______) _______ - ___________

Pursuant to Rule 16 of the Committee Rules, notice is hereby given of the entry of the undersigned as counsel for ____ in (select one):

- ◉ **All matters before the Committee**
- ○ **The following matters (describe the scope of representation):**

____

____

All further notice and copies of papers and other material relevant to this action should be directed to and served upon:

Attorney's name: ____

Attorney's email address: ____

Firm name (where applicable): ____________________________________

Complete Mailing Address: ______________________________________

____

I agree to notify the Committee within 1 business day of any change in representation.

____ ____________________
Signature of Attorney **Date**

Appendix B

Consumer Financial Protection Bureau

Consumer Financial Protection Bureau

1700 G Street, N.W., Washington, DC 20552

December 21, 2017

The Honorable Trey Gowdy
Chairman
Committee on Oversight and Government Reform
U.S. House of Representatives
2157 Rayburn House Office Building
Washington, DC 20515

Dear Chairman ~~Gowdy~~ TREY:

I write in response to your December 8, 2017 letter, which requests a list of guidance documents issued by the Consumer Financial Protection Bureau since January 1, 2008. I appreciate this opportunity to provide your Committee with information regarding the Bureau's efforts to communicate guidance on matters within its statutory authority.

Attached to this letter is a spreadsheet prepared by Bureau staff, which lists to the best of our knowledge after a comprehensive review, the extant guidance documents issued by the Bureau since its creation, as well as other documents responsive to your request. In preparing the list, the Bureau has construed your request for "guidance" to include: interpretative rules; documents designated as "Bulletins" by the Bureau; documents designated as "Official Guidance" on the Bureau's website; other documents designated as guidance or policies in the Federal Register (including several that were issued jointly with other agencies); editions of "Supervisory Highlights," which are Bureau documents sharing findings from recent supervisory examinations and information about supervisory priorities; Fair Lending reports describing the Bureau's fair lending activities and priorities; and notices issued under § 612(f) of the Fair Credit Reporting Act. The list also includes a number of additional documents that are available on the Bureau's "Compliance and Guidance" web page or that the Bureau has elsewhere referred to as guidance, bulletins, or compliance documents, including documents describing its rulemaking agenda, examination manuals, and small entity compliance guides.

The Bureau did not include informal documents available on the Bureau's website, such as press releases, blog posts, and speeches, because the Bureau does not regard these as guidance and did not understand them to fall within the categories of documents requested in the Committee's letter. However, the Bureau can compile such a list at the Committee's request.

The Bureau, as an independent regulatory agency under 44 U.S.C. § 3502(5), has not previously submitted guidance to the Office of Information and Regulatory Affairs and has not made determinations as to whether the guidance is "significant." *See* Final Bulletin for Agency Good Guidance Practices, 72 Fed. Reg. 3432, 3439 (Jan. 25, 2007) ("agency" excludes "independent regulatory agencies"). The Bureau has submitted the four interpretive rules included on the list to Congress and the Government Accountability Office pursuant to the Congressional Review Act: (1) Homeownership Counseling Organizations List Interpretive Rule, submitted November 25, 2013; (2) Application of Regulation Z's Ability-To-Repay Rule to Certain Situations Involving Successors-in-Interest, submitted October 30, 2014; (3) Homeownership Counseling Organizations Lists and High-Cost Mortgage Counseling Interpretive Rule, submitted April 21, 2015; and (4) Safe Harbors From Liability Under the Fair Debt Collection Practices Act for Certain Actions Taken in Compliance With Mortgage Servicing Rules Under the Real Estate Settlement Procedures Act (Regulation X) and the Truth in Lending Act (Regulation Z), submitted December 22, 2016.

Finally, the Bureau has formed an internal task force to coordinate and deepen the agency's focus on concerns about regulatory burdens and projects to identify and reduce unwarranted regulatory burdens. The immediate focus of this task force is on binding legislative rules, but it is anticipated that related agency guidance will also be the subject of review.

The Bureau looks forward to being transparent with congressional oversight committees on all matters. Should you have questions about this matter, please contact me or have your staff contact Laura Hussain of the Bureau's Legal Division or Jonathan Slemrod of the Bureau's Office of the Acting Director. Ms. Hussain can be reached at [redacted], and Mr. Slemrod can be reached at [redacted]

Sincerely,

Mick Mulvaney
Acting Director

HWG3:
Call me anytime if you want more detail on this.
MM

cc: The Honorable Elijah E. Cummings, Ranking Member
Committee on Oversight and Government Reform

The Honorable Mark Meadows, Chairman
Subcommittee on Government Operations
Committee on Oversight and Government Reform

The Honorable Gerald E. Connolly, Ranking Member
Subcommittee on Government Operations
Committee on Oversight and Government Reform

The Honorable Jim Jordan, Chairman
Subcommittee on Healthcare, Benefits, and Administrative Rules
Committee on Oversight and Government Reform

The Honorable Raja Krishnamoorthi, Ranking Member
Subcommittee on Healthcare, Benefits, and Administrative Rules
Committee on Oversight and Government Reform

The Honorable Gary J. Palmer, Chairman
Subcommittee on Intergovernmental Affairs
Committee on Oversight and Government Reform

The Honorable Val Butler Demings, Ranking Member
Subcommittee on Intergovernmental Affairs
Committee on Oversight and Government Reform

The Honorable Blake Farenthold, Chairman
Subcommittee on the Interior, Energy, and Environment
Committee on Oversight and Government Reform

The Honorable Stacey E. Plaskett, Ranking Member
Subcommittee on the Interior, Energy, and Environment
Committee on Oversight and Government Reform

Title	Form	Brief description	Issue date	Agency	FR Cite	URL	RIN
Letter from Len Kennedy regarding timing of financial institutions' obligations under 1071	Letter	This letter was issued in response to multiple inquiries the Consumer Financial Protection Bureau (“CFPB” or “Bureau”) had received regarding the timing of financial institutions’ obligations under section 1071 of the Dodd-Frank Wall Street Reform and Consumer Protection Act (“Dodd-Frank Act”).	11-Apr-11	CFPB	N/A	https://www.consumerfinance.gov/policy-compliance/guidance/implementation-guidance/general-counsel-letter-regarding-section-1071-dodd-frank-act/	N/A
Bulletin 2011-1, amendments to AMTPA	Bulletin	The Bureau issued amendments to the Alternative Mortgage Transaction Parity Act (“AMTPA”) pursuant to section 1083 of the Dodd-Frank Wall Street Reform and Consumer Protection Act (“Dodd-Frank Act”). The amendments affect what laws apply to mortgage loans issued by state chartered or licensed lenders after that effective date.	27-Jun-11	CFPB	N/A	https://www.consumerfinance.gov/policy-compliance	N/A
Bulletin 2011-2, Interstate Land Sales Full Disclosure Act	Bulletin	The Bureau of Consumer Financial Protection (CFPB) issued this bulletin (Interim ILS Guidance) to address certain administrative issued relating to the Interstate Land Sales Full Disclosure Act (ILS).	21-Jul-11	CFPB	N/A	https://www.consumerfinance.gov/policy-compliance/guidance/implementation-guidance/bulletin-interstate-land-sales-full-disclosure-act/	N/A
Bulletin 2011-4, Notice and Opportunity to Respond and Advise (NORA) prior to enforcement proceedings	Bulletin	Before the Office of Enforcement recommends that the Bureau commence enforcement proceedings, the Office of Enforcement may give the subject of such recommendation notice of the nature of the subject’s potential violations and may offer the subject the opportunity to submit a written statement in response	7-Nov-11	CFPB	N/A	https://www.consumerfinance.gov/policy-compliance/guidance/implementation-guidance/bulletin-notice-opportunity-respond-advise/	N/A
Interagency statement for determining asset size of institutions for supervisory and enforcement purposes	Statement	The Statement explains how the total assets of an insured depository institution or insured credit union (“Institution”) will be measured for purposes of determining supervisory and enforcement responsibilities under sections 1025 and 1026 of the Dodd-Frank Wall Street Reform and Consumer Protection Act (Dodd-Frank).	17-Nov-11	CFPB and prudentials	N/A	https://www.consumerfinance.gov/policy-compliance/guidance/implementation-guidance/interagency-statement-determining-asset-size-institutions/	N/A
Bulletin 2011-5, Whistleblower information, law enforcement tips, and anti-retaliation protections	Bulletin	The Consumer Financial Protection Bureau issued this bulletin to solicit information from knowledgeable sources about potential violations of Federal consumer financial laws.	15-Dec-11	CFPB	N/A	https://www.consumerfinance.gov/policy-compliance/guidance/implementation-guidance/bulletin-whistleblower-law-enforcement-information-protections/	N/A
Bulletin 2012-1, The Bureau's supervisory authority and treatment of confidential supervisory information	Bulletin	The Consumer Financial Protection Bureau ("Bureau") issued this letter to provide guidance regarding its collection of information through the supervisory process and the confidentiality protections that this process provides to supervised institutions.	4-Jan-12	CFPB	N/A	https://www.consumerfinance.gov/policy-compliance/guidance/implementation-guidance/bulletin-supervision-authority-confidential-information/	N/A
Unified Agenda	Report	Twice a year, the CFPB publishes an agenda of its planned rulemaking activities.	13-Feb-12	CFPB	77 FR 8034	https://www.consumerfinance.gov/policy-compliance	N/A
Bulletin 2012-2, The payment of compensation to loan originators	Bulletin	This Bulletin was issued in response to several inquiries the Consumer Financial Protection Bureau (“Bureau”) has received regarding the payment of compensation to loan originators under Regulation Z, 12 C.F.R. § 1026.36 (“Compensation Rules”).	2-Apr-12	CFPB	N/A	https://www.consumerfinance.gov/policy-compliance/guidance/implementation-guidance/bulletin-payment-compensation-loan-originators/	N/A
Fair Credit Reporting Act Disclosures	Notice	The Bureau is required to increase the $8.00 amount referred to in Section 612(f)(1)(A)(i) of the FCRA on January 1 of each year, based proportionally on changes in the Consumer Price Index (CPI), with fractional changes rounded to the nearest fifty cents.	3-Apr-12	CFPB	44 U.S.C. 3502(5)	https://www.consumerfinance.gov/policy-compliance/rulemaking/final-rules/fair-credit-reporting-act-disclosures/	3170–AA06

Title	Form	Brief description	Issue date	Agency	FR Cite	URL	RIN
Bulletin 2012-4, Lending discrimination	Bulletin	In response to recent inquiries, the Consumer Financial Protection Bureau ("CFPB" or "Bureau") issued this bulletin to provide guidance about compliance with the fair lending requirements of the Equal Credit Opportunity Act ("ECOA"), and its implementing regulation, Regulation B.	18-Apr-12	CFPB	N/A	https://www.consumerfinance.gov/policy-compliance/guidance/implementation-guidance/bulletin-lending-discrimination/	N/A
Bulletin 2012-5, SAFE Act and transitional licensing of mortgage loan originators	Bulletin	This Bulletin was issued in response to several inquiries the Consumer Financial Protection Bureau (CFPB or Bureau) has received regarding whether states may, consistent with the Secure and Fair Enforcement for Mortgage Licensing Act of 2008 (SAFE Act), permit transitional licensing of mortgage loan originators.	19-Apr-12	CFPB	N/A	https://www.consumerfinance.gov/policy-compliance/guidance/implementation-guidance/bulletin-SAFE-act-transitional-licensing-mortgage-loan-originators/	N/A
Interagency guidance on mortgage servicing practices concerning military homeowners with permanent change of station orders	Guidance	This guidance was issued to address mortgage servicer practices that may pose risks to homeowners who are serving in the military and to ensure compliance with applicable consumer laws and regulations. Specifically, this guidance addresses risks related to military homeowners who have informed the servicer that they have received military Permanent Change of Station (PCS) orders (hereafter, "homeowners with PCS orders").	21-Jun-12	Board, CFPB, FDIC, NCUA, OCC	N/A	https://www.consumerfinance.gov/policy-compliance/guidance/implementation-guidance/interagency-guidance-mortgage-servicing-practices/	N/A
Disclosure of Certain Credit Card Complaint Data	Policy statement	The CFPB (the Bureau) issued a final policy statement (the Policy Statement) to provide guidance on how the Bureau plans to exercise its discretion to publicly disclose certain credit card complaint data that do not include personally identifiable information.	22-Jun-12	CFPB	77 FR 37558-01	https://www.consumerfinance.gov/policy-compliance/notice-opportunities-comment/archive-closed/disclosure-of-consumer-complaint-data/	N/A
Bulletin 2012-6, Marketing of credit card add-on products	Bulletin	Credit card issuers market various "add-on" products to card users, including debt protection, identity theft protection, credit score tracking, and other products that are supplementary to the credit provided by the card itself. This bulletin outlined the Consumer Financial Protection Bureau's ("CFPB" or "the Bureau") expectation that institutions under its supervision and their service providers offer such products in compliance with Federal consumer financial law.	27-Jun-12	CFPB	N/A	https://www.consumerfinance.gov/policy-compliance/guidance/implementation-guidance/bulletin-marketing-credit-card-add-on-products/	N/A
Supervisory Highlights	Report	We periodically publish Supervisory Highlights to share key examination findings. These reports also communicate operational changes to our supervision program and provide a convenient and easily accessible resource for information on our recent guidance documents.	1-Oct-12	CFPB	N/A	http://files.consumerfinance.gov/f/201210_cfpb_supervisory-highlights-fall-2012.pdf	N/A
Consumer reporting exam procedures	Exam manual	The Bureau's examination manual describes how we supervise and examine these companies and gives our examiners direction on how to assess compliance with federal consumer financial laws.	1-Oct-12	CFPB	N/A	https://www.consumerfinance.gov/documents/4544/102012_cfpb_consumer-reporting-larger-participants_procedures.pdf	N/A
Debt collection exam procedures	Exam manual	The Bureau's examination manual describes how we supervise and examine these companies and gives our examiners direction on how to assess compliance with federal consumer financial laws.	1-Oct-12	CFPB	N/A	https://www.consumerfinance.gov/documents/4760/201210_cfpb_debt-collection-examination-procedures.pdf	N/A
Consumer Leasing Act exam procedures	Exam manual	The Bureau's examination manual describes how we supervise and examine these companies and gives our examiners direction on how to assess compliance with federal consumer financial laws.	1-Oct-12	CFPB	N/A	https://www.consumerfinance.gov/documents/4562/102012_cfpb_consumer-leasing-act_procedures.pdf	N/A

Title	Form	Brief description	Issue date	Agency	FR Cite	URL	RIN
Fair Credit Reporting Act exam procedures	Exam manual	The Bureau's examination manual describes how we supervise and examine these companies and gives our examiners direction on how to assess compliance with federal consumer financial laws.	1-Oct-12	CFPB	N/A	https://www.consumerfinance.gov/documents/4564/102012_cfpb_fair-credit-reporting-act-fcra_procedures.pdf	N/A
Fair Debt Collection Practices Act exam procedures	Exam manual	The Bureau's examination manual describes how we supervise and examine these companies and gives our examiners direction on how to assess compliance with federal consumer financial laws.	1-Oct-12	CFPB	N/A	https://www.consumerfinance.gov/documents/4566/102012_cfpb_fair-debt-collections-practices-act-fdcpa_procedures.pdf	N/A
Home Mortgage Disclosure Act exam procedures	Exam manual	The Bureau's examination manual describes how we supervise and examine these companies and gives our examiners direction on how to assess compliance with federal consumer financial laws.	1-Oct-12	CFPB	N/A	https://www.consumerfinance.gov/documents/4568/102012_cfpb_home-mortgage-disclosure-act-hmda_procedures.pdf	N/A
Homeowners Protection Act exam procedures	Exam manual	The Bureau's examination manual describes how we supervise and examine these companies and gives our examiners direction on how to assess compliance with federal consumer financial laws.	1-Oct-12	CFPB	N/A	https://www.consumerfinance.gov/documents/4570/102012_cfpb_homeowners-protection-act-hpa-pmi-cancellation-act_procedures.pdf	N/A
Secure and Fair Enforcement for Mortgage Licensing exam procedures	Exam manual	The Bureau's examination manual describes how we supervise and examine these companies and gives our examiners direction on how to assess compliance with federal consumer financial laws.	1-Oct-12	CFPB	N/A	https://www.consumerfinance.gov/documents/4572/102012_cfpb_secure-fair-enforcement-for-mortgage-licensing-safe-act_procedures.pdf	N/A
Truth in Savings Act exam procedures	Exam manual	The Bureau's examination manual describes how we supervise and examine these companies and gives our examiners direction on how to assess compliance with federal consumer financial laws.	1-Oct-12	CFPB	N/A	https://www.consumerfinance.gov/documents/4574/102012_cfpb_truth-savings-act-tisa_procedures.pdf	N/A
UDAAP exam procedures	Exam manual	The Bureau's examination manual describes how we supervise and examine these companies and gives our examiners direction on how to assess compliance with federal consumer financial laws.	1-Oct-12	CFPB	N/A	https://www.consumerfinance.gov/documents/4576/102012_cfpb_unfair-deceptive-abusive-acts-practices-udaaps_procedures.pdf	N/A
Statement to advise supervised entities that CFPB encourages them to work with consumers affected by Hurricane Sandy	Statement	The Consumer Financial Protection Bureau (CFPB) issued this statement to advise our supervised entities that the CFPB encourages them to work with borrowers and other consumers affected by Hurricane Sandy. Like the Federal Reserve Board, the Federal Deposit Insurance Corporation, and the Office of the Comptroller of the Currency, the CFPB will provide regulatory flexibility to entities working with borrowers affected by the hurricane.	16-Nov-12	CFPB	N/A	https://www.consumerfinance.gov/policy-compliance/guidance/implementation-guidance/statement-supervisory-practices-affected-hurricane-sandy/	N/A
Bulletin 2012-8, Implementation of the remittance rule (Regulation E, Subpart B)	Bulletin	The Consumer Financial Protection Bureau (CFPB or the Bureau) issued a bulletin in advance of a proposal to refine three elements of its rule regarding foreign remittance transfers. The proposal will be narrowly targeted to address the rule’s provisions on: (1) errors resulting from incorrect account numbers provided by senders of remittance transfers; (2) the disclosure of certain foreign taxes and third-party fees; and (3) the disclosure of sub-national, foreign taxes.	27-Nov-12	CFPB	N/A	https://www.consumerfinance.gov/policy-compliance/guidance/implementation-guidance/bulletin-implementation-remittance-rule/	N/A

Title	Form	Brief description	Issue date	Agency	FR Cite	URL	RIN
Bulletin 2012-9, FCRA streamlined process for consumers to obtain free annual reports from nationwide specialty consumer reporting agencies	Bulletin	The Fair Credit Reporting Act (FCRA) requires nationwide specialty consumer reporting agencies (NSCRAs) to provide, upon request of a consumer, a free annual disclosure of the consumer's file, commonly known as a consumer report. The FCRA's implementing Regulation (Regulation V) includes a rule mandated by the FCRA that requires each NSCRA to establish a "streamlined process for consumers to request [their free annual] consumer reports . . . which shall include, at a minimum, the establishment by each such agency of a toll-free telephone number for such requests." 15 U.S.C. § 1681j; 12 C.F.R. § 1022.137.	29-Nov-12	CFPB	N/A	https://www.consumerfinance.gov/policy-compliance/guidance/implementation-guidance/bulletin-FCRA-process-requirement-consumers/	N/A
Fair Lending Report	Report	The Bureau provides a comprehensive overview of our fair lending program and describes our work in this area, while also fulfilling congressional reporting requirements under § 1013(c)(2)(D) of the Dodd-Frank Wall Street Reform and Consumer Protection Act.	1-Dec-12	CFPB	N/A	http://files.consumerfinance.gov/f/201212_cfpb_fair-lending-report.pdf3	N/A
Fair Credit Reporting Act Disclosures	Notice	The Bureau is required to increase the $8.00 amount referred to in Section 612(f)(1)(A)(i) of the FCRA on January 1 of each year, based proportionally on changes in the Consumer Price Index (CPI), with fractional changes rounded to the nearest fifty cents.	18-Dec-12	CFPB	77 FR 74831-01	https://www.consumerfinance.gov/policy-compliance/rulemaking/final-rules/fair-credit-reporting-act-disclosures/	N/A
Unified Agenda	Report	Twice a year, the CFPB publishes an agenda of its planned rulemaking activities.	8-Jan-13	CFPB	78 FR 1652	https://www.consumerfinance.gov/policy-compliance/rulemaking/regulatory-agenda/	N/A
Bulletin 2013-2, Indirect Auto Lending and Compliance with the Equal Credit Opportunity Act	Bulletin	This bulletin provides guidance about compliance with the fair lending requirements of the Equal Credit Opportunity Act (ECOA) and its implementing regulation, Regulation B, for indirect auto lenders that permit dealers to increase consumer interest rates and that compensate dealers with a share of the increased interest revenues. This guidance applies to all indirect auto lenders within the jurisdiction of the Consumer Financial Protection Bureau (CFPB), including both depository institutions and nonbank institutions.	21-Mar-13	CFPB	N/A	http://files.consumerfinance.gov/f/201303_cfpb_march_-Auto-Finance-Bulletin.pdf	N/A
Disclosure of Consumer Complaint Data	Policy statement	The CFPB (Bureau) issued a final policy statement (Policy Statement) to provide guidance on how the Bureau plans to exercise its discretion to publicly disclose certain consumer complaint data that do not include personally identifiable information.	10-Apr-13	CFPB	78 FR 21218-01	https://www.consumerfinance.gov/policy-compliance/guidance/implementation-guidance/disclosure-consumer-complaint-data/	N/A
Electronic Fund Transfers; Determination of Effect on State Laws (Maine and Tennessee)	Notice	The CFPB (Bureau) published a final determination as to whether certain laws of Maine and Tennessee relating to unclaimed gift cards are inconsistent with and preempted by the Electronic Fund Transfer Act and Regulation E.	25-Apr-13	CFPB	78 FR 24386-05	https://www.consumerfinance.gov/consumerfinance.gov/201304_cfpb_Preemption-Determination	N/A
Bulletin 2013-5, SAFE Act – uniform state test for state-licensed mortgage loan originators	Bulletin	The Consumer Financial Protection Bureau (CFPB) issued this guidance in response to questions about whether states may use the Uniform State Test (UST) developed by the Nationwide Mortgage Licensing System and Registry (NMLSR) as part of a qualified written test under the Secure and Fair Enforcement for Mortgage Licensing Act of 2008 (SAFE Act).	20-May-13	CFPB	N/A	https://www.consumerfinance.gov/policy-compliance/guidance/implementation-guidance/bulletin-SAFE-act-uniform-state-test/	N/A

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Bulletin 2013-6, Responsible business conduct: self-policing, self-reporting, remediation, and cooperation	Bulletin	The Bureau considers many factors in the exercise of its enforcement discretion. These include, for example: (1) the nature, extent, and severity of the violations identified; (2) the actual or potential harm from those violations; (3) whether there is a history of past violations; and (4) a party's effectiveness in addressing violations. This guidance is being provided to inform those subject to the Bureau's enforcement authority that in addition to these and other factors, there are activities they can engage in both before and after the conduct in question has occurred that the Bureau may favorably consider in exercising its enforcement discretion.	25-Jun-13	CFPB	N/A	https://www.consumerfinance.gov/policy-compliance/guidance/implementation-guidance/bulletin-responsible-business-conduct/	N/A
Bulletin 2013-8, Representations regarding effect of debt payments on credit reports and scores	Bulletin	In response to practices observed during supervisory examinations and enforcement investigations, the Consumer Financial Protection Bureau (CFPB or Bureau) issued this bulletin to provide guidance to creditors, debt buyers, and third-party collectors about compliance with the Fair Debt Collection Practices Act (FDCPA) and sections 1031 and 1036 of the Dodd-Frank Wall Street Reform and Consumer Protection Act of 2010 (Dodd-Frank Act) when making representations about the impact that payments on debts in collection may have on credit reports and credit scores.	10-Jul-13	CFPB	N/A	https://www.consumerfinance.gov/policy-compliance/guidance/implementation-guidance/bulletin-effect-debt-payments-credit-reports-scores/	N/A
Bulletin 2013-7, Prohibition of UDAAPs in the collection of consumer debts	Bulletin	Under the Dodd-Frank Wall Street Reform and Consumer Protection Act (Dodd-Frank Act), all covered persons or service providers are legally required to refrain from committing unfair, deceptive, or abusive acts or practices (collectively, UDAAPs) in violation of the Act. The Consumer Financial Protection Bureau (CFPB or Bureau) issued this bulletin to clarify the contours of that obligation in the context of collecting consumer debts.	10-Jul-13	CFPB	N/A	https://www.consumerfinance.gov/policy-compliance/guidance/implementation-guidance/bulletin-prohibition-practices-collection-consumer-debts/	N/A
Unified Agenda	Report	Twice a year, the CFPB publishes an agenda of its planned rulemaking activities.	23-Jul-13	CFPB	78 FR 44350	https://www.consumerfinance.gov/policy-compliance/rulemaking/regulatory-agenda/	N/A
Supervisory Highlights	Report	We periodically publish Supervisory Highlights to share key examination findings. These reports also communicate operational changes to our supervision program and provide a convenient and easily accessible resource for information on our recent guidance documents.	1-Aug-13	CFPB	N/A	http://files.consumerfinance.gov/f/201308_cfpb_supervisory-highlights_august.pdf	N/A
Short-term, small-dollar lending exam procedures	Exam manual	The Bureau's examination manual describes how we supervise and examine these companies and gives our examiners direction on how to assess compliance with federal consumer financial laws.	1-Sep-13	CFPB	N/A	https://www.consumerfinance.gov/documents/4754/201309_cfpb_payday_manual_revisions.pdf	N/A

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Bulletin 2013-9, FCRA requirement to investigate disputes and review "all relevant" information	Bulletin	The Fair Credit Reporting Act (FCRA) generally requires a consumer reporting agency (CRA) to notify a furnisher when a consumer disputes the accuracy or completeness of an item of information provided by the furnisher to the CRA. The CRA must also promptly provide the furnisher "all relevant information" regarding the dispute that the CRA timely received from the consumer. The furnisher, in turn, must "conduct an investigation with respect to the disputed information," "review all relevant information" provided by the CRA, and respond appropriately based on the result of the investigation. The CFPB expects CRAs and furnishers to comply fully with these FCRA requirements, thereby promoting the accuracy and completeness of information in the consumer reporting system.	4-Sep-13	CFPB	N/A	https://www.consumerfinance.gov/policy-compliance/guidance/implementation-guidance/bulletin-FRCA-requirement-investigate-disputes/	N/A
Bulletin 2013-10: Payroll card accounts (Regulation E)	Bulletin	The Consumer Financial Protection Bureau (CFPB or the Bureau) issued this bulletin to reiterate the application of the Electronic Fund Transfer Act (EFTA) and Regulation E, which implements the EFTA, to payroll card accounts.	12-Sep-13	CFPB	N/A	https://www.consumerfinance.gov/policy-compliance/guidance/implementation-guidance/bulletin-payroll-card-accounts/	N/A
Interagency guidance on privacy laws and reporting financial abuse of older adults	Guidance	The agencies issued this guidance to financial institutions to clarify the applicability of privacy provisions of the Gramm-Leach-Bliley Act (GLBA) to reporting suspected financial exploitation of older adults.	24-Sep-13	Board, CFTC, CFPB, FDIC, FTC, NCUA, OCC, SEC	N/A	https://www.consumerfinance.gov/policy-compliance/guidance/implementation-guidance/interagency-guidance-reporting-financial-abuse-older-adults/	N/A
Remittance transfer exam procedures	Exam manual	The Bureau's examination manual describes how we supervise and examine these companies and gives our examiners direction on how to assess compliance with federal consumer financial laws.	1-Oct-13	CFPB	N/A	https://www.consumerfinance.gov/documents/4756/201310_cfpb_remittance-transfer-examination-procedures.pdf	N/A
Electronic Fund Transfer Act exam procedures	Exam manual	The Bureau's examination manual describes how we supervise and examine these companies and gives our examiners direction on how to assess compliance with federal consumer financial laws.	1-Oct-13	CFPB	N/A	https://www.consumerfinance.gov/documents/4752/201310_cfpb_updated-regulation-e-examination-procedures_including-remittances.pdf	N/A
HMDA resubmission schedule and guidelines exam procedures	Exam manual	The Bureau's examination manual describes how we supervise and examine these companies and gives our examiners direction on how to assess compliance with federal consumer financial laws.	1-Oct-13	CFPB	N/A	https://www.consumerfinance.gov/documents/4748/201310_cfpb_hmda_resubmission-guidelines_fair-lending.pdf	N/A
Bulletin 2013-11, the Home Mortgage Disclosure Act (HMDA) and Regulation C – Compliance management; CFPB HMDA resubmission schedule and guidelines; and HMDA enforcement	Bulletin	In this bulletin, the Consumer Financial Protection Bureau (CFPB or Bureau) addresses mortgage lenders' compliance with the Home Mortgage Disclosure Act (HMDA) and its implementing regulation, Regulation C.	9-Oct-13	CFPB	N/A	https://www.consumerfinance.gov/policy-compliance/guidance/implementation-guidance/bulletin-compliance-HMDA-regulation-C/	N/A
Bulletin 2013-12, Implementation guidance for certain mortgage servicing rules	Bulletin	The Consumer Financial Protection Bureau (CFPB) issued this bulletin to provide guidance in implementing certain of the 2013 Real Estate Settlement Procedures Act (RESPA) and Truth in Lending Act (TILA) Servicing Final Rules.	15-Oct-13	CFPB	N/A	https://www.consumerfinance.gov/policy-compliance/guidance/implementation-guidance/bulletin-implementation-mortgage-servicing-rules/	N/A
Policy To Encourage Trial Disclosure Programs; Information Collection	Policy	The CFPB (Bureau) issued its Policy to Encourage Trial Disclosure Programs (Policy), which is intended to carry out the Bureau's authority under of the Dodd-Frank Wall Street Reform and Consumer Protection Act of 2010 (Dodd-Frank Act).	29-Oct-13	CFPB	78 FR 64389-01	files.consumerfinance.gov/f/201310_cfpb_1032e-trial-disclosure-policy.pdf	N/A

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Electronic Fund Transfers (Regulation E)	Notice	On September 26, 2012, the CFPB (Bureau) issued a safe harbor list of countries that qualify for an exception in subpart B of Regulation E, which implements the Electronic Fund Transfer Act, and published this list on its Web site. The Bureau then published this list, which is unchanged from the prior release, in the Federal Register. The Bureau recognizes that the list may change, and it intends to revise the list periodically.	5-Nov-13	CFPB	78 FR 66251-01	https://www.consumerfinance.gov/policy-compliance/notice-opportunities-comment/archive-closed/notice-of-publication-electronic-fund-transfers-regulation-e-remittance-rule-safe-harbor-list/	3170–AA33
Bulletin 2013-13, Homeownership counseling list requirements	Bulletin	The Consumer Financial Protection Bureau (CFPB) issued this bulletin to provide guidance to lenders regarding the homeownership counseling list requirement finalized in the High-Cost Mortgage and Homeownership Counseling Amendments to the Truth in Lending Act (Regulation Z) and Homeownership Counseling Amendments to the Real Estate Settlement Procedures Act (RESPA Housing Counselor Amendments) Final Rule (2013 HOEPA Final Rule).	8-Nov-13	CFPB	N/A	https://www.consumerfinance.gov/policy-compliance/guidance/implementation-guidance/homeownership-counseling-list-requirements/	N/A
Homeownership Counseling Organizations Lists Interpretive Rule	Interpretive rule	This rule describes data instructions for lenders to use in complying with the requirement under the High-Cost Mortgage and Homeownership Counseling Amendments to the Truth in Lending Act (Regulation Z) and Homeownership Counseling Amendments to the Real Estate Settlement Procedures Act (RESPA Homeownership Counseling Amendments) Final Rule to provide a homeownership counseling list using data made available by the Bureau or Department of Housing and Urban Development (HUD).	14-Nov-13	CFPB	78 FR 68343-01	http://files.consumerfinance.gov/f/201311_cfpb_interpretive-rule_homeownership-counseling-organizations-lists.pdf	3170-AA37
Social Media: Consumer Compliance Risk Management Guidance	Guidance	The Federal Financial Institutions Examination Council (FFIEC), on behalf of its members, issued this final supervisory guidance entitled “Social Media: Consumer Compliance Risk Management Guidance” (Guidance).	17-Dec-13	FFIEC	78 FR 76297-01	https://www.consumerfinance.gov/policy-compliance/guidance/implementation-guidance/FFIEC-guidance-social-media/	N/A
Fair Credit Reporting Act Disclosures	Notice	The Bureau is required to increase the $8.00 amount referred to in Section 612(f)(1)(A)(i) of the FCRA on January 1 of each year, based proportionally on changes in the Consumer Price Index (CPI), with fractional changes rounded to the nearest fifty cents.	30-Dec-13	CFPB	78 FR 79410-01	https://www.consumerfinance.gov/policy-compliance/rulemaking/final-rules/fair-credit-reporting-act-disclosures/	N/A
Supervisory Highlights	Report	We periodically publish Supervisory Highlights to share key examination findings. These reports also communicate operational changes to our supervision program and provide a convenient and easily accessible resource for information on our recent guidance documents.	1-Jan-14	CFPB	N/A	http://files.consumerfinance.gov/f/201401_cfpb_supervisory-highlights-winter-2013.pdf	N/A
ECOA valuation small entity compliance guide	Small entity compliance guide	We have resources to help entities understand rules and their implications as well as links to various other helpful resources, because timely and efficient regulatory implementation of new rules is an important factor in delivering consumer protections to the market.	1-Jan-14	CFPB	N/A	http://files.consumerfinance.gov/f/201401_cfpb_compliance-guide_ecoa.pdf	N/A

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TILA HPML appraisals small entity compliance guide	Small entity compliance guide	We have resources to help entities understand rules and their implications as well as links to various other helpful resources, because timely and efficient regulatory implementation of new rules is an important factor in delivering consumer protections to the market.	1-Jan-14	CFPB	N/A	http://files.consumerfinance.gov/f/201401_cfpb_tila-hpml_appraisal-rule-guide.pdf	N/A
Unified Agenda	Report	Twice a year, the CFPB publishes an agenda of its planned rulemaking activities.	7-Jan-14	CFPB	79 FR 1242	https://www.consumerfinance.gov/policy-compliance/rulemaking/regulatory-agenda/	N/A
Bulletin 2014-01, FCRA requirement that furnishers conduct investigations of disputed information	Bulletin	Debt buyers, debt collectors, and others who furnish information to credit reporting agencies have a variety of obligations under the Fair Credit Reporting Act (FCRA) and Regulation V. The Consumer Financial Protection Bureau (CFPB) issued this bulletin to highlight one of those obligations – the obligation of furnishers to investigate disputed information in a consumer report.	27-Feb-14	CFPB	N/A	https://www.consumerfinance.gov/policy-compliance/guidance/implementation-guidance/bulletin-fcra-requirement-furnishers-conduct-investigations/	N/A
Fair Lending Report	Report	The Bureau provides a comprehensive overview of our fair lending program and describes our work in this area, while also fulfilling congressional reporting requirements under § 1013(c)(2)(D) of the Dodd-Frank Wall Street Reform and Consumer Protection Act.	1-Apr-14	CFPB	N/A	files.consumerfinance.gov/f/201404_cfpb_report_fair-lending.pdf	N/A
Supervisory Highlights	Report	We periodically publish Supervisory Highlights to share key examination findings. These reports also communicate operational changes to our supervision program and provide a convenient and easily accessible resource for information on our recent guidance documents.	1-May-14	CFPB	N/A	http://files.consumerfinance.gov/f/201405_cfpb_supervisory-highlights-spring-2014.pdf	N/A
Unified Agenda	Report	Twice a year, the CFPB publishes an agenda of its planned rulemaking activities.	13-Jun-14	CFPB	79 FR 34146	https://www.consumerfinance.gov/policy-compliance/rulemaking/regulatory-agenda/	N/A
Application of Regulation Z's Ability-To-Repay Rule to Certain Situations Involving Successors-in-Interest	Interpretive rule	The CFPB (Bureau) issued this interpretive rule to clarify that the Bureau's Ability-to-Repay Rule incorporates the existing definition of assumption under Regulation Z.	17-Jul-14	CFPB	79 FR 41631-01	https://www.consumerfinance.gov/policy-compliance/rulemaking/final-rules/application-regulation-zs-ability-repay-rule-certain-situations-involving-successors-interest/	3170–ZA00
Policy Guidance on Supervisory and Enforcement Considerations Relevant to Mortgage Brokers Transitioning to Mini-Correspondent Lenders	Policy guidance	The CFPB (CFPB or Bureau) issued supervisory and enforcement guidance entitled Policy Guidance on Supervisory and Enforcement Considerations Relevant to Mortgage Brokers Transitioning to Mini-Correspondent Lenders, (Policy Guidance) which relates to the Bureau's exercise of its authority to supervise and enforce compliance with RESPA and Regulation X and TILA and Regulation Z in certain transactions involving mini-correspondent lenders.	17-Jul-14	CFPB	79 FR 41671-02	https://www.consumerfinance.gov/policy-compliance/guidance/implementation-guidance/guidance-brokers-mini-correspondent-model/	N/A
Guidance regarding certain consumer credit practices	Guidance	The Board of Governors of the Federal Reserve System (Board), Consumer Financial Protection Bureau (CFPB), Federal Deposit Insurance Corporation (FDIC), National Credit Union Administration (NCUA), and Office of the Comptroller of the Currency (OCC) (collectively, the Agencies) issued this guidance regarding certain consumer credit practices.	22-Aug-14	FFIEC	N/A	https://www.consumerfinance.gov/policy-compliance/guidance/implementation-guidance/FFIEC-credit-practices-guidance/	N/A

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Supervisory Highlights	Report	We periodically publish Supervisory Highlights to share key examination findings. These reports also communicate operational changes to our supervision program and provide a convenient and easily accessible resource for information on our recent guidance documents.	1-Sep-14	CFPB	N/A	http://files.consumerfinance.gov/f/201409_cfpb_supervisory-highlights_auto-lending_summer-2014.pdf5	N/A
Bulletin 2014-2, Marketing of credit card promotional offers	Bulletin	The Consumer Financial Protection Bureau (CFPB or Bureau) issued this Bulletin to inform credit card issuers of the risk of engaging in deceptive and/or abusive acts and practices in connection with solicitations that offer a promotional annual percentage rate (APR) on a particular transaction over a defined period of time. These transactions include, but are not limited to, convenience checks, deferred interest/promotional interest rate purchases, and balance transfers.	3-Sep-14	CFPB	N/A	https://www.consumerfinance.gov/policy-compliance/guidance/implementation-guidance/bulletin-marketing-credit-card-promotional-APR-offers/	N/A
Supervisory Highlights	Report	We periodically publish Supervisory Highlights to share key examination findings. These reports also communicate operational changes to our supervision program and provide a convenient and easily accessible resource for information on our recent guidance documents.	1-Oct-14	CFPB	N/A	http://files.consumerfinance.gov/f/201410_cfpb_supervisory-highlights_fall-2014.pdf	N/A
Compliance Bulletin and Policy Guidance, Mortgage Servicing Transfers; CFUB Bulletin 2014-1	Bulletin	The CFPB (CFPB) issued a compliance bulletin and policy guidance entitled Compliance Bulletin and Policy Guidance, Mortgage Servicing Transfers in light of potential risks to consumers that may arise in connection with transfers of residential mortgage servicing rights.	23-Oct-14	CFPB	79 FR 63295-01	https://www.consumerfinance.gov/policy-compliance/guidance/implementation-guidance/bulletin-mortgage-servicing-transfers/	N/A
Bulletin 2014-3, Social Security disability income verification	Bulletin	The Consumer Financial Protection Bureau (Bureau) issued this compliance bulletin to remind creditors of (1) their obligations under the Equal Credit Opportunity Act (ECOA) and its implementing regulation, Regulation B, with respect to consideration of public assistance income; and (2) relevant standards and guidelines regarding verification of Social Security Disability Insurance (SSDI) and Supplemental Security Income (SSI) income (collectively, Social Security disability income) received by mortgage applicants.	18-Nov-14	CFPB	N/A	https://www.consumerfinance.gov/policy-compliance/guidance/implementation-guidance/bulletin-social-security-disability-income-verification/	N/A
Fair Credit Reporting Act Disclosures	Notice	The Bureau is required to increase the $8.00 amount referred to in Section 612(f)(1)(A)(i) of the FCRA on January 1 of each year, based proportionally on changes in the Consumer Price Index (CPI), with fractional changes rounded to the nearest fifty cents.	15-Dec-14	CFPB	79 FR 74068-02	https://www.consumerfinance.gov/policy-compliance/rulemaking/final-rules/fair-credit-reporting-act-disclosures/	N/A
Unified Agenda	Report	Twice a year, the CFPB publishes an agenda of its planned rulemaking activities.	22-Dec-14	CFPB	79 FR 76808	https://www.consumerfinance.gov/policy-compliance/rulemaking/regulatory-agenda/	N/A
Credit card account management exam procedures	Exam manual	The Bureau's examination manual describes how we supervise and examine these companies and gives our examiners direction on how to assess compliance with federal consumer financial laws.	1-Feb-15	CFPB	N/A	https://www.consumerfinance.gov/documents/4762/201502_cfpb_credit_card_account_management_examination_guide.pdf	N/A
Compliance Bulletin 2015-1, Treatment of Confidential Supervisory Information	Bulletin	The Bureau's examination manual describes how we supervise and examine these companies and gives our examiners direction on how to assess compliance with federal consumer financial laws.	25-Feb-15	CFPB	80 FR 10072-01	https://www.consumerfinance.gov/about-us/newsroom/consumer-financial-protection-bureau-issues-supervisory-compliance-bulletin/	N/A

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Supervisory Highlights	Report	We periodically publish Supervisory Highlights to share key examination findings. These reports also communicate operational changes to our supervision program and provide a convenient and easily accessible resource for information on our recent guidance documents.	1-Mar-15	CFPB	N/A	http://files.consumerfinance.gov/f/201503_cfpb_supervisory-highlights-winter-2015.pdf	N/A
Loan originator small entity compliance guide	Small entity compliance guide	We have resources to help entities understand rules and their implications as well as links to various other helpful resources, because timely and efficient regulatory implementation of new rules is an important factor in delivering consumer protections to the market.	1-Mar-15	CFPB	N/A	http://files.consumerfinance.gov/f/201503_cfpb_2013-loan-originator-rule-small-entity-compliance-guide.pdf	N/A
Disclosure of Consumer Complaint Narrative Data	Policy statement	The CFPB (the Bureau) issued a final policy statement (Final Policy Statement) to provide guidance on how the Bureau plans to exercise its discretion to disclose publicly unstructured consumer complaint narrative data (narratives or consumer narratives) via its web-based, public facing database (the Consumer Complaint Database or Database).	24-Mar-15	CFPB	80 FR 15572-01	http://files.consumerfinance.gov/f/201503_cfpb_disclosure-of-consumer-complaint-narrative-data.pdf	N/A
Fair Lending Report	Report	The Bureau provides a comprehensive overview of our fair lending program and describes our work in this area, while also fulfilling congressional reporting requirements under § 1013(c)(2)(D) of the Dodd-Frank Wall Street Reform and Consumer Protection Act.	1-Apr-15	CFPB	N/A	http://files.consumerfinance.gov/f/201504_cfpb_fair_lending_report.pdf	N/A
Homeownership Counseling Organizations Lists and High-Cost Mortgage Counseling Interpretive Rule	Interpretive rule	The CFPB (Bureau) reissued a prior interpretive rule regarding the provision of lists of HUD-approved housing counseling agencies to mortgage loan applicants with additional interpretations describing permissible addresses for list generation, as well as additional details for generation. This interpretive rule also provides guidance, in addition to existing commentary, on the qualifications for providing high-cost mortgage counseling and on lender participation in such counseling.	21-Apr-15	CFPB	80 FR 22091-01	http://files.consumerfinance.gov/f/201504_cfpb_housing-counselor-interpretive-rule.pdf	3170–AA52
Bulletin 2015-2, Section 8 housing choice voucher homeownership program	Bulletin	The Consumer Financial Protection Bureau (Bureau) issued this compliance bulletin to remind creditors of their obligations under the Equal Credit Opportunity Act (ECOA) and its implementing regulation, Regulation B, to provide non-discriminatory access to credit for mortgage applicants using income from the Section 8 Housing Choice Voucher (HCV) Homeownership Program.	11-May-15	CFPB	N/A	https://www.consumerfinance.gov/policy-compliance/guidance/implementation-guidance/bulletin-section-8-housing-choice-voucher-homeownership-program/	N/A
Supervisory Highlights	Report	We periodically publish Supervisory Highlights to share key examination findings. These reports also communicate operational changes to our supervision program and provide a convenient and easily accessible resource for information on our recent guidance documents.	1-Jun-15	CFPB	N/A	http://files.consumerfinance.gov/f/201506_cfpb_supervisory-highlights.pdf	N/A
Auto finance exam procedures	Exam manual	The Bureau's examination manual describes how we supervise and examine these companies and gives our examiners direction on how to assess compliance with federal consumer financial laws.	1-Jun-15	CFPB	N/A	https://www.consumerfinance.gov/documents/4764/201506_cfpb_automobile-finance-examination-procedures.pdf	N/A

Title	Form	Brief description	Issue date	Agency	FR Cite	URL	RIN
Final Interagency Policy Statement Establishing Joint Standards for Assessing the Diversity Policies and Practices of Entities Regulated by the Agencies	Policy statement	The OCC, Board, FDIC, NCUA, CFPB, and SEC issued a final interagency policy statement establishing joint standards for assessing the diversity policies and practices of the entities they regulate, as required by the Dodd-Frank Wall Street Reform and Consumer Protection Act of 2010.	10-Jun-15	OCC, Board, FDIC, NCUA, CFPB, SEC	80 FR 33016	https://www.federalregister.gov/articles/2015/06/10/2015-14126/joint-standards-for-assessing-the-diversity-policies-and-practices-of-entities-regulated-by-the	N/A
Unified Agenda	Report	Twice a year, the CFPB publishes an agenda of its planned rulemaking activities.	18-Jun-15	CFPB	80 FR 35116	https://www.consumerfinance.gov/policy-compliance/rulemaking/regulatory-agenda/	N/A
Bulletin 2015-3, Private mortgage insurance cancellation and termination	Bulletin	The Bureau of Consumer Financial Protection (CFPB) issued this compliance bulletin to provide guidance to assist residential mortgage servicers and subservicers (collectively, servicers) in their compliance with the private mortgage insurance (PMI) cancellation and termination provisions of the Homeowners Protection Act of 1998 (HPA). This compliance bulletin explains HPA requirements and describes examples from CFPB's supervisory experience of PMI cancellation and termination procedures that violate the HPA or create a substantial risk of noncompliance.	4-Aug-15	CFPB	N/A	https://www.consumerfinance.gov/policy-compliance/guidance/implementation-guidance/bulletin-private-mortgage-insurance-cancellation-termination/	N/A
Compliance Bulletin 2015-4, Amendment to the Interstate Land Sales Full Disclosure Act	Bulletin	The CFPB issued a compliance bulletin titled Amendment to the Interstate Land Sales Full Disclosure Act to provide information to developers and other interested parties relating to a recent Congressional amendment to the Interstate Land Sales Full Disclosure Act.	17-Aug-15	CFPB	80 FR 49127-01	http://files.consumerfinance.gov/f/201508_cfpb_bulletin-on-interstate-land-sales-full-disclosure-act-amendment-federal-register.pdf	N/A
Mortgage origination exam procedures	Exam manual	The Bureau's examination manual describes how we supervise and examine these companies and gives our examiners direction on how to assess compliance with federal consumer financial laws.	1-Sep-15	CFPB	N/A	https://www.consumerfinance.gov/documents/4758/201509_cfpb_mortgage-origination-examination-procedures.pdf	N/A
Real Estate Settlement Procedures Act exam procedures	Exam manual	The Bureau's examination manual describes how we supervise and examine these companies and gives our examiners direction on how to assess compliance with federal consumer financial laws.	1-Sep-15	CFPB	N/A	https://www.consumerfinance.gov/documents/4746/201509_cfpb_regulation-x-real-estate-settlement-procedures-act-exam-procedures.pdf	N/A
Truth in Lending Act exam procedures	Exam manual	The Bureau's examination manual describes how we supervise and examine these companies and gives our examiners direction on how to assess compliance with federal consumer financial laws.	1-Sep-15	CFPB	N/A	https://www.consumerfinance.gov/documents/4744/201509_cfpb_truth-in-lending-act-exam-procedures.pdf	N/A
Supervisory Highlights	Report	We periodically publish Supervisory Highlights to share key examination findings. These reports also communicate operational changes to our supervision program and provide a convenient and easily accessible resource for information on our recent guidance documents.	1-Oct-15	CFPB	N/A	http://files.consumerfinance.gov/f/201510_cfpb_supervisory-highlights.pdf	N/A
Equal Credit Opportunity Act exam procedures	Exam manual	The Bureau's examination manual describes how we supervise and examine these companies and gives our examiners direction on how to assess compliance with federal consumer financial laws.	1-Oct-15	CFPB	N/A	https://www.consumerfinance.gov/documents/4750/201510_cfpb_ecoa-narrative-and-procedures.pdf	N/A
ECOA baseline review exam procedures	Exam manual	The Bureau's examination manual describes how we supervise and examine these companies and gives our examiners direction on how to assess compliance with federal consumer financial laws.	1-Oct-15	CFPB	N/A	https://www.consumerfinance.gov/documents/4676/102013_cfpb_equal_credit_opportunity_act_ecoa_baseline.pdf	N/A

Title	Form	Brief description	Issue date	Agency	FR Cite	URL	RIN
Bulletin 2015-5, RESPA compliance and marketing services agreements	Bulletin	The Consumer Financial Protection Bureau (CFPB or the Bureau) issued this compliance bulletin to remind participants in the mortgage industry of the prohibition on kickbacks and referral fees under the Real Estate Settlement Procedures Act (RESPA) (12 U.S.C. 2601, et seq.) and describe the substantial risks posed by entering into marketing services agreements (MSAs).	8-Oct-15	CFPB	N/A	https://www.consumerfinance.gov/policy-compliance/guidance/implementation-guidance/bulletin-RESPA-compliance-marketing-services-agreements/	N/A
Joint Statement of Principles on Student Loan Servicing	Statement	On September 29, 2015, the CFPB (Bureau) joined with the U.S. Department of the Treasury and the U.S. Department of Education to release a Joint Statement of Principles on Student Loan Servicing as a framework for policymakers and market participants looking to improve student loan servicing practices, promote borrower success, and mitigate defaults. This Policy Guidance sets forth those joint principles.	2-Nov-15	CFPB, Treasury, Ed	80 FR 67389-02	http://files.consumerfinance.gov/f/201509_cfpb_treasury_education-joint-statement-of-principles-on-student-loan-servicing.pdf	N/A
Appeals of Supervisory Matters	Policy	In this guidance, the CFPB laid out a supervisory appeals process for financial service providers, including depository institutions.	3-Nov-15	CFPB	N/A	https://www.consumerfinance.gov/policy-compliance/guidance/implementation-guidance/supervisory-matters-appeal-process/	N/A
Fair Credit Reporting Act Disclosures	Notice	The Bureau is required to increase the $8.00 amount referred to in Section 612(f)(1)(A)(i) of the FCRA on January 1 of each year, based proportionally on changes in the Consumer Price Index (CPI), with fractional changes rounded to the nearest fifty cents.	20-Nov-15	CFPB	80 FR 72711-02	https://www.consumerfinance.gov/policy-compliance/rulemaking/final-rules/fair-credit-reporting-act-disclosures/	N/A
Bulletin 2015-6, Requirements for consumer authorizations for preauthorized electronic fund transfers	Bulletin	The CFPB issued this Compliance Bulletin to industry to remind entities of their obligations under the Electronic Fund Transfer Act (EFTA) and Regulation E when obtaining consumer authorizations for preauthorized electronic fund transfers (EFTs) from a consumer's account.	23-Nov-15	CFPB	N/A	https://www.consumerfinance.gov/policy-compliance/guidance/implementation-guidance/bulletin-consumer-authorizations-preauthorized-EFT/	N/A
Unified Agenda	Report	Twice a year, the CFPB publishes an agenda of its planned rulemaking activities.	15-Dec-15	CFPB	80 FR 78056	https://www.consumerfinance.gov/policy-compliance/rulemaking/regulatory-agenda/	N/A
Bulletin 2015-7, In-person collection of consumer debt	Bulletin	The Consumer Financial Protection Bureau (CFPB or Bureau) issued this compliance bulletin to provide guidance to creditors, debt buyers, and third-party collectors about compliance with sections 1031 and 1036 of the Dodd-Frank Wall Street Reform and Consumer Protection Act of 2010 (DoddFrank Act) and the Fair Debt Collection Practices Act (FDCP A) when collecting debt from consumers.	16-Dec-15	CFPB	N/A	https://www.consumerfinance.gov/policy-compliance/guidance/implementation-guidance/bulletin-personal-collection-consumer-debt/	N/A
Compliance Bulletin, The FCRA's Requirement That Furnishers Establish and Implement Reasonable Written Policies and Procedures Regarding the Accuracy and Integrity of Information Furnished to All Consumer Reporting Agencies.	Bulletin	This document highlights existing obligations under the Fair Credit Reporting Act (FCRA) for furnishers of consumer information to consumer reporting agencies (CRAs) to establish and implement reasonable written policies and procedures regarding the accuracy and integrity of information furnished to all CRAs.	4-Feb-16	CFPB	81 FR 5992-01	http://files.consumerfinance.gov/f/201602_cfpb_supervisory-bulletin-furnisher-accuracy-obligations.pdf	N/A

Title	Form	Brief description	Issue date	Agency	FR Cite	URL	RIN
Policy on No-Action Letters; Information Collection	Policy statement	The CFPB (Bureau) issued a final policy statement on No-Action Letters (Policy), which is intended to further objectives under section 1021 of the Dodd-Frank Wall Street Reform and Consumer Protection Act of 2010 (Dodd-Frank Act).	22-Feb-16	CFPB	81 FR 8686-02	http://files.consumerfinance.gov/f/201602_cfpb_no-action-letter-policy.pdf	N/A
ATR/QM small entity compliance guide	Small entity compliance guide	We have resources to help entities understand rules and their implications as well as links to various other helpful resources, because timely and efficient regulatory implementation of new rules is an important factor in delivering consumer protections to the market.	1-Mar-16	CFPB	N/A	http://files.consumerfinance.gov/f/201603_cfpb_atr-qm_small-entity-compliance-guide.pdf	N/A
HOEPA small entity compliance guide	Small entity compliance guide	We have resources to help entities understand rules and their implications as well as links to various other helpful resources, because timely and efficient regulatory implementation of new rules is an important factor in delivering consumer protections to the market.	1-Mar-16	CFPB	N/A	http://files.consumerfinance.gov/f/201603_cfpb_hoepa-compliance-guide.pdf	N/A
Escrows small entity compliance guide	Small entity compliance guide	We have resources to help entities understand rules and their implications as well as links to various other helpful resources, because timely and efficient regulatory implementation of new rules is an important factor in delivering consumer protections to the market.	1-Mar-16	CFPB	N/A	http://files.consumerfinance.gov/f/201603_cfpb_tila-hpml-escrow_compliance-guide.pdf	N/A
Fair Lending Report	Report	The Bureau provides a comprehensive overview of our fair lending program and describes our work in this area, while also fulfilling congressional reporting requirements under § 1013(c)(2)(D) of the Dodd-Frank Wall Street Reform and Consumer Protection Act.	12-May-16	CFPB	81 FR 29533-02	https://www.consumerfinance.gov/documents/3654/201704_cfpb_Fair_Lending_Report.pdf	N/A
Supervisory Highlights	Report	We periodically publish Supervisory Highlights to share key examination findings. These reports also communicate operational changes to our supervision program and provide a convenient and easily accessible resource for information on our recent guidance documents.	16-May-16	CFPB	81 FR 30257-01	http://files.consumerfinance.gov/f/201603_cfpb_supervisory-highlights.pdf	N/A
Interagency Guidance Regarding Deposit Reconciliation Practices	Guidance	The Board of Governors of the Federal Reserve System, the Consumer Financial Protection Bureau, the Federal Deposit Insurance Corporation, the National Credit Union Administration, and the Office of the Comptroller of the Currency (collectively, the Agencies) issued guidance to ensure that financial institutions are aware of the Agencies' supervisory expectations regarding customer account deposit reconciliation practices.	18-May-16	CFPB, Board, FDIC, NCUA, OCC	N/A	http://www.consumerfinance.gov/f/documents/201605_cfpb_interagency-guidance-regarding-deposit-reconciliation-practices.pdf	N/A
Mortgage servicing exam procedures	Exam manual	The Bureau's examination manual describes how we supervise and examine these companies and gives our examiners direction on how to assess compliance with federal consumer financial laws.	1-Jun-16	CFPB	N/A	https://www.consumerfinance.gov/documents/657/11.5_Mortgage_Servicing_Exam_Procedures_June_2016.pdf	N/A
Unified Agenda	Report	Twice a year, the CFPB publishes an agenda of its planned rulemaking activities.	9-Jun-16	CFPB	81 FR 37412	https://www.consumerfinance.gov/policy-compliance/rulemaking/regulatory-agenda/	N/A

Title	Form	Brief description	Issue date	Agency	FR Cite	URL	RIN
Supervisory Highlights	Report	We periodically publish Supervisory Highlights to share key examination findings. These reports also communicate operational changes to our supervision program and provide a convenient and easily accessible resource for information on our recent guidance documents.	15-Jul-16	CFPB	81 FR 46063-01	http://files.consumerfinance.gov/f/documents/Mortgage_Servicing_Supervisory_Highlights_11_Final_web_.pdf	N/A
Supervisory Highlights	Report	We periodically publish Supervisory Highlights to share key examination findings. These reports also communicate operational changes to our supervision program and provide a convenient and easily accessible resource for information on our recent guidance documents.	18-Jul-16	CFPB	81 FR 46652-02	http://files.consumerfinance.gov/f/documents/Supervisory_Highlights_Issue_12.pdf	N/A
Military Lending Act exam procedures	Exam manual	The Bureau's examination manual describes how we supervise and examine these companies and gives our examiners direction on how to assess compliance with federal consumer financial laws.	1-Sep-16	CFPB	N/A	https://www.consumerfinance.gov/documents/1031/092016_cfpb_MLAExamManualUpdate.pdf	N/A
Notice of Availability of Revised Methodology for Determining Average Prime Offer Rates	Notice	The CFPB (Bureau) announced the availability of a revised methodology statement, entitled the Methodology for Determining Average Prime Offer Rates. The methodology statement describes the methodology used to calculate average prime offer rates for purposes of Regulation C and Regulation Z. The Bureau removed from the methodology statement the references to the sources of survey data used to calculate average prime offer rates.	19-Sep-16	CFPB	81 FR 64142-01	N/A	N/A
Status of New Uniform Residential Loan Application and Collection of Expanded Home Mortgage Disclosure Act Information About Ethnicity and Race in 2017	Notice	The CFPB (Bureau) published a notice pursuant to the Equal Credit Opportunity Act concerning the new Uniform Residential Loan Application and the collection of expanded Home Mortgage Disclosure Act information about ethnicity and race in 2017.	29-Sep-16	CFPB	81 FR 66930-01	https://www.consumerfinance.gov/documents/1007/092016_cfpb_HMDAEthinicityRace.pdf	N/A
Reverse mortgage servicing exam procedures	Exam manual	The Bureau's examination manual describes how we supervise and examine these companies and gives our examiners direction on how to assess compliance with federal consumer financial laws.	1-Oct-16	CFPB	N/A	https://www.consumerfinance.gov/documents/1387/102016_cfpb_ReverseMortgageServicingExaminationProcedures.pdf	N/A
Privacy of Consumer Financial Information exam procedures	Exam manual	The Bureau's examination manual describes how we supervise and examine these companies and gives our examiners direction on how to assess compliance with federal consumer financial laws.	1-Oct-16	CFPB	N/A	https://www.consumerfinance.gov/documents/1381/102016_cfpb_GLBAExamManualUpdate.pdf	N/A
Safe Harbors From Liability Under the Fair Debt Collection Practices Act for Certain Actions Taken in Compliance With Mortgage Servicing Rules Under the Real Estate Settlement Procedures Act (Regulation X) and the Truth in Lending Act (Regulation Z)	Interpretive rule	The CFPB (Bureau) issued this interpretive rule under the Fair Debt Collection Practices Act (FDCPA) to clarify the interaction of the FDCPA and specified mortgage servicing rules in Regulations X and Z. This interpretive rule constitutes an advisory opinion for purposes of the FDCPA and provides safe harbors from liability for servicers acting in compliance with specified mortgage servicing rules in three situations.	19-Oct-16	CFPB	81 FR 71977-01	https://www.consumerfinance.gov/documents/811/20160804_cfpb_Bureau_Interpretations_Safe_Harbors_from_Liability_under_FDCPA.pdf	3170–AA49

Title	Form	Brief description	Issue date	Agency	FR Cite	URL	RIN
Compliance Bulletin and Policy Guidance; 2016-02, Service Providers	Bulletin	The Bureau reissued its guidance on service providers, formerly titled CFPB Bulletin 2012-03, Service Providers to clarify that the depth and formality of the risk management program for service providers may vary depending upon the service being performedits size, scope, complexity, importance and potential for consumer harmand the performance of the service provider in carrying out its activities in compliance with Federal consumer financial laws and regulations.	26-Oct-16	CFPB	81 FR 74410-01	https://www.consumerfinance.gov/documents/1385/102016_cfpb_OfficialGuidanceServiceProviderBulletin.pdf	N/A
Mortgage servicing small entity compliance guide 3.0 [and other docs]	Small entity compliance guide	We have resources to help entities understand rules and their implications as well as links to various other helpful resources, because timely and efficient regulatory implementation of new rules is an important factor in delivering consumer protections to the market.	1-Nov-16	CFPB	N/A	https://www.consumerfinance.gov/policy-compliance/guidance/implementation-guidance/mortserv/	N/A
Uniform Interagency Consumer Compliance Rating System	Guidance	The Federal Financial Institutions Examination Council (FFIEC), on behalf of its members, revised the Uniform Interagency Consumer Compliance Rating System, more commonly known as the CC Rating System.	14-Nov-16	FFIEC	81 FR 79473	https://www.ffiec.gov/press/pr110716.htm	N/A
Fair Credit Reporting Act Disclosures	Notice	The Bureau is required to increase the $8.00 amount referred to in Section 612(f)(1)(A)(i) of the FCRA on January 1 of each year, based proportionally on changes in the Consumer Price Index (CPI), with fractional changes rounded to the nearest fifty cents.	18-Nov-16	CFPB	81 FR 81745-02	https://www.consumerfinance.gov/policy-compliance/rulemaking/final-rules/fair-credit-reporting-act-disclosures/	N/A
Supervisory Highlights	Report	We periodically publish Supervisory Highlights to share key examination findings. These reports also communicate operational changes to our supervision program and provide a convenient and easily accessible resource for information on our recent guidance documents.	22-Nov-16	CFPB	81 FR 83811-01	http://files.consumerfinance.gov/f/documents/Supervisory_Highlights_Issue_13__Final_10.31.16.pdf	N/A
Unified Agenda	Report	Twice a year, the CFPB publishes an agenda of its planned rulemaking activities.	23-Dec-16	CFPB	81 FR 94844	https://www.consumerfinance.gov/policy-compliance/rulemaking/regulatory-agenda/	N/A
Compliance Bulletin 2016-03: Detecting and Preventing Consumer Harm From Production Incentives	Bulletin	This bulletin compiled guidance that has previously been given by the CFPB in other contexts and highlights examples from the CFPB's supervisory and enforcement experience in which incentive programs contributed to substantial consumer harm. It also describes compliance management steps supervised entities should take to mitigate risks.	18-Jan-17	CFPB	82 FR 5541-01	https://www.consumerfinance.gov/documents/1537/201611_cfpb_Production_Incentives_Bulletin.pdf	N/A
Remittance small entity compliance guide 4.0 [and other docs]	Small entity compliance guide	We have resources to help entities understand rules and their implications as well as links to various other helpful resources, because timely and efficient regulatory implementation of new rules is an important factor in delivering consumer protections to the market.	31-Jan-17	CFPB	N/A	https://www.consumerfinance.gov/policy-compliance/guidance/implementation-guidance/remittance-transfer-rule/	N/A
Supervisory Highlights	Report	We periodically publish Supervisory Highlights to share key examination findings. These reports also communicate operational changes to our supervision program and provide a convenient and easily accessible resource for information on our recent guidance documents.	6-Apr-17	CFPB	82 FR 16808-02	https://www.consumerfinance.gov/documents/2774/201703_cfpb_Supervisory-Highlights-Consumer-Reporting-Special-Edition.pdf	N/A

Title	Form	Brief description	Issue date	Agency	FR Cite	URL	RIN
Policy on Ex Parte Presentations in Rulemaking Proceedings	Policy	The Consumer Financial Protection Bureau (CFPB) adopted the following updated policy on ex parte presentations in rulemaking proceedings. The original policy was posted on the CFPB's Web site on August 16, 2011.	21-Apr-17	CFPB	82 FR 18687-01	https://www.consumerfinance.gov/documents/4162/201704_cfpb_ex-parte_policy-guidance-and-procedural-rule.pdf	N/A
Supervisory Highlights	Report	We periodically publish Supervisory Highlights to share key examination findings. These reports also communicate operational changes to our supervision program and provide a convenient and easily accessible resource for information on our recent guidance documents.	12-May-17	CFPB	82 FR 22119-01	https://www.consumerfinance.gov/data-research/research-reports/supervisory-highlights-spring-2017/	N/A
Fair Lending Report	Report	The Bureau provides a comprehensive overview of our fair lending program and describes our work in this area, while also fulfilling congressional reporting requirements under § 1013(c)(2)(D) of the Dodd-Frank Wall Street Reform and Consumer Protection Act.	1-Jun-17	CFPB	82 FR 25250-01	https://www.consumerfinance.gov/documents/3654/201704_cfpb_Fair_Lending_Report.pdf	N/A
Education loan exam procedures	Exam manual	The Bureau's examination manual describes how we supervise and examine these companies and gives our examiners direction on how to assess compliance with federal consumer financial laws.	1-Jun-17	CFPB	N/A	https://www.consumerfinance.gov/documents/4858/201706_cfpb_Education-Loan-Servicing-Exam-Manual.pdf	N/A
Prepaid small entity compliance guide [and other docs]	Small entity compliance guide	We have resources to help entities understand rules and their implications as well as links to various other helpful resources, because timely and efficient regulatory implementation of new rules is an important factor in delivering consumer protections to the market.	1-Jun-17	CFPB	N/A	https://www.consumerfinance.gov/policy-compliance/guidance/implementation-guidance/prepaid-rule/	N/A
Policy Guidance on Supervisory and Enforcement Priorities Regarding Early Compliance With the 2016 Amendments to the 2013 Mortgage Rules Under the Real Estate Settlement Procedures Act (Regulation X) and the Truth in Lending Act (Regulation Z)	Policy guidance	The Consumer Financial Protection Bureau (Bureau) issued policy guidance on its supervisory and enforcement priorities regarding early compliance with the final rule it issued in August 2016 (2016 Mortgage Servicing Final Rule) amending certain of the Bureau's mortgage servicing rules.	30-Jun-17	CFPB	82 FR 29713-01	https://www.consumerfinance.gov/documents/4882/201706_cfpb_guidance-on-early-compliance-with-2016-amendments-to-reg-x-and-reg-z.pdf	N/A
CMS exam procedures	Exam manual	The Bureau's examination manual describes how we supervise and examine these companies and gives our examiners direction on how to assess compliance with federal consumer financial laws.	1-Aug-17	CFPB	N/A	https://www.consumerfinance.gov/documents/5236/201708_cfpb_compliance-management-review_supervision-and-examination-manual.pdf	N/A
Compliance Bulletin 2017-01: Phone Pay Fees	Bulletin	The Consumer Financial Protection Bureau (CFPB or Bureau) issued this Compliance Bulletin to provide guidance to covered persons and service providers regarding fee assessments for pay-by-phone services (phone pay fees) and the potential for violations of sections 1031 and 1036 of the Dodd-Frank Wall Street Reform and Consumer Protection Act's (Dodd-Frank Act) prohibition on engaging in unfair, deceptive, or abusive acts or practices (collectively, UDAAPs) when assessing phone pay fees.	2-Aug-17	CFPB	82 FR 35936-01	https://www.consumerfinance.gov/documents/5090/201707_cfpb_compliance-bulletin-phone-pay-fee.pdf	N/A

Title	Form	Brief description	Issue date	Agency	FR Cite	URL	RIN
Memorandum on financial institution and law enforcement efforts to combat elder financial exploitation	Memorandum	This memorandum addresses the role financial institutions can play, together with law enforcement, Adult Protective Services, and other federal, state, and local agencies or programs, to detect, respond to, and protect against elder financial exploitation.	8-Aug-17	CFPB, Treasury, FINCEN	N/A	https://www.consumerfinance.gov/policy-compliance/guidance/implementation-guidance/memorandum-financial-institution-and-law-enforcement-efforts-combat-elder-financial-exploitation/	N/A
Unified Agenda	Report	Twice a year, the CFPB publishes an agenda of its planned rulemaking activities.	24-Aug-17	CFPB	82 FR 40386	https://www.consumerfinance.gov/policy-compliance/rulemaking/regulatory-agenda/	N/A
Statement on supervisory practices regarding financial institutions and consumers affected by Hurricanes Harvey and Irma	Statement	This statement encourages supervised entities to make use of existing regulatory flexibility where doing so would benefit consumers affected by a major disaster or emergency and provides related examples. It also advises on supervisory practices regarding supervised entities that may have experienced difficulties due to a major distaster or emergency.	8-Sep-17	CFPB	N/A	https://www.consumerfinance.gov/policy-compliance/guidance/implementation-guidance/statement-supervisory-practices-affected-hurricanes-harvey-and-irma/	N/A
Statement on supervisory practices regarding financial institutions and consumers affected by Hurricane Maria	Statement	This statement encourages supervised entities to make use of existing regulatory flexibility where doing so would benefit consumers affected by a major disaster or emergency and provides related examples. It also advises on supervisory practices regarding supervised entities that may have experienced difficulties due to a major distaster or emergency.	22-Sep-17	CFPB	N/A	https://www.consumerfinance.gov/policy-compliance/guidance/implementation-guidance/statement-supervisory-practices-regarding-financial-institutions-and-consumers-affected-hurricane-maria/	N/A
HMDA small entity compliance guide [and other docs]	Small entity compliance guide	We have resources to help entities understand rules and their implications as well as links to various other helpful resources, because timely and efficient regulatory implementation of new rules is an important factor in delivering consumer protections to the market.	1-Oct-17	CFPB	N/A	https://www.consumerfinance.gov/policy-compliance/guidance/implementation-guidance/hmda-implementation/	N/A
TILA-RESPA integrated disclosure small entity compliance guide 5.0 [and other docs]	Small entity compliance guide	We have resources to help entities understand rules and their implications as well as links to various other helpful resources, because timely and efficient regulatory implementation of new rules is an important factor in delivering consumer protections to the market.	1-Oct-17	CFPB	N/A	https://www.consumerfinance.gov/policy-compliance/guidance/implementation-guidance/tila-respa-disclosure-rule/	N/A
Supervisory Highlights	Report	We periodically publish Supervisory Highlights to share key examination findings. These reports also communicate operational changes to our supervision program and provide a convenient and easily accessible resource for information on our recent guidance documents.	19-Oct-17	CFPB	82 FR 48703-01	https://www.consumerfinance.gov/documents/5386/201709_cfpb_Supervisory-Highlights_Issue-16.pdf	N/A
Fair Credit Reporting Act Disclosures	Notice	The Bureau is required to increase the $8.00 amount referred to in Section 612(f)(1)(A)(i) of the FCRA on January 1 of each year, based proportionally on changes in the Consumer Price Index (CPI), with fractional changes rounded to the nearest fifty cents.	16-Nov-17	CFPB	82 FR 53481-01	https://www.consumerfinance.gov/policy-compliance/rulemaking/final-rules/fair-credit-reporting-act-disclosures/	N/A

Appendix C

Commodity Futures Trading Commission

U.S. Commodity Futures Trading Commission
Three Lafayette Centre, 1155 21st Street, NW, Washington, DC 20581
www.cftc.gov

J. Christopher Giancarlo
Chairman

(202) 418-5030
jcgiancarlo@cftc.gov

January 16, 2018

The Honorable Trey Gowdy
Chairman
U.S. House of Representatives
Committee on Oversight and Gov't Affairs
Washington, D.C. 20515

The Honorable Mark Meadows
Chairman
Subcommittee on Government Operations
Committee on Oversight and Gov't Affairs
Washington, D.C. 20515

The Honorable Jim Jordan
Chairman
Subcommittee on Healthcare, Benefits,
and Administrative Rules
Committee on Oversight and Gov't Affairs
Washington, D.C. 20515

The Honorable Gary J. Palmer
Chairman
Subcommittee on Intergovernmental Affairs
Committee on Oversight and Gov't Affairs
Washington, D.C. 2051

The Honorable Blake Farenthold
Chairman
Subcommittee on the Interior, Energy,
and Environment
Committee on Oversight and Gov't Affairs
Washington, D.C. 20515

Dear Congressman Gowdy, Meadows, Jordan, Palmer and Farenthold:

Thank you for your letter dated December 8, 2017 requesting a list of all guidance documents issued by the Commodity Futures Trading Commission (CFTC) since January 1, 2008. It is the agency's intention to fully comply with your request.

In the attached document, we have provided a list of documents that meet the criteria for guidance as outlined by the Government Accountability Office's (GAO) report, *Regulatory Guidance Processes: Selected Departments Could Strengthen Internal Control and Dissemination Practices,* GAO-15-368 (April 2015). This list includes Commission-approved guidance. We did not include staff no-action, exemptive, or interpretive letters issued by CFTC Divisions. Nor did we include interpretive guidance that was a part of a final rulemaking; guidance in this category was submitted to Congress and GAO as part of the final rules package. With this response, we believe we have fully complied with the intent of the request.

If you have further questions, please do not hesitate to reach out to Charlie Thornton, Director, Office of Legislative Affairs at [redacted].

Sincerely,

J C Giancarlo

Enclosure

cc: The Honorable Elijah E. Cummings, Ranking Member
Committee on Oversight and Government Reform

The Honorable Gerald E. Connolly, Ranking Member
Subcommittee on Government Operations

The Honorable Raja Krishnamoorthi, Ranking Member
Subcommittee on Healthcare, Benefits, and Administrative Rules

The Honorable Val Butler Demings, Ranking Member
Subcommittee on Intergovernmental Affairs

The Honorable Stacey E. Plaskett, Ranking Member
Subcommittee on Interior, Energy, and Environment

Commission Approved Guidance Issued Since January 1, 2008

Division	Title of Guidance	Form of Guidance (Guidance, Interpretation, etc.)	Brief Description of Subject of Guidance	Date of Issuance	Was Guidance Submitted to Congress and GAO pursuant to the Congressional Review Act?	Has the CFTC's Regulatory Reform Task Force announced plans to review the Guidance?	Federal Register Citation for Guidance	Hyperlink to Guidance
Office of General Counsel	Interpretive Guidance and Policy Statement Regarding Compliance with Certain Swap Regulations	Interpretive Guidance and Policy Statement	Cross-border application of the swaps provisions of the Commodity Exchange Act added by Title VII of the Dodd-Frank Act	17-Jul-13	No	No	78 FR 45291, July 26, 2013	http://www.cftc.gov/idc/groups/public/@lrfederalregister/documents/file/2013-17958a.pdf https://www.gpo.gov/fdsys/pkg/FR-2013-07-26/pdf/2013-17958.pdf
Office of General Counsel	Retail Commodity Transactions Under Commodity Exchange Act	Interpretation	The meaning of the term "actual delivery," as set forth in the Commodity Exchange Act	20-Aug-13	No	No	78 FR 52426, Aug 23, 2013	http://www.cftc.gov/idc/groups/public/@lrfederalregister/documents/file/2013-20617a.pdf https://www.gpo.gov/fdsys/pkg/FR-2013-08-23/pdf/2013-20617.pdf
Office of General Counsel	Forward Contracts With Embedded Volumetric Optionality	Interpretation	The CFTC and the Securities and Exchange Commission, after consultation with the Federal Reserve Board, jointly issued the CFTC's clarification of its interpretation concerning forward contracts with embedded volumetric optionality.	12-May-15	No	No	80 FR 28239, May 18, 2015	http://www.cftc.gov/idc/groups/public/@lrfederalregister/documents/file/2015-11946a.pdf https://www.gpo.gov/fdsys/pkg/FR-2015-05-18/pdf/2015-11946.pdf

Office of General Counsel	Swap Data Repositiories: Interpretative Statement Regarding the Confidentiality and Indemnification Provisions of the Commodity Exchange Act (Note that portions of this Interpretative Statement have been superseded by amendments to the Commodity Exchange Act made by Section 86001 of the FAST Act, Pub. L. 114-94)	Interpretive Statement	Provides guidance regarding the applicabllility of the confidentiality and indemnification provisions of section 21(d) of the Commodity Exchange Act. The Statement clarifies that the provisions of section 21(d) of the Commodity Exchange Act should not operate to inhibit or prevent foreign regulatory authorities from accessing data in which they have an independent and sufficient regulatory interest, even if the data has also been report pursuant to the Commodity Exchange Act and CFTC regulations.	25-Oct012	No	No	77 FR 65177 (October 25, 2012	http://www.cftc.gov/idc/groups/public/@lrfederalregister/documents/file/2012-26298a.pdf
Division of Swaps and Intermediary Oversight	Interpretative Statement Regarding Funds related to Cleared-Only Contracts Determined to Be Included in a Customer's Net Equity (Note that this Interpretative Statement has been superseded by Section 724 of the Dodd-Act and CFTC implementing regulations)	Interpretive Guidance and Policy Statement	Clarified the appropriate treatment under the commodity broker provisions of the Bankruptcy Code and Part 190 of the CFTC's Regulations of claims arising from contracts (''cleared-only contracts'') that, although not executed or traded on a Designated Contract Market or a Derivatives Transaction Execution Facility, are subsequently submitted for clearing through a Futures Commission Merchant to a Derivatives Clearing Organization.	2-Oct-08	No	No	73 FR 57235, Oct. 2, 2008	http://www.cftc.gov/idc/groups/public/@lrfederalregister/documents/file/e8-23277a.pdf

Division of Swaps and Intermediary Oversight	1-FR FCM Instructions Manual	Interpretive	A Commission approved instructions manual detailing guidance for filing monthly CFTC Form 1-FR for registered Futures Commission Merchants.	1-Mar-10	No	No	81 FR 89447	https://www.gpo.gov/fdsys/pkg/FR-2016-12-12/pdf/2016-29613.pdf
							N/A	http://www.cftc.gov/IndustryOversight/Intermediaries/FCMs/1fr-fcminstructions

Appendix D

Consumer Product Safety Commission

UNITED STATES
CONSUMER PRODUCT SAFETY COMMISSION
4330 EAST WEST HIGHWAY
BETHESDA, MD 20814

ACTING CHAIRMAN ANN MARIE BUERKLE

December 22, 2017

The Honorable Trey Gowdy
Chairman
Committee on Oversight
and Government Reform
U.S. House of Representatives
Washington, D.C. 20515

The Honorable Mark Meadows
Chairman
Subcommittee on Government Operations
Committee on Oversight
and Government Reform
U.S. House of Representatives
Washington, D.C. 20515

The Honorable Jim Jordan
Chairman
Subcommittee on Healthcare, Benefits,
and Administrative Rules
Committee on Oversight
and Government Reform
U.S. House of Representatives
Washington, D.C. 20515

The Honorable Gary Palmer
Chairman
Subcommittee on Intergovernmental Affairs
Committee on Oversight
and Government Reform
U.S. House of Representatives
Washington, D.C. 20515

The Honorable Blake Farenthold
Chairman
Subcommittee on the Interior, Energy,
and Environment
Committee on Oversight
and Government Reform
U.S. House of Representatives
Washington, D.C. 20515

Dear Chairmen Gowdy, Meadows, Jordan, Palmer, and Farenthold:

Thank you for your December 8, 2017 letter and the opportunity to aid the committee in better understanding the use of guidance documents by federal agencies and, specifically, guidance documents issued by the U.S. Consumer Product Safety Commission (CPSC). I am pleased to provide this information to the Committee and have enclosed the agency's response to your request. None of the guidance listed in this response has been determined to be "significant guidance" according to the Office of Management and Budget's Final Bulletin for Agency Good Guidance Practices, 72 Fed. Reg. 3432 (Jan. 25, 2007).

Should you or your staff have any questions, please do not hesitate to contact me or Aaron Hernandez, Acting Director, Office of Legislative Affairs, by phone at [redacted] or e-mail at: [redacted]

Sincerely,

Ann Marie Buerkle
Acting Chairman

Enclosure

cc: The Honorable Elijah Cummings, Ranking Member
The Honorable Gerald Connolly, Ranking Member
The Honorable Raja Krishnamoorthi, Ranking Member
The Honorable Val Butler Demmings, Ranking Member
The Honorable Stacey E. Plaskett, Ranking Member

	Title	Form of Guidance	Description	Website Link	Issuance Date	Significant Y/N	OIRA Y/N	Congress/GAO	Issuing Agency, Component, Office or Program
1	Industry Letter to the Liquid Nicotine Packagers/Manufacturers	Letter	This letter was sent out to industry to inform them of the Agency's authority for packaging of liquid nicotine product and requirements for special packaging of those products.	Direct Link	Jul-16	No	No	No	Compliance
2	Drawstrings in Children's Upper Outerwear: Frequently Asked Questions	FAQs	CPSC staff answered the most common questions about Drawstrings. Some answers were in regards to the 18 deaths and 38 nonfatal incidents associated with neck/hood drawstrings on children's outerwear between January 1985 and September 2009, involving children 18 months to 10 years of age.	Direct Link	2009	No	No	No	Compliance
3	Sleepwear Policy and Loungewear Position Letter	Letter	This letter was sent out to industry to inform them of the Agency's sleepwear policy and position on children's loungewear.	Direct Link	Dec-11	No	No	No	Compliance
4	CPSC Safety Alert on Halloween Safety	Alert	CPSC staff sent out a safety alert notifying consumers of flame resistant costumes for children.	Direct Link	Mar-12	No	No	No	Compliance
5	Safety Alert on Children’s Sleepwear Safety	Alert	CPSC staff sent out a safety alert so that industry and consumers understood the difference between “Flame-resistant” and “tight-fitting” children’s sleepwear garments.	Direct Link	Apr-12	No	No	No	Compliance
6	Drawstring Bulletin	Bulletin	A one page bulletin was administered to industry to remind them of the 2012 Commission determination that drawstrings on children’s upper outerwear present a substantial product hazard. The Commission then issued a rule, 15 U.S.C. 2064(j), under Section 15(j) which states that drawstrings at the hood or neck and waist or bottom areas that do not meet certain requirements present a substantial product hazard, present an unreasonable risk of injury and are considered a defect subject to reporting requirements and corrective action, including recalls and penalties.	Direct Link	2013	No	No	No	Compliance
7	Children’s Apparel Products Trifold Pamphlet	Pamphlet	A six paged pamphlet was created for CPSC employees to give out as a summarization of children’s general requirements and flammability requirements for apparel under the FFA and CPSA. CPSC employees distribute this pamphlet after lectures and seminars. The pamphlet contains helpful detailed information such as; testing, testing exceptions, certification documents, prohibited textile fabrics, lead limit requirements and direct website links. The pamphlet is available online and also in the Spanish language.	Direct Link	2014	No	No	No	Compliance
8	FFA Children's Sleepwear Recall Roundup	Video	In this edition of Recall Roundup: Four companies recalled Children's Sleepwear and Loungewear garments nationwide. These garments were found to be in violation of the FFA. The video provided detailed information on the garments and how to return them to the recalling company.	Direct Link	Jun-15	No	No	No	Compliance
9	Sleepwear Policy and Loungewear Position Letter	Letter	The letter was reissued to restate the agency’s sleepwear policy and position on children’s loungewear and to notify the industry of the obligations under the Consumer Product Safety Improvement Act of 2008 (CPSIA).	Direct Link	Feb-15	No	No	No	Compliance
10	Testing to the Children’s Sleepwear Standards, 16 C.F.R. Parts 1615 &1616 Laboratory Bulletin	Bulletin	CPSC staff became aware of cases in which the fabric and seam and trim prototypes pass the flammability testing requirements, but the production garments fail the testing requirements. The bulletin had further discussion in the Supplemental Data Analysis section. Also, CPSC staff became aware of children’s pajamas being testing incorrectly to The Standard for the Flammability of Clothing Textiles, 16 C.F.R. Part 1610, instead of the children’s sleepwear Standards, more detailed information was provided in the bulletin in the scope of the Standards section.	Direct Link	Jan-16	No	No	No	Compliance
11	Self-Balancing Scooters	Letter	A request urging those who import, manufacture, distribute or sell in the US the self-balancing scooters, the requirement to comply with voluntary standards	Direct Link	Feb-16	No	No	No	Compliance
12	Bath Seats	Bulletin	On June 4, 2010, the Commission published a final rule establishing a Safety Standard for Infant Bath Seats (Standard) under section 104(b) of the Consumer Product Safety Improvement Act of 2008. The Standard, which became effective on December 6, 2010, is published in the Code of Federal Regulations at 16 C.F.R. part 1215, and the Standard currently incorporates by reference ASTM F1967-11a, *Standard Consumer Safety Specification for Infant Bath Seats*. The Standard establishes performance requirements, test methods, and labeling requirements to promote the safe use of infant bath seats and reduce the risk of death and injury, particularly drownings and near-drownings, when a bath seat is occupied by an infant.	Direct Link	Jul-13	No	No	No	Compliance
13	Certification	FAQs	Guidance on responsibility of issuing a certificate, etc.	Direct Link		No	No	No	Compliance
14	Tracking Requirements	FAQs	Guidance on requirements for tracking information on a children's product	Direct Link		No	No	No	Compliance

15	Regulated Product Handbook	Manual	Guidance for the regulated industry on the statutes and regulations	Direct Link	May-13	No	No	No	Compliance
16	Certification and the Poison Prevention Packaging Act	FAQs	Guidance for the regulated industry on certification requirements for the PPPA	Direct Link		No	No	No	Compliance
17	Magnet Sets	Bulletin	Guidance was provided in 2015 but then removed from the business link page due to the overturn of the magnet set rule		Jun-15	No	No	No	Compliance
18	Guidance Document on Hazardous Additive, Non-Polymeric Organohalogen Flame Retardants in Certain Consumer Products (82 FR 45268)	Guidance Document	The Commission announces that it has approved a statement that provides guidance for manufacturers, importers, distributors, retailers, and consumers of certain consumer products that may contain harmful organohalogen flame retardants in an additive form.	Direct Link	Sep-17	No	No	No	CPSC
19	CPSC Litigation Guidance and Recommended Best Practices for Protective Orders and Settlement Agreements in Private Civil Litigation (81 FR 87023)	Guidance	The U.S. Consumer Product Safety Commission is publishing this Litigation Guidance to provide recommendations for best practices to all parties in relevant litigation related to providing an exemption in protective orders and settlement agreements for reporting information to the CPSC.	Direct Link	Dec-16	No	No	No	CPSC
20	Statement of Policy on Enforcement Discretion Regarding General Conformity Certificates for Adult Wearing Apparel Exempt from Testing (81 FR 12587)	Statement of Policy	The Consumer Product Safety Commission has approved a Statement of Policy regarding the CPSC's enforcement of the requirement for a general conformity assessment certificate with respect to adult wearing apparel that is exempt from testing under the CPSC's clothing flammability standard.	Direct Link	Mar-16	No	No	No	CPSC
21	Strong Sensitizer Guidance (78 FR 15710)	Guidance	The U.S. Consumer Product Safety Commission is announcing the availability of a document prepared by CPSC staff titled, "Strong Sensitizer Start Printed Page 15711Guidance." This guidance document is intended to clarify the "strong sensitizer" definition, assist manufacturers in understanding how CPSC staff would assess whether a substance and/or product containing that substance should be considered a "strong sensitizer," and how the Commission would make such a determination.	Direct Link	Mar-13	No	No	No	CPSC
22	Children's Toys and Child Care Articles Containing Phthalates; Final Guidance on Inaccessible Component Parts (78 FR 10503)	Final Guidance	On August 14, 2008, Congress enacted the Consumer Product Safety Improvement Act of 2008 (CPSIA), Public Law 110-314. Section 108 of the CPSIA, as amended by Public Law 112-28, provides that the prohibition on specified products containing phthalates does not apply to any component part of children's toys or child care articles that is not accessible to a child through normal and reasonably foreseeable use and abuse of such product. In this document, the Consumer Product Safety Commission (CPSC or Commission) issues guidance on inaccessible component parts in children's toys or child care articles subject to section 108 of the CPSIA.	Direct Link	Feb-13	No	No	No	CPSC
23	Codification of Animal Testing Policy (77 FR 73286)	Statement of Policy	The Consumer Product Safety Commission (CPSC or Commission) codifies its statement of policy on animal testing that provides guidance for manufacturers of products subject to the Federal Hazardous Substances Act (FHSA) regarding replacement, reduction, and refinement of animal testing methods.	Direct Link	Dec-12	No	No	Yes - 2/26/1	CPSC
24	Interpretation of Children's Product (75 FR 63067)	Final Rule	The Consumer Product Safety Commission ("CPSC," "Commission," or "we") is issuing a final interpretative rule on the term "children's product" as used in the Consumer Product Safety Improvement Act of 2008 ("CPSIA"), Public Law 110-314. The final interpretative rule provides additional guidance on the factors that are considered when evaluating what is a children's product.	Direct Link	Oct-10	No	No	Yes - 1/13/1	CPSC
25	Civil Penalty Factors (75 FR 15993)	Interpretive Rule	The Consumer Product Safety Improvement Act of 2008 ("CPSIA") requires the Consumer Product Safety Commission ("Commission") to issue a final rule providing its interpretation of the civil penalty factors found in the Consumer Product Safety Act ("CPSA"), the Federal Hazardous Substances Act ("FHSA"), and the Flammable Fabrics Act ("FFA"), as amended by section 217 of the CPSIA. These statutory provisions require the Commission to consider certain factors in determining the amount of any civil penalty to seek.	Direct Link	Mar-10	No	No	Yes - 4/1/10	CPSC

26	Guidelines and Requirements for Mandatory Recall Notices (75 FR 3355)	Final Rule	The Consumer Product Safety Commission ("Commission," "CPSC," "we") is issuing a final rule establishing guidelines and requirements for mandatory recall notices as required by section 214 of the Consumer Product Safety Improvement Act of 2008 ("CPSIA"). The rule contains the Commission's interpretation of information which must appear on mandatory recall notices ordered by the Commission or a United States district court pursuant to certain sections of the Consumer Product Safety Act ("CPSA"). The rule also contains Commission guidelines for additional information that the Commission or a court may order to be included on a mandatory recall notice.	Direct Link	Jan-10	No	No	Yes - 1/29/1(	CPSC
27	Interim Enforcement Policy on Component Testing and Certification of Children's Products and Other Consumer Products to the August 14, 2009 Lead Limits (74 FR 68593)	Statement of Policy	The Consumer Product Safety Commission ("CPSC," "Commission," or "we") is announcing an interim enforcement policy regarding component testing and certification of children's products and other consumer products to the 90 parts per million (ppm) lead in paint limit and to the 300 ppm lead limit for children's products established in section 101 of the Consumer Product Safety Improvement Act of 2008 ("CPSIA").	Direct Link	Dec-09	No	No	No	CPSC
28	Notice of Availability of a Statement of Policy: Testing and Certification of Lead Content in Children's Products (74 FR 55820)	Statement of Policy	The Consumer Product Safety Commission (Commission) is announcing the availability of a document titled, "Statement of Policy: Testing and Certification of Lead Content in Children's Products."	Direct Link	Oct-09	No	No	No	CPSC
29	Notice of Availability of a Statement of Policy: Interpretation and Enforcement of Section 103(a) of the Consumer Product Safety Improvement Act (74 FR 41868)	Statement of Policy	The Consumer Product Safety Commission ("Commission") is announcing the availability of a document titled, "Statement of Policy: Interpretation and Enforcement of Section 103(a) of the Consumer Product Safety Improvement Act" ("Statement of Policy"). Section 103(a) of the Consumer Product Safety Improvement Act ("CPSIA") requires manufacturers of children's products to mark their products so that certain identifying information is ascertainable by the manufacturer and the consumer.	Direct Link	Aug-09	No	No	No	CPSC
30	Notice of Availability of a Statement of Policy: Testing of Component Parts With Respect to Section 108 of the Consumer Product Safety Improvement Act (74 FR 41400)	Statement of Policy	The Consumer Product Safety Commission ("Commission") is announcing the availability of a document titled, "Statement of Policy: Testing of Component Parts With Respect to Section 108 of the Consumer Product Safety Improvement Act" ("Statement of Policy"). Section 108 of the Consumer Product Safety Improvement Act of 2008 ("CPSIA") prohibits the sale of certain products containing specified phthalates. The Statement of Policy establishes the Commission's position with respect to testing products to determine whether they contain phthalates in excess of the statutory limits.	Direct Link	Aug-09	No	No	No	CPSC
31	Children's Products Containing Lead; Interpretative Rule on Inaccessible Component Parts (74 FR 39535)	Interpretive Rule	The Consumer Product Safety Commission ("Commission") is issuing a final rule providing guidance as to what product components or classes of components will be considered to be "inaccessible." Section 101(b)(2)(A) of the Consumer Product Safety Improvement Act ("CPSIA") provides that the lead limits shall not apply to any component part of a children's product that is not accessible to a child through normal and reasonably foreseeable use and abuse. Section 101(b)(2)(B) of the CPSIA requires the Commission to issue, by August 14, 2009, a rule providing guidance with respect to what product components, or classes of components, will be considered to be inaccessible. This final rule satisfies the Commission's statutory obligation.	Direct Link	Aug-09	No	No	Yes - 8/10/0(	CPSC
32	Sling Carriers Business Guidance & Small Entity Compliance Guide	Business Education Compliance Guides	A compliance guide created by the Small Business Ombudsman to aid entities complying with 82 FR 8671. In general, it is the practice of the Small Business Ombudsman—who is responsible for creating and publishing business education compliance guides on CPSC.gov in conjunction with the passage of Agency final rules—to publish such business guidance documents at a time that occurs between the publication of a final rule in the Federal Register and the date at which the final rule becomes effective.	Direct Link		No	No	No	Small Business Ombudsman

33	Frame Child Carriers Business Guidance and Small Entity Compliance Guide	Business Education Compliance Guides	A compliance guide created by the Small Business Ombudsman to aid entities complying with 80 FR 11113. In general, it is the practice of the Small Business Ombudsman—who is responsible for creating and publishing business education compliance guides on CPSC.gov in conjunction with the passage of Agency final rules—to publish such business guidance documents at a time that occurs between the publication of a final rule in the Federal Register and the date at which the final rule becomes effective.	Direct Link		No	No	No	Small Business Ombudsman
34	Soft Infant and Toddler Carriers Business Guidance and Small Entity Compliance Guide	Business Education Compliance Guides	A compliance guide created by the Small Business Ombudsman to aid entities complying with 79 FR 17422. In general, it is the practice of the Small Business Ombudsman—who is responsible for creating and publishing business education compliance guides on CPSC.gov in conjunction with the passage of Agency final rules—to publish such business guidance documents at a time that occurs between the publication of a final rule in the Federal Register and the date at which the final rule becomes effective.	Direct Link		No	No	No	Small Business Ombudsman
35	Carriages and Strollers Business Guidance and Small Entity Compliance Guide	Business Education Compliance Guides	A compliance guide created by the Small Business Ombudsman to aid entities complying with 79 FR 13208. In general, it is the practice of the Small Business Ombudsman—who is responsible for creating and publishing business education compliance guides on CPSC.gov in conjunction with the passage of Agency final rules—to publish such business guidance documents at a time that occurs between the publication of a final rule in the Federal Register and the date at which the final rule becomes effective.	Direct Link		No	No	No	Small Business Ombudsman
36	Bedside Sleepers Business Guidance and Small Entity Compliance Guide	Business Education Compliance Guides	A compliance guide created by the Small Business Ombudsman to aid entities complying with 79 FR 2581. In general, it is the practice of the Small Business Ombudsman—who is responsible for creating and publishing business education compliance guides on CPSC.gov in conjunction with the passage of Agency final rules—to publish such business guidance documents at a time that occurs between the publication of a final rule in the Federal Register and the date at which the final rule becomes effective.	Direct Link		No	No	No	Small Business Ombudsman
37	Bassinets and Cradles Business Guidance and Small Entity Compliance Guide	Business Education Compliance Guides	A compliance guide created by the Small Business Ombudsman to aid entities complying with 78 FR 77574. In general, it is the practice of the Small Business Ombudsman—who is responsible for creating and publishing business education compliance guides on CPSC.gov in conjunction with the passage of Agency final rules—to publish such business guidance documents at a time that occurs between the publication of a final rule in the Federal Register and the date at which the final rule becomes effective.	Direct Link		No	No	No	Small Business Ombudsman
38	Hand-Held Infant Carriers Business Guidance and Small Entity Compliance Guide	Business Education Compliance Guides	A compliance guide created by the Small Business Ombudsman to aid entities complying with 78 FR 73415. In general, it is the practice of the Small Business Ombudsman—who is responsible for creating and publishing business education compliance guides on CPSC.gov in conjunction with the passage of Agency final rules—to publish such business guidance documents at a time that occurs between the publication of a final rule in the Federal Register and the date at which the final rule becomes effective.	Direct Link		No	No	No	Small Business Ombudsman
39	Third-Party Testing Laboratory Accreditation and Small Entity Compliance Guide	Business Education Compliance Guides	Requirements Pertaining to Third Party Conformity Assessment Bodies, 16 CFR parts 112 and 1118 Business Guidance and Small Entity Compliance Guide. In general, it is the practice of the Small Business Ombudsman—who is responsible for creating and publishing business education compliance guides on CPSC.gov in conjunction with the passage of Agency final rules—to publish such business guidance documents at a time that occurs between the publication of a final rule in the Federal Register and the date at which the final rule becomes effective.	Direct Link		No	No	No	Small Business Ombudsman
40	Periodic Testing and Small Entity Compliance Guide	Business Education Compliance Guides	Compliance guide and FAQs to aid entities in complying with 76 FR 69482. In general, it is the practice of the Small Business Ombudsman—who is responsible for creating and publishing business education compliance guides on CPSC.gov in conjunction with the passage of Agency final rules—to publish such business guidance documents at a time that occurs between the publication of a final rule in the Federal Register and the date at which the final rule becomes effective.	Direct Link		No	No	No	Small Business Ombudsman
41	Infant Swings Business Guidance and Small Entity Compliance Guide	Business Education Compliance Guides	A compliance guide created by the Small Business Ombudsman to aid entities complying with 77 FR 66703. In general, it is the practice of the Small Business Ombudsman—who is responsible for creating and publishing business education compliance guides on CPSC.gov in conjunction with the passage of Agency final rules—to publish such business guidance documents at a time that occurs between the publication of a final rule in the Federal Register and the date at which the final rule becomes effective.	Direct Link		No	No	No	Small Business Ombudsman

42	Play Yards Business Guidance and Small Entity Compliance Guide	Business Education Compliance Guides	A compliance guide created by the Small Business Ombudsman to aid entities complying with 77 FR 52220. In general, it is the practice of the Small Business Ombudsman—who is responsible for creating and publishing business education compliance guides on CPSC.gov in conjunction with the passage of Agency final rules—to publish such business guidance documents at a time that occurs between the publication of a final rule in the Federal Register and the date at which the final rule becomes effective.	Direct Link		No	No	No	Small Business Ombudsman
43	Portable Bed Rails Business Guidance and Small Entity Compliance Guide	Business Education Compliance Guides	A compliance guide created by the Small Business Ombudsman to aid entities complying with 77 FR 12182. In general, it is the practice of the Small Business Ombudsman—who is responsible for creating and publishing business education compliance guides on CPSC.gov in conjunction with the passage of Agency final rules—to publish such business guidance documents at a time that occurs between the publication of a final rule in the Federal Register and the date at which the final rule becomes effective.	Direct Link		No	No	No	Small Business Ombudsman
44	Component Part Testing and Small Entity Compliance Guide	Business Education Compliance Guides	Compliance guide to aid entities complying with 76 FR 69546. In general, it is the practice of the Small Business Ombudsman—who is responsible for creating and publishing business education compliance guides on CPSC.gov in conjunction with the passage of Agency final rules—to publish such business guidance documents at a time that occurs between the publication of a final rule in the Federal Register and the date at which the final rule becomes effective.	Direct Link		No	No	No	Small Business Ombudsman
45	Toddler Beds Business Guidance and Small Entity Compliance Guide	Business Education Compliance Guides	A compliance guide created by the Small Business Ombudsman to aid entities complying with 76 FR 22019. In general, it is the practice of the Small Business Ombudsman—who is responsible for creating and publishing business education compliance guides on CPSC.gov in conjunction with the passage of Agency final rules—to publish such business guidance documents at a time that occurs between the publication of a final rule in the Federal Register and the date at which the final rule becomes effective.	Direct Link		No	No	No	Small Business Ombudsman
46	Full-Size Baby Cribs Business Guidance and Small Entity Compliance Guide	Business Education Compliance Guides	A compliance guide created by the Small Business Ombudsman to aid entities complying with 75 FR 81765. In general, it is the practice of the Small Business Ombudsman—who is responsible for creating and publishing business education compliance guides on CPSC.gov in conjunction with the passage of Agency final rules—to publish such business guidance documents at a time that occurs between the publication of a final rule in the Federal Register and the date at which the final rule becomes effective.	Direct Link		No	No	No	Small Business Ombudsman
47	Non-Full-Size Baby Cribs Business Guidance and Small Entity Compliance Guide	Business Education Compliance Guides	A compliance guide created by the Small Business Ombudsman to aid entities complying with 75 FR 81765. In general, it is the practice of the Small Business Ombudsman—who is responsible for creating and publishing business education compliance guides on CPSC.gov in conjunction with the passage of Agency final rules—to publish such business guidance documents at a time that occurs between the publication of a final rule in the Federal Register and the date at which the final rule becomes effective.	Direct Link		No	No	No	Small Business Ombudsman
48	Infant Walkers Business Guidance and Small Entity Compliance Guide	Business Education Compliance Guides	A compliance guide created by the Small Business Ombudsman to aid entities complying with 75 FR 35266. In general, it is the practice of the Small Business Ombudsman—who is responsible for creating and publishing business education compliance guides on CPSC.gov in conjunction with the passage of Agency final rules—to publish such business guidance documents at a time that occurs between the publication of a final rule in the Federal Register and the date at which the final rule becomes effective.	Direct Link		No	No	No	Small Business Ombudsman
49	Infant Bath Seats Business Guidance and Small Entity Compliance Guide	Business Education Compliance Guides	A compliance guide created by the Small Business Ombudsman to aid entities complying with 75 FR 31691. In general, it is the practice of the Small Business Ombudsman—who is responsible for creating and publishing business education compliance guides on CPSC.gov in conjunction with the passage of Agency final rules—to publish such business guidance documents at a time that occurs between the publication of a final rule in the Federal Register and the date at which the final rule becomes effective.	Direct Link		No	No	No	Small Business Ombudsman
50	Regulatory Robot Tool	Business Guidance	The Regulatory Robot Tool is a comprehensive program that asks users to answer a series of product safety questions and gives them a customized system generated report with specific business guidance applicable to their product. The Regulatory Robot is a unique tool among federal agencies in that it encompasses and provides guidance on all of the Agency’s mandatory regulations and requirements in one place.	Direct Link	Jan-16	No	No	No	Small Business Ombudsman

51	Art Materials Business Guidance	Business Guidance	Art materials for consumers of all ages must comply with a number of requirements under federal law. Describes requirements for art materials, including those that are designed or intended primarily for children 12 years of age or younger.	Direct Link	Nov-12	No	No	No	Small Business Ombudsman
52	ATV Action Plans	Business Guidance	Provides several examples of ATV action plans, which must be approved by the Commission in accordance with Section 42(e)(2) of the CPSA.	Direct Link		No	No	No	Small Business Ombudsman
53	Best Practices for Safety	Business Guidance	An outline of recommendations and resources for manufacturers and importers on best practices for design and manufacturing.	Direct Link	Jan-16	No	No	No	Small Business Ombudsman
54	Children's Products Overview	Business Education/FAQs	Overview and FAQs on children's products that are subject to a set of federal safety rules.	Direct Link	May-11	No	No	No	Small Business Ombudsman
55	Consumer Registration Card	Business Education/FAQs	Information related to the product registration card requirement for durable infant or toddler products.	Direct Link	Nov-11	No	No	No	Small Business Ombudsman
56	Desktop Reference Guide	Guidance	A quick reference guide for small businesses.	Direct Link	Jan-11	No	No	No	Small Business Ombudsman
57	Durable Infant or Toddler Products	Business Education/FAQs	FAQs related to durable infant toddler products, including categories, safety rules, registration requirements and third-party testing.	Direct Link	Nov-11	No	No	No	Small Business Ombudsman
58	Fidget Spinner Business Guidance	Business Guidance/FAQs	An overview of requirements, certifications and obligations related to fidget spinners.	Direct Link	Aug-17	No	No	No	Small Business Ombudsman / Compliance
59	Apparel, Rugs, and Mattresses: What you need to know about the Flammable Fabrics Act	Business Education	Guidance on products covered by the Flammable Fabrics Act.	Direct Link	May-15	No	No	No	Small Business Ombudsman
60	Electrical Products (Household)	Business Education	Product safety information related to hair dryers, seasonal lighting and extension cords.	Direct Link	Jan-15	No	No	No	Small Business Ombudsman
61	Lead Paint	Business Guidance	Overview of the federal requirements limiting lead in paint and similar surface coatings in children's products.	Direct Link	Feb-12	No	No	No	Small Business Ombudsman
62	Phthalates	Business Education	Provides information for businesses seeking guidance on how to comply with the federal consumer product safety rules on phthalates.	Direct Link	Aug-11	No	No	No	Small Business Ombudsman
63	Buying Promotional Products: A Guide to Federal Safety Laws	Business Guidance	Guide for suppliers or distributors of promotional products complying with federal consumer product safety laws.	Direct Link	Jan-13	No	No	No	Small Business Ombudsman
64	Resale and Thrift Stores Information Center	Business Education	A collection of resources to aid resellers in keeping unsafe products out of the hands of consumers.	Direct Link	Jan-13	No	No	No	Small Business Ombudsman
65	Retailers: Product Safety and Your Responsibility	Business Education	Overview for retailers on complying with federal consumer product safety laws.	Direct Link	Jan-11	No	No	No	Small Business Ombudsman
66	Duty to Report to CPSC: Rights and Responsibilities of Businesses	Recall Guidance/FAQ	Overview and FAQs on the legal obligation to immediately report information to the CPSC.	Direct Link	Jan-13	No	No	No	Small Business Ombudsman
67	Total Lead Content	Business Education	An overview on the federal requirements limiting lead in children's products.	Direct Link	Feb-12	No	No	No	Small Business Ombudsman
68	Toy Safety	Business Education	Provides information for businesses seeking guidance on how to comply with the federal toy safety standard, ASTM F963-16.	Direct Link		No	No	No	Small Business Ombudsman
69	Tracking Label Requirement for Children's Products	Business Education/FAQ	Overview of requirements and FAQ to help entities comply with tracking label requirements for children's products.	Direct Link	Dec-11	No	No	No	Small Business Ombudsman
70	An Update on Formaldehyde (Publication 725)	Guidance Document	This booklet provides information about what formaldehyde is, what products it may be found in, where you may come in contact with it, how exposure to formaldehyde may affect your health, and how you might reduce your exposure to it.	Direct Link	Feb-16	No	No	No	Hazard Identification and Reduction

71	Remediation Guidance for Homes with Corrosion from Problem Drywall	CPSC/HUD Remediation Guidance	Summarizes what the staffs of CPSC and HUD believe is an effective approach to addressing potential health and safety issues related to problem drywall.	Direct Link	Mar-13	No	No	No	Hazard Identification and Reduction
72	Identification Guidance for Homes with Corrosion from Problem Drywall	CPSC/HUD Remediation Guidance	Guidance on identifying problem drywall.	Direct Link	Mar-11	No	No	No	Hazard Identification and Reduction
73	Guidance for Outdoor Wooden Structures (Publication 270)	CPSC/EPA/USDA/US Forest Service Document	Provides information on chromated copper arsenate (CCA) pressure treated wood.	Direct Link	Jun-11	No	No	No	Hazard Identification and Reduction
74	What You Should Know About Using Paint Strippers	Guidance Document	Health and safety recommendations on using paint strippers.	Direct Link	Jan-13	No	No	No	Hazard Identification and Reduction
75	Poison Prevention Packaging Act Business Guidance	Business Guidance	Overview and FAQs related to the Poison Prevention Packaging Act.	Direct Link	Jun-13	No	No	No	Hazard Identification and Reduction
76	Crumb Rubber Information Center	Safety Education	Status report on crumb rubber research and advice for communities concerned about playgrounds with recycled tire surfaces.	Direct Link	Feb-16	No	No	No	Hazard Identification and Reduction
77	Notice of Availability of Draft Guidance Regarding Which Children's Products Are Subject to the Requirements of CPSIA Section 108	Guidance Document	Draft Guidance on Children's Products Covered by Section 108.	Direct Link	Feb-09	No	No	No	Hazard Identification and Reduction
78	Public Playground Safety Handbook	Guidance Document	Recommendations related to playground-related injuries and mechanical mechanisms of injury.	Direct Link	Dec-15	No	No	No	Hazard Identification and Reduction
79	CPSC’s Safety Barrier Guidelines for Residential Pools (Publication 362)	Guidance Document	Safety barrier guidelines to prevent child drownings.	Direct Link	Aug-12	No	No	No	Hazard Identification and Reduction
80	Laboratory Test Manual for Toy Testing	Guidance Document	Test manual for testing toys and other articles intended for use by children 12 years and under.	Direct Link	Jun-10	No	No	No	Hazard Identification and Reduction
81	Hoverboard Safety Alert	Safety Education	Safety alert and recommendations concerning hoverboards.	Direct Link	Nov-17	No	No	No	Hazard Identification and Reduction
82	Fireworks (Publication 12)	Guidance Document	Examples of deaths caused by fireworks, injury statistics, description of agency action related to the regulation of fireworks and information on state fireworks laws.	Direct Link	Jun-15	No	No	No	Hazard Identification and Reduction
83	Laboratory Test Manual for 16 CFR part 1610	Manual	A reference guide designed to assist with the testing procedures specified in the Standard for the Flammability of Clothing Textiles codified at 16 CFR Part 1610.	Direct Link	Oct-08	No	No	No	Hazard Identification and Reduction
84	Laboratory Test Manual for 16 CFR parts 1615 and 1616	Manual	A reference guide designed to assist with the testing procedures specified in the Standards for the Flammability of Children’s Sleepwear codified at 16 CFR Parts 1615 and 1616.	Direct Link	Jul-10	No	No	No	Hazard Identification and Reduction
85	Laboratory Test Manual for 16 CFR part 1632	Manual	A reference guide designed to assist with the testing procedures specified in the Standards for the Flammability of Mattresses and Mattress Pads codified CFR part 1632.	Direct Link	Dec-14	No	No	No	Hazard Identification and Reduction
86	Laboratory Test Manual for 16 CFR part 1633	Manual	A reference guide designed to assist with the testing procedures specified in the Standards for the Flammability (Open-Flame) of Mattress Sets codified at CFR part 1633.	Direct Link	Jan-11	No	No	No	Hazard Identification and Reduction

Appendix E

Chemical Safety and Hazard Investigation Board

U.S. Chemical Safety and
Hazard Investigation Board

1750 Pennsylvania Avenue NW, Suite 910 | Washington, DC 20006
Phone: (202) 261-7600 | Fax: (202) 261-7650
www.csb.gov

Honorable Vanessa Allen Sutherland
Chairperson and Member

Honorable Manny Ehrlich, Jr.
Board Member

Honorable Rick Engler
Board Member

Honorable Kristen M. Kulinowski
Board Member

January 25, 2018

The Honorable Trey Gowdy, Chairman
The Honorable Mark Meadows, Chairman, Subcommittee on Government Operations
The Honorable Jim Jordan, Chairman, Subcommittee on Healthcare, Benefits and Administrative Rules
The Honorable Gary Palmer, Chairman, Subcommittee on Intergovernmental Affairs
The Honorable Blake Farenthold, Chairman, Subcommittee on the Interior, Energy and Environment
Committee on Oversight and Government Reform
United States House of Representatives
2157 Rayburn House Office Building
Washington, DC 20515

Dear Chairman Gowdy, Chairman Meadows, Chairman Jordan, Chairman Palmer, and Chairman Farenthold:

In response to your letter dated January 11, 2018, the U.S. Chemical Safety and Hazard Investigation Board (CSB) has thoroughly reviewed the Committee's request. Enclosed are the CSB's responses to the questions and the requested materials.

We have made a good faith effort to be fully responsive to the Committee's request. Our staff conferred with the members of your staff in response to the document request. At the suggestion of the Committee staff, the CSB staff reviewed the April 2015 GAO report entitled "Regulatory Guidance Processes: Selected Departments Could Strengthen Internal Control and Dissemination Practices." After careful analysis, we do not believe that the CSB's investigative reports would be considered "guidance" as defined by GAO.

The CSB is an independent, non-regulatory agency charged with investigating chemical disasters. Authorized by the Clean Air Act Amendments of 1990, the agency does not issue fines or citations related to regulations, but does make recommendations to plants, regulatory agencies such as the Occupational Safety and Health Administration (OSHA) and the Environmental Protection Agency (EPA), industry organizations, and labor groups. Congress designed the CSB to be non-regulatory and independent of other agencies so that its investigations might, where appropriate, review the effectiveness of regulations and regulatory enforcement.

As part of its legislative mandate, the CSB issues recommendations to other Federal agencies to revise or expand existing regulations or issue additional guidance related to existing regulations. The CSB has included all investigative reports resulting in such recommendations in the attached submission.

Although the CSB does not make statements of general applicability and future effect to "set[ ] forth a policy or interpret[ ] a statutory or regulatory issue"[1] as the Office of Management and Budget defines guidance documents, the CSB has made recommendations to other Federal agencies that relate to *their* existing regulations, as Congress directed in the CSB's authorizing legislation.[2] As such, we are producing the information requested for those recommendations issued since January 1, 2008.

Over the last ten years, the CSB has issued twelve investigation reports that include recommendations directed to Federal entities to revise, expand or issue guidance related to existing regulations. It is important to point out that a CSB recommendation is non-binding and does not preclude an agency from complying with all applicable statutes and rulemaking procedures. The CSB has included the relevant answers to questions 1-7 as outlined by the Committee and provided a hyperlink to the relevant investigative reports.

If you need any additional information, please contact Communications Manager Hillary Cohen at [redacted].

Sincerely,

Vanessa Allen Sutherland
Chairperson & CEO

cc: The Honorable Elijah E. Cummings, Ranking Member
Committee on Oversight and Government Reform

The Honorable Gerald E. Connolly, Ranking Member
Subcommittee on Government Operations

The Honorable Raja Krishnamoorthi, Ranking Member
Subcommittee on Healthcare, Benefits, and Administrative Rules

The Honorable Val Butler Demings, Ranking Member
Subcommittee on Intergovernmental Affairs

The Honorable Stacey E. Plaskett, Ranking Member
Subcommittee on the Interior, Energy, and Environment

[1] GOV'T ACCOUNTABILITY OFFICE, GAO-17-404T, REGULATORY GUIDANCE PROCESSES: SELECTED DEPARTMENTS COULD STRENGTHEN INTERNAL CONTROL AND DISSEMINATION PRACTICES 7 (April 2015), *available at* http://www.gao.gove/assets/670/669688.pdf.

[2] 42 U.S.C. §7412(r)(6).

U.S. Chemical Safety and Hazard Investigation Board

1750 Pennsylvania Avenue NW, Suite 910 | Washington, DC 20006
Phone: (202) 261-7600 | Fax: (202) 261-7650
www.csb.gov

Office of the General Counsel

January 25, 2018

Committee on Oversight and Government Reform
United States House of Representatives
2157 Rayburn House Office Building
Washington, DC 20515

To Whom It May Concern:

The CSB has searched all areas that could reasonably contain documents responsive to the Committee's request, and we have completed a diligent search of all documents in our possession, custody, or control. All responsive documents identified during this search have been produced to the Committee in the attached submission.

Sincerely,

Kara A. Wenzel
Acting General Counsel

Report Title and Relevant Recommendations	Form of Guidance	Brief Description	Date of Issuance	Issuing Agency	Guidance Indicator	Hyperlink
Barton Solvents Explosions and Fire 2007-06-I-KS-R1	Final Investigative Report	On July 17, 2007, explosions and fire erupted at the Barton Solvents facility in Valley Center, Kansas, north of Wichita. The incident led to the evacuation of thousands of residents and resulted in projectile damage offsite, as well as extensive damage to the facility.	June 26, 2008	U.S. Chemical Safety Board	Not Applicable	http://www.csb.gov/file.aspx?DocumentId=367
Bayer CropScience Pesticide Waste Tank Explosion 2008-08-I-WV-R11	Final Investigative Report	Two workers were fatally injured when a waste tank containing the pesticide methomyl violently exploded, damaging a process unit at the Bayer CropScience chemical plant in Institute, West Virginia.	January 20, 2011	U.S. Chemical Safety Board	Not Applicable	http://www.csb.gov/assets/1/19/Bayer_Report_Final.pdf
Donaldson Enterprises, Inc. Fatal Fireworks Disassembly Explosion and Fire 2011-06-I-HI-R1 2011-06-I-HI-R2 2011-06-I-HI-R3 2011-06-I-HI-R9 2011-06-I-HI-R10	Final Investigative Report	On April 8, 2011, at approximately 8:50 am, an explosion and fire occurred at a magazine located at Waikele Self Storage in Waipahu, Hawaii, that was leased and used by Donaldson Enterprises, Inc. (DEI) for seized fireworks storage and disposal-related activities. Five DEI personnel in the magazine at the time of the incident were fatally injured.	January 17, 2013	U.S. Chemical Safety Board	Not Applicable	http://www.csb.gov/file.aspx?DocumentId=409
Caribbean Petroleum Refining Tank Explosion and Fire 2010-02-I-PR-R1 2010-02-I-PR-R3 2010-02-I-PR-R4	Final Investigative Report	A massive fire and explosion sent huge flames and smoke plumes into the air at the Caribbean Petroleum Corporation near San Juan, Puerto Rico. The resulting pressure wave damaged surrounding buildings and impacted moving vehicles.	October 21, 2015	U.S. Chemical Safety Board	Not Applicable	http://www.csb.gov/file.aspx?DocumentId=714+
DuPont Corporation Toxic Chemical Release 2010-06-I-WV-R1	Final Investigative Report	On January 23, 2010, there was a release of highly toxic phosgene, exposing an operator at the DuPont facility in Belle, West Virginia, and resulting in his death one day later. The phosgene release followed two other accidents at the same plant in the same week, including an ongoing release of chloromethane from the plant's F3455 unit, which went undetected for several days, and a release from a spent sulfuric acid unit.	September 20, 2011	U.S. Chemical Safety Board	Not Applicable	http://www.csb.gov/assets/1/19/CSB%20Final%20Report.pdf
Hoeganaes Corporation Fatal Flash Fires 2011-4-I-TN-R1 2011-4-I-TN-R2 2011-4-I-TN-R3	Final Investigative Report	The CSB's investigation report examines multiple iron dust flash fires and a hydrogen explosion at the Hoeganaes facility in Gallatin, Tennessee. The first iron dust flash fire incident killed two workers and the second injured an employee. The third incident, a hydrogen explosion and resulting iron dust flash fires, claimed three lives and injured two other workers.	January 5, 2012	U.S. Chemical Safety Board	Not Applicable	http://www.csb.gov/file.aspx?DocumentId=418
Macondo Well Blowout and Explosion CSB2010-10-I-OS-R01 CSB2010-10-I-OS-R06 CSB2010-10-I-OS-R07 CSB2010-10-I-OS-R08 CSB2010-10-I-OS-R11 CSB2010-10-I-OS-R14 CSB2010-10-I-OS-R15 CSB2010-10-I-OS-R16	Final Investigative Report	On April 20, 2010, a sudden explosion and fire occurred on the Deepwater Horizon oil rig. The accident resulted in the deaths of 11 workers and caused a massive, ongoing oil spill into the Gulf of Mexico. The rig was located approximately 50 miles southeast of Venice, Louisiana, and had a 126-member crew onboard.	April 20, 2016	U.S. Chemical Safety Board	Not Applicable	http://www.csb.gov/assets/1/7/20140605_Macondo_Vol2_(0605v1).pdf http://www.csb.gov/assets/1/19/Macondo_Vol3_Final_20160527.pdf http://www.csb.gov/assets/1/19/Macondo_Vol4_Final_20160527.pdf
Oil Site Safety Study 2011-1-H-R01	Final Investigative Report	This investigation focuses on the deaths of two teenagers killed on October 31, 2009, when an oil tank in Carnes, Mississippi, suddenly exploded. On April 14, 2010, a similar tank explosion took the life of a member of the public in Weleetka, Oklahoma, at an unattended oil and gas production site.	October 27, 2011	U.S. Chemical Safety Board	Not Applicable	http://www.csb.gov/file.aspx?DocumentId=419
Tesoro Refinery Fatal Explosion and Fire 2010-08-I-WA-R1	Final Investigative Report	On April 2, 2008, an explosion and fire led to the fatal injury of seven employees when a nearly forty-year-old heat exchanger catastrophically failed during a maintenance operation to switch a process stream between two parallel banks of exchangers at the Tesoro refinery in Anacortes, Washington.	May 1, 2014	U.S. Chemical Safety Board	Not Applicable	http://www.csb.gov/file.aspx?DocumentId=600
US Ink Fire 2013-0-I-NJ-R2	Final Investigative Report	This case study examines the explosion and flash fires that occurred at the US Ink manufacturing facility in East Rutherford, New Jersey, on October 9, 2012. Seven workers suffered burn injuries when they congregated at the entrance to the ink mixing room after seeing signs of an initial flash fire from a bag dumping station. A second flash fire then occurred, injuring the employees.	January 15, 2015	U.S. Chemical Safety Board	Not Applicable	http://www.csb.gov/assets/1/19/CSB_case_study.pdf
West Fertilizer Explosion and Fire 2013-02-I-TX-R1 2013-02-I-TX-R2 2013-02-I-TX-R3 2013-02-I-TX-R4 2013-02-I-TX-R5	Final Investigative Report	A massive explosion at a fertilizer storage and distribution facility fatally injured twelve volunteer firefighters, two members of the public and caused hundreds of injuries in West, Texas.	January 28, 2016	U.S. Chemical Safety Board	Not Applicable	http://www.csb.gov/file.aspx?DocumentId=732
Xcel Energy Hydroelectric Plant Penstock Fire 2008-01-I-CO-R1	Final Investigative Report	On October 2, 2007, a chemical fire inside a confined space at Xcel Energy's hydroelectric plant in a remote mountain location 45 miles west of Denver, Colorado, killed five and injured three workers. Flammable solvent being used to clean the epoxy application equipment in the open penstock atmosphere ignited, likely from a static spark. The initial fire quickly grew as it ignited additional buckets of solvent and substantial amounts of combustible epoxy material, trapping and preventing five of the 11 workers from exiting the single point of egress within the penstock. August 25, 2010	August 25, 2010	U.S. Chemical Safety Board	Not Applicable	http://www.csb.gov/file.aspx?DocumentId=452

U.S. Chemical Safety Board Response to
House Committee on Oversight and Government Reform Request
Guidance Documents from January 1, 2008 to Present

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2010-02-I-PR-R4	000361
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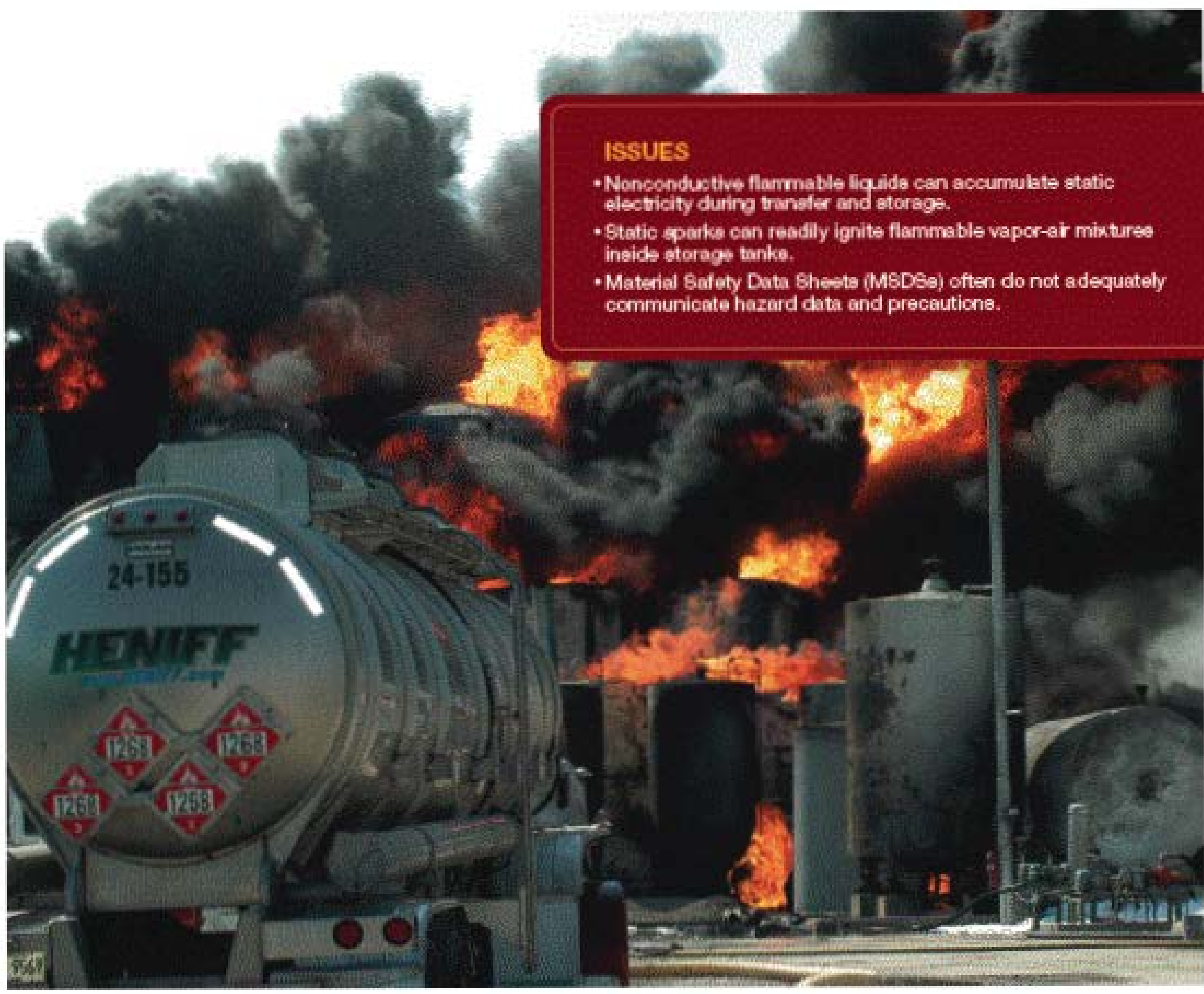
Xcel Energy Hydroelectric Plant Penstock Fire	**001598**
2008-01-I-CO-R1	001713

U.S. Chemical Safety and Hazard Investigation Board

Barton Solvents

Static Spark Ignites Explosion Inside Flammable Liquid Storage Tank

No. 2007-06-I-KS



ISSUES

- Nonconductive flammable liquids can accumulate static electricity during transfer and storage.
- Static sparks can readily ignite flammable vapor-air mixtures inside storage tanks.
- Material Safety Data Sheets (MSDSs) often do not adequately communicate hazard data and precautions.

000001

Who's at Risk…

Companies that transfer (pump) bulk flammable liquids into or from storage tanks.

1. INTRODUCTION

On July 17, 2007, at about 9 a.m., an explosion and fire occurred at the Barton Solvents Wichita facility in Valley Center, Kansas. Eleven residents and one firefighter received medical treatment. The incident triggered an evacuation of Valley Center (approximately 6,000 residents); destroyed the tank farm; and significantly interrupted Barton's business. An investigation by the U.S. Chemical Safety and Hazard Investigation Board (CSB) has concluded that the initial explosion occurred inside a vertical above-ground storage tank that was being filled with Varnish Makers' and Painters' (VM&P) naphtha. VM&P naphtha is a National Fire Protection Association (NFPA) Class IB flammable liquid[1] that can produce ignitable vapor-air mixtures inside tanks and, because of its low electrical conductivity, can accumulate dangerous levels of static electricity.[2]

The CSB is publishing this Case Study to help companies understand the hazards associated with static-accumulating flammable liquids that can form ignitable vapor-air mixtures inside storage tanks. In addition, the CSB wants to urge companies to take extra precautions to prevent explosions and fires like the one at Barton. This Case Study also examines industry Material Safety Data Sheet (MSDS) hazard communication practices and makes recommendations to ensure that MSDSs identify these hazards and outline appropriate precautions.

[1] Liquids most likely to form ignitable vapor-air mixtures during tank filling at ambient operating temperatures are normally those designated as Class IB or Class IC in NFPA 30 (flammability hazard rating of "3" in NFPA 704). In the American Petroleum Institute (API) classification system these liquids usually fall into the "Intermediate Vapor Pressure Products" category. A notable exception is motor gasoline, an NFPA Class IB liquid that is designated as a "High Vapor Pressure Product" in the API system, implying that (except at very low operating temperatures) the vapor-air mixture formed during tank filling rapidly becomes too rich to be ignitable. (See NFPA 30, Section 4.3 "Classification of Liquids" and NFPA 704 Chapter 6 for a detailed discussion of NFPA's classification and flammability hazard rating systems. See API 2003 (2008 edition), Section 3 "Definitions" for an explanation of "High," "Intermediate," and "Low" vapor pressure product classes.

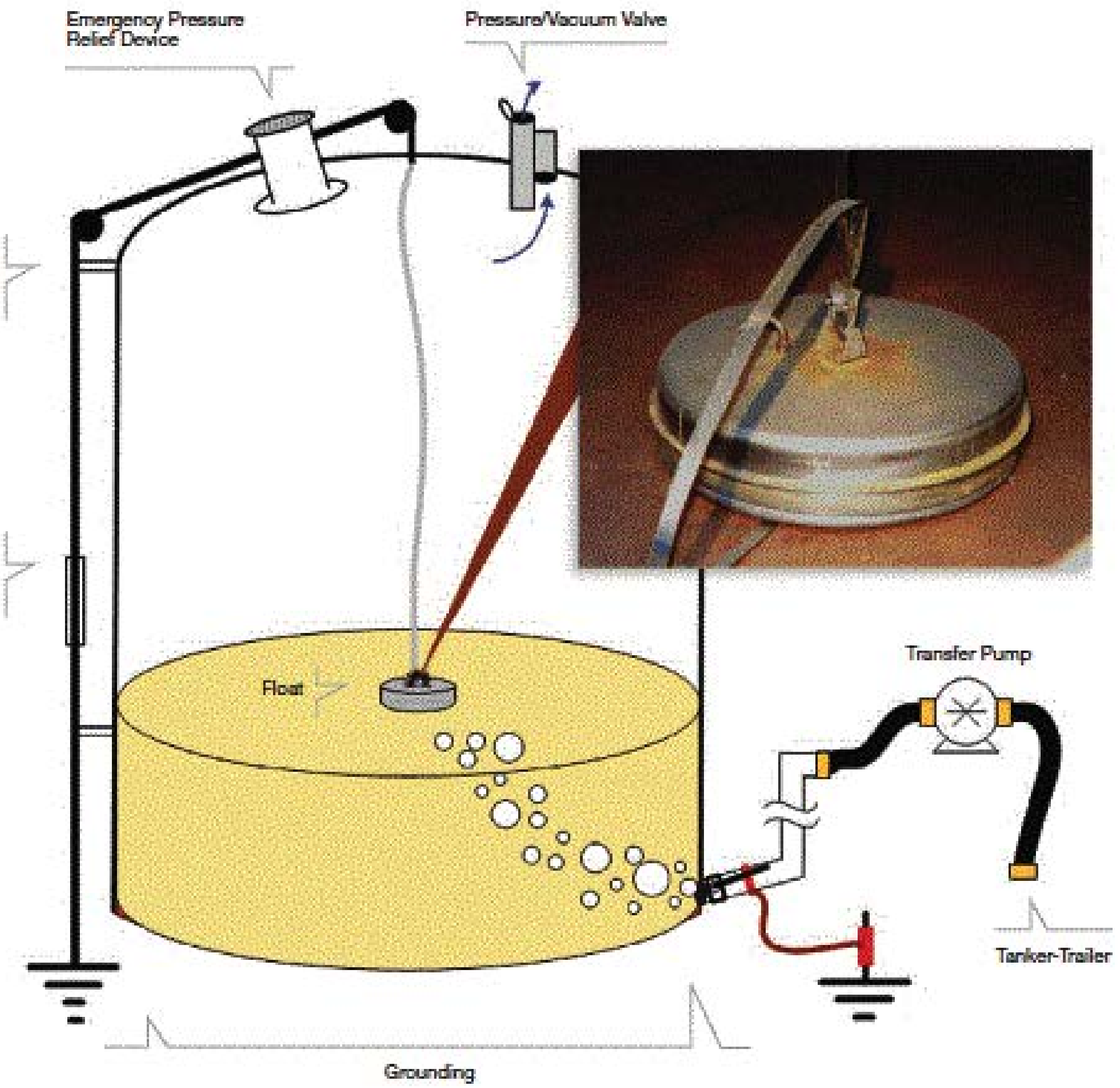
[2] On October 29, 2007, fire destroyed a large portion of a Barton facility in Des Moines, Iowa. Flammable liquids and static electricity were also involved in that incident. Because of the incident-specific findings associated with the Wichita incident investigation, this Case Study focuses solely on the Wichita incident.

2. INCIDENT DESCRIPTION

The initial explosion occurred soon after the tank farm supervisor started the transfer of the final compartment of a tanker-trailer containing VM&P naphtha into a 15,000 gallon above-ground storage tank (Figure 1).

FIGURE 1

VM&P naphtha tank and photo of an example float



000003

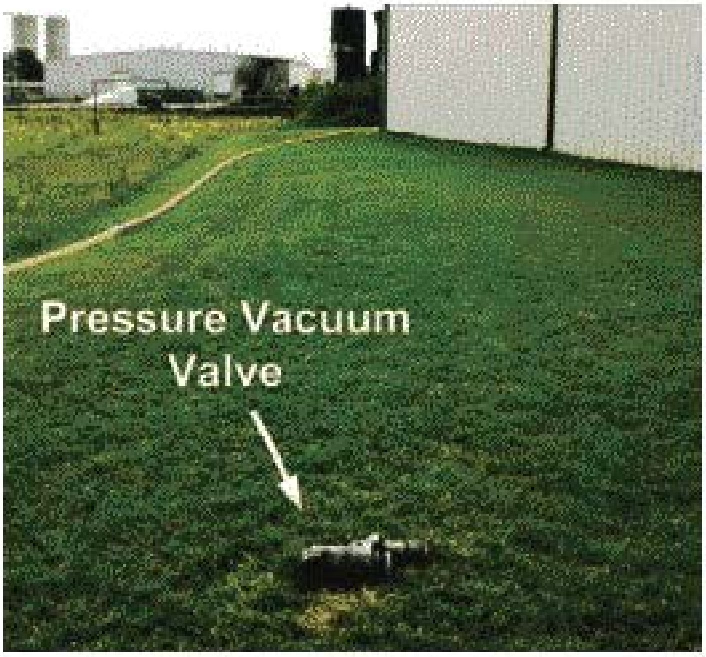
The explosion sent the VM&P tank rocketing into the air, trailing a cloud of smoke and fire from the burning liquid; it landed approximately 130 feet away. Witnesses heard the explosion and saw the fireball from several miles away. Within moments, two more tanks ruptured and released their contents into the rapidly escalating fire that was concentrated inside the earthen spill containment area surrounding the tank farm.[3] As the fire burned, the contents of other tanks over-pressurized or ignited, launching steel tank tops (10-12 feet in diameter); vent valves; pipes; and steel parts off-site and into the adjoining community. A tank top struck a mobile home in the community (approximately 300 feet away) and a pressure/vacuum valve hit a neighboring business nearly 400 feet away (Figures 2 and 3).

FIGURE 2

Tank top projectile struck a mobile home

FIGURE 3

Pressure vacuum valve projectile struck neighboring business



[3] Approximately 20,000 gallons of flammable liquid were released into the spill containment. The tank farm included 43 above-ground storage tanks with capacities ranging from 3,000 to 20,000 gallons. Tank heights ranged from approximately 15 to 40 feet.

3. FLAMMABLE LIQUIDS AND STATIC ELECTRICITY

Fire occurs when there is an ignitable vapor-air mixture and a source of ignition, such as a static electric spark. At normal handling temperatures, flammable storage tanks, like those containing gasoline, may contain vapor-air mixtures that typically cannot be ignited by a static electric spark because the vapor-air mixture is too rich (i.e., contains too much fuel and not enough oxygen) to burn. VM&P naphthas, however, and other flammable liquids (e.g., many NFPA Class IB Flammables), may form ignitable vapor-air mixtures inside tanks at normal handling temperatures.

Static electricity is generated as liquid flows through pipes, valves, and filters while being transferred.[4] It can also be produced by entrained water or air, splashing or agitation, and when sediment in the bottom of the tank becomes suspended (Britton, 1999).

Because nonconductive liquids, such as VM&P naphtha and other flammable liquids, dissipate (or "relax") static electricity slowly, they pose a risk of dangerous static electric accumulation that can produce sparks inside tanks.[5]

Common Static-Accumulating Flammable Liquids That May Form Ignitable Vapor-Air Mixtures

- VM&P naphtha
- Cyclohexane
- n-Heptane
- Benzene
- Toluene
- n-Hexane
- Xylene
- Ethyl benzene
- Styrene

4. KEY FINDINGS

The CSB determined that several factors likely combined to produce the initial explosion:

- The tank contained an ignitable vapor-air mixture in its head space.
- Stop-start filling, air in the transfer piping, and sediment and water (likely present in the tank) caused a rapid static charge accumulation inside the VM&P naphtha tank.
- The tank had a liquid level gauging system float with a loose linkage that likely separated and created a spark during filling.
- The MSDS for the VM&P naphtha involved in this incident did not adequately communicate the explosive hazard.

Normal Bonding and Grounding May Not Be Enough!

Companies that handle, transfer, and store flammable liquids should contact manufacturers to determine if these liquids can accumulate dangerous levels of static electricity, and if they can form explosive vapor-air mixtures inside storage tanks. If so, extra precautions—beyond normal bonding and grounding—may be necessary.

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[4] The rate of static charge generation during flow through pipe increases roughly with the square of the flow velocity. A liquid whose conductivity is less than 100 pico siemens per meter (pS/m) is generally considered nonconductive (Britton, 1999). The VM&P naphtha involved in the Barton incident had a conductivity of 3 pS/m. Some common nonconductive liquids are listed in NFPA 77 (Annex B – Table B.2). See the Resources Section at the end of this Case Study for web access instructions.

[5] The length of the transfer piping from the pump to the storage tank was approximately 215 feet (66 meters); the piping was 2.5 inch NPS Schedule 40, (6.3 cm inside diameter); and the pump flow velocity was 4.6 meters per second (15 feet per second). A 425 micron (0.017 inch) mesh strainer was located at the pump outlet.

000005

4.1. FLAMMABILITY OF VM&P NAPHTHA

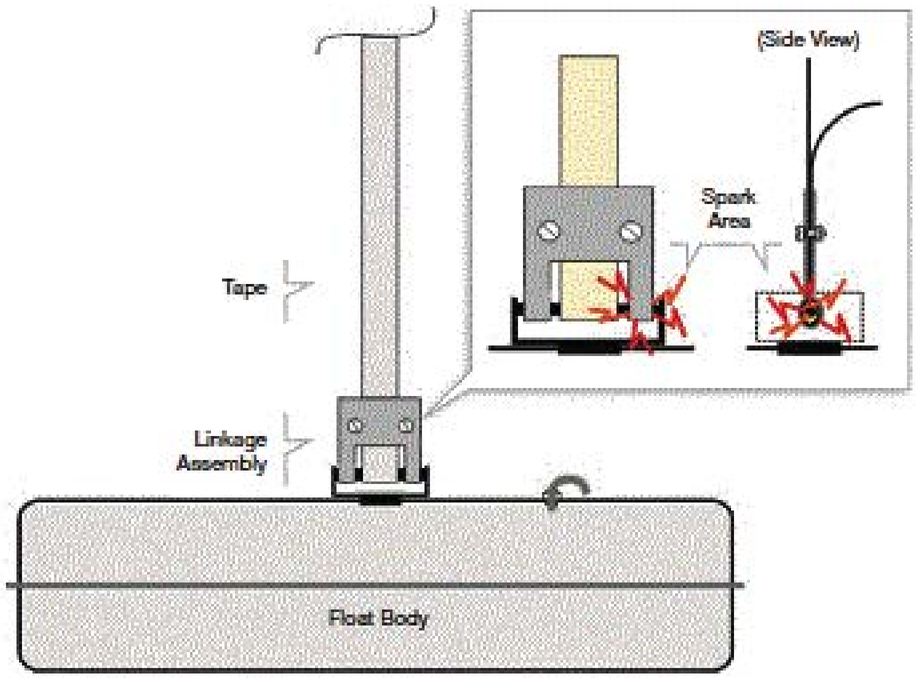
The CSB tested the VM&P naphtha involved in the Barton explosion to determine if an ignitable vapor-air mixture could have been present inside the tank at the time of the explosion.[6] The results revealed that, at approximately 77°F (25°C) (the handling temperature of the VM&P naphtha at the time of the incident), the tank head space likely contained a readily ignitable vapor-air mixture. The energy from a static spark would have been adequate to ignite this vapor-air mixture.[7]

4.2. TANK LEVEL FLOAT DESIGN

The design of the tank liquid level gauging system float used by Barton incorporates a loose linkage at the float/tape junction that can separate slightly, interrupting grounding (see Section 4.3) and creating the potential for a spark (Figure 4).[8] The CSB concluded that turbulence and bubbling during the stop-start transfer pumping, in addition to creating rapid static charge accumulation, also likely created slack in the gauge tape connected to the float, causing the linkage to separate and spark.[9]

FIGURE 4

Float linkage and area where the spark likely occurred



[6] Its flashpoint was 58°F (14°C); its vapor pressure was approximately 0.7 kPa (5 mmHg) at 68°F (20°C) using an isoteniscope; and its flammable range was approximately 0.9-6.7% in air. The Reid VP of the VM&P naphtha was 3.1 psia (21.4 kPa) at 100°F (38°C).

[7] The CSB estimates that the minimum ignition energy required for a spark to ignite the Barton VM&P naphtha was 0.22 mJ (plus/minus 0.02 mJ).

[8] Electrical testing of an exemplar tank level float indicated that a loose linkage could produce a spark with sufficient energy to ignite a flammable vapor-air mixture inside a tank.

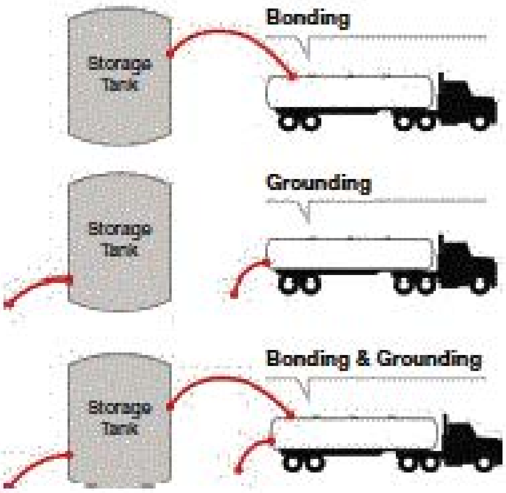
[9] While the CSB has concluded that the loose linkage level float was the most likely spark location, a spark from a "brush discharge" cannot be ruled out. Brush discharges encompass a variety of "non-spark" static discharges that occur between a charged liquid surface and a grounded conductive object, such as a dip pipe or other metal component acting as an electrode, or even the tank wall itself. Brush discharges can occur even when all equipment is properly bonded and grounded (Britton, 1999). See the Resources Section at the end of this Case Study for more information on brush discharge.

4.3. BONDING AND GROUNDING

Bonding is the process of electrically connecting conductive objects, like tanker-trailers, to transfer pumps to equalize their individual electrical potentials and prevent sparking (Figure 5).

FIGURE 5

Bonding and grounding



Grounding (earthing) means connecting a conductive object to the earth to dissipate electricity, like accumulated static, lightning strikes, and equipment faults, into the ground, away from employees/equipment and ignitable mixtures.

According to witnesses at Barton, the tanker-trailer, pump, piping, and storage tank were bonded and grounded at the time of the incident.[10] However, published safety guidance indicates that bonding and grounding measures applied to typical transfer and storage operations may not be enough if nonconductive flammable liquids are involved. Nonconductive liquids accumulate static electricity and dissipate (relax) it more slowly than conductive liquids, and therefore require additional precautions (see Section 5).

4.4. STATIC ACCUMULATION IN THE PUMPED LIQUID

Barton pumped the VM&P naphtha from three separate compartments in the tanker-trailer to the VM&P tank. Air pockets were introduced into the fill piping, and then transferred into the tank when the transfer hose was reconnected to the tanker-trailer after compartments were changed. Studies have found that static electricity accumulates rapidly during pump startup when nonconductive liquids are transferred to storage tanks (Walmsley, 1996). In this case, the static electricity accumulation was likely exacerbated by the air pockets (bubbling) and the likely presence of suspended sediment and water in the tank.[11] In addition, the VM&P tank was approximately 30 percent filled at the time of the explosion, which would have produced a liquid surface potential (voltage) close to the maximum expected during filling.

[10] The transfer hose was severely damaged during the fire, however, which prevented investigators from determining if bonding/grounding was effective.

[11] Barton indicated that it had no records of the VM&P tank ever being cleaned, and the tank had no manway or access opening to facilitate cleaning. Employees stated that they scooped sediment from the bottoms of similar tanks to prepare them for inspection.

4.5. MATERIAL SAFETY DATA SHEETS

According to the Occupational Safety and Health Administration (OSHA) Hazard Communication Standard (HCS),[12] employees both need and have the right to know the identities and hazards of the chemicals they are exposed to when working. The purpose of the HCS is to ensure that chemical manufacturers and importers evaluate the hazards and communicate them, along with appropriate precautionary measures, to employers and employees through a hazard communication program.[13] The primary method of communicating this information is via detailed technical bulletins called Material Safety Data Sheets (MSDSs).

The MSDSs supplied by the manufacturer of the Barton VM&P naphtha indicated that the material may accumulate a static electrical charge that could discharge and ignite accumulated vapors. It did not, however, provide critical physical and chemical property data and warnings that the material may form an ignitable vapor-air mixture inside storage tanks. Nor did it list any precautionary measures, beyond normal bonding and grounding practices, or reference relevant consensus guidance that Barton could have used to help prevent this explosion.

To prevent explosions with flammable liquids like VM&P naphtha, MSDSs should communicate

- warnings that the material is a static accumulator and can form an ignitable vapor-air mixture inside storage tanks;
- that bonding and grounding may not be enough;
- specific examples of additional precautions (see Section 5) and references to the published guidance targeted at preventing static electric discharge; and
- conductivity testing data,[14] so that companies know the degree to which the material will accumulate static and can compare it to the published guidance. Information about the published guidance is included in the Information Resources section at the end of this report.

Material Safety Data Sheets (MSDSs)

MSDSs do not typically communicate critical physical and chemical properties, and specific precautions or reference guidance for flammable liquids that may pose a static ignition hazard. Companies should contact the manufacturer (or an expert familiar with the relevant consensus guidance) for this information. Manufacturers should in turn update their MSDSs to provide this critical safety information.

[12] 29 CFR 1910.1200.

[13] 29 CFR 1910.1200(a)(1) and (2).

[14] The units routinely used to report conductivity are pico Siemens per meter (pS/m).

4.5.1. INDUSTRY MSDSs REVIEW

The CSB reviewed 62 MSDSs of some of the most widely used nonconductive flammable liquids to determine if they provided the warnings, precautionary measures and references, and conductivity testing data discussed above.

- **Static Accumulator and Storage Tank Ignitable Vapor-Air Mixture Potential:** Of the MSDSs reviewed, 39 (67 percent) contained a warning about the potential for the material to accumulate static electricity. Nearly all (97 percent) included a warning about ignitable flammable vapors. However, only one specifically warned of the potential for the material to form an ignitable vapor-air mixture inside a storage tank.

- **Specific Precautions and References to Prevent Explosions:** Of the MSDSs reviewed, 52 (84 percent) advised companies to properly bond and ground equipment, but only seven (all prepared by the same manufacturer) indicated that bonding and grounding alone may not be enough to prevent a static discharge. Each of the seven also referenced NFPA 77 and API 2003,[15] and 11 others referenced NFPA 77 and/or API 2003, but did not specifically warn that bonding and grounding may not be enough. Only eight of the 62 provided one or more specific precautionary measures such as adding nonflammable (inert) gases to tank head spaces, adding an anti-static agent, or reducing the pump flow velocity during transfer.

- **Conductivity Testing Data:** Only three MSDSs (all prepared by the same manufacturer) included conductivity testing data.

4.5.2. REGULATORY AND CONSENSUS GUIDANCE FOR PREPARING MSDSs

The three chemical hazard classification systems discussed in this section contain guidance to assist manufacturers who prepare MSDSs. OSHA establishes the regulatory requirements governing the content of an MSDS.

- **Occupational Safety and Health Administration:** OSHA describes the HCS as largely a performance-oriented standard that gives employers the flexibility to adapt the rule to the needs of the workplace, instead of having to follow specific, rigid requirements. Consequently, the HCS generally identifies categories of information to be included in the MSDS, including physical and chemical characteristics, physical hazards, and applicable precautions and/or control measures for handling materials safely. However, neither the standard nor its compliance directive[16] identifies the specific physical and chemical data, hazard warnings or precautions necessary to address some chemical hazards. The HCS places the responsibility on the preparer to identify the specific hazards within these broad categories.

  The OSHA advisory document, "Guidance for Hazard Determination For Compliance with the OSHA Hazard Communication Standard (29 CFR 1910.1200)," is intended to help MSDS preparers identify and communicate chemical hazards. While the document lists certain data and physical hazards recommended for inclusion in labels and MSDSs, it does not address relevant data and hazards associated with static-accumulating flammable liquids.

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[15] NFPA 77 and API 2003 are consensus standards that provide static electric safety guidance.

[16] CPL 02-02-038 – CPL 2-2.38D, "Inspection Procedures for the Hazard Communication Standard."

- **Globally Harmonized System of Classification and Labeling of Chemicals (GHS):** The GHS, first adopted by the Sub-Committee on the Globally Harmonized System of Classification and Labeling of Chemicals (SCEGHS) in December 2002, is an initiative to establish international consensus on criteria for classifying chemical hazards for international distribution, and to create consistent requirements for MSDSs. The GHS has been revised twice: once in 2005, and again in 2007. According to the GHS Sub-Committee of Experts, the GHS is now ready for worldwide implementation.

  The GHS provides specific criteria for identifying and classifying flammable liquids, but it does not provide identification criteria or warning guidance for liquids that, in addition to being ignitable inside tanks at ambient temperatures, also accumulate static electricity that can ignite them. In addition, the GHS does not require a preparer to include conductivity testing data in an MSDS, data that are essential to identify a material as nonconductive.

  OSHA participates in the GHS criteria development process, and on September 12, 2006, published an Advance Notice of Proposed Rulemaking (71 FR 53617), indicating its intent to adopt the GHS guidance into the requirements of the HCS.

- **American National Standards Institute (ANSI) Z400.1-2004 "American National Standard for Hazardous Industrial Chemicals - Material Safety Data Sheets - Preparation":** ANSI Z400.1-2004 is a voluntary consensus standard, and is recognized by OSHA's HCS compliance directive as a consensus standard that provides valuable guidance to MSDS preparers.

  Because the OSHA HCS is performance-based, it provides minimal substantive guidance for MSDS preparers. ANSI Z400.1 was developed to provide such guidance; it identifies information that must be included in an MSDS to comply with OSHA's HCS, and includes additional guidance to help MSDS preparers comply with state and federal environmental and safety rules.

  ANSI Z400.1 gives the following example of a general warning about what practices to avoid or restrict: "To reduce the potential for static discharge, bond and ground containers when transferring material." However, the example does not warn that bonding and grounding may be insufficient to eliminate the potential for static discharge, particularly if the material is a nonconductive flammable liquid. The standard includes no additional precautions or relevant consensus guidance references, and no requirements for a preparer to include conductivity testing data in an MSDS.

5. ADDITIONAL PRECAUTIONS

Companies that handle, transfer, and store nonconductive flammable liquids, such as naphthas, toluene, benzene, and heptane, should take additional precautions to avoid an incident like the one at Barton.

Additional Precautions

- Request additional manufacturer guidance
- Add an inert gas to the tank head space
- Modify or replace loose linkage tank level floats
- Add an anti-static agent
- Reduce flow (pumping) velocity

5.1. REQUEST ADDITIONAL MANUFACTURER GUIDANCE

As discussed, MSDSs do not typically provide conductivity testing data or specific examples of additional precautions that should be observed, and do not typically reference the relevant consensus guidance pertaining to static electricity and storage tank vapor-air mixture hazards. Therefore, to determine if additional precautions to eliminate the potential for an explosion are necessary, companies that transfer flammable liquids should contact the manufacturers, or a qualified expert, to determine if the flammable liquid is

- nonconductive (a static accumulator); and
- capable of producing an ignitable vapor-air mixture inside a storage tank.

5.2. ADD A NONFLAMMABLE, NONREACTIVE (INERT) GAS TO TANK HEAD SPACES[17]

Using an inert gas such as nitrogen, if done correctly, is effective in reducing the potential for an ignitable incident (explosion) as it renders tank head spaces incapable of supporting ignition from a static spark.[18] However, because this practice can produce oxygen-deficient environments inside tanks, extreme caution should be exercised when opening tanks for routine inspections and maintenance.[19]

[17] See NFPA 69 "Standard on Explosion Prevention Systems" (2008) for guidance pertaining to proper inerting practices.

[18] Before using inert gases in tanks, companies should contact the liquid manufacturer to determine if the proposed gas is appropriate for the particular liquid.

[19] Employers who require employees to enter confined spaces—particularly those with oxygen-deficient or other hazardous atmospheres—must comply with the requirements of the OSHA "Permit Required Confined Space Program" (29 CFR 1910.146).

5.3. MODIFY OR REPLACE LOOSE LINKAGE TANK LEVEL FLOATS

Companies with tanks that may contain ignitable vapor-air mixtures and that are equipped with conductive loose linkage level floats should take one or more of the following measures:

- Use an appropriate gas to inert tank head spaces.
- Inspect and replace, as appropriate, floats with level measuring devices that will not promote sparks inside the tank.
- Modify floats so that they are properly bonded and grounded (see Figure 6).[20]
- Reduce the liquid flow (pumping) velocity.[21]
- Remove any slack in the tape connected to the float mechanism that could allow a spark gap to form.

5.4. ANTI-STATIC ADDITIVES

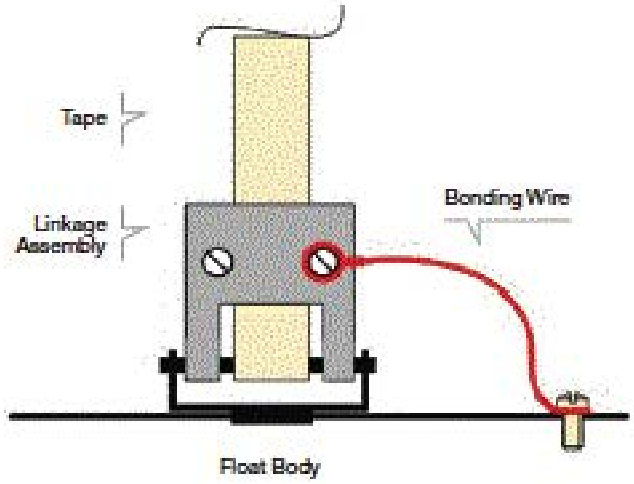
Anti-static (conductivity-enhancing) additives increase the conductivity of liquids, helping reduce static accumulation. Before relying solely on these additives, however, companies should contact the flammable liquid manufacturer to determine if such an additive is appropriate and effective for the particular liquid.

5.5. REDUCED FLOW (PUMPING) VELOCITY

Various guidance suggests that nonconductive flammable liquids capable of forming ignitable vapor-air mixtures inside tanks should be transferred at reduced flow (pumping) velocities to minimize the potential for a static ignition.[22]

FIGURE 6

Tank level float bonding wire



[20] This figure illustrates the modification recommended by the manufacturer of the floats used at Barton's Wichita facility. Companies with floats equipped with loose linkages should contact the manufacturer for modification recommendations.

[21] NFPA 77 (2007); API 2003 (2008); and Britton (1999) recommend a flow (pumping) velocity of 1 meter per second when the risk of static ignition is high. Until the spark potential inside the tank is eliminated, companies should use a pump flow velocity at (or near) 1 meter per second to transfer nonconductive flammable liquids.

[22] The guidance pertaining to reduced flow (pumping) velocities include API 2003 (2008), Sections 4.2.5.6 and 4.5.1; NFPA 77 (2007), Table 8.6 (footnote f); and Laurence Britton, "Avoiding Static Ignition Hazards in Chemical Operations", Chapters 2-1.6 and 5-4. While toluene and heptane are specifically identified in NFPA 77, Table 8.6 (footnote f), typical VM&P naphthas exhibit similar characteristics and should also be transferred at reduced flow rates. Recommended maximum flow (pumping) velocities provided in the various guidance differ. However, the most protective recommended flow (pumping) velocity is 1 meter per second.

000012

6. RECOMMENDATIONS

6.1. OCCUPATIONAL SAFETY AND HEALTH ADMINISTRATION

2007-06-I-KS-R1

Revise the "Guidance for Hazard Determination for compliance with the OSHA Hazard Communication Standard" to advise chemical manufacturers and importers that prepare MSDSs to

- Evaluate flammable liquids to determine their potential to accumulate static electricity and form ignitable vapor-air mixtures in storage tanks.
- Test the conductivity of the flammable liquid and include the testing results in the MSDS.

2007-06-I-KS-R2

Prior to the next revision, communicate to the Sub-Committee on the Globally Harmonized System of Classification and Labeling of Chemicals (SCEGHS) the need to amend the GHS to advise chemical manufacturers and importers that prepare MSDSs to

- Identify and include a warning for materials that are static accumulators and that may form ignitable vapor-air mixtures in storage tanks.
- Advise users that bonding and grounding may be insufficient to eliminate the hazard from static-accumulating flammable liquids, and provide examples of additional precautions and references to the relevant consensus guidance (e.g., NFPA 77, Recommended Practice on Static Electricity (2007), and API Recommended Practice 2003, Protection Against Ignitions Arising Out of Static, Lightning, and Stray Currents (2008)).
- Provide conductivity testing data for materials that are static accumulators and that may form ignitable vapor-air mixtures in storage tanks.

6.2. AMERICAN NATIONAL STANDARDS INSTITUTE (ANSI) Z400.1 COMMITTEE

2007-06-I-KS-R3

Revise ANSI Z400.1 to advise chemical manufacturers and importers that prepare MSDSs to

- Identify and include a warning for materials that are static-accumulators and that may form ignitable vapor-air mixtures in storage tanks;
- Advise users that bonding and grounding may be insufficient to eliminate the hazard from static-accumulating flammable liquids, and provide examples of additional precautions and references to the relevant consensus guidance (e.g., NFPA 77, Recommended Practice on Static Electricity (2007), and API Recommended Practice 2003, Protection Against Ignitions Arising Out of Static, Lightning, and Stray Currents (2008)); and
- Provide conductivity testing data for materials that are static accumulators and that may form ignitable vapor-air mixtures in storage tanks.

6.3. INDUSTRY ASSOCIATIONS

AMERICAN CHEMISTRY COUNCIL
2007-06-I-KS-R4

AMERICAN PETROLEUM INSTITUTE
2007-06-I-KS-R5

NATIONAL ASSOCIATION OF CHEMICAL DISTRIBUTORS
2007-06-I-KS-R6

NATIONAL PAINT AND COATINGS ASSOCIATION
2007-06-I-KS-R7

NATIONAL PETROCHEMICAL AND REFINERS ASSOCIATION
2007-06-I-KS-R8

SOCIETY FOR CHEMICAL HAZARD COMMUNICATION
2007-06-I-KS-R9

Recommend to your membership companies that prepare MSDSs to update the MSDSs to

- Identify and include a warning for materials that are static accumulators and that may form ignitable vapor-air mixtures in storage tanks.
- Include a statement that bonding and grounding may be insufficient to eliminate the hazard from static-accumulating flammable liquids, and provide examples of additional precautions and references to the relevant consensus guidance (e.g., NFPA 77, Recommended Practice on Static Electricity (2007), and API Recommended Practice 2003, Protection Against Ignitions Arising Out of Static, Lightning, and Stray Currents (2008)).
- Include conductivity testing data for the materials that are static accumulators and that may form ignitable vapor-air mixtures in storage tanks.

7. INFORMATION RESOURCES

The following references include additional information on the safe use of static-accumulating flammable liquids:

1. American Petroleum Institute (API), "API Recommended Practice 2003: Protection Against Ignitions Arising Out of Static, Lightning, and Stray Currents," 7th ed., 2008.
2. Britton, L.G., and J.A. Smith, "Static Hazards of Drum Filling," *Plant/Operations Progress*, Vol. 7, No. 1 (1988) pg. 53-78.
3. Britton, L.G., "*Avoiding Static Ignition Hazards in Chemical Operations*," AIChE-CCPS Concept Book, 1999.
4. National Fire Protection Association (NFPA), "NFPA 30: Flammable and Combustible Liquid Code," 2008.
5. NFPA, "NFPA 69: Standard on Explosion Prevention Systems," 2008 ed.
6. NFPA, "NFPA 77: Recommended Practice on Static Electricity," 2007 ed. NFPA 77 can be viewed, free of charge, on the NFPA website (www.nfpa.org). Access directions: At the NFPA Homepage, go the "Codes and Standards" pull down tab, then click on "Code development process" and scroll down to "Online access."
7. Walmsley, H.L., "The Electrostatic Potentials Generated by Loading Multiple Batches of Product into a Road Tanker Compartment," *J. Electrostatics*, Vol. 38, 1996, pg.177-186.

U.S. CHEMICAL SAFETY AND HAZARD INVESTIGATION BOARD

INVESTIGATION REPORT

Pesticide Chemical Runaway Reaction Pressure Vessel Explosion

(Two Killed, Eight Injured)

BAYER CROPSCIENCE, LP

INSTITUTE WEST VIRGINIA

AUGUST 28, 2008

KEY ISSUES:

- PROCESS HAZARDS ANALYSIS
- PRE-STARTUP SAFETY REVIEW
- PROCESS SAFETY INFORMATION AND TRAINING
- EMERGENCY PLANNING AND RESPONSE

Report No. 2008-08-I-WV
January 2011

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Acronyms and Abbreviations

ATF	U.S. Bureau of Alcohol, Tobacco, and Firearms, and Explosives
CAD	(Emergency Operations Center) Computer aided dispatch
CCPS	Center for Chemical Process Safety
CFR	Code of Federal Regulations
CPQRA	Chemical process quantitative risk assessment
CSB	U.S. Chemical Safety and Hazard Investigation Board
DCS	Distributed control system
DEP	Department of Environmental Protection
DMDS	Dimethyl disulfide
ECC	East Carbamoylation Center
EHA	Extraordinarily hazardous substance
EMS	Emergency Medical Services
EOC	Emergency Operations Center
EPA	U.S. Environmental Protection Agency
FDA	U.S. Food and Drug Administration
FIFRA	Federal Insecticide, Fungicide and Rodenticide Act
fps	feet per second
GUI	Graphical user interface
HAZOP	Hazard and operability study
HSE	U.K. Health and Safety Executive
IC	Incident Commander
ICS	Incident Command System
IDLH	Immediately dangerous to life or health
IR	Infrared radiation
KCEAA	Kanawha County Emergency Ambulance Authority
KCSD	Kanawha County Sheriff's Department
KPEPC	Kanawha-Putnam County Emergency Planning Committee
LOPA	Layer of Protection Analysis
m^3	cubic meter
MAWP	Maximum allowable working pressure
mg	milligram
MIBK	Methyl isobutyl ketone

MIC	Methyl isocyanate
MOCR	Management of change review
MSAO	Methylthioacetaldoxime (also called Oxime)
MSDS	Material Safety Data Sheet
MSS	MIC stripping still
NAS	National Academy of Sciences
NIMS	National Incident Management System
NIOSH	The National Institute for Occupational Safety and Health
OES	West Virginia State Office of Emergency Services
OIG	Office of Inspector General
OSHA	U.S. Department of Labor, Occupational Safety and Health Administration
PEL	Permissible exposure limit
PFD	Probability of failure on demand
PHA	Process hazard analysis
PIO	Public Information Officer
ppm	parts per million
PSSR	Pre-startup safety review
PSM	Process Safety Management (29 CFR 1910.119)
REL	Recommended exposure limit
RHS	Reactive Hazard Substance
RMP	Risk Management Program (40 CFR 68)
RRT	Regional Response Team
SOP	Standard operating procedure
TCPA	(New Jersey) Toxic Catastrophe Prevention Act
TLV	Threshold limit value
TQ	Threshold quantity (OSHA PSM or EPA Risk Management Program)
UCC	Union Carbide Corporation
UCS	Unified Command System
VOC	Volatile organic compound
WCC	West Carbamoylation Complex

Executive Summary

On August 28, 2008, at about 10:35 p.m., a runaway chemical reaction occurred inside a 4,500 gallon pressure vessel known as a residue treater, causing the vessel to explode violently in the methomyl unit at the Bayer CropScience facility in Institute, West Virginia. Highly flammable solvent sprayed from the vessel and immediately ignited, causing an intense fire that burned for more than 4 hours. The fire was contained inside the Methomyl-Larvin insecticide unit by the Bayer CropScience fire brigade with mutual aid assistance from local volunteer and municipal fire departments.

The incident occurred during the restart of the methomyl unit after an extended outage to upgrade the control system and replace the original residue treater vessel. Two company employees who had been dispatched by the control room personnel to investigate why the residue treater pressure was increasing were near the residue treater when it ruptured. One died from blunt force trauma and burn injuries sustained at the scene; the second died 41 days later at the Western Pennsylvania Burn Center in Pittsburgh, Pennsylvania. Six volunteer firefighters who assisted in the unit fire suppression activities and two contractors working at the facility were treated for possible toxic chemical exposure.

The Kanawha-Putnam County Emergency Management Director advised more than 40,000 residents, including the resident students at the West Virginia State University adjacent to the facility, to shelter-in-place for more than three hours as a precaution. The fire and drifting smoke forced the state police and local law enforcement authorities to close roads near the facility and the interstate highway, which disrupted traffic for hours.

The Chemical Safety Board (CSB) investigation team determined that the runaway chemical reaction and loss of containment of the flammable and toxic chemicals resulted from deviation from the written start-up procedures, including bypassing critical safety devices intended to prevent such a condition. Other contributing factors included an inadequate pre-startup safety review; inadequate operator training on the newly installed control system; unevaluated temporary changes, malfunctioning or missing equipment, misaligned valves, and bypassed critical safety devices; and insufficient technical expertise available in the control room during the restart.

Poor communications during the emergency between the Bayer CropScience incident command and the local emergency response agency confused emergency response organizations and delayed public announcements on actions that should be taken to minimize exposure risk. Although Bayer CropScience reported that “no toxic chemicals were released because they were consumed in the intense fires,” the CSB later confirmed that the only air monitors suitably placed near the unit to detect toxic chemicals were, in fact, not operational at the time of the incident. No reliable data or analytical methods were available to determine what chemicals were released, or predict any exposure concentrations.

The methomyl unit used the highly toxic chemical, methyl isocyanate (MIC), in a series of complex chemical reactions to produce methomyl, a dry chemical used to make the pesticide, Larvin. MIC is manufactured in a separate production unit at the facility and stored in large underground pressure vessels. Liquid MIC was pumped to a “day tank” pressure vessel near the Methomyl-Larvin unit, which provided the daily production quantity of MIC for the methomyl unit and the carbofuran unit, which is about 200 feet west of the methomyl unit. The MIC storage tank adjacent to the methomyl unit and the MIC transfer piping between the production unit and the manufacturing units were not damaged, nor did the MIC storage tank overheat or pressurize above the operating limits during the fire.

The CSB investigation identified the following incident causes:

1. Bayer did not apply standard Pre-startup Safety Review (PSSR) and turnover practices to the methomyl control system redesign project. The equipment was not tested and calibrated before the unit was restarted.
2. Operations personnel were inadequately trained to operate the methomyl unit with the new distributed control system (DCS).
3. Malfunctioning equipment and the inadequate DCS checkout prevented the operators from achieving correct operating conditions in the crystallizers and solvent recovery equipment.
4. The out-of-specification methomyl-solvent mixture was fed to the residue treater before the residue treater was pre-filled with solvent and heated to the minimum safe operating temperature.
5. The incoming process stream normally generated an exothermic decomposition reaction, but methomyl that had not crystallized due to equipment problems greatly increased the methomyl concentration in the residue treater, which led to a runaway reaction that overwhelmed the relief system and over-pressurized the residue treater.

Many industrial facilities in the Kanawha river valley that surrounds Charleston, West Virginia, the state capital, handle thousands of pounds of toxic and flammable materials. Local community involvement in safe handling of hazardous chemicals and emergency planning and the Kanawha Valley Industrial Emergency Planning Council date back to the 1950s. In 1995, the planning council was renamed the Kanawha Putnam Emergency Planning Committee, which functions as the local emergency planning committee (LEPC) as required by the Superfund Amendments and Reauthorization Act, Emergency Planning and Community Right-to-Know Act (SARA Title III).

Although federal law requires the owner or operator of the facility to promptly provide information to the LEPC necessary for developing and implementing the emergency plan [EPCRA 303(d)(3)], it does not provide LEPCs or other local agencies with the authority to conduct reviews of facility process safety programs or directly participate in hazard reviews or incident investigations. A few state governments have passed laws that authorize local governments to become directly involved with industry process safety programs. For example, the New Jersey Toxic Catastrophe Prevention Act, [1] created in 1986, significantly expands the requirements contained in the U.S. Environmental Protection Agency Risk Management Program (40 CFR68). In 1999, the Contra Costa County, California Board of Supervisors approved an industrial safety ordinance[2] that established broad authority to the county health services department to oversee local refining and chemical industries. The ordinance includes mandatory safety plan submission by regulated industries, and audit and facility inspections by the county.

Like Contra Costa County, the Kanawha valley has many facilities that handle large quantities of hazardous materials, some of which are acutely toxic. Furthermore, the valley contains environmentally sensitive areas such as the Kanawha River, which is an important transportation corridor. Yet, the local government does not have the authority to directly participate in facility safety planning and oversight even though many community stakeholders have long campaigned for such authority and involvement. The local government could adopt regulations and implement a program similar to Contra Costa County that would likely improve stakeholder awareness and improve emergency planning and accident prevention.

The Bayer CropScience investigation was the agency's first case involving company assertions of Sensitive Security Information (SSI) under the Maritime Transportation Security Act of 2002. Federal law requires a company to mark all SSI containing documents and notify the recipient that the documents must be controlled in accordance with Department of Homeland Security regulations. Early in the investigation, Bayer CropScience management asserted that most of their records contained SSI information, and therefore the CSB was prohibited from releasing it to the public. The

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[1] New Jersey Administrative Code Title 7 Chapter 31.

[2] Contra Costa County, California, Ordinance Code Title 4 – Health and Safety, Division 450 – Hazardous Materials and Wastes, Chapter 450-8 – Risk Management.

CSB consulted with the U.S. Coast Guard and determined that the Bayer claim was without basis. The president of Bayer CropScience, LP later admitted in testimony to the U.S. House of Representatives Committee on Energy and Commerce "[W]e concede that our pursuit of SSI coverage was motivated, in part, by a desire to prevent that public debate [concerning the use of MIC] from occurring in the first place." [3]

The controversy created by the SSI issue and the Bayer CropScience admission prompted the U.S. Congress to enact legislation to amend Section 70103(d) of Title 46, United States Code. The new law, titled ''American Communities' Right to Public Information Act,'' prohibits designating information to be SSI to "prevent or delay the release of information that does not require protection in the interest of transportation security, including basic scientific research information not clearly related to transportation security."

Ever since the 1984 tragic accident in Bhopal, India, which released highly toxic MIC into the community and killed thousands of nearby residents, many in the Kanawha valley community have tried to convince the owners of the Institute facility to drastically reduce or eliminate MIC. In fact, the Institute facility is the only facility in the United States that stores and uses large quantities of the highly toxic chemical. The August 2008 incident, which could have caused an MIC release into the nearby community, reinvigorated community pressure to reduce the MIC risk to the public.

In 2009, the U.S. House of Representatives Committee on Energy and Commerce asked the CSB to provide recommendations to Bayer CropScience, and federal and state regulators to "reduce the dangers posed by on-site storage of MIC." Many of the recommendations contained in this report address that request. Also in 2009, the U.S. Congress appropriated $600,000 to the CSB to directly

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[3] Statement of William B. Buckner, president and chief executive officer of Bayer CropScience, LP before the U.S. House of Representatives Committee on Energy and Commerce Subcommittee on Oversight and Investigations, April 21, 2009.

fund a study “by the National Academy of Sciences to examine use and storage of MIC…and feasibility of implementing alternative chemicals or processes at the facility.”

Bayer CropScience has taken specific action to reduce the risk of an incident involving MIC. The company did not rebuild the damaged methomyl unit and discontinued production of two of the MIC-based pesticides. The company also made an investment of more than $25 million to redesign and modify the MIC production unit to significantly reduce the on-site inventory of MIC and make other process upgrades to reduce the risk associated with handling large quantities of MIC. The improvements including eliminating the aboveground MIC storage vessels and replacing the underground storage vessels were scheduled to be completed by late 2010. In January 2011, Bayer announced it would eliminate the production of the two remaining carbamate pesticides, aldicarb and carbaryl, during 2012 and end all production, use, and storage of MIC.

Based on the findings of this report recommendations are made to Bayer CropScience located in Research Triangle Park, North Carolina, and in Institute, West Virginia. The Board also makes recommendations to the Secretary of the West Virginia Department of Health and Human Resources Commissioner of the Kanawha-Charleston Health Department, the West Virginia State Fire Commission, Kanawha Putnam Emergency Planning Committee, the Environmental Protection Agency, and the Occupational Safety and Health Administration. Implementation of the recommendations will improve hazardous chemicals management, and improve local government and community involvement with companies that use large quantities of hazardous chemicals.

1.0 Introduction

1.1 Background

On August 28, 2008, at about 10:25 p.m., two Bayer CropScience employees at the Institute, West Virginia, manufacturing facility were asked to investigate why pressure was unexpectedly increasing in the residue treater, a pressure vessel located on the south side of the Methomyl-Larvin unit about midpoint along an adjacent road. About 10 minutes later, as they approached the newly installed residue treater, it suddenly and violently ruptured. Approximately 2,200 gallons of flammable solvents and toxic insecticide residues sprayed onto the road and into the unit and immediately erupted in flames as severed electrical cables or sparks from steel debris striking the concrete ignited the solvent vapor.

Debris was thrown in all directions, some hundreds of feet. The 5,700-pound residue treater ripped out piping, electrical conduit, and a structural steel support column as it split apart and careened northeast into the Methomyl-Larvin production unit structure (Figure 1). The blast overpressure moderately damaged the unit control building and other nearby structures. Flying debris struck the protective steel shield blanket surrounding a 6,700-gallon methyl isocyanate (MIC) “day tank” located about 70 feet southwest of the residue treater (Figure 2), but did not damage the day tank. The steel blanket also protected the MIC day tank from the radiant heat generated by the nearby fires that burned for more than 4 hours.

One employee died at the scene from blunt force trauma and thermal burn injuries. Responding unit personnel helped the second employee out of the unit. He was transported to the Western Pennsylvania Burn Center in Pittsburgh, Pennsylvania, and died 41days later. Five Tyler Mountain firefighters and one Institute firefighter who assisted the Bayer CropScience fire brigade at the unit reported possible chemical exposure symptoms. Two Norfolk Southern railroad employees working at the facility the night of the incident also reported chemical exposure symptoms. None reported acute or long-term effects. Doctors identified heat exhaustion in at least two of the cases.

Figure 1. Residue treater came to rest inside the Methomyl-Larvin unit

The in-house fire brigade immediately responded to the incident. The Tyler Mountain and Institute Volunteer Fire Departments also arrived at the front gate of the facility to assist the fire brigade as planned in the mutual aid emergency response protocol. However, poor communications with the Metro 9-1-1 call center delayed the community shelter-in-place notification and interfered with effective off-site response activities.

The St. Albans, West Virginia, fire chief, unable to obtain specific information about the chemicals involved or the extent of the incident, prepared to issue a shelter-in-place for his community after he assumed that the smoke drifting across the river might contain toxic chemicals. After many unsuccessful attempts to communicate directly with the Bayer incident commander (IC) during the first hour of the incident, the Kanawha/Putnam County Emergency Management director declared a shelter-in-place, which affected approximately 40,000 residents. Approximately 3 hours later county authorities lifted the shelter-in-place about 3 hours later.

Figure 2. MIC day tank shield blanket structure

As far as 7 miles from the explosion epicenter, residences, businesses, and vehicles sustained overpressure damage that included minor structural and minor exterior damage and broken windows. Acrid, dense smoke billowed from the fire into the calm night air for many hours. Smoke drifted over Interstate 64 and nearby roads to the north of the facility, forcing many road closures and disrupting highway traffic.

Methomyl and solvents were released from the residue treater, and solvents and other toxic chemicals were released from ruptured unit piping including flammable and toxic MIC. The released chemicals rapidly ignited, producing undetermined combustion products. MIC air monitoring devices in and near the Methomyl-Larvin unit were not operational the night of the incident. Only two fenceline air monitors were operational, but they were more than 800 feet away and not located downwind of the smoke; in addition these fenceline monitors were only designed to detect carbon monoxide, hydrogen sulfide, flammable gas and oxygen. The four-gas air monitors[4] worn by emergency responders did not detect hazardous chemicals in the air near the unit. There were no reports of river water contamination from fire suppression water runoff.

The incident occurred during the first methomyl restart after an extended outage to install a new process control system and replace the old carbon steel residue treater with a stainless steel pressure vessel with equivalent pressure and temperature operating limits. The residue treater was designed to decompose methomyl in a heated methyl isobutyl ketone (MIBK) solvent. During normal operations, dissolved methomyl and other waste chemicals were fed into the preheated residue treater partially filled with solvent. The methomyl safely decomposed inside the residue treater to a concentration of less than 0.5 percent by weight.[5] The liquid was then transferred to an auxiliary fuel tank where it was mixed with other flammable liquid waste materials and used as a fuel in one of the facility boilers.

On the night of the incident, methomyl-containing solvent was pumped into the residue treater before the vessel was pre-filled with clean solvent and heated to the required minimum operating temperature specified in the operating procedure. The emergency vent system was overwhelmed by the evolving gas from the runaway decomposition reaction of methomyl, and the residue treater

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[4] Fire department and other emergency responder personnel typically wear a "four-gas air monitor" to measure concentrations of carbon monoxide and hydrogen sulfide, flammable gas, and oxygen concentration. An alarm sounds if any of the measured gases exceed the setpoint programmed in the detector.

[5] All percent values used in the report are weight percent unless noted.

violently exploded. The estimated energy of the explosion was equivalent to about 17 pounds of TNT (See Appendix C).

1.2 Investigative Process

The CSB investigation team arrived at the Bayer CropScience facility the morning of August 30, 2008, and met with the Bureau of Alcohol, Tobacco, and Firearms and Explosives (ATF), Occupational Safety and Health Administration (OSHA) investigators, and Bayer management personnel to explain the CSB purpose and authority for conducting an investigation independently of other agencies and organizations. On September 2, 2008, the ATF concluded that the incident was not a criminal act and ceased its on-scene investigative activities.

Over the following 6 weeks, the CSB investigators examined and photographed the residue treater and associated process equipment; MIC day tank, blast blankets, and support structure; surveyed the control building damage; mapped the debris field; interviewed employees working at the facility on the night of the incident; and interviewed outside emergency personnel who participated in the response. The team examined methomyl unit operating procedures, control system data, process chemistry documents, worker training records, and maintenance records. Finally, the CSB commissioned computer modeling to evaluate the blast shield used to protect the MIC day tank.

1.2.1 Agency Access to Security Related Documents

The Bayer CropScience investigation is the first incident investigated by the CSB that involves the Maritime Transportation Safety Act[6] and Sensitive Security Information (SSI). SSI is information that, if publicly released, would be detrimental to transportation security.[7] Federal law requires a company to mark all documents containing SSI and to notify the recipient that the documents must be controlled in accordance with Department of Homeland Security regulations. Bayer's attempts to use

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[6] 46 U.S.C. § 70102

[7] 49 CFR 1520.

the SSI designation to suppress public disclosure of information related to the investigation forced the CSB to delay the planned interim public meeting and ultimately led to congressional action to prevent future misuse of the regulation.

In January 2009, the Head of the Health, Safety, and Environment Expertise Center at the Bayer CropScience Institute facility contacted the U.S. Coast Guard Commanding Officer, Marine Safety Unit in Huntington, West Virginia and suggested “to discuss this [SSI] further with your headquarters so that we can better communicate to the CSB and possibly discourage them from even seeking this information.” [8] Then, in March 2009, Bayer CropScience sent a letter to the CSB asserting that many of the documents already delivered to the CSB contained SSI and requested the documents be returned to them so each page could be marked as required by the regulation. The company also claimed photos, interview records, and other CSB produced investigatory documents might contain SSI. The CSB declined the request to return the documents and a later request to examine the documents at the CSB office and directed Bayer CropScience to properly label and resubmit all SSI containing documents. Bayer CropScience officials later admitted they had attempted to use the Maritime Transportation Safety Act to block public disclosure of information related to methyl isocyanate and possible negative publicity.

The controversy created by raising the SSI issue to restrict CSB investigative activities resulted in the U.S. Congress enacting legislation on October 8, 2009, to amend Section 70103(d) of title 46, United States Code. The new law, titled the “American Communities’ Right to Public Information Act”[9] added the following restriction on SSI claims:

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[8] E-mail from the Head, Health, Safety, and Environment Expertise Center, Bayer CropScience, to the Commanding Officer, Marine Safety Unit Huntington, U.S. Coast Guard (Jan. 29, 2009).

[9] Public Law 111-83.

‘‘(d) Nondisclosure of information, 2) Limitations.—Nothing in paragraph (1) shall be construed to authorize the designation of information as sensitive security information (as defined in section 1520.5 of title 49,Code of Federal Regulations ; (A) to conceal a violation of law, inefficiency, or administrative error; (B) to prevent embarrassment to a person, organization, or agency; (C) to restrain competition; or (D) to prevent or delay the release of information that does not require protection in the interest of transportation security, including basic scientific research information not clearly related to transportation security.

1.2.2 CSB Interim Public Meeting

On April 28, 2009, the CSB held a public meeting in Institute, West Virginia, which was attended by more than 250 people. The investigation staff presented the incident timeline, described the processes and equipment involved, described the county emergency response activities, and summarized the preliminary findings of the investigation. The meeting included presentations from Bayer CropScience, the West Virginia State Fire Marshal, the Kanawha Putnam County Emergency Management Director, a representative from the International Association of Machinists, a chemical industry expert, and a representative from the community advocacy group People Concerned about Methyl Isocyanate.

The Board also heard testimony from 16 people in attendance including residents who live near the facility, the president of West Virginia State University, workers from Bayer CropScience, and other interested individuals.

1.3 Facility Description

1.3.1 Institute Manufacturing Industrial Park

The Institute facility is located 9 miles west of Charleston, West Virginia, and is bordered on the north by Route 25 and Interstate 64, on the east by the West Virginia State University, and along the south by the Kanawha River. St. Albans, West Virginia, is across the river 3 miles west (Figure 3). Raw materials and products used or manufactured at the facility are transported by truck, rail, and barge.

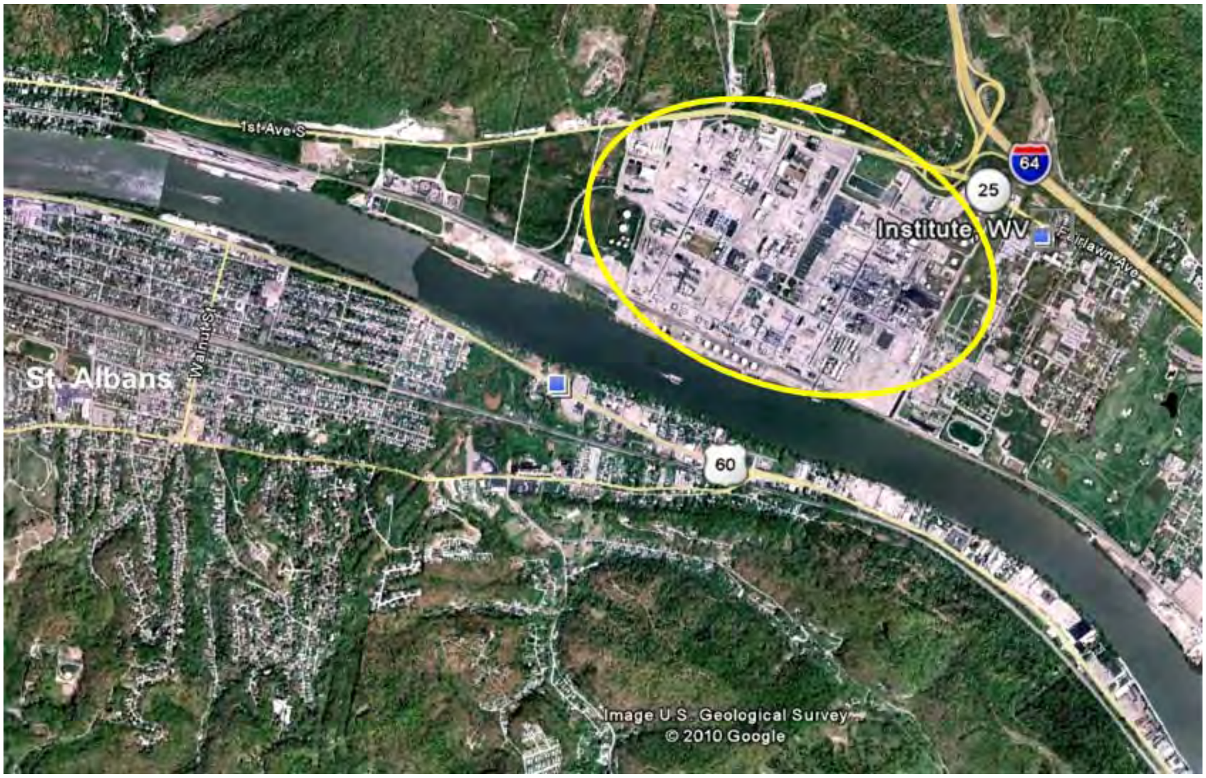

Figure 3. Institute Manufacturing Industrial Park

1.3.2 Facility Ownership History

The site was originally Wertz Field Airport and closed in 1942 to become a large, government-sponsored synthetic rubber production plant for the World War II effort managed by the Carbide and Carbon Chemicals Corporation and the United States Rubber Company. In 1947, the Union Carbide Corporation (UCC) purchased the plant to produce carbamate insecticides. In 1986, Rhone-Poulenc, a French-owned chemical company, purchased the agricultural division of UCC and operated the Institute facility until 2000. Aventis, formed by a merger of Rhone-Poulenc and AgrEvo, took over the facility until Bayer CropScience acquired it in 2002.

In August 2008, the 460-acre, multi-tenant Institute Manufacturing Industrial Park employed approximately 645 workers. The seven tenants on the facility included Bayer CropScience, Adisseo, FMC Corporation, Dow Chemical, Catalyst Refiners, Reagent Chemical, and Praxair (Figure 4). The site contains 16 production units and five utility and support units. Some of the tenants produce chemicals that are used as feedstocks in units owned or operated by other tenants.

Figure 4. Seven tenants own or operate processes at the Institute Industrial park

Bayer owns and operates nine production and utility units. Two additional process units are operated by Bayer employees under contractual agreements with the unit owners, Adisseo, and FMC. Bayer employs approximately 545 at the Institute facility.

1.4 Bayer CropScience, LP

Bayer CropScience is an independently operated company within Bayer, AG, (Bayer Group) which is the chemical and pharmaceutical parent company headquartered in Leverkusen, Germany. Bayer CropScience, Bayer HealthCare, and Bayer Material Science make up the three business areas of the Bayer Group.

The Bayer CropScience business, headquartered in Monheim, Germany, employs more than 18,000 personnel in more than 120 countries. A 12-member global executive committee, including the Bayer Board of Management chairperson, manages Bayer CropScience. Executive committee members oversee research, operations, planning, and administrative functions, as well as regional business areas. A 12-member supervisory board composed of Bayer Group executives, independent experts, and trade union representatives comprise a supervisory board to oversee company operations. The Bayer CropScience U.S. headquarters is in Research Triangle Park, North Carolina.

Bayer CropScience (Bayer) is a global provider of crop protection agents, such as insecticides, herbicides, and fungicides for commercial and private consumer use. The Crop Protection division serves the agriculture sector and the BioScience division uses gene technology to produce genetically modified crops as an alternative to conventional pesticide applications. The Environmental Science division provides services for professional weed and pest control customers.

1.4.1 Institute Operations

Bayer has three insecticide manufacturing complexes on the Institute site supported by two powerhouses and a wastewater treatment unit. The East Carbamoylation Complex (ECC) includes the MIC and Phosgene production unit and the Aldicarb and Carbaryl units. The MIC and phosgene production unit supplies feedstock to the Aldicarb and Carbaryl unit for the production of insecticides. The Methomyl-Larvin® unit occupied the West Carbamoylation Complex (WCC), along with the FMC-owned carbosulfan and carbofuran unit, which was operated by Bayer. The Adisseo-owned Rhodimet® unit makes up the third complex that Bayer also operates.

1.5 Bayer Operating Organization

For many years the methomyl unit operated in a traditional organizational structure for chemical plant operating units; that is, with a first-line supervisor who directed the work of a team of operators. Four operating crews typically covered rotating shifts, and each team included a supervisor and a crew of operators. The supervisor's responsibilities included monitoring the operators' work to ensure that they were successfully running the process and included completing administrative tasks for those operators, such as scheduling, payroll, sick-time call-out, safety and health, and other supervisor duties. The supervisor and the operators worked the same rotating shift, and except when filling in as substitutes on other shifts or units for worker vacations and sick days, the operators reported directly to the same supervisor when they worked their normal schedule. The operators worked with the supervisor an average of 40 hours per week. If the operators had questions about their job or administrative procedures, they generally asked the supervisor who was in the unit with them at that time.

From 2004 to 2007, Bayer management analyzed and restructured the unit supervisory and technical oversight staffing. First-line supervisor positions in each operating unit were eliminated and self-directed, or self-empowered work teams were implemented. Four teams of operators worked rotating shifts, supported by a Technical Advisor and Run Plant Engineer, both day-shift workers. Instead of a first-line supervisor, all operators including the Technical Advisor report to the Production Leader (Figure 5).

A single Industrial Park Site Shift Leader, which management describes as a "first among equals," is responsible for all facility operations, rotates on shift with the shift operators, and oversees site operations. Some personnel in the Shift Leader role have prior experience as first-line supervisors on various operating units. However, the Shift Leader is not a first-line supervisor, as none of the operators report to him/ her. Instead, the Shift Leader oversees the entire facility and can advise in any area of the plant as necessary. The Shift Leader also serves as the Incident Commander if an incident requires emergency response. Bayer management describes Shift Leaders as "very good operators who have worked their way through the technical advisor role."

Bayer intended the Technical Advisor, who is not a first-line supervisor, to be an experienced operator who works the day shift, helps schedule production to meet demand, and advises the on-shift operators. The operators can call the Technical Advisor and ask questions any time of the day or night. The other operators do not report to him/her, and the Technical Advisor does not have the strong work-checking or "looking over the shoulder" function of a historical first-line supervisor or foreman.

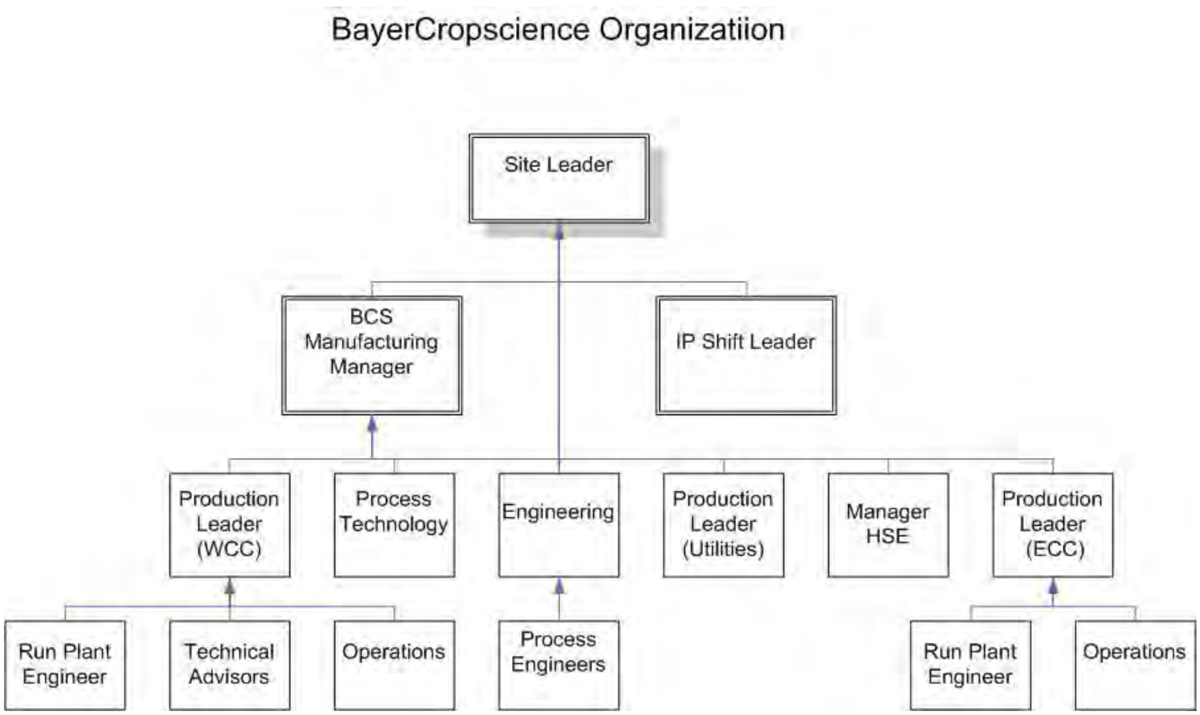

Figure 5. Institute site organization structure.

1.6 Process Chemicals

1.6.1 Methomyl

Bayer produced methomyl for international customers and as an intermediate feedstock used to make Larvin® (Thiodicarb), an insecticide and ovicide.[10] Methomyl is a white, crystalline solid with a slight sulfurous odor. Methomyl dust is combustible and can form explosive mixtures when dispersed in air. It was introduced in 1966 as a carbamate insecticide and registered by the U.S. Environmental

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[10] An ovicide is a chemical used to control insect larvae. Larvin is used worldwide on crops such as corn, cotton, fruits, grapes, sorghum, soybeans, and vegetables.

Protection Agency (EPA) in 1968 as a restricted use pesticide[11] due to its high human toxicity. It is a broad-spectrum insecticide used on vegetable, fruit, and cotton crops worldwide and targets insects though direct contact and systemic absorption.

Methomyl is a cholinesterase inhibitor that disrupts central and peripheral nervous system functions. Routes of exposure include inhalation, ingestion, and skin and eye absorption. Reversible and irreversible effects can result depending on the concentration and duration of the exposure. The National Institute for Occupational Safety and Health (NIOSH) recommended exposure limit (REL) for methomyl is 2.5 mg/m3. When burned, methomyl decomposes to form toxic gases and vapors such as nitrogen oxides, sulfur oxides, acetonitrile, hydrogen cyanide, and methyl isocyanate (Sittig, 2008).

Table 1 lists the exposure limits, characteristics, and OSHA Process Safety Management (PSM) and EPA Risk Management Program (RMP) threshold quantities for the principal chemicals used to make methomyl. Phosgene is used to make MIC and MIC is used to make methomyl; both phosgene and MIC are highly toxic.

1.6.2 Phosgene

Phosgene is a colorless, dense gas that smells like freshly cut hay or grass. Although highly toxic, phosgene is an important industrial chemical used to make thermoplastics such as eyeglass lenses, and isocyanates, intermediate chemicals used to make polyurethanes and pesticides.

[11] Restricted use pesticides are limited to commercial applicators certified by the EPA and the Food and Drug Administration (FDA) state programs for pesticide safety education under the Federal Insecticide, Fungicide and Rodenticide Act (FIFRA).

Table 1. Characteristics of the toxic chemicals used to manufacture methomyl

Chemical	NIOSH IDLH[12] (ppm)	NIOSH REL (ppm)	OSHA PEL (ppm)	ACGIH TLV (ppm)	Odor Threshold[13] (ppm)	Odor	RMP Threshold (lbs)	PSM Threshold (lbs)
Chlorine	10	0.5	1	0.5	0.002	characteristic odor	2500	1500
Methyl Isocyanate	3	0.02	0.02	0.02	2	sharp, strong odor	10,000	250
Methyl Mercaptan	150	0.5	10	0.5	0.002	garlic or rotten cabbage	10,000	5000
Phosgene	2	0.1	0.1	0.1	0.4	hay or grass	500	100

The NIOSH-recommended time-weighted average concentration limit is 0.1 ppm.[14] Phosgene reacts with proteins in the pulmonary alveoli, disrupting the blood-air barrier in the lungs. The onset of symptoms may be delayed and, based on available information, there appears to be no specific proven antidote against phosgene-induced lung injury. However, clinical experience indicates that early treatment of suspected phosgene exposure may be more effective than treating clinically overt pulmonary edema. Early treatment options include steroids and positive airway pressure ventilation, Patients are expected to fully recover from low-dose exposure.

Bayer produces phosgene at the Institute facility by reacting carbon monoxide and chlorine gas in the presence of a carbon catalyst. The phosgene is stored in the ECC until it is used in three nearby

[12] The NIOSH definition for an IDLH exposure is a condition that poses a threat of exposure to airborne contaminants when that exposure is likely to cause death or immediate or delayed permanent adverse health effects or prevent escape from such an environment.

[13] An odor threshold is the lowest airborne concentration that can be detected by a population of individuals.

[14] Time-weighted average concentration is based on up to a 10-hour workday during a 40-hour work week.

process units and to make methyl isocyanate, an intermediate chemical used to make four additional products.

1.6.3 Methyl Isocyanate

Methyl isocyanate, or MIC, is one of the key chemicals used to make methomyl and two other products at the Institute site. MIC is a clear, colorless liquid with a strong, pungent odor, is highly reactive with water, and must be stored in stainless steel or glass containers at temperatures below 40 °C (104 °F) to prevent a highly exothermic[15] self-polymerization reaction.

The NIOSH-recommended time-weighted average concentration limit is 0.02 ppm. MIC can damage human organs by inhalation, ingestion, and skin contact in quantities as low as 0.4 ppm. Exposure symptoms include coughing, chest pain, dyspnea, asthma, irritation of the eyes, nose, and throat, and skin damage. Exposure levels above about 21 ppm can result in pulmonary or lung edema, emphysema and hemorrhages, bronchial pneumonia, and death.

Bayer is the only facility in the U.S. that manufactures, stores, and consumes large quantities of MIC. It stores the liquid in underground pressure vessels in the MIC production unit located in the ECC, about 2,500 feet east of the Methomyl-Larvin unit. Each pressure vessel is insulated and double-wall construction, with leak detection in the annulus between the inner and outer wall. The MIC is refrigerated to between -10 °C and 0 °C (14 and 32 °F).

Prior to the incident, liquid MIC was transferred through an insulated piping system to an aboveground pressure vessel called a “day tank” located on the southwest corner of the Methomyl-

[15] An exothermic reaction is a chemical reaction that generates heat.

Larvin production unit near the control room.[16] After refilling the day tank, operators drained the transfer line and purged it with nitrogen.

The maximum MIC inventory in the 6,700-gallon capacity, stainless steel day tank was approximately 37,000 pounds (about 75 percent full). The pressure vessel was rated at 100 psig, but it was normally operated at 10 psig using a dedicated nitrogen supply system. The MIC was circulated through a chiller, and cooling coils were attached to the outside of the insulated day tank to maintain the MIC between -10 °C and 0 °C (14 and 32 °F). The chiller used a non-MIC reactive solvent, MIBK, rather than a water-ethylene glycol mixture to prevent a possible MIC-water reaction should the chiller leak. The MIBK system pressure was maintained greater than the MIC system pressure and the refrigerated ethylene glycol-water mixture system pressure in the MIBK chiller to ensure that water would not enter the MIC system in the event of a leak in both heat exchangers.

The control system contained redundant pressure, temperature, and flow instruments including high-pressure and high-temperature alarms and refrigeration system failure alarms. The area around the tank was equipped with air monitors to detect MIC. Firewater monitors (stationary spray nozzles) were located nearby to mitigate an MIC leak and suppress a fire that might threaten the tank. A wire rope blast blanket surrounded the entire tank and top piping connections (Figure 2) to stop debris from striking the day tank and to provide a thermal shield from radiant heat from a nearby fire. Finally, an emergency dump tank adjacent to the day tank was available to receive the contents of the MIC day tank and cross plant transfer line.

The MIC recirculation system, carbofuran unit transfer line, and the cross plant transfer line were equipped with emergency block valves that were operated from the control room. Emergency

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[16] The day tank at the Methomyl-Larvin unit also supplied MIC to the FMC-owned carbosulfan - carbofuran unit through a double wall piping system. Bayer stopped using the day tank, cross-unit transfer piping and FMC unit in August 2010 as part of the MIC storage reduction effort.

generators provided power to the refrigeration system in the event of a loss of normal plant electricity. MIC system vents were connected to the process and emergency vent systems.

1.7 Methomyl-Larvin Unit

The Methomyl-Larvin unit is located in the West Carbamoylation Complex (Figure 6). Methomyl was produced, packaged, and stored in a unit warehouse for later use in manufacturing Larvin or sold directly to commercial customers. Control room and outside operators were trained to work on both the methomyl and Larvin units. Although independent, both units were operated from the same control room (Figure 7).

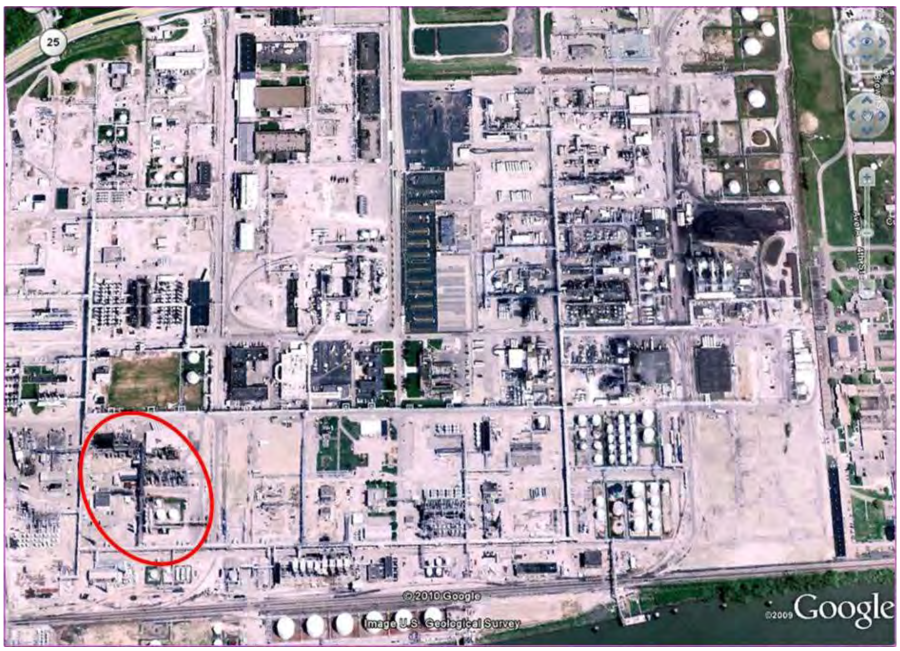

Figure 6. Aerial view of Bayer Institute Manufacturing Park. Methomyl-Larvin unit (circled) is in the West Carbamoylation Complex

Figure 7. Overhead view of the Methomyl-Larvin production unit

1.7.1 Methomyl Synthesis

Methomyl production involved a series of complex chemical reactions. The process began by reacting aldoxime and chlorine to make chloroacetaldoxime, which was reacted with sodium methyl mercaptide in MIBK solvent to produce methylthioacetaldoxime (MSAO). Finally, MSAO was reacted with methyl isocyanate in MIBK to produce methomyl (Figure 8). Excess MIC was removed from the methomyl-solvent solution and then the solution was pumped to the crystallizers where an anti-solvent was added to cause the methomyl to crystallize. Finally, the crystallized methomyl was separated from the solvents in the centrifuges and the methomyl cake was removed from the centrifuges, dried, cooled, packaged in drums, and moved to the warehouse. The liquid exiting the centrifuges, known as mother liquor, contained MIBK and hexane, very small quantities of methomyl, and other impurities.

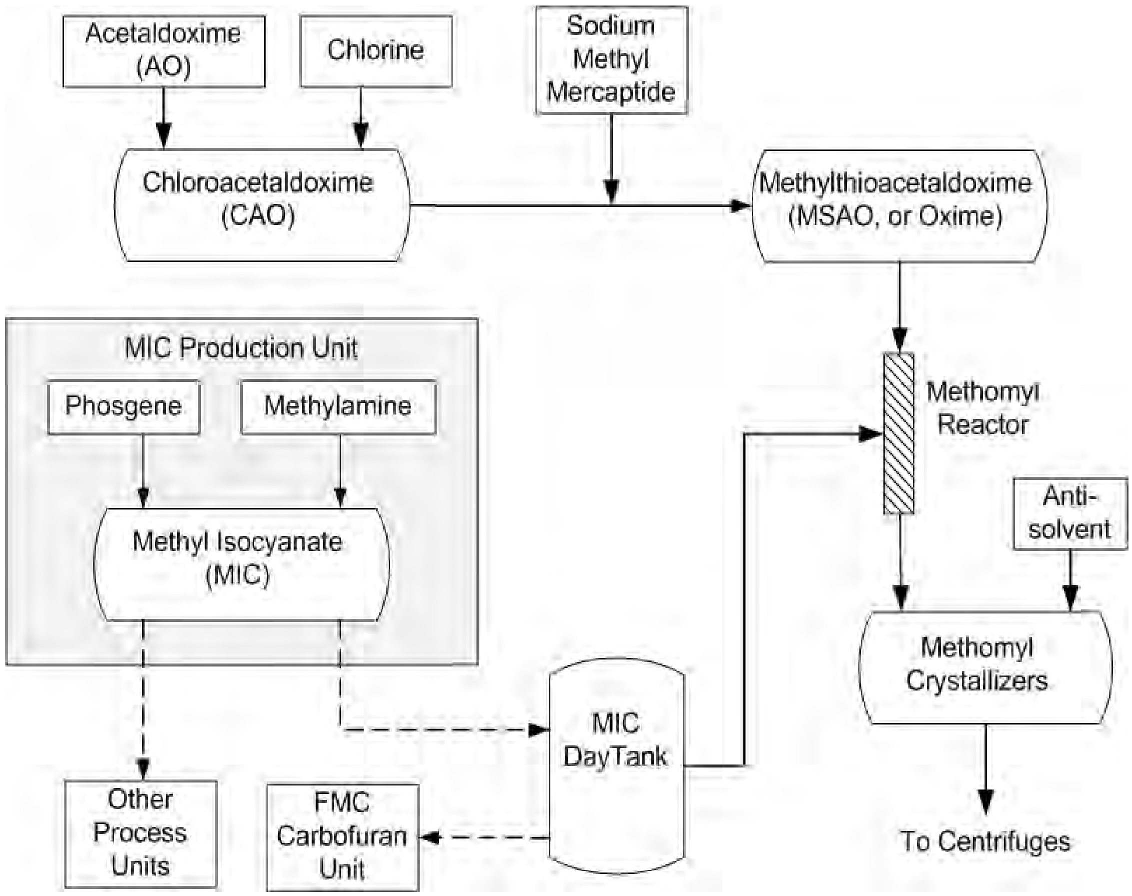

Figure 8. Methomyl synthesis process flow (dashed lines are unit-to-unit transfer pipes)

Distillation separated the solvents in solvent recovery flashers and recycled the solvents back to the beginning of the process (Figure 9). The unvaporized solvents and impurities including up to about 22 percent methomyl, accumulated in the bottom of the flasher. The flammable liquids could be used as fuel in the facility steam boilers. However, before this flammable waste liquid, called "flasher bottoms," could be pumped to an auxiliary fuel tank, the methomyl concentration had to be reduced to not more than about 0.5 percent for environmental and processing considerations.[17]

[17] The maximum methomyl concentration limit in the auxiliary fuel was based on environmental effluent criteria and the prevention of an uncontrolled methomyl decomposition reaction in the auxiliary fuel storage tank.

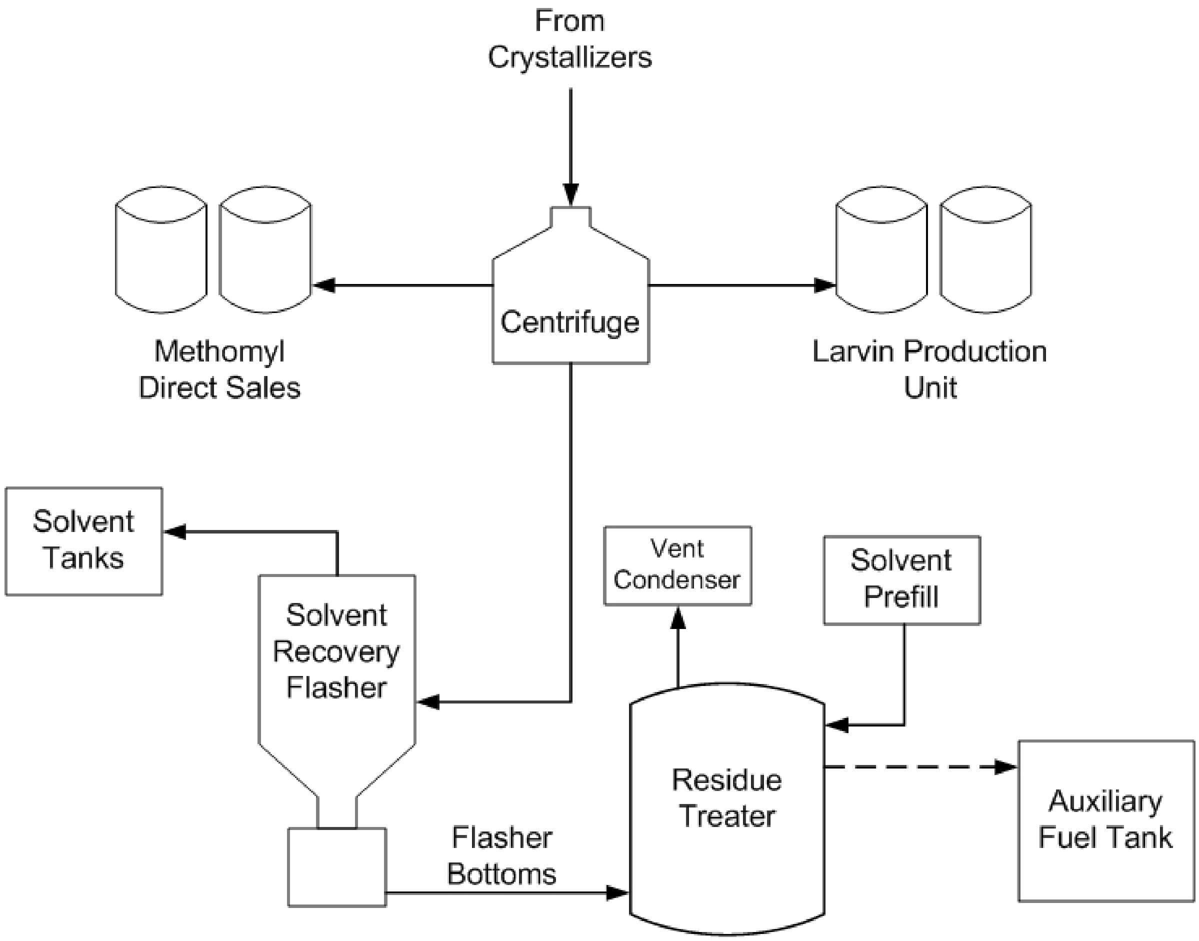

Figure 9. Methomyl centrifuge and solvent recovery process flow

The residue treater was used to dilute the incoming flasher bottoms in MIBK solvent and was designed to operate at a high enough temperature, and with sufficient residence time, to decompose the methomyl in the flasher bottoms stream to below 0.5 percent. The solvent and residual waste material were transferred to the auxiliary fuel tank for use as a fuel in the facility steam boiler. Vapor generated in the methomyl decomposition reaction exited through the vent condenser to the process vent system where toxic and flammable vapor were removed.

1.7.2 Control System Upgrade

Operators were qualified to operate the methomyl and the Larvin units, each from a separate work station in the control room. In 2007 Bayer upgraded the Larvin unit control system to a Siemens distributed control system (DCS)[18] and upgraded the methomyl control system during the 2008 methomyl outage.[19] Bayer, with assistance from Siemens, conducted formal operator training on the Larvin control system upgrade in 2007 and by spring 2008, the operators were proficient in using the Larvin DCS.

The DCS contains three control system interlock matrices: Safety, Operating, and Control. The safety matrix consists of pre-defined process deviations and computer-controlled process actions that determine how and when fail-safe automatic control functions are activated. The status of all safety matrix interlocks is displayed on a color-coded spreadsheet on the display console. Process mimic screens[20] also displayed safety matrix component cause/effect[21] status next to the component icon. A password, which board operators did not have access to, was required to bypass (override) or change a safety matrix cause/effect fail-safe control.

Like the Larvin system upgrade, board operators and unit engineers directly participated in configuring the design of the methomyl DCS. New display screens designed to mimic the process flow incorporated automated icons for critical equipment to show operating status and other parameters, included a mouse user interface, and featured improved human-machine interfaces.

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[18] DCS are dedicated systems used to control manufacturing processes that are continuous or batch-oriented. The DCS is connected to sensors and actuators and uses setpoint controls to control process variables.

[19] The methomyl process was not run year-round, as demand for methomyl was such that the methomyl unit was operated for a few months at a time with extended outages between runs. The optimal time to perform major repairs and system upgrades was during these outages.

[20] A mimic screen is a simplified graphical representation of a process that uses icons to display piping and equipment with color-coded operating status, instrumentation with output values and setpoint data, and other key equipment and information maintain situation awareness and to control the process.

[21] A safety matrix cause element is a pre-defined process deviation value that triggers the specified process component action or effect. For example, if the tank level exceeds the high-high setpoint (the cause), the fill line process valve is commanded to close (the effect).

1.7.3 Residue Treater

The residue treater was a 4,500-gallon pressure vessel with a maximum allowable operating pressure of 50 psig. The relief system on the residue treater was designed to handle a maximum methomyl concentration not to exceed 1.0 percent.

The vessel mechanical integrity program inspection results found that the 25-year-old vessel had sustained significant wall thinning due to generalized corrosion. Using the management of change (MOC) program, Bayer replaced the vessel during the summer 2008 outage with a new stainless steel pressure vessel to improve corrosion resistance. The existing recirculation piping, controls, and instruments were not modified.

The vent condenser piping at the top of the residue treater was prone to blockages during unit operation. Gases that evolved from the methomyl decomposition reaction passed through the vent condenser to the flare system. The gas flow carried trace amounts of solid material into the vent system where they were deposited on the surface of the pipe. Over time, the accumulating deposits would choke the flow and cause the residue treater pressure to climb. The board operator directed outside operators to attach a temporary steam line to the vent pipe and flush the deposits from the vent pipe whenever the deposits blocked the vent and caused the residue treater pressure to approach the upper operating limit.

Because the original design did not consider the need to periodically clear blockages, the valves and connection ports were hard to reach, so Bayer repositioned them during the unit outage to improve access.

1.7.3.1 Residue Treater Operation

The residue treater (Figure 10) had an automatic level control system to control the liquid level at about 50 percent. The residue treater recirculation system was used to heat the solvent at the beginning of a new production run, mix the incoming flasher bottoms into the partially filled vessel, and remove excess heat generated from the exothermic decomposition of the methomyl inside the vessel.

An automatic temperature control system on the residue treater monitored both the bulk liquid temperature in the residue treater and the liquid in the recirculation loop. During startup, the control system modulated the recirculation and steam flows through the heater. When the liquid temperature increased to the setpoint limit, the control system closed the steam flow valve, and changed the position of the circulation valves to redirect the recirculation flow from the heater to the cooler. The cooler was provided with constantly circulated 80 °C (176 °F) water, which was sufficient to remove excess heat from the decomposing methomyl and to maintain the liquid temperature within the operating limits, provided that the bulk methomyl average concentration inside the residue treater remained below about 0.5 percent.

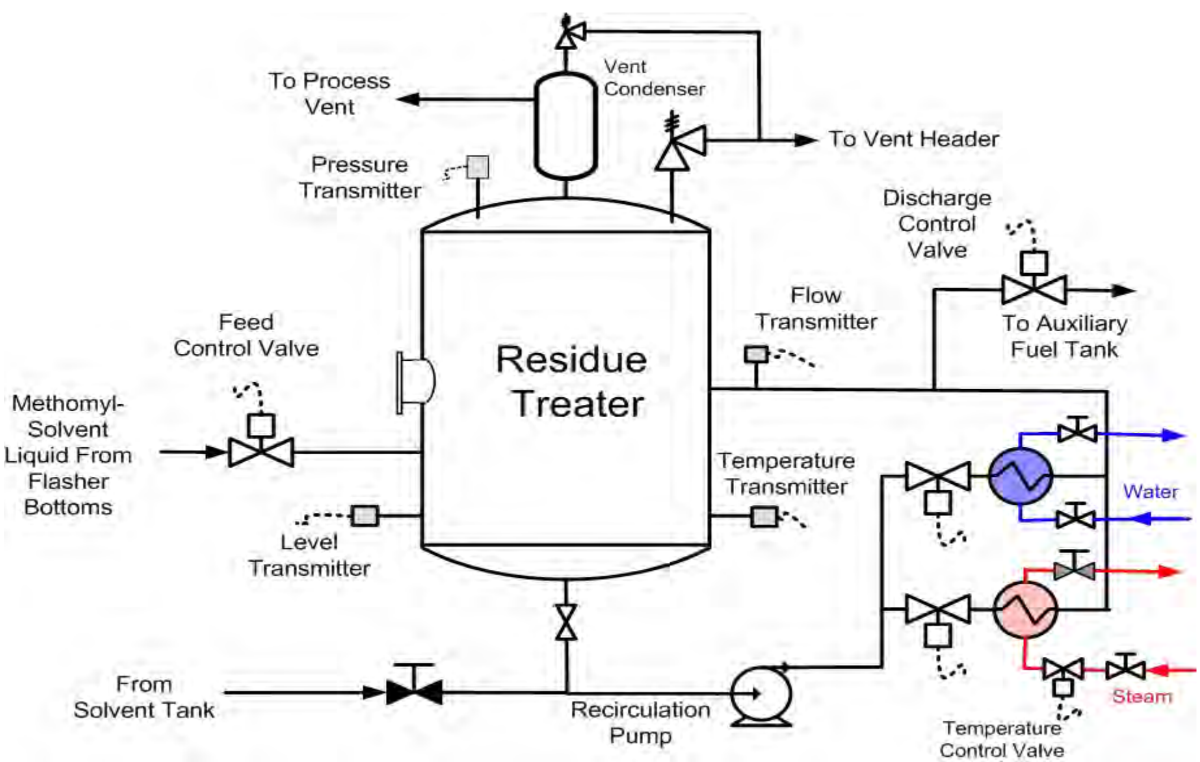

Figure 10. Residue treater piping system layout

At normal operating conditions, the temperature of the flasher bottoms liquid was kept at about 80 °C (176 °F) to prevent an uncontrolled auto-decomposition of the higher concentration methomyl. The contents of the residue treater were maintained at approximately 135 °C (275 °F), the temperature that assured the incoming methomyl quickly decomposed so as not to accumulate to an unsafe concentration inside the residue treater. As the flasher bottoms liquid entered the hot solution in the residue treater, the methomyl began to decompose. The exothermic heat of decomposition was controlled by vaporization, and condensing of the solvent in the vent cooler, supplemented as needed by the recirculation loop cooler.

1.7.3.2 Operating Limit Control Interlocks

The residue treater control system was equipped with operating limit controllers integrated into the automatic feed control valve operation. A minimum temperature interlock and a maximum pressure interlock prevented the feed control valve from opening until the minimum temperature of the residue treater contents were at or above the setpoint and the residue treater pressure was below the setpoint, respectively. Both were designated as safety interlocks; thus, bypass control was password-protected. A third interlock, designated "operating," also prevented the feed control valve from opening until residue treater recirculation flow was established. The standard operating procedure (SOP) specifically discussed the importance of these interlocks:

> Mother liquor flasher tails [flasher bottoms] can not be introduced into the residue treater until the pressure is not high-high, the tank temperature is not high-high or low-low and the circulation flow is not low-low.

The SOP contained an administrative control[22] that the operator had to perform before putting the residue treater methomyl feed in automatic operation: "If the tank is allowed to cool below 130 °C [266 °F], for any reason, it must be sampled before being heated up again." Furthermore, the SOP

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[22] An administrative control is an action or activity that is described and managed through a specific operating or maintenance procedure.

cautioned, “[I]f the methomyl concentration is above 1.3 %, a run away [sic] reaction could result upon heating the tank.” Furthermore, the process hazards analysis stated:

> [R]egular samples of residues [flasher bottoms] from the flasher would assure proper operation and safety...Take regular samples of residues from the flasher and residue treatment tank. This will assure proper operation and safety since safety relief sizing is based on a certain maximum methomyl concentration in each item.

However, the SOP did not require analyzing the flasher bottoms, nor was the system configured such that operators could collect a liquid sample for analysis. As discussed in the incident analysis, one key factor contributing to the incident was that the operators were unaware the flasher bottoms contained an excessively high concentration of dissolved methomyl.

1.7.3.3 Startup and Operation

The SOP contained specific steps for starting the residue treater. During these startup steps, the flasher bottoms flow control valve was to be set in the manual, closed position. The safety interlocks on the flasher bottoms flow control valve were designed to prevent feeding methomyl into the residue treater until the limit conditions were satisfied. The startup sequence also required the operator to sample the liquid remaining in the residue treater from the previous run and send it to the lab to confirm that it contained less than 0.5 percent methomyl.

The startup sequence required the board operator, with the assistance from an outside operator, to manually pre-fill the residue treater with solvent to the minimum level of about 30 percent and to start the pump and achieve steady state recirculation. After reviewing the residue treater sample lab results to confirm the methomyl concentration was below 0.5 percent, the board operator started the solvent heating cycle, which was typically controlled automatically by the computer system. Finally, the SOP required the outside operator to collect another sample of the residue treater contents and send it to the lab for analysis to re-verify that the liquid contained not more than 0.5 percent methomyl.[23] Once confirmed, the board operator set the flasher bottoms flow control valve in the automatic position, and flasher bottoms would begin entering the residue treater. These steps ensured that when the flasher bottoms began flowing into the residue treater, the flasher bottoms were diluted and heated so that the methomyl would decompose rather than accumulate above safe limits.

As long as the flasher and residue treater level controllers and temperature controllers were set to automatic, no further operator action was required to control the system. The SOP required the outside operator to collect a liquid sample from the residue treater only once every 24 hours and send it to the lab to confirm that the methomyl concentration in the liquid being transferred to the alternate fuel tank remained below 0.5 percent.

The residue treater liquid level control was designed to operate in the automatic, continuous flow mode. However, in this operating mode, the flow rate was very low; thus, the alternate fuels outgoing transfer pipe frequently became plugged with viscous material. Therefore, the board operators kept the level controller in the manual operating mode and allowed the residue treater level to increase to the upper fill limit, and periodically transferred the liquid at a much higher flow rate to prevent the line from becoming plugged. The SOP was not revised to incorporate this change.

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[23] Since the residue treater was new and not previously operated, this step was not needed for the August restart. However, the SOP did not allow this deviation.

2.0 Incident Description

The incident is described in chronological order, beginning with pre-startup activities that contributed to the conditions leading up to the explosion. It continues with equipment preparation, then through the startup of the principal methomyl unit subsystems. This section next discusses the specific conditions that led to the runaway reaction in the residue treater and ends with the emergency response discussion.

2.1 Pre-Startup Activities

Unlike the normal methomyl restart after a routine shutdown, the August restart involved operations personnel, engineering staff, and contractors working around the clock to complete the control system upgrade and residue treater replacement. Work included finalizing the software upgrades, modifying the work station, calibrating instruments, and checking critical components. Board operators were provided time at the methomyl work station so that they could familiarize themselves with the new control functions, equipment and instrument displays, alarms, and other system features. Other personnel were completing the residue treater replacement, reinstalling piping and components, and reconnecting the control and instrument wiring. These activities progressed in parallel with the ongoing Larvin unit operation.

The methomyl control system upgrade required a revision to the SOP to incorporate the changes needed to operate the methomyl unit with the new Siemens system, and to reformat the SOP to a computerized document. However, at the time of the incident the SOP revision remained incomplete; the operators were using an unapproved SOP [24] that did not contain the new control system operating details.

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[24] The review and approval record of the working copy in use at the time of the incident was unsigned. A watermark on each page read “draft in review 11/13/07.”

2.1.1 Solvent Flush and Equipment Conditioning

Many of the subsystems in the methomyl unit required a solvent flush and nitrogen gas purge to clean and dry the systems before startup. These activities were critical to safely start the residue treater system as the feed, recirculation, and vent piping had been disconnected and a new pressure vessel had been installed. The solvent-only run was also needed to verify instrument calibrations, proper equipment operating sequences, and other operating parameters in the new DCS.

The staff flushed the process equipment with solvent to remove contaminants and water that might have gotten into the system during the outage. However, contrary to the SOP [25] the staff did not perform the residue treater solvent run.[26] Operators reported that solvent flow restrictions upstream impeded completion of instrument calibrations because the proper adjustments could not be made at low flow rates. Even had the staff not needed to verify the control system function and operability, the solvent run was required to pre-fill the residue treater to the minimum operating level and to heat the liquid to the minimum operating temperature before adding the methomyl containing flasher bottoms feed.[27] This was essential for safe, controlled methomyl decomposition. As discussed in Section 1.7.3.2, the control system design prevented adding methomyl until the solvent was at minimum volume and temperature, but the operators bypassed the safety devices during the startup.

2.2 Unit Restart

Although the operations staff acknowledged that management had not prescribed a specific deadline for resuming methomyl production, onsite stockpiles of methomyl necessary to make Larvin were dwindling. Unit personnel recognized the important role of methomyl in the business performance of

[25] Although the SOP had not been reviewed and approved, as with the prior approved SOP, it required the solvent run.

[26] The staff acknowledged that the solvent-only run was not performed on the residue treater, but were unable to explain who decided to proceed with feeding methomyl to the empty, unheated residue treater.

[27] The SOP warned that a runaway reaction would result if methomyl were allowed to accumulate in the residue treater before the treater is properly heated.

the facility, and a recent increase in worldwide demand for Larvin created a significant, sustained production schedule. Methomyl-Larvin operating staff told CSB investigators that they looked forward to resuming methomyl production and a return to the normal daily work routine after the long unit shutdown.

Operator logs documented the plan to start the MSAO (a.k.a. Oxime) unit Monday morning, August 25. Methomyl synthesis needed to begin shortly thereafter. However, critical startup activities were not completed, and the staff struggled with many problems as they attempted to bring each subsystem on line. To complicate the startup problems, process computer system engineers had not verified the functionality of all process controls and instruments in the new control system.

2.2.1 Equipment Malfunctions

Although the methomyl unit outage and new DCS implementation were incomplete, the staff proceeded with the unit restart. Some of the equipment was not yet operational and some equipment malfunctioned. For example, a few days before the incident, operators discovered that a valve had not been installed on a solvent feed line, which resulted in excessive solvent consumption. During one shift, operators discovered that heat tracing on a process line was not operating, which allowed the contents in the pipe to cool and solidify.

Another problem was traced to a broken stem on a water cooling system valve on a vapor condenser. The closed valve prevented adequate condenser cooling, which led to an imbalance in the crystallizer solvent ratios and excess MSAO in the flasher bottoms. Operators also encountered many problems tuning control loops and calibrating instruments for the newly installed computer control system. These issues were compounded because the operators had not become familiar with all of the methomyl work station functions and changes made to some process variables.

2.2.2 Methomyl Synthesis and Crystallization

The board operator startup log reported many continuing adjustments and corrections to the computer system. By mid-week, methomyl was being synthesized in the methomyl reactor and the crystallizers were put in service. The next step was to start the centrifuges to separate the crystallized methomyl from the solvents. The SOP was written such that two centrifuges operated in parallel. While one was progressing through the crystal-liquid separation cycles, the other was emptied of the crystallized methomyl "cake" and then refilled with a new batch of slurry. From there the methomyl cake went to the drying and packaging stages. This operating sequence assured that the upstream methomyl synthesis processes could run continuously.

At the beginning of this startup, only one centrifuge was operational; the other had continuing problems with electrical connections. Regardless, the operators proceeded with the restart, using only one centrifuge to separate the crystallized methomyl from the liquid solvents. An operator told CSB investigators that maintaining the proper solvent ratios was much more difficult during the startup, and that he needed to closely focus on the operating conditions and frequently adjust control variables in the DCS.

After feeding what they presumed to be normal methomyl-solvent slurry into the centrifuge, the outside operators opened the centrifuge to remove the methomyl crystal cake but discovered there were no methomyl crystals in the centrifuge basket. The absence of methomyl crystals could have been due to two causes: either a malfunction prevented methomyl from being synthesized in the methomyl reactor, or the crystallizer solvent/anti-solvent ratio was incorrect and the methomyl remained in solution rather than being crystallized. If the former was the cause, methomyl would not be present in the flasher bottoms feed to the residue treater—there would be no methomyl to decompose in the residue treater. If the latter was the cause, the methomyl concentration in the residue treater feed would likely be significantly greater than expected—uncrystallized methomyl would remain in solution and eventually accumulate in the flasher bottoms.

2.2.3 Solvent Recovery

As the operators worked through the ongoing myriad problems during the methomyl startup, they were depleting the fresh solvent inventory faster than expected. Therefore, they needed to get the solvent recovery system on line as quickly as possible to replenish the solvents. The residue treater was the last processing step in the solvent recovery system.

The liquid exiting the centrifuge normally contained only about 0.5 percent methomyl, some MSAO, trace impurities, and solvents. Routine collection and testing during startup indicated that the methomyl concentration was more than double the maximum operating limit value and as high as 4.0 percent, eight times greater than the specified operating limit for the four collected samples. These samples confirmed that methomyl was being synthesized in the reactor and that the solvent ratio was off specification in the crystallizer so the methomyl did not crystallize. Again, ongoing equipment issues and improperly calibrated and tuned instruments distracted the staff. They did not review the lab results so were unaware of the over-concentration problem and continued solvent recovery startup activities.

The solvent flasher separated and extracted the solvents for reuse. Trace impurities and MSAO accumulated in the bottom of the flasher along with the non-recoverable solvents and methomyl. These so-called flasher bottoms typically contained about 22 percent methomyl when all upstream process equipment was operating within the specified parameters. However, unknown to the startup team, the gross solvent imbalance in the crystallizer caused the methomyl concentration to climb to as high as 40 percent, nearly twice the design basis amount.[28]

[28] The process hazards analysis (PHA) discussed the importance of sampling the residue treater feed (flasher bottoms) to verify that the methomyl concentration did not exceed the residue treater design limits. However, the SOP did not require such a sample, and no sample collection point was available in the system. The designers presumed that the flasher feed sample and in-specification flasher column operation would assure methomyl concentration in the flasher bottoms would not exceed the design limit.

2.2.4 Residue Treater Startup

The residue treater was the last equipment to be started. The critical startup safety prerequisites, pre-startup solvent fill and heat-up were omitted from the restart activities. Furthermore, the board operators bypassed the minimum operating temperature interlock that prevented adding methomyl into the residue treater, as some operators were accustomed to doing. The minimum recirculation loop flow interlock on the feed valve was also left bypassed by the computer programmers. Without recirculation flow, the concentrated methomyl feed was not adequately mixed with what should have been preheated solvent already in the residue treater.

Operators told CSB investigators that, based on operating experience, there would be little methomyl in the system "this early in the startup." That is most likely the reason the operators skipped the sample collection and analysis steps.

On August 28, at approximately 4 a.m., the board operator manually opened the residue treater feed control valve and began feeding flasher bottoms into the nearly empty vessel. With a low flow rate of about 1.5 gallons per minute, more than 24 hours would be required to fill the residue treater to 50 percent, the normal operating level. The operations staff did not discuss the residue treater operating status at the 6 a.m. shift change, as they were preoccupied with other startup issues.

Samples from the second sample point, the residue treater outlet, were not collected and tested as required by the startup procedure or at the normally scheduled time, the beginning of the day shift. Operators offered two explanations for not sampling the residue treater contents during the restart activities. First, since the centrifuges contained no methomyl cake, the staff incorrectly concluded that methomyl had not been synthesized. Second, the outside operator on the day shift was unaware that the residue treater had been put into operation—the night shift crew did not tell the day shift crew that the feed to the residue treater had been started.

The outside operator started the recirculation pump at 6:14 p.m. as directed by the board operator. The residue treater liquid level was approximately 30 percent (1,300 gallons) and the temperature ranged between 60 and 65 °C (140-149 °F), still significantly below 135 °C (275 °F), the critical decomposition temperature. The pressure remained constant at 22 psig. At 6:38 p.m., the temperature began steadily rising about 0.6 degrees per minute (Figure 11). At 10:21 p.m., the level was 51 percent when the recirculation flow suddenly dropped to zero.[29] In less than 3 minutes, the temperature was at 141 °C (286 °F), rapidly approaching 155 °C (311 °F), the safe operating limit, and climbing at the rate of more than two degrees per minute.

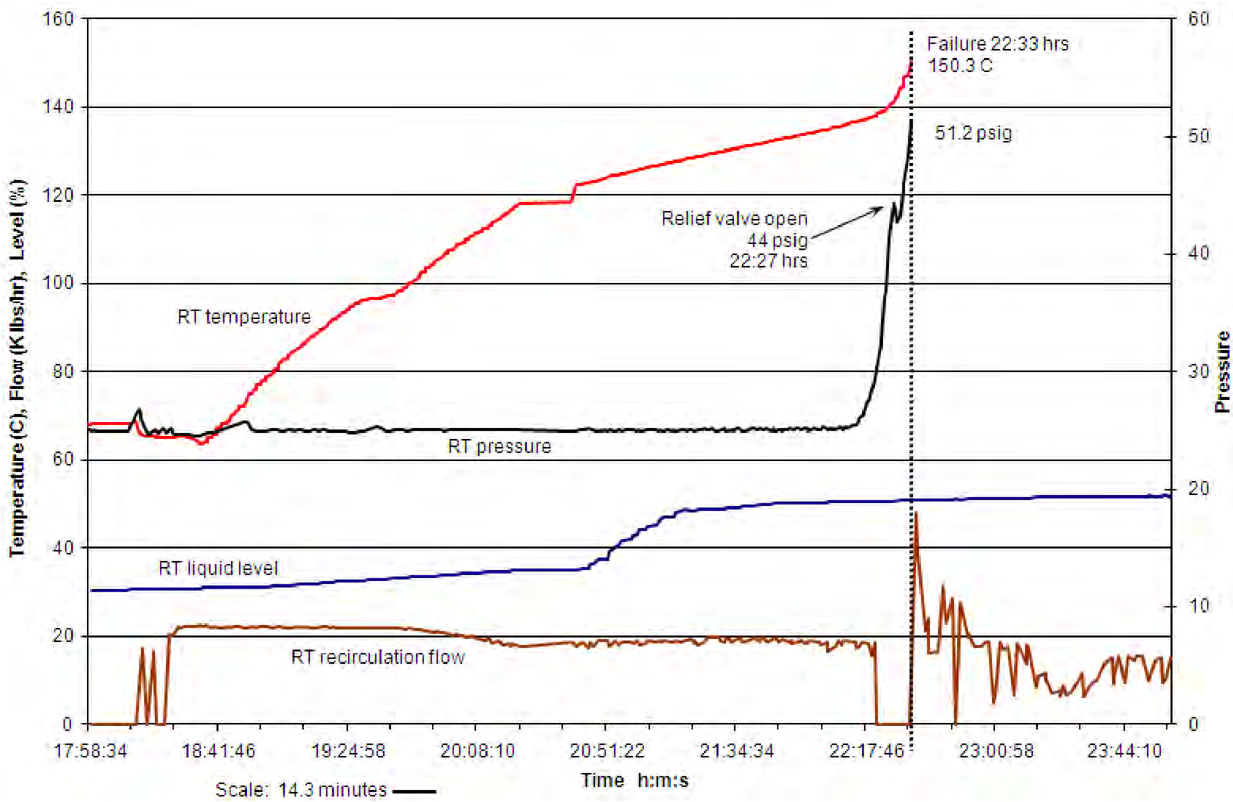

Figure 11. Residue treater process variables before the explosion. Failure occurred at 22:33, as shown at vertical dotted line

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[29] A Bayer review after the incident determined that the split-range temperature control was incorrectly programmed in the DCS. In the process of changing from heating to cooling, the residue treater recirculation flow valves to both the heater and cooler closed, blocking all recirculation flow. However, the CSB concluded that this was not causal to the runaway reaction and vessel rupture.

At approximately 10:25 p.m., the residue treater high pressure alarm sounded at the work station. The board operator immediately observed that the residue treater pressure was above the maximum operating pressure and climbing rapidly. Not understanding what was wrong, but suspecting a blockage in the vent line, he contacted the outside operator and directed him to go to the residue treater to check the vent system.[30] He also asked a second outside operator to assist. He then manually switched the residue treater recirculation system to full cooling, hoping that that might slow or stop the climbing pressure.

2.3 Explosion and Fire

At 10:33 p.m., a few minutes after the board operator talked to the outside operators, a violent explosion rocked the control room. A huge fireball erupted on the south side of the unit as alarms sounded on the methomyl and Larvin work stations. Operators scrambled to shut the systems down. The onsite fire station located nearby shook from the explosion as the emergency alarm sounded. Outside operators rushed to close valves, de-energize equipment, and activate stationary water cannons to begin fire suppression efforts. Water cannons were also directed at the MIC day tank blast blanket structure to help keep the day tank cool and prevent the fire from spreading to the tank.

Shortly after the explosion one of the two outside operators who had gone to investigate the residue treater problem was seen walking toward the control room. Coworkers quickly came to his aid and took him to a safe area until help arrived. He was badly burned. The body of the other outside operator was located about 4 hours later.

The bolts holding the residue treater support legs to the concrete foundation sheared off as the shell and top head of the 5,700-pound residue treater careened into the methomyl unit. The bottom head separated from the shell (Figure 12 and Figure 13) and came to rest about 20 feet from the residue

[30] The CSB was later told that, in hindsight, plugging in the newly installed vent system could not have been the cause of the pressure excursion. The residue treater had not operated long enough to cause deposits to accumulate inside the vent pipe.

treater foundation. The explosion destroyed nearby pumps, heat exchangers, and electrical switchgear. The fire was fueled primarily by the solvent inside the residue treater and other flammable liquids that spilled from the ruptured piping systems.

Figure 12. Residue treater bottom head (left); vessel shell and top head (right)

Figure 13. Residue treater shell and top head recovered from inside the Methomyl-Larvin unit

The residue treater struck a large support column on the four-story process unit structure and sheared it off the baseplate on the concrete foundation (Figure 14). Small debris, including conduit, valves, small diameter pipe segments, and insulation, was thrown in all directions, some of which struck, but did not penetrate the MIC day tank blast blanket. The blast blanket also functioned as a heat shield to protect the tank and attached piping from the intense solvent-fueled fire.

Figure 14. Structural column (arrow) ripped from the steel baseplate (left)

The overpressure produced by the rupturing residue treater damaged properties in the surrounding community. Mobile homes, houses, businesses, and vehicles sustained primarily window breakage and minor structural damage. The majority of the property damage reports were within 1.5 miles of the explosion epicenter; however, some damage was reported as far away as 7 miles (Figure 15). Bayer received 57 property damage claims from residences and businesses totaling about $37,000.

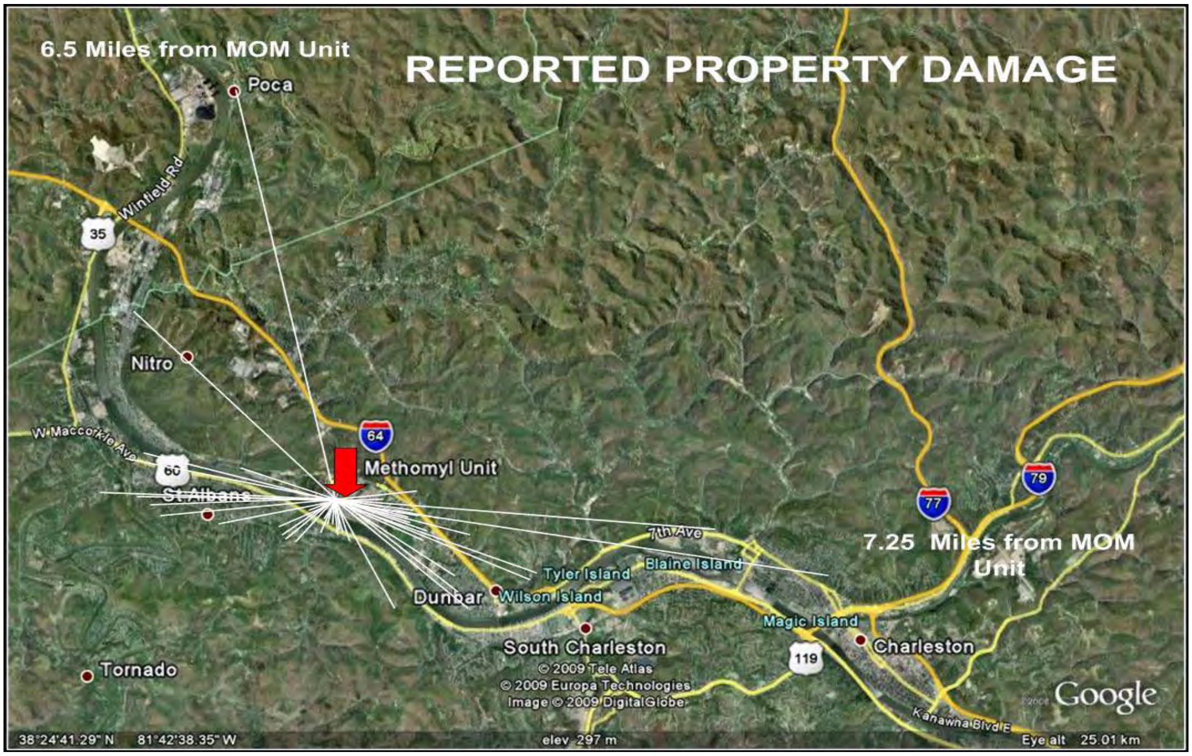

Figure 15. Aerial view of locations of reported offsite property damage

2.4 Emergency Notification and Response

2.4.1 Bayer CropScience Response

The Bayer fire brigade was at the scene within minutes of the explosion and set up a command post northeast of the methomyl unit, where the incident commander began coordinating the response as fire equipment and personnel arrived. Plant responders established and directed a water stream to the fire zone from the north.

About 5 minutes after the explosion, Metro 9-1-1 contacted the Kanawha County Emergency Ambulance Authority (KCEAA) and advised the agency of a large explosion at the Bayer plant. Emergency Medical Services (EMS) personnel began staging at the main gate about 2 minutes later.

Within 6 minutes of the explosion, fire alarms sounded at the Institute and Tyler Mountain volunteer fire departments in accordance with the established mutual aid protocol. Institute fire department responders staged at the main gate with backup equipment and supplies. Tyler Mountain firefighters joined the Bayer fire brigade at the methomyl unit to battle the blaze. A Metro 9-1-1 operator contacted the security guard at the Bayer main gate 9 minutes after the explosion.[31] Bayer activated its Emergency Operations Center (EOC) at 10:45 p.m. Twelve minutes into the incident, the Bayer security guard asked the Metro 9-1-1 operator to dispatch an ambulance for a worker burned in the fire. The emergency response timeline is shown in Appendix B.

2.4.2 Local and State Emergency Response Agencies

As provided in the Kanawha Putnam Emergency Management Plan, the Kanawha Emergency Management Director ordered the Kanawha Putnam Emergency Operations Center (EOC) to be activated. County personnel staffed the EOC, which served as the centralized communications hub for all emergency response dispatch of police, fire, and EMS for Kanawha and Putnam counties.

The Kanawha County Sheriff heard a loud explosion at about 10:30 p.m. After hearing state and county radio traffic indicating that an explosion had occurred near the Bayer plant, he radioed Metro 9-1-1 while en route to the facility. He then requested that Metro Communications contact the Nitro and Dunbar Police Departments to arrange for roadblocks of Route 25 at the city limits to restrict traffic flow into the Institute area. The county EOC also routed information to and from the various responding municipal, state, and county agencies. Responding agencies included South Charleston, Nitro, and Dunbar Police Departments; the Jefferson and St. Albans Fire Departments; the Kanawha County Sheriff's Department; the State Fire Marshal's Office; the U.S. Bureau of Alcohol, Tobacco, and Firearms and Explosives, (ATF); and the KCEAA. All of these agencies routed their communications through the EOC during the emergency (Figure 16). As the night progressed, the Metro 9-1-1 call center received more than 2,700 phone calls, which overwhelmed the system.

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[31] The Bayer security guard told investigators that he tried many times to get through to Metro 9-1-1 but the line rang busy. The Metro 9-1-1 operator also had trouble getting through to the Bayer guard shack.

Upon arrival at the main gate about 10 minutes after the incident occurred, the Institute Volunteer Fire Department chief set up a command post and assumed the role of resource commander. In this role, he coordinated with the Bayer IC to provide outside mutual aid resources of personnel and equipment as needed. After the Institute fire department chief made the initial contact, the Bayer IC advised him that based on air monitoring information, “everything [was] being consumed in the fire” and that a shelter-in-place was not necessary. However, when the Kanawha County Sheriff arrived, he noticed an acrid smell in the air and not knowing the source, felt that he and his deputies might be at risk; thus, he ordered his deputies and state police to relocate to the Shawnee Park EOC, the location so designated in pre-planning exercises.

Immediately after the incident began, the Director of Regional Response Teams (RRT) for West Virginia, who works in the State Office of Emergency Services (OES) and was unsatisfied with the information being provided by Bayer, called the State Fire Marshal to assess the incident.[32] Bayer EOC personnel directed the Fire Marshal to the onsite EOC, where he tried, unsuccessfully, to get information that would allow an accurate assessment of the conditions and status of the incident response. Based on his observations of fire suppression operations, the Fire Marshal ordered the RRT unit, a trailer with supplies and other resources stationed in Nitro, be brought to the site for use if needed. He then went to the EOC at Shawnee Park.

[32] The State Fire Marshal is responsible for hazardous material incidents, incidents involving weapons of mass destruction, and mass casualty operations. The State Fire Marshal also provides guidance to 447 departments; more than 11,000 firefighters; and is responsible for code enforcement, fire safety, and investigations.

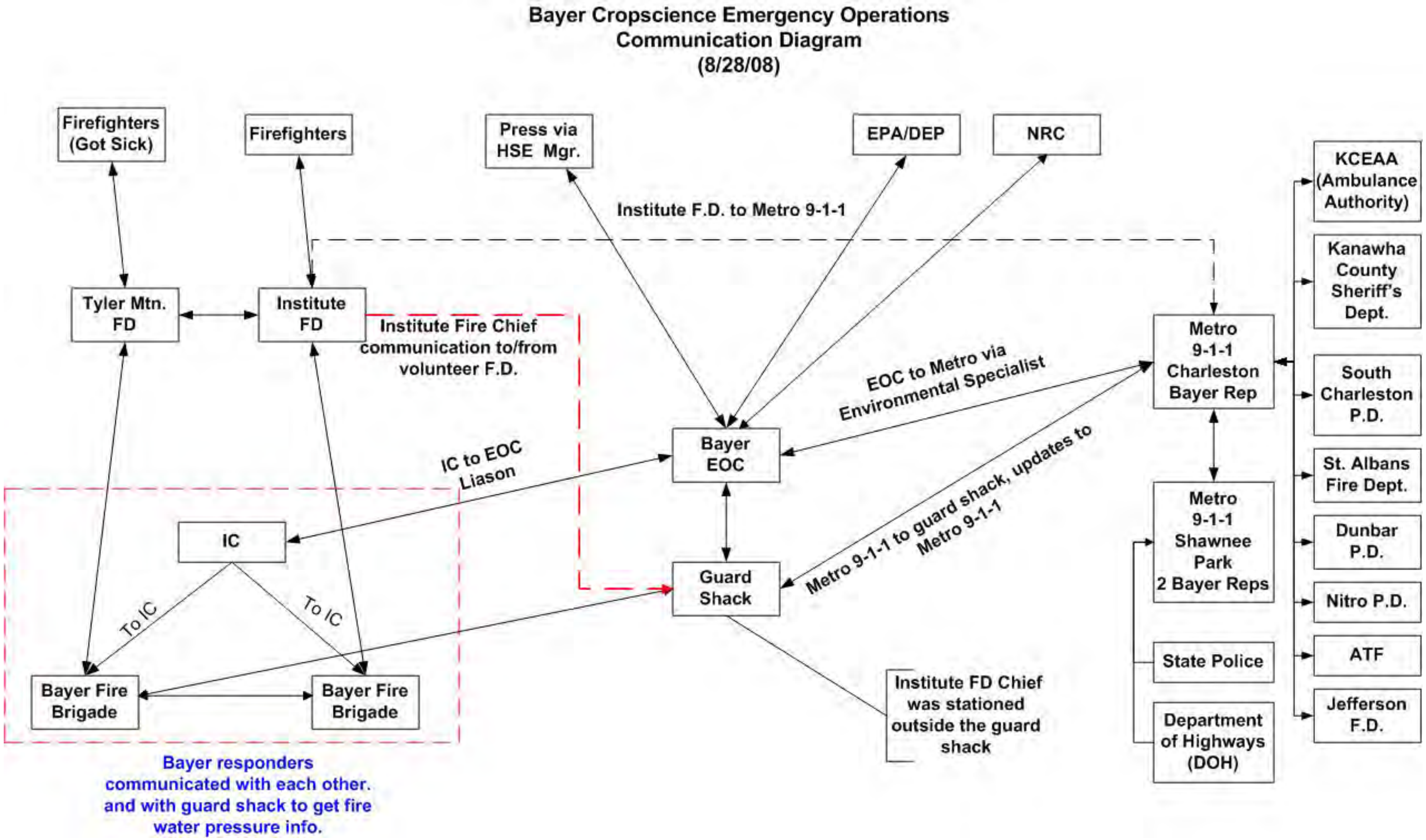

Figure 16. Methomyl unit explosion emergency communications diagram

At about 11:00 p.m., the St. Albans fire chief, after seeing a smoke cloud advancing towards St. Albans, requested information from Metro 9-1-1 about the composition of the cloud. As it approached, the chief advised Metro 9-1-1 dispatchers that if he did not get clear information regarding the make-up of the cloud, he would initiate a shelter-in-place advisory for the St. Albans community.

At 11:19 p.m., Metro 9-1-1 announced a shelter-in-place for the immediate area surrounding the Bayer facility, and initiated a reverse ring-down notification[33] to the residents in the affected community. Five minutes later, Bayer recommended that Metro dispatchers issue a shelter-in-place for the St. Albans area. At about 11:34 p.m., the KPEPC activated the County Emergency Alert System, which in turn initiated a shelter-in-place for the areas west of Charleston to Putnam County line. The shelter-in-place affected about 40,000 residents (Figure 17).

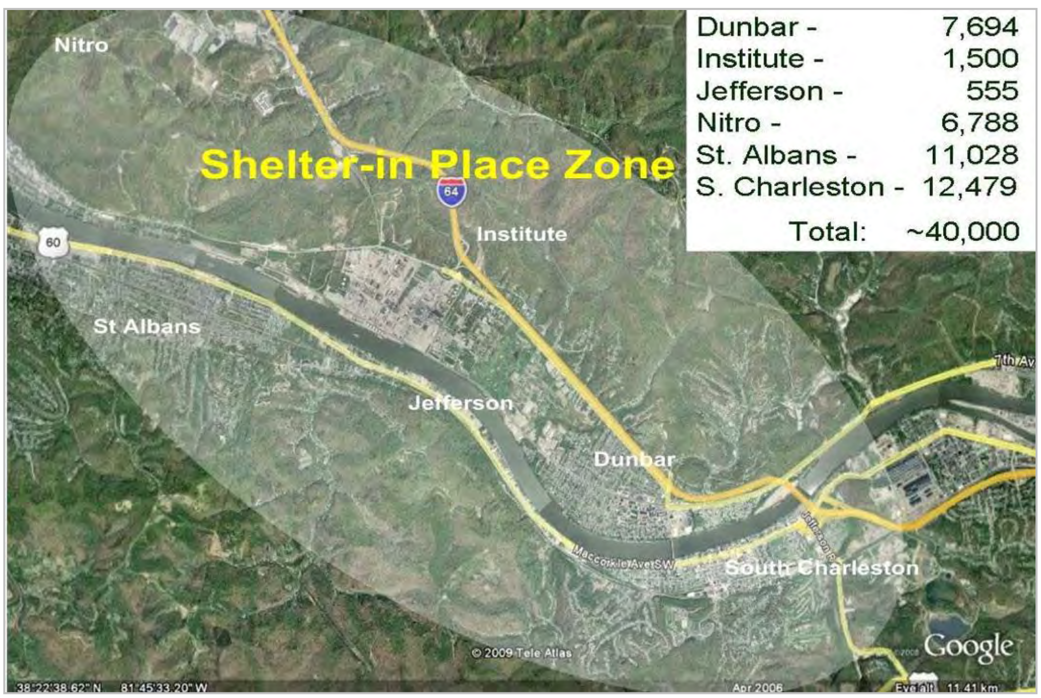

Figure 17. Areas and population affected by the shelter-in-place

[33] A reverse ring-down notification system is an automatic calling system that automatically calls residents and businesses in pre-defined areas. It delivers a pre-recorded message advising action to be taken in response to a community emergency.

At 12:34 a.m., a little more than two hours after the incident occurred, Bayer notified the National Response Center. At 2:05 a.m., about 3 hours and 30 minutes after the incident began, Kanawha Putnam EOC declared the area west of Charleston, which included St. Albans, Nitro, Jefferson, Dunbar and Institute safe to re-enter and canceled the shelter-in-place action.

2.4.3 Emergency Operations Center Activations

As the response to the emergency progressed, three EOCs were activated, which contributed to confusion and communication difficulties. The first, the Bayer EOC, was located along the northern boundary of the plant adjacent to Route 25, and was staffed by Bayer personnel including the WCC unit manager; Health, Safety, and Environmental Manager; and operations manager. This site was less than one-half mile from the incident and was part of the Bayer emergency planning process. One function of the Bayer EOC was to coordinate communication with Bayer corporate staff in Raleigh, North Carolina, and provide updates to the media. It was also responsible for communicating incident status and mutual aid assistance with the outside emergency response agencies.

The Kanawha Putnam EOC was activated at the Metro 9-1-1 call center in South Charleston. The center was staffed by county personnel and served as the centralized communications hub for all emergency response dispatch of police, fire, and EMS for Kanawha County.

As part of the Bayer emergency notification ring-down system, the plant's environmental specialist was notified of the incident and advised to report to the Kanawha Putnam EOC in response to its request for a Bayer representative to relay information directly to the county authorities. The environmental specialist arrived at the Kanawha Putnam EOC between 11:40 p.m. and 12:00 a.m. Shortly after arriving, he phoned the Bayer EOC to obtain information regarding the location of the fire and the substances thought to be involved. He spoke to the Health, Safety, and Environmental Manager and his supervisor and was able to provide the dispatchers with information regarding three substances thought to be involved in the incident: dimethyl disulfide (DMDS), methyl isobutyl ketone (MIBK), and acetonitrile. However, Bayer was slow to provide additional details.

The Kanawha Emergency Management Director also activated a mobile EOC at Shawnee Park, which was located on Route 25 less than a mile to the southeast of Bayer. Two Bayer environmental specialists reported there to act as liaisons with non-Bayer responders. Representatives from the Department of Highways, State Police, and the Sheriff's office also reported to the Shawnee Park EOC.

2.5 Air Monitoring

At the time of the incident, the two AreaRae® fence line air monitors[34] were positioned on the east end of the plant and on the west riverbank to detect concentrations of airborne chemical contaminants and alert facility occupants if air concentrations exceeded safe levels and had traveled beyond plant boundaries. The CSB investigators examined the monitor data and determined that the fence line monitors did not detect hazardous concentrations of the chemicals sampled. Another AreaRae system monitor recorded atmospheric winds, temperature, and barometric pressure.

Continuous air monitors were located in and around the production units to detect fugitive leaks in process equipment[35] or leaks resulting from process upsets. The Methomyl-Larvin unit had 16 localized MIC sample points connected to an analyzer, which Bayer installed in March 2006 to continuously sample and record MIC concentrations at 2-minute intervals. If concentrations exceeded 1.0 ppm, the system was designed to activate a visual alarm display in a room on the second floor of the Methomyl-Larvin control building.

However, in May 2008, the analyzer malfunctioned, causing spurious alarms. Although technicians investigated, they had not resolved the problem before the August methomyl unit startup. The CSB learned that the system had not been repaired and restarted even though the MIC storage tank had

[34] An AreaRae instrument is a direct-reading device that continuously samples for a wide range of chemicals including oxygen, carbon monoxide, chlorine, volatile organic compounds (VOC), and methane.

[35] A fugitive leak is a small leak in process equipment. Such leaks are commonly called "fugitive emissions," which must be identified and corrected.

remained in service. On the night of the incident, the personnel in the Bayer EOC were unaware that the monitoring system was not active, therefore they assumed it would alarm if it detected airborne MIC or other detectable chemicals during the incident response. They had no way of knowing if toxic vapors from chemicals used in the methomyl unit were escaping into the air.

The MIC production unit, located about 1,800 feet from the Methomyl-Larvin unit, had a similar MIC air monitoring system with 16 stationary sample points. The analyzer recorded the results at 2-minute intervals. This analyzer was operational on the night of the incident but did not detect any chemicals including MIC during or after the incident.

3.0 Incident Analysis

3.1 Residue Treater Replacement

The Mechanical Integrity program on the original, 25 year old carbon steel residue treater identified significant service degradation. Bayer, through the MOC program, replaced it with a corrosion-resistant stainless steel vessel in anticipation of the planned increase in methomyl production. With the exception of substituting stainless steel for the carbon steel and associated material thickness changes required by the American Society of Mechanical Engineers Boiler and Pressure Vessel Code (ASME Code), Section VIII design rules, the new ASME Code-stamped vessel was identical to the original. The CSB concluded that this process modification did not contribute to the incident cause or consequences.

3.2 Internal Compliance Auditing

3.2.1 Corporate Process Safety Management Audits

The Bayer North America corporate assessment team conducted an audit of the Methomyl-Larvin unit in July 2005. The team, composed of four auditors from other Bayer facilities and business units, specialized in process safety, mechanical integrity, and pressure vessel engineering. The team audited against 7 of the 14 elements in the OSHA Process Safety Management standard[36] and the emergency response requirements in the EPA Risk Management Program.

The final report, issued in 2006, identified 17 PSM compliance issues in the audit focus areas. Several findings included deficiencies with tracking the status of recommendations and corrective actions from PHAs, equipment inspections, and compliance audits. As required by Bayer corporate standards, the Institute site developed a list of recommendations and corrective actions to resolve the findings

[36] The 2005 corporate PSM audit focused on process safety information, process hazards analysis, operating procedures, mechanical integrity, management of change, incident investigation, and compliance audits.

and entered them into a new action tracking system with an assigned responsible person for completion.

3.2.2 Audit Action Tracking System Upgrade

In 2006, Bayer implemented a new action tracking system in response to OSHA citations issued in a 2005 Institute facility inspection, which faulted Bayer for not having a tracking system to assure PHA recommendations were resolved, documented, and communicated. In 2006, Bayer program developers in Research Triangle Park, North Carolina developed the system for the Bayer facilities. A new tracking system feature contained a workflow integration function that automatically sent notifications to responsible parties and required electronic approval by managers to close completed actions. However, even with this new system, problems with action item tracking and closure continued.

3.2.3 Process Safety Management Self Assessments

Institute site personnel audited the Methomyl-Larvin unit against the PSM standard in 2004 and in 2007. The PSM "facilitated self assessment" was conducted every three years as required by the PSM standard. The 2007 facilitated self assessment found that action tracking deficiencies identified in previous corporate PSM audits and facilitated self assessments remained unaddressed. The audit also found that even after the OSHA citation 2 years earlier, action items generated in PHAs on the Methomyl-Larvin unit still were not being tracked and closed.

CSB investigators reviewed the corrective action plans identified in the corporate PSM audits and the PSM facilitated self assessments and identified similar shortcomings. For the 2005 corporate PSM audit, some listed corrective action items were still open. Some of the items listed on the 2007 facilitated self-assessment action plan were overdue by more than 9 months at the time of the August 2008 incident including one requiring the revision of Methomyl-Larvin unit SOPs.

3.3 Process Hazards Analysis

A Bayer team that included an experienced facilitator, process engineer, and experienced unit operations personnel conducted the methomyl system process hazards analysis (PHA) in 2005 using a hazard and operability study (HAZOP) technique. The team also used Bayer's semi-quantitative risk matrix to analyze whether additional protections were required for the various scenarios identified in the HAZOP. Properly applied, these tools can identify improvements that could have prevented the residue treater incident. However, the relatively short duration of the PHA, and the team's poor application of the tools during the process, produced results that failed to identify significant unmitigated scenarios that needed recommendations.

3.3.1 PHA Duration and Staffing Deficiencies

Poor execution of the PHA was due in part to the way Bayer had structured it and the total hours the PHA team worked. Bayer assigned methomyl unit operators to the PHA team, but most were only present for a few hours each. Most revealing is that in just 12 meeting days, for an average of 6 hours per day, the team analyzed 37 HAZOP nodes, including analyzing risks to determine if additional protections were needed. Considering the complexity of the unit the time spent on the HAZOP was insufficient to address all the critical process safety information, draw logical conclusions, and determine appropriate recommendations.

3.3.2 PHA Assumptions Deficiencies

The 2005 PHA team failed to validate critical assumptions used in their analyses. For example, the team accepted defined procedure steps without confirming that the operators rigorously followed the procedures. They also incorrectly assumed that the automatic safeguard controls listed in the safety matrix remained operational during all operating modes. Through staff interviews, CSB investigators learned that some board operators bypassed the two safety interlocks on the residue treater feed control valve during startups based on their experience with the residue treater heater not heating the solvent to the minimum temperature interlock setpoint. With the interlocks in bypass, they manually opened the flasher bottoms feed valve when the residue treater temperature was about five degrees below the required operating temperature. The heat generated by the decomposing MSAO and methomyl would finally increase the residue treater temperature to the minimum operating value.

Because the PHA team was apparently unaware of any problem with the residue treater heater, and assumed the safeguards were active, it did not recommend that management resolve the residue treater startup issues. However, with the interlocks in bypass, the residue treater had insufficient protections to prevent accumulating a large quantity of cold, highly concentrated methomyl and MSAO in the residue treater.

The CSB investigators noted another significant PHA performance deficiency, namely that the PHA team identified an issue with the old control system that persisted in the new system:

> The control system for methomyl is antiquated and there is no Safety Instrumented System (SIS) for a process with an above average level of hazards and risks. The operators have access to the control system that allows them to make unauthorized program changes and to alter alarm settings...

ANSI/ISA standard 84.00.01–2004 (*Functional Safety: Safety Instrumented Systems for the Process Industry Sector*) – which is a recognized good engineering practice required for compliance with the OSHA Process Safety Management standard – recommends a Safety Instrumented System that is separate and independent from the basic process control functions. Among other requirements, the standard provides that “Bypass switches shall be protected by key locks or passwords to prevent unauthorized use.”

Despite knowing that interlock settings could be accessed and changed by the operating staff without proper safety reviews as required by the management of change program, the PHA team did not make any recommendations to improve computer access control. In the August 2008 incident, lack of password access control to the new DCS allowed the staff to bypass the safety interlocks, which directly resulted in the runaway reaction and catastrophic residue treater failure.

3.3.3 Inadequate Process Safety Information Reviews

The PHA did not adequately incorporate the process safety information used as a basis for the assumptions and conclusions. The process safety information package from the original construction project discussed the importance of controlling the methomyl concentration in the flasher bottoms feed to the residue treater to preclude a runaway reaction. The Methomyl Process Description in the SOP discussed the importance of controlling methomyl concentration in the residue treater at least five times. For example, it cautioned, "Even with normal flow rates, care must be taken to prevent over concentrating residues in the mother liquor flasher tails." Again, it warned, "The interlocks should prevent feeding the tank when it is cold, but if the methomyl concentration is above 1.3%, a run away [sic] reaction could result upon heating the tank." In contrast, the PHA team concluded that a high residue concentration in the flasher feed was an operations issue having "no consequence." Another PHA item concluded, without substantiation, that the residue treater feed valve low-temperature safety interlock would "function as intended" and prevent a high methomyl concentration runaway reaction.

A September 1994 PHA considered high methomyl concentration caused by off-specification solvent in the crystallizer. However, that PHA team concluded that the solvent recovery system and the residue treater system could handle the excess methomyl because they considered the existing safety interlocks to be adequate protections. The team did not consider any operational errors or startup and shutdown scenarios that could lead to a large quantity of under-temperature methomyl and MSAO in the residue treater.

The 2005 PHA team used the "Bayer CropScience PHA Quick Reference Guide" to qualitatively evaluate the unmitigated and mitigated risk for various scenarios and determine whether the system needed more protections. It concluded that high methomyl concentration downstream of the crystallizer was only a product quality problem, which the operations staff would resolve. In analyzing a possible residue treater rupture caused by a runaway reaction scenario, the team assumed that the low temperature interlock and the operating sequence described in the SOP provided adequate controls to prevent feeding methomyl until the system was at the minimum safe operating conditions. Based on these protections, the team determined that the outcome was in a range that the guide listed as not requiring additional protections. However, the original design basis concluded that a relief system could not be designed to prevent a catastrophic failure of the residue treater if the methomyl concentration exceeded the design limit.

3.3.4 Analysis Deficiencies

In addition to analyzing the hazards of a process based on the equipment information, the PHA should examine the human interactions with the equipment. In particular, for operational tasks that depend heavily on task performance and operator decisions, the team should analyze the procedures step-by-step to identify potential incident scenarios and their consequences, and to determine if the protections in place are sufficient.

According to “Guidelines for Hazard Evaluation Procedures” (CCPS, 2008),

> Personnel may have less operating experience with procedure-based operations that are heavily dependent on task performance and operator decision-making. In addition, safeguards may be bypassed or not fully functional during some modes of operation such as at start-up of a continuous process. Performing a hazard evaluation of procedures can identify steps where the operator is most vulnerable and point to means of reducing the risk of an incident, such as by adding engineered safeguards and improving administrative controls.

The publication further recommends that procedures expected to involve major hazards should be subjected to a detailed procedure-based HAZOP study using guidewords similar to those used for batch chemical processes. CCPS also gives guidance for hazard analyses for processes that include programmable control systems, chemical reactivity hazards, facility siting, and the combination of tools such as Hazard and Operability Studies with Layer of Protection Analysis. The PHA team could have addressed all these topics in analyzing the methomyl process.

3.4 Pre-Startup Safety Review

The CSB concluded that Bayer did not conduct an adequate Pre-Startup Safety Review (PSSR) for the control system upgrade and the residue treater replacement. Furthermore, staff interviews indicated that the limited PSSR work did not directly involve operators or other subject matter specialists. An eight-page checklist recorded the PSSR for the residue treater and required a “yes,” “no,” or “not applicable” checkbox mark for a series of questions and key subjects; a field at the bottom of the page was available for comments. The PSSR team incorrectly identified some items as being completed when they clearly had not been. For example, the team did not identify the SOP inadequacies that should have been addressed in the PSSR checklist item, “Do operating procedures exist that adequately cover the MOCR (management of change review)?” The existing operating procedures were not revised to address information specific to the new control system. However, the PSSR question was incorrectly answered “yes.”

The PSSR for the control system change had errors involving equipment checkouts that were marked as complete. A thorough PSSR should include verification that all equipment has been installed and configured for startup before any chemical is introduced into the system. As discussed in Section 2.2.1, while starting the unit, staff discovered that a valve had not been installed on a solvent drip line and that another valve was broken. The PSSR missed these two equipment installation problems that directly contributed to the overconcentration of methomyl in the flasher bottoms and ultimately led to the residue treater explosion.

The control system PSSR also had errors involving incomplete items. Although the PSSR marked the items as incomplete, the team did not record due dates for follow-up items. For example, the PSSR asked whether adequate technical coverage had been specified for the startup, and the PSSR team marked the item "no." They listed two people as responsible for this follow-up, but did not specify a due date for completion. Section 0 discusses the lack of sufficient technical coverage during the startup.

3.5 Human Factors Deficiencies

3.5.1 Control System Upgrade

The introduction of the Siemens PCS7 control system significantly changed the interactions between the board operators and the DCS interface. The Siemens control system contained features intended to minimize human error such as graphical display screens that simulated process flow and automated icons to display process variables. But the increased complexities of the new operating system challenged operators as they worked to familiarize themselves with the system and units of measurement for process variables differed from those in the previously used Honeywell system.[37]

Human interactions with computers are physical, visual, and cognitive. New visual displays and modified command entry methods, such as changing from a keyboard to a mouse, can influence the usability of the human-computer interface and impair human performance when training is inadequate. Operators told CSB investigators they were concerned with the slower command response times in the Siemens system and they talked about the methomyl process control issues they would face during the restart, which was much more difficult to control than the Larvin process. Board operators also told CSB investigators that the detailed process equipment displays in the DCS were difficult to navigate. Routine activities like starting a reaction or troubleshooting alarms would require operators to move between multiple screens to complete a task, which degraded operator awareness and response times.

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[37] For example, one variable in the old computer system was displayed as "percent full" whereas the new system recorded total "pounds" in the vessel.

The old system display and command entry was basically a spreadsheet, or line-item display. The new system used a graphical user interface (GUI) that displayed an illustrative likeness of the process and its various components (Figure 18). The board operator selected the device that needed to be changed. This made data entry clearer, but much slower. In the old system, board operators could change multiple process variables simultaneously, but they could select and change only one variable at a time in the Siemens system.

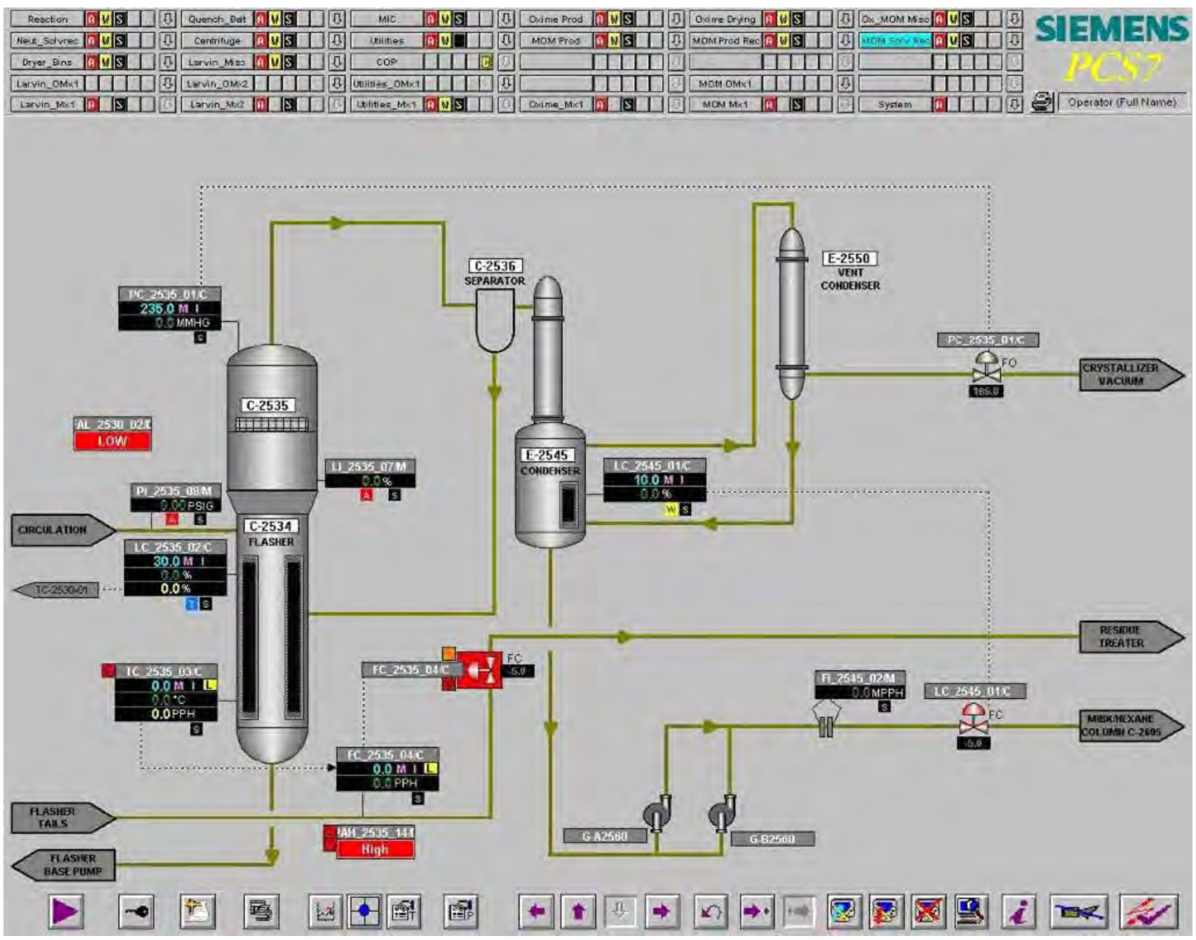

Figure 18. Typical Siemens work station screen display

The new control system also changed how board operators monitored multiple pieces of equipment. The methomyl board operators' station had five display screens available to monitor the methomyl processes and one display screen dedicated to process alarms. However, operating some methomyl equipment required the operators to use at least three of the five display screens. To simplify the operation, they asked the Siemens project engineers to add equipment overview screens to display multiple pieces of equipment. The board operators believed that the overview screens would provide more effective control of the unit; however, the screens were not available for the August 2008 startup.

3.5.2 Operator Training

The Siemens system switchover configuration for the Larvin unit began in early 2006, and the Larvin unit startup with that new DCS occurred in early 2007. The Larvin board operators attended four sessions of formal training during their shifts prior to the actual Larvin start-up. A Bayer process engineer and a contractor from the engineering company that configured the DCS conducted comprehensive training on the Larvin system before the Larvin unit was restarted. Board operators also used a Siemens operating station simulator to learn the Larvin system DCS functions and familiarize themselves with controlling different devices such as block valves, control valves, and pumps. Informal, on-shift training also took place and resources were available during the Larvin startup to assist operators, and support continued to be provided as needed.

For the Larvin system, board operators received a document labeled the "Siemens training manual" that included a system architecture description; glossary of tag names for controllers, alarms, and indicators; and an overview of the screen layouts. The manual also included a description of the application of operational and safety interlock matrices. Well-designed training manuals typically contain precise descriptions of computer control steps, icon definitions, menu hierarchy, and equipment-specific control examples. However, the Siemens training manual was not a well-designed computer system training tool. The information in the manual did not correspond with the procedural steps the operators would take to run the control system. According to the Center for Chemical Process Safety (CCPS, 1994) control system providers should develop training tools and procedures based on how the user perceives the task. Using those tools in conjunction with classroom sessions and simulator training on normal and abnormal conditions fully prepares operators for transitioning to a new control system.

Management concluded that comprehensive formal training and practice using the new DCS on the methomyl process was unnecessary. They incorrectly assumed the methomyl and oxime board operators had become proficient from the many operating hours using the DCS on the Larvin unit. Methomyl and oxime board operators had minimal training on a few specific processes, but general training took place during the operators' shift as time allowed, and was self-directed and self-paced. Informal, on-the-job training intended to develop the necessary skills to run the system can lead to inappropriate or incorrect practices that became the norm in the absence of proper training tools and instruction (CCPS, 1994). The CSB concluded the training was inadequate.

Prior to the methomyl startup, management provided operators time on the console during the DCS upgrade to practice using the new system. However, management did not require any methomyl operator to use this time to learn and practice operating the methomyl unit, and operators could decide for themselves how much time they needed to become familiar with the new DCS. Management also assumed that operators directly involved in designing the mimic displays, such as the one in Figure 18, and other customizable features would have had adequate exposure to the new system.

Although operators had become proficient using the system on the Larvin unit, they acknowledged that the new methomyl control system created new challenges with operating the methomyl process unit, some of which were driven by the highly complex process chemistries involved in synthesizing methomyl. Substituting previous control system experience for training on a new process can be problematic. Even minor differences in operation challenge an unfamiliar operator unless the operator has had process-specific training on the new equipment (CCPS, 1994).

Operators also told CSB investigators that the mouse interface command entry sequence responded slower than the Honeywell keyboard command entry process. They also reported that they were not familiar with some of the revised units of measure used to display equipment status and operating conditions that had been changed with the new DCS system installation. For example, one operator reported that the old control system used “percent full” to indicate the level in a vessel, but the new control system listed the level in total gallons inside the vessel. The methomyl operators had to improvise solutions to resolve the confusion by attaching paper conversion sheets on the work console for quick reference. However, at the time of the incident, some conversion charts had not yet been made. One operator told investigators:

> There was an issue with the solvent ratio, because when we went to the Siemens system the ratio was a different number…We were not sure if we were feeding the wrong amounts…When we first started this process we were pretty much guessing…No one came in and told us what amounts to put in for the new system.

As with any new control system, the Siemens system required process tuning before it was placed in service. Specifically, an issue arose in the MIBK-hexane separation column: high MIBK concentration prevented the automatic control system from effectively operating the separation column. The board operators observed that the column temperature was fluctuating undesirably and that the automated valves were operating sluggishly. The unstable MIBK-hexane separation column caused excess methomyl to pass downstream as there was too little hexane in the system to achieve proper methomyl crystallization. Had the board operators received comprehensive DCS training, they might have recognized the problem much sooner.

3.5.3 Operator Fatigue

Unit startups and shutdowns typically involve significant increases in staff workload, which may result in longer work hours and extended back-to-back workdays. Many operators and other key staff were working 60 to 70 hours per week prior to the August 2008 methomyl startup, and some reported working 18-hour shifts with only 6 hours of downtime. Overtime and shift work demands disrupt sleep cycles and cause fatigue, which can adversely affect performance and safety (Stanton, 2010).

The rigors of shift work, rotating between day and night shifts, and working large amounts of overtime can impair decision-making, reaction times, and degrade communications. Performing infrequently used startup and shutdown procedures while fatigued increases the chance of errors. Fatigue also degrades competencies and alertness necessary to successfully operate an unfamiliar control system. Personnel are more likely to make mistakes as fatigue increases. Labor-intensive, non-routine activities including integrating utilities such as steam and other ancillary systems into the startup sequence complicate operator startup duties.

The staff was confronted with many startup problems and equipment malfunctions. The startup was further complicated because of the new, unfamiliar process control system. However, the CSB was unable to determine if fatigue specifically contributed to any of the staff actions during the startup, or the decisions to continue the startup in spite of the ongoing problems.

3.6 Shift Change Communications

Operators maintained an electronic notepad (eLog) on the computer system to summarize daily progress and identify ongoing activities for the incoming shift. They also held a verbal turnover meeting in the control room when shifts were changing. However, a number of key items were inadequately addressed in the shift change during the morning and evening shift changes the day of the incident. Had the written and verbal shift turnover activities been properly performed, the incident most likely would not have occurred.

As discussed, the solvent run and residue treater prefill and heatup were not performed on the residue treater, yet these deficiencies were never entered in the eLog nor were they discussed in the shift change meetings by either the board or the outside operators. Second, the night shift staff did not inform the day shift crew that they had started filling the residue treater with flasher bottoms. Third, the methomyl unit day shift operator, distracted while assisting another board operator with an operational problem at the end of his shift, neglected to inform the incoming night shift operator that the lab results from the scheduled flasher bottoms sample identified excessively high methomyl concentration. Believing that the operators had not yet started the residue treater system and it remained empty, the day shift outside operator did not collect the residue treater liquid sample as the residue treater SOP required.

3.7 Procedure Deficiencies

The CSB identified significant problems with the methomyl unit SOP. As noted, the operators were using an unreviewed, unapproved draft SOP. Regardless, the draft SOP was essentially the same as the previously approved SOP; the deficiencies discussed below existed in the earlier version.

The SOP was so complex that the table of contents spanned more than 12 pages. The SOP contained more than 1000 pages organized in 16 major sections that included much more than procedures typically used by unit operations staff to operate the process equipment. Subjects unrelated to process operations such as Change Procedure, Vendor Information, and History of Major Incidents were in the SOP. The methomyl unit SOP was last updated and approved in May 2006.

Only about 400 pages of the SOP contained detailed startup, normal operation, and emergency shutdown procedures for operating the unit with the Honeywell computer operating system. It was available only from the computerized document control system. Operators could print specific pages for information only purposes.[38]

Many operators reported that they did not rely on the SOP: they felt that they understood how to run the unit correctly without instructions. The SOP complexity may have also discouraged its use. This may be acceptable for frequently performed tasks but, to prevent errors, directly using the written procedure is critical especially when performing infrequent or uncommon tasks such as start-up after a major turnaround.

3.8 Process Chemistry Problems

Safe and correct operation of the methomyl unit involved closely controlling many complex chemical reactions. However, during the August startup the staff was confronted with equipment malfunctions and process chemistry problems in key equipment including:

- The methomyl reactor,
- The MIC stripping still (MSS) side-draw condenser,
- The crystallizers,
- The MIBK-hexane column, and
- The residue treater.

During steady-state conditions in the methomyl reactor, MIC and MSAO react to form methomyl. Bayer ran the reactor with enough excess MIC to consume as much MSAO as possible, which minimized the MSAO content in the methomyl product. On the day of the incident, the MIC to MSAO ratio was lower than normal, which left more MSAO unconverted and formed less methomyl.

Adding hexane to the dissolved methomyl and solvent caused the methomyl to crystallize. The crystallized methomyl could then be separated from the liquid solvents in the centrifuges. However,

[38] Printed pages contained a note at the bottom of each page that said "Uncontrolled when printed."

excess MIBK caused the MIBK-hexane ratio to be out of specification so that the methomyl remained in solution and passed directly through the centrifuge. Not understanding the chemistry imbalance, the staff concluded that methomyl was not being synthesized in the reactor. Had they reviewed the lab results from routine flasher feed liquid samples downstream of the crystallizer they would have quickly recognized that the reactor was producing methomyl and the problem was related to the solvent ratios. Four flasher feed samples that had been collected over 2 days contained methomyl significantly above the acceptance criteria. During the solvent recovery step, uncrystallized methomyl accumulated in the flasher bottoms significantly above the concentration normally fed to the residue treater.

The residue treater cooler had enough capacity to remove the heat of reaction from the decomposing methomyl if the average concentration in the residue treater did not exceed about 0.5 percent. As the methomyl concentration in the residue treater climbed, the decomposition reaction rate increased exponentially[39] until the heat and evolving gases generated enough pressure to overcome the relief system capacity and rupture the residue treater.

The methomyl decomposition reaction had important characteristics:

- It was an exothermic, or heat-releasing, reaction;
- It was a self reaction, as methomyl needed no other chemicals to begin decomposing;
- The reaction rate was faster at a higher temperature and higher methomyl concentration; and
- It rapidly produced non-condensable gases and solvent vapors.

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[39] As the temperature increases, the rate of a chemical reaction generally increases exponentially.

The original design of the residue treater included features to control the reaction rate. First, the residue treater was intended to operate between 30 and 70 percent full of MIBK to ensure the feed to the residue treater flowed into a large volume of hot solvent. The hot solvent provided four functions:

- It diluted the incoming feed, which reduced the concentration of methomyl;
- It heated the incoming methomyl so that the methomyl would decompose quickly and not accumulate to a high concentration in the residue treater; and
- It absorbed the heat from the methomyl decomposition.

The second important safe operating condition involved the startup sequence, which was intended to ensure a safe decomposition rate at the beginning of the run. The control system contained interlocks to prevent opening the residue treater feed valve if the temperature, level, and pressure were not within the specified operating ranges. First, the operators had to fill the residue treater with solvent and start the recirculation pumps. Next, the circulation loop had to heat the solvent to the minimum operating temperature. Only then would the automatic feed control system open the flasher bottoms feed valve to begin feeding the methomyl-solvent into the preheated and circulating MIBK. This sequence assured that enough solvent was present to absorb the heat generated from the MSAO and methomyl decomposition reactions, and that the solvent was hot enough to ensure rapid decomposition to prevent the methomyl from accumulating in the residue treater.

The purpose of the residue treater was to eliminate the methomyl from the solvent before the solvent was used as a fuel in the boiler. The feed also contained unconverted MSAO. Like methomyl, MSAO decomposes exothermically, but will begin decomposing at a lower temperature than methomyl. As MSAO content in the auxiliary fuel was not a concern, the staff likely was not aware that MSAO decomposition played a role in residue treater performance and temperature control.

Although the temperature in the residue treater was lower than normal operation, the MSAO and methomyl began decomposing. Because they were both present in abnormally high concentrations, the decomposition generated a significant amount of heat. The operators filled the residue treater to about 35 percent with flasher bottoms and then pumped hot MIBK into the residue treater to bring the level up to 50 percent. After starting the recirculation pump, the board operator set the recirculation temperature control to the automatic mode to begin the normal heating cycle. As discussed earlier, the closed steam valve prevented the heater from heating the liquid. The board operator was unaware that the temperature was climbing because large quantities of MSAO and methomyl were decomposing in an uncontrolled fashion.

The rapidly forming gases overwhelmed the vent system and the residue treater pressure started climbing. The rate of reaction continued increasing until the evolving gases caused the relief system to activate and then overwhelm the relief system. The pressure rapidly rose until the residue treater suddenly ruptured.

The relief device was sized to handle an external fire around the residue treater, but only if the residue treater contained less than 2 weight percent methomyl equivalent (280 pounds). Post-incident analysis estimated that the residue treater contained at least 40 weight percent methomyl and 7 weight percent MSAO just before the runaway reaction initiated, which could not be safely vented by the existing relief system.

The most important layer of protection against over-concentrating methomyl in the residue treater was the minimum temperature and minimum flow interlocks on the flasher bottoms feed valve, which were bypassed the night of the incident. The administrative controls requiring laboratory sampling were not robust. The most important variable, the chemical composition of the flasher bottoms going to the residue treater, was not required to be analyzed before or during residue treater operation. Although analysis results for samples would likely have alerted the operators to the high risk situation of concentrated methomyl accumulating in the residue treater, these lab results took more than an hour to process, too long to be an effective input to the operators to prevent overcharging the residue treater with concentrated methomyl. The existing layers of protection were inadequate to prevent a runaway reaction.

3.9 Unit Restart Equipment Problems

Unit staff encountered many problems with equipment during the restart activities. One involved a longstanding issue with the residue treater heater operation. Others were directly related to the new control system installation, and some involved equipment malfunctions or misaligned valves.

3.9.1 Residue Treater Heater Performance

The original design basis specified the minimum residue treater operating temperature to be 85 °C (185 °F), but early system runs did not adequately decompose the methomyl at that temperature. Subsequent kinetic studies determined that the ideal safe operating temperature to achieve the required methomyl decomposition was 135 °C (275 °F). Engineers added a heater in the residue treater recirculation system to preheat the MIBK solvent to the higher minimum temperature. However, more than one board operator told CSB investigators the heater could increase the temperature to only about 130 °C (266 °F). To resolve the issue during start-ups, some board operators bypassed the minimum temperature safety interlock and manually opened the flasher bottoms feed valve when the residue treater solvent temperature was within about 5-10 degrees of the operating temperature. After feeding methomyl and MSAO into the solvent, the exothermic decomposition reactions generated enough energy to heat the contents the remaining few degrees needed to satisfy the minimum temperature interlock setpoint, but not enough energy to cause an explosion. Thus, operators became accustomed to bypassing the interlocks and manually opening the feed valve before the residue treater contents were at the minimum operating temperature.

On the night of the incident, the residue treater was not pre-filled with solvent, and based on experience with the heater, the minimum temperature safety interlock was bypassed. The flasher bottoms were hot enough for the concentrated MSAO and methomyl to begin decomposing. The temperature continued climbing until the reaction reached a runaway condition that led to the explosion.

3.9.2 Broken, Missing, and Misaligned Valves

Other equipment problems continued to disrupt the operators and cause chemical imbalances in the system.

3.9.2.1 Instrument Drip System Valve

The instrument drip system provided MIBK solvent to various components and instruments to prevent solids from depositing and accumulating inside pipe and equipment. As “drip system” implies, MIBK was intended to be added using a minute, drip-wise flow rate into the process stream. During the methomyl unit outage, a valve on the instrument drip system was inadvertently left out of a line, so that MIBK flowed continuously into the system. This oversight was not discovered and fixed until the day before the incident, which allowed off-specification material to proceed through the process. This “hydraulic load” made maintaining balanced operating conditions in the methomyl crystallizers more difficult, which contributed to the high methomyl content in the flasher bottoms feed to the residue treater.

3.9.2.2 Cooling Water Valve

A broken cooling water valve on an upstream distillation column side-draw condenser further over-concentrated the MIBK. Without the cooling water, MIBK was not condensing out of the vapor stream, worsening the solvent ratio imbalance.

3.9.2.3 Residue Treater Recirculation System Block Valves

While examining the damaged unit, CSB investigators discovered, and Bayer later confirmed, that a valve on the residue treater recirculation heater steam supply was closed, instead of fully opened as intended. This incorrect valve position should have been identified either during a formal valve alignment checkout before the unit restart began, or during a residue treater system solvent run.

However, the staff did not perform either activity before they began the unit restart so the misaligned valve was not detected during the startup.

The board operator told investigators that he believed that the heater was working correctly because the residue treater temperature was increasing in a similar way to what he had expected during a residue treater startup. The CSB concluded that the residue treater liquid temperature was climbing because highly concentrated methomyl and MSAO were already decomposing and the self-sustaining decomposition reactions were rapidly increasing and would soon go out of control.

Post-incident examination of the computer data suggested that steam was flowing into the heater (Figure 19). However, the CSB concluded that with the steam supply block valve confirmed to have been in the closed position,[40] the only possible explanation for indicated steam flow was an improperly calibrated instrument, misaligned vent valve, or malfunctioning flow instrument. This was yet another example of the inadequate system checkout.

Another equipment malfunction that should have been identified before the restart involved the residue treater heating/cooling control configuration in the DCS. About 15 minutes before the residue treater explosion, the data indicated that recirculation flow suddenly dropped to zero (Figure 11, bottom trace).

[40] The valve was removed from the pipe and visually examined. Water placed in the valve body did not leak past the seat in any measurable amount.

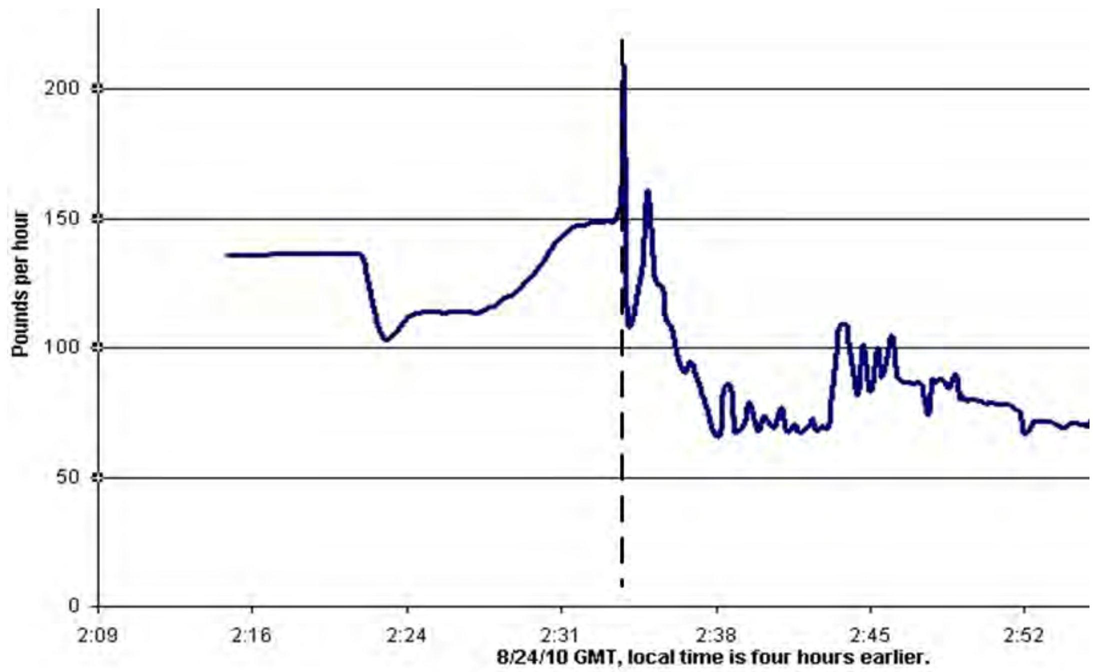

Figure 19. Indicated steam flow through the residue treater heater. Vertical dashed line shows point of vessel failure. Actual flow was zero because valve was closed

Figure 20. Closed steam block valve recovered from residue treater heater steam supply valve

It was determined that the automatic temperature control system closed both the heater and cooler flow control valves (see Figure 10) at the same time when the recirculation temperature control transitioned from heating to cooling. Bayer examined the temperature controller and its investigation team concluded that

> [An] undocumented change in the heating/cooling control scheme was made during the control system upgrade that resulted in a flow restriction when changing from heating to cooling.

Regardless of this control system error, both the CSB and Bayer concluded that even if full flow had been established, the cooler could not remove enough heat to stop the runaway reaction and prevent the explosion.

3.9.3 Other Process Equipment Problems

At the Institute facility, supervisors commonly left their passwords logged in to allow operators to bypass safety systems considered troublesome during startup. Without supervisors' direct involvement, best practices were ignored to get the process underway quickly.

The excessively high concentration of MIBK caused by the equipment malfunctions upstream prevented the methomyl from crystallizing in the crystallizers: the methomyl remained dissolved in the solvent. Dissolved methomyl remaining in the solution caused the liquid level in the centrifuges to trip a high-level alarm and abort the centrifuge cycle. Operators, unaware that the problem involved a solvent ratio imbalance in the crystallizers, used the unsecured control system supervisory access[41] screen to bypass the centrifuge high-level trip interlock and operated the centrifuges manually.

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[41] Safety matrix and operating matrix function changes were administratively controlled using a secure password to prevent inadvertent or unauthorized changes or bypassing without engineering approval. However, during startup, a supervisor logon to the operator matrix edit screen was left active so that anyone could defeat the control functions.

Improper or incomplete checkout and calibration of the Siemens control system caused more centrifuge problems. A malfunctioning relay in the new system caused the centrifuges to trip off when the operators attempted to run both at the same time, which was the normal condition. That problem combined with many recurring high-level alarms in the centrifuges led operators to believe that the two issues were linked. They did not recognize the real issue: the malfunctioning equipment upstream of the crystallizer prevented proper methomyl crystallization. Uncrystallized methomyl increased the liquid level in the centrifuges, which triggered the high level alarms.

3.10 Air Monitoring Systems Deficiencies

3.10.1 Fenceline Air Monitors

Fenceline air monitors are often relied on to determine if chemicals released from a plant enter the community. The locations of the monitors, as well as their limited chemical sensitivity, often make release determinations difficult. On the night of the incident, two property fenceline monitoring devices were operating, one on the east side and one on the west side of the facility. The closest monitor was more than 800 feet from the methomyl unit and would be effective only if it were downwind of a release. The monitors were configured to detect chlorine, carbon monoxide, methane, and oxygen. Each monitor contained a 10.6 eV (electron volt) lamp and a VOC sensor capable of picking up chemical compounds only within a certain range of ionization energies. Because the VOC sensor can detect several different chemical compounds, it is useful only in estimating a concentration if the released material is suspected and possesses an ionization energy in the detectable range. The AreaRae monitor, which was used the night of the incident, could not detect specific compounds such as methomyl or some of its intermediates. Laboratory analyses of air or swipe samples were the only sampling methods available to determine if methomyl was released, but those tests were performed days later.

The fence line monitors were also unreliable because they could not detect buoyant gas releases unless strong wind currents drove the gas back down to the detector locations. Weather conditions the night of the explosion, including wind direction and velocity, were unfavorable for proper detection of any toxic or flammable gas by either fence line monitor.[42]

3.10.2 Unit Air Monitors

The air sample analyzer collected and analyzed samples at 16 locations in the Methomyl-Larvin unit and near the MIC day tank at 2-minute intervals. The analytical results were recorded in a data historian and any concentrations exceeding 1.0 ppm triggered a visual alarm notification on a display panel on the second floor of the Methomyl/Larvin control building and at the board operator's console. The analyzer used a fixed filter photometer consisting of an infrared radiation (IR) source to absorb and detect the concentration of MIC within a range of 0 to 10 ppm.

In May 2008, the analyzer malfunctioned and reported erroneous concentrations in excess of 1 ppm and failed to activate control building alarms. Two weeks before the August incident, the monitor data logging system stopped recording for an unknown reason. The analyzer manufacturer worked with Bayer to resolve the problem, but the analyzer was not repaired and returned to service before the incident.

Unknown to EOC personnel the monitor was not operating the night of the incident. Assuming it was working, they concluded that the explosion did not cause an MIC release, or if MIC had been released, it was being consumed in the fires. The PSSR for the residue treater, completed prior to the methomyl restart, did not specifically list MIC analyzer operation as a requirement for startup or operation.

[42] Weather conditions the night of the incident were 66° F (19° C) and calm wind conditions.

3.11 Organizational Deficiencies

One experienced methomyl unit operator described how the organizational structure changes degraded the technical support available during unit operations:

> When we started getting rid of people--not getting rid of people--“thinning”--less technical assistance, if you will. There were some guys, they were in charge--we had a guy in charge of methomyl, a guy in charge of oxime, and a guy in charge of the warehouse. And that was their baby. And now we have like one guy doing it all. No shift supervisor.

This and other interviews led the CSB investigation team to conclude that the multiple shortcomings in the technical support available to the operators made recognizing and addressing problems with the system more difficult.

The reorganization resulted in only one Technical Advisor assigned to the entire Methomyl-Larvin unit who worked the day shift. The Shift Leader was also available to assist but did not work with the operators on a daily basis, operators relied primarily on the Technical Advisor. However, the night shift did not have a Technical Advisor on duty. If the board operators had a process question during their shift, they could call the Shift Leader or Technical Advisor who was on-call on nights and weekends. The Technical Advisor also served as a liaison to the capital project team.

For the system upgrade capital project, Bayer assigned a second Technical Advisor to assist with the increased workload. The first Technical Advisor focused on Larvin production, and the new Technical Advisor, who had no methomyl unit operating experience, focused on methomyl production. The second Technical Advisor had experience as a technical advisor and had DCS control system training. That experience, however, was in a different unit and the training was on a different brand of control system. A highly experienced methomyl unit operator helped the Technical Advisor with limited project work such as the functional acceptance testing, but the Technical Advisor was the primary contact.

In the days leading up to the incident, the only assigned Technical Advisor had worked as many as 15 to 17 hours a day, and 10 hours on the day shift preceding the incident. Throughout the evening preceding the incident, operators struggled with stabilizing the operating conditions in the methomyl unit, and yet the Technical Advisor had already left for the day. During this critical first startup using a new control system, management should have ensured that a highly experienced Technical Advisor was assigned to the control room staff during both shifts.

A Run Plant Engineer was another person operators could consult for technical assistance. The role of the Run Plant Engineer varied depending on the needs in the particular unit and mainly involved working on improvement and repair projects, and turnarounds. The Run Plant Engineer had little involvement on day-to-day operational support. The Methomyl-Larvin unit Run Plant Engineer had less than one year of experience before the incident. In his previous assignment, he had primarily defined and installed improvement and repair projects and did not typically deal with unit startup and operating issues. This engineer told CSB investigators that he knew very little about the details of the DCS upgrade project and was not even sure who had been designated as the project manager. More importantly, he said he lacked knowledge of the methomyl unit equipment and chemistry. He had hoped to learn more about the process by having greater involvement in the unit startup, but was unable because operational difficulties on the Larvin unit demanded his attention.

The Production Leader was another resource available to the operators. However, the reorganization also changed the relationship between the operators and the Production Leader. In the traditional structure, only one team of board operators reported to a supervisor, but in the self-directed work structure, the Production Leader was responsible for four self-directed work teams. The methomyl Production Leader worked the day shift and was responsible primarily for administrative activities and had little interaction with the operators related to unit startup and operation.

The organizational changes directly contributed to the incident causes. With the self-directed team organization in place, management did not directly advise or control the unit restart schedule. The self-directed work team ultimately decided to start the methomyl unit even though the control system and some equipment were not ready and the SOP was not up-to-date. Furthermore, management was so far removed from the process operation that they were unaware that the operators seldom used the SOP and some bypassed the critical safety interlocks, which directly led to the residue treater explosion.

3.12 Previous Methomyl-Larvin Unit Incident

On August 18, 1993, at approximately 10:15 a.m., an explosion occurred in the chloracetaldoxime (CAO) reactor loop of the methomyl unit. At the time of the incident the facility was owned and operated by Rhone-Poulenc. The explosion caused one death and injuries to two workers who were in the unit at the time of the incident. Investigators concluded that a flow indicator malfunction led to over-chlorination of acetaldoxime, which led to a violent decomposition. They further concluded that the workers' activities were not causally related to the incident. The explosion ignited a massive fire, which was fueled by flammable liquids being released by ruptured pipes.

The investigation team made the following recommendations:

- Identify, and treat as critical, all ESD interlock alarms. Examine and rigorously apply the Institute Plant Alarm Management procedure with regard to nuisance alarms; and
- Review and revise the unit procedures for "Disabling Alarms" and "By-passing Interlocks" to address a temporary bypass of a safeguard for operational purposes, such as during a unit startup.

Contrary to the 1993 recommendation to improve administrative controls involving critical process interlocks, the residue treater incident more than 15 years later directly involved similar improper control system interlock changes.

3.13 Emergency Planning and Response

3.13.1 National Incident Management System

The National Incident Management System (NIMS) is an organized system of roles, responsibilities, and procedures for the command and control of emergency operations. OSHA 1910.120(q) requires that both public safety and industrial emergency response organizations use a nationally recognized Incident Command System (ICS) for emergencies involving hazardous materials. ICS is an organized system of roles, responsibilities, and standard operating procedures used to manage and direct emergency operations (Figure 21).

Another important component of this network is the Unified Command System (UCS). UCS is a process of determining overall incident strategies and tactical objectives by having all agencies, organizations or individuals who have jurisdictional responsibility participate in the decision-making process.

As part of a comprehensive national incident management system, most state, local, and volunteer organizations are familiar with the NIMS process and use it for even routine incidents. Interviews with the St. Albans fire chief, the Kanawha County Sheriff, and Metro 9-1-1 staff revealed knowledge of the NIMS system and their use of the process in routine incidents such as traffic accidents and residential emergencies.

On the night of the incident, all of the responding outside agencies communicated via the Kanawha Putnam EOC. However, the Bayer EOC did not use a shared network to communicate with all responding agencies; thus, the responding agencies did not receive timely status updates. Important information updates about the continually changing conditions at the fire scene were not communicated to the other responding agencies (Knoll, 2005).

INCIDENT COMMAND STRUCTURE

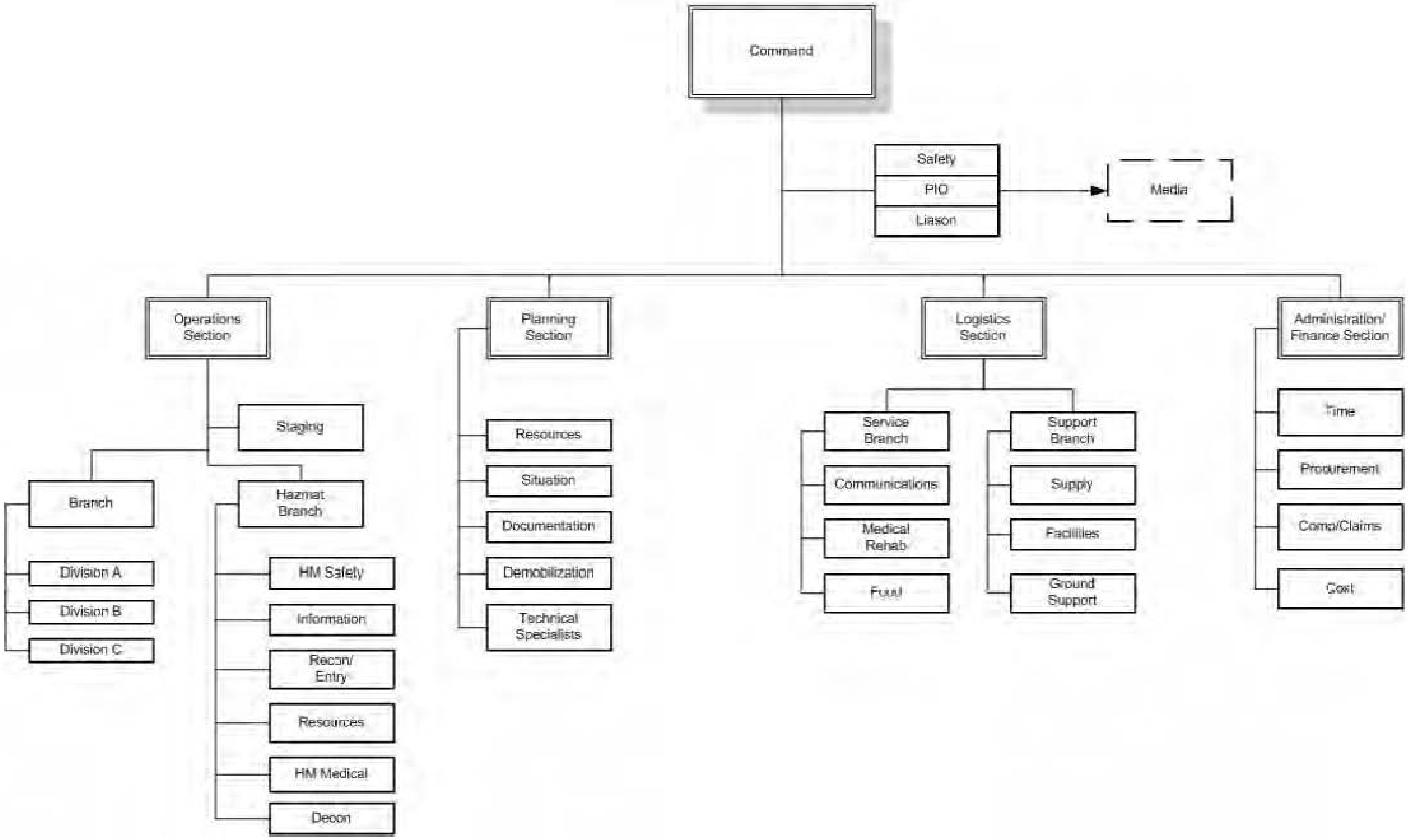

Figure 21. NIMS incident command structure

3.13.2 Kanawha Putnam Emergency Planning Committee

The Kanawha Putnam Emergency Planning Committee (KPEPC) history dates back to the 1950s when it began as the Kanawha Valley Industrial Emergency Planning Council to serve as a mutual aid group doing business in Kanawha County. In 1995, the KPEPC began functioning as the Local Emergency Planning Committees (LEPC)[43] in Kanawha and Putnam counties. The federally mandated committee includes volunteers from the community, industrial businesses, and representatives from the emergency response organizations in the area. KPEPC has 12 board members, 10 annex committees, and about 125 members that oversee emergency response planning. It is funded by its membership, the U.S. Department of Transportation, and West Virginia state grants.

KPEPC activities include conducting emergency drills (e.g., fire or hazardous materials spills) with member companies; holding monthly meetings; and interfacing with other LEPCs in West Virginia. The committee also serves as a resource and supports training of various emergency response agencies.

3.13.3 Kanawha Putnam Emergency Management Plan

The Kanawha Putnam Emergency Management Plan provides "general guidelines for planning, managing and coordinating the response and recovery activities of local government" in the event of a major emergency or disaster.[44] The president of the County Commission is responsible for executing the plan when the emergency involves the county. The plan is divided into a "basic plan" and two annexes. The "Functional" annex contains guidelines for participating agencies to use in developing agency-specific operating documents. The "Hazards" annex contains non-routine emergency

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[43] An LEPC is a committee appointed by the state emergency response commission, as required by SARA Title III, to formulate a comprehensive emergency plan for its jurisdiction.

[44] West Virginia Emergency Act Chapter 15, Article 5, "Emergency Services."

scenarios. The Emergency Management Director is responsible for the operational aspects of the plan and plan revisions.

The Basic Plan addresses only governmental organizations—it fails to address roles and responsibilities of facility personnel in the event of a chemical incident at a facility. The Basic Plan requires that only one EOC be in place for an emergency and all staffing functions be provided by emergency response agencies. Furthermore, the plan states, correctly, that an Incident Commander (IC) is responsible for tactical operations in the field and assigns "absolute control over all on-scene operations" and requires all emergency activities to conform to the ICS and NIMS.

However, the Basic Plan does not address the facility owner's roles and responsibilities to establish an internal incident command structure in accordance with the NIMS process. It does not provide any information or direction when the facility owner assigns the IC and establishes an EOC, as was the case during the August 2008 Bayer incident.

The CSB also found that at least two functional annexes contradict the Basic Plan. Chemical HazMat Response, Annex A16, states that "the manufacturing facility (plant) Incident Commander will be part of the Unified Command structure." Additionally, Mining Accidents, Annex 26, states that "Initially, the coal company is in charge of the incident." The annex defines the criteria for official transfer of the incident command to state and federal government agencies when they arrive on-scene. The omissions and contradictions in the Basic Plan are likely to confuse critical emergency response activities in the event of a fire or chemical release at a facility.

3.13.4 Chemical Release Notification Law

In 2009, the State of West Virginia revised the Mine and Industrial Accident Rapid Response System regulation (West Virginia Code Chapter 15 Article 5B), to require prompt reporting of chemical releases. The new law applies to all facilities regulated by the EPA Risk Management Program regulation (40 CFR 68). It does not apply to facilities regulated only by the Occupational Safety and

Health Administration (OSHA) Process Safety Management standard (29 CFR 1910.119). The law requires the facility to notify the Mine and Industrial Accident Emergency Operations Center by telephone within 15 minutes of the industrial facility ascertaining the occurrence of an emergency event. The regulation also requires the reporting facility to:

- Implement a communications system designed to provide timely information to appropriate state and local officials;
- Upon request, provide appropriate state and local officials with timely authorized access to the person or persons charged with managing the event on behalf of the facility and the area(s) where the emergency event is being managed or the industrial facility's response to the emergency event is being coordinated; and
- Provide appropriate state and local officials with timely authorized access to any areas affected by the emergency event.

The law also requires that within 30 minutes of obtaining information that affects the public health, safety and welfare, state and local officials shall notify the public of any hazardous materials or events which may affect the area.

3.14 Incident Response and Communication Deficiencies

3.14.1 Bayer CropScience Facility

The Bayer IC led the plant’s internal emergency response team but did not have direct contact with the Kanawha Putnam EOC. Because the information to and from the Bayer EOC was not part of a UCS, responding municipal, county, and state agencies were not provided updated and reliable information regarding the status of the incident throughout the response.

Concerns expressed post-incident cited a number of troubling issues, including police and fire responders’ potential exposure to toxic substances while performing their duties. Responding agencies also cited the threat to the surrounding communities due to the lack of timely information that would have made for better coordination of the shelter-in-place decision-making process. The CSB could find no evidence of an effort by Bayer to align operations with other responders in a UCS.

The Bayer IC established radio communication with the Institute VFD fire chief, who was also a Bayer employee; Bayer fire brigade members; and the Bayer EOC. Information relayed to municipal, county, and state agencies that responded to the incident was not first-hand in most cases and so was prone to errors as information was relayed from one source to another.

3.14.2 Facility and Emergency Responders' Communications

Timely and accurate information updates from the Bayer EOC to the outside emergency responders were an issue throughout the incident. The quality and lack of timely information regarding the status of the incident and information necessary to make decisions advising shelter-in-place emerged as recurring concerns post-incident from participating agencies. The agencies also felt that communities were placed at greater risk and that better information would have helped in providing useful advisories to police and fire units.

More than 10 minutes elapsed before Bayer was able to alert Metro 9-1-1 and even then, the information was inadequate. The guard at Bayer's main guard shack told investigators that he tried several times to call them but was unable to get through.[45] Finally, at 10:42 p.m. contact was made when the guard was calling for an ambulance to transport a burn victim to the hospital. When the Metro 9-1-1 operator questioned him about the explosion, the caller indicated that he could not provide any information.[46] Similar exchanges continued throughout the night until the all-clear was sounded at about 5:50 a.m. the following morning.

Another control and communication deficiency involved possible toxic exposure to on-scene emergency responders. The decontamination area located outside the fire zone was shut down shortly after the all-clear was sounded, but before all the emergency responders involved in the fire

[45] The Metro 9-1-1 operator made a similar observation as he attempted to call the Bayer site.

[46] Bayer management instructed the guard, who was the official point of contact with Metro 9-1-1 for such communications, not to provide any information other than what the IC directed.

suppression activities had decontaminated their clothing and equipment. The responders from the Tyler Mountain Fire Department returned to their fire station with contaminated gear. The CSB learned that the next day they complained of symptoms indicative of toxic exposure.

3.14.3 Kanawha Valley Emergency Communications Process Improvement Initiatives

The Kanawha Putnam Emergency Plan requires that police, fire, and EMS dispatch be coordinated and directed from the Metro 9-1-1 call center. Located in Charleston, West Virginia, the facility employs about 100 dispatchers, administrative support, and supervisors. All calls for emergency assistance requiring municipal or county resources are consolidated through the call center. Metro 9-1-1 is also a member of the KPEPC and participates in the committee meetings.

To address the communication issues that occurred during the Bayer incident response, Metro 9-1-1 and KPEPC developed new tools and processes for use by the agencies charged with emergency response in the Kanawha Valley. Post-incident, Metro 9-1-1 participated in a drill with the Institute site and local emergency response organizations and implemented the following emergency response improvements:

- Developed a list of questions to use when any fixed facility calls the center and trained all telecommunications personnel;
- To improve response times when receiving calls for assistance, Metro 9-1-1 no longer serves as the conduit for KPEPC reporting requirements.[47] Plants complete and submit chemical release information forms to the KPEPC within 14 days of an incident;
- Established one-mile zones around fixed facilities for rapid, automatic reverse ringdown phone calls in the event of a release;

[47] Releases of Extremely Hazardous Substances as listed in 40 CFR 355, Appendix A, or chemicals that require release reporting as defined in section 103(a) of the Comprehensive Environmental Response, Compensation and Liability Act (CERCLA), Must be reported to LEPCs within 14 days of a chemical release.

Table 2. New Metro 9-1-1 questionnaire for fixed chemical facilities
(Courtesy Metro 9-1-1)

Fixed Facility Chemical Questions	
1	What is your name?
2	What is your title?
3	What is the address/Location of the actual alarm?
4	What phone number do we use to call back about the alarm?
5	Is any outside assistance requested?
On initial call only: If the nature of the alarm or chemical is not known at this point, cease questions until plant personnel call back	
6	What is the Chemical involved? - How is it spelled? and/or - What is the CAS number?
7	Is the chemical involved on the "extremely hazardous" list?
8	Has the chemical been released into the air, water, or ground? If there has been a release, is it a "reportable quantity"?
9	Are there any recommended protective actions for the public?

- Established a 15-minute rule (starting when the call is first received) for the Metro 9-1-1 Emergency Management Director to call for an advisory shelter-in-place if the call center has knowledge of an event, but the company has not provided timely or quality information about the material involved in the release. (Section 3.13.4 discusses the new state law that requires facility owners to report certain chemical releases to the Mine and Industrial Accident Emergency Operations Center);
- Developed a process for emailing residents in the affected zone when a release occurs;
- Developed a protocol for notification when a release is reported to Metro 9-1-1 that uses email, reverse ringdown phone calls, and emergency sirens;
- Increased call center phone capacity by 50 percent to address increased telephone traffic during emergencies;

- Identified mid-level personnel contact information for Bayer, DuPont, and Dow who are authorized to talk directly with Metro 9-1-1 staff during an emergency; and
- Developed a matrix that identifies the information that should be provided to the public as soon as it becomes available.

To address the communication problem between the Bayer EOC and METRO 9-1-1, Bayer installed a dedicated telephone line that directly connects the Bayer EOC to Metro 9-1-1. This is intended to ensure that overloaded phone lines do not block calls between the two parties, which typically occur in such incidents.

3.15 Environmental Impact

More than 2,000 gallons of toxic and flammable liquid was expelled from the residue treater, ruptured piping, and other equipment, most of which burned in the ensuing fire. Although the residue treater feed contained significant quantities of methomyl and MSAO, those chemicals were rapidly decomposing in the residue treater. Post-incident, trace amounts of methomyl were found in swipe samples from equipment in the vicinity of the explosion; however, the specific quantities of un-decomposed or unburned methomyl or other toxic chemicals that might have escaped into the atmosphere were indeterminate.

The MIC day tank and cross-unit transfer piping were not damaged in the incident. However, the liquid in the residue treater contained significant quantities of methomyl and MSAO products of decomposition and possibly some quantity of methyl isocyanate.[48] MIC might have also been released from ruptured process piping and vent piping. MIC is flammable and highly reactive with water; at least some of any released MIC likely burned in the fire or reacted with the water used to

[48] The flasher bottoms likely contained small amounts of MIC, and MIC could have been one of the products of the methomyl decomposition reaction.

fight the fires. There were no reports of river water contamination or other offsite ground contamination.

3.16 MIC Day Tank Blast Shield Analysis

The MIC day tank was adjacent to the methomyl-Larvin unit. A steel rope mesh ballistic shield (blast blanket), mounted on the sides of and on top of a structural frame, protected the tank in the event of an explosion in the unit or nearby equipment (see Figure 2). Flying debris from the residue treater explosion struck the blast blanket. The fires radiated intense heat on the blast blankets.

After the incident, Bayer removed the blast blanket and the MIC day tank insulation and associated piping. They visually examined the day tank for impact or heat damage. They also pressure tested the day tank. The day tank showed no evidence of heat damage— the blast mat provided highly effective protection against radiant heat from the external fires. The examination and testing confirmed the day tank and associated piping were not damaged by the explosion.

As reported by the blast mat manufacturer and confirmed by independent studies, the blast mat provided effective protection against penetration by small projectiles traveling at near sonic velocity, as well as penetration by a large fragment travelling more than 100 miles per hour.[49] An analysis commissioned by Bayer after the August 2008 incident also concluded the blast mat provided effective protection against small, high-velocity projectiles.

To fully protect the day tank, the blast blanket and frame assembly had to absorb the dynamic energy from any debris strike. The original structural frame design only considered the blast mat weight and wind loading, it did not examine dynamic loading. The CSB analyzed the structural frame to determine if it provided adequate protection against overpressure blast energy and a large projectile

[49] The manufacturer worked with the Israeli Defense Force and the Southwest Research Institute to evaluate the ballistic shield design. Testing demonstrated that it is capable of withstanding detonation pressures resulting from thousands of pounds of TNT more than 30 feet from the source of the detonation.

impact into the blast mat (Appendix C). The analysis examined both maximum theoretical deflection and structural component failure. It concluded that the structural frame was adequate to prevent damage to the MIC day tank and attached vent pipe from the overpressure energy. The analysis concluded that the structure provided only marginal impact energy absorption protection from a large fragment strike at velocities predicted to result from the residue treater explosion.

Therefore, had the residue treater traveled unimpeded in the direction of the day tank, and struck the shield structure just above the top of the MIC day tank, the shield structure might have impacted the relief valve vent pipe. A puncture or tear in the vent pipe or MIC day tank head would have released MIC vapor into the atmosphere above the day tank.

4.0 Methyl Isocyanate Risk Reduction at the Institute Facility

4.1 Congressional Action

In May 2009, the U.S. House of Representatives Committee on Energy and Commerce sent a letter to the U.S. Chemical Safety Board Chairman requesting that the Board:

1. "Conduct an investigation to determine options for Bayer to reduce or eliminate the use or storage of MIC by switching to alternative chemicals or processes."
2. "Determine whether Bayer has adequately examined the feasibility of switching to alternative chemicals or processes."
3. "Provide specific recommendations for Bayer and its state and federal regulators on how to reduce the dangers posed by on-site storage of MIC."
4. "Brief our staff on the Board's findings and recommendations at the end of its investigation."

In the fall 2009, the Congress appropriated $600,000 to the CSB fiscal 2010 budget and directed that the funds

> [S]hall be for a study by the National Academy of Sciences [NAS] to examine the use and storage of methyl isocyanate including the feasibility of implementing alternative chemicals or process and an examination of the cost of alternatives at Bayer CropScience facility in Institute, WV.

The NAS study was designed to address item 1 in the May 2009 committee request. Historical studies addressing MIC alternatives conducted by Bayer and the prior owners of the Institute facility are discussed in Section 4.2.

The CSB published a draft scope of work for the NAS study in *The Federal Register*[50] on April 23, 2010, to solicit public comment. The CSB reviewed all submitted comments and revised the NAS scope of work. The CSB awarded the contract to the NAS in September 2010. The CSB is currently considering the impact of Bayer's announcement concerning the planned total elimination of MIC on the NAS study.

4.2 Alternative MIC Technology Analysis History

4.2.1 Union Carbide Corporation Studies

UCC began alternative MIC technology research in November 1976. The initial research focused in the area of "adducts," which are chemical structures that can be easily added and removed from the desired chemical. The intention of an adduct is to change undesired characteristics of the chemical to which the adduct is attached. In the case of MIC, the adduct made it water soluble and ultimately less hazardous should it escape containment. However, the MIC adduct was not easily removed, so it contaminated the insecticide products.

In July 1984, UCC researched a palladium catalyzed reaction that had the potential to completely eliminate both MIC and phosgene use. However, the cost of the catalyst greatly outweighed any potential feasibility for this process. At the time, it would have cost more than $14 per pound of insecticide, merely to cover the cost of the palladium catalyst, which was cost prohibitive.

During its ownership, UCC reviewed 97 patents dealing with alternative technologies to MIC production but concluded that none could perform as well as the existing process. In the last year of the facility ownership, UCC found three different pyrolysis[51] techniques that showed promise to

[50] The Federal Register. Chemical Safety and Hazard Investigation Board, National Academy of Sciences Study, Vol. 75, No. 78 / Friday, April 23, 2010, pg. 21223.

[51] Pyrolysis is a term for chemically decomposing organic materials through heating--a form of thermal decomposition.

eliminate phosgene and/or reduce the MIC stockpile, but sold the facility before completing the studies.

4.2.2 Rhone-Poulenc Studies

Rhone-Poulenc continued research into pyrolysis through March 1989, but determined that the pyrolysis approach to manufacturing pesticide products was not cost-effective. Rhone-Poulenc also researched different approaches to operating the processes that use MIC and phosgene, intending to reduce the stockpiles of both. In all five new techniques studied, Rhone-Poulenc concluded that either the stress placed on the process equipment was too great or the new process would be unacceptably difficult to control.

Following the deadly MIC release from the Union Carbide facility in Bhopal, India, in 1984, DuPont implemented a new technology for producing the carbamate pesticide methomyl at its plant in La Porte, Texas, which did not require a large inventory of MIC. The technology also eliminated phosgene from the production process. In DuPont's technology, the less acutely toxic chemical methylformamide is converted into MIC on an as-needed basis and immediately consumed in a subsequent reaction, avoiding the need to store MIC. In the 1980s, Bayer itself used a similar approach to producing the carbamate pesticide propoxur in Europe; according to a published account, Bayer used an alternative chemistry where MIC was produced and consumed in tandem (Worthy, 1985).

Rhone-Poulenc also researched various in-situ processes for MIC, which would allow MIC to be synthesized and almost instantly consumed in the process line. This form of production eliminates the MIC stockpile and often removes the need for phosgene. In February 1989, Rhone-Poulenc analyzed the in-situ process DuPont used but did not adopt the technology, possibly due to patent restrictions.

In December 1989, Rhone-Poulenc reviewed what was thought to be a promising in-situ process proposed by Enichem. The Enichem process was going to be used at a facility in Brazil, and the suggestion was that it could also be used at the Institute facility. The available historical records did not explain why Rhone-Poulenc did not implement the Enichem technology.

4.2.3 Bayer CropScience Studies

Bayer CropScience continued to research the Enichem in-situ process that would eliminate phosgene and the MIC stockpile. However, the company reported that a byproduct of this reaction degrades the effectiveness of pesticide products by nearly 50 percent. As of August 2010, Bayer claimed that it has had not found an alternative to MIC suitable for its products manufactured in Institute, West Virginia. Bayer however committed to cooperate with the NAS and consider the recommendations that result from the NAS study.

4.3 Bayer CropScience MIC Storage Reduction

Concern expressed by many in the community, local regulators, and Congress ultimately prompted Bayer CropScience to reevaluate MIC use at the Institute facility. In August 2009, the company reported that the use of MIC would not be eliminated at the facility and that in-situ production of MIC at the operating units where MIC is used was not a viable alternative. However, Bayer committed to significantly reduce the on-site inventory of MIC, make process unit upgrades, and continue to study alternate chemistries that could eliminate the need for MIC for pesticide production. The full text of the Bayer CropScience announcement is contained in Appendix D.

Bayer management announced the following planned changes at the Institute facility:

1. Reduce the MIC storage at the Institute facility by 80 percent;
2. Eliminate all aboveground MIC storage;
3. Eliminate all transfer, storage, and use of MIC in the West Carbamoylation Center; and
4. Eliminate manufacturing methomyl and carbofuran.

Bayer did not repair the damaged Methomyl unit and abandoned methomyl production at the Institute facility. Bayer negotiated a carbofuran unit shutdown schedule with FMC, the owner of the unit, which ended carbofuran production in August 2010.[52] Bayer then stopped storing MIC in the Methomyl-Larvin unit day tank.

Bayer also committed to replacing the MIC production unit underground storage system with new, smaller storage vessels and a new underground containment vault. Bayer further committed to decommissioning the remaining aboveground storage vessels at the facility. Bayer CropScience management also stated to the CSB it would revise the MIC system Process Hazard Analysis and commission an independent review of the PHA. The facility upgrade work is scheduled to be complete by February 2011.

Subsequent to Bayer's announcement of its MIC inventory reduction plans, in August 2010 the Environmental Protection Agency and Bayer reached an agreement to phase out the production of aldicarb, one of two remaining MIC-derived pesticides made in Institute, by the end of 2014. On January 11, 2011, Bayer announced plans to end the production of both aldicarb and carbaryl by mid-2012 and thereby eliminate the production, storage, and use of all MIC and phosgene. Bayer stated it would continue to produce Larvin at the plant by the conversion of methomyl purchased from commercial sources; however, this process does not require MIC or phosgene to operate.

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[52] On May 15, 2009, the Environmental Protection Agency revoked all food tolerances for carbofuran and effectively prohibited the use of the pesticide. The EPA stated that "dietary, worker, and ecological risks are unacceptable for all uses of carbofuran." See http://www.epa.gov/opp00001/reregistration/carbofuran/carbofuran_noic.htm, January 9, 2011.

5.0 Regulatory Analysis

5.1 Occupational Safety and Health Administration

5.1.1 Process Safety Management Program

The PSM standard requires employers to prevent or minimize the consequences of catastrophic releases of highly hazardous chemicals. PSM applies to processes that involve any of 137 listed toxic chemicals at, or above, threshold quantities and processes with flammable liquids or gases onsite in one location in quantities of 10,000 pounds or more. The Methomyl-Larvin unit was covered by the PSM standard because it contained listed toxic chemicals including methyl isocyanate (threshold quantity [TQ] = 250 pounds); methyl mercaptan (TQ = 5,000 pounds); and various flammable liquids including hexane and methyl isobutyl ketone, each in quantities significantly above the 10,000 pound flammable liquid/gas TQ. Chlorine (TQ = 1,500 pounds) is also used in the methomyl unit.

The PSM standard requires the owner to perform an initial PHA [1910.119(e)], and to revalidate the PHA at least every five years thereafter. Furthermore, the standard requires the employer to

> [A]ssure that recommendations are resolved in a timely manner and that the resolution is documented; document what actions are to be taken; complete actions as soon as possible; develop a written schedule of when these actions are to be completed.

5.1.2 PSM Inspections at the Bayer Facility

OSHA conducted a planned inspection of the Bayer Institute facility in 2005. The inspection identified deficiencies in PSM program elements including conduct of PHAs and compliance audits. After the August 2008 incident, OSHA conducted a compliance audit that focused on the Methomyl-Larvin unit.

In addition to the PHA deficiencies discussed in Section 3.3, both the CSB and OSHA investigations found that many PHA recommendations had not been resolved, including operating procedure deficiencies and deficient hazard analyses. Delays in addressing these issues persisted even after the methomyl system PHA conducted in 2005 identified the problem.[53] The Bayer PSM-facilitated self-assessment, dated Oct 30-Nov 9, 2007, again identified that many action items, called "risk sheets," from the 2005 PHA remained incomplete and unassigned. An internal Bayer memo dated August 7, 2008, three weeks before the incident, noted 48 open risk sheets.

The CSB investigation team also identified other significant PSM program deficiencies associated with Operating Procedures [1910.119(f)]; Training [1910.119(g)]; and Pre-startup Review [1910.119(i)], which are discussed in Section 3.0. The OSHA inspection conducted after the incident identified 12 items that violated the PSM program requirements, two of which OSHA classified as "repeat" violations.

5.1.3 PSM Program Deficiency Findings in Other CSB Investigations

The PSM program deficiencies identified in the Bayer incident investigation parallel findings in many other CSB investigations (Table 3). Notably, the BP Texas City refinery investigation identified PSM deficiencies in MOC, PHA, PSSR, and operating procedures practices.

At the BP Texas City refinery CSB investigators found that, "deviations from the procedure were made without performing MOC hazard analyses." The same situation occurred during the methomyl unit startup at Bayer. The CSB identified organizational change control deficiencies existed at both BP and Bayer. In the case of the BP incident, the company did not apply the PSM MOC process to evaluate the organization changes in the Isom unit operation. Although Bayer applied the MOC process to the organization redesign implemented in 2007, the MOC failed to adequately address the impact the changes had on technical support during special operating situations, such as the methomyl unit startup with a completely new control system.

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[53] The recommendations and corrective action listed in the 2005 PHA report to Bayer management contain the finding that "some areas of concern were identified…Many of the risk sheets identified in previous PHAs have not been mitigated."

Table 3. Common PSM program deficiencies identified in CSB investigations

	PHA	MOC	PSSR	Standard Operating Procedures
Bayer (2008)	X	X	X	X
BP (2005)	X	X	X	X
Formosa (2004)	X	X		X
DPC (2002)	X			X
Honeywell (2003)	X	X		
INDSPEC (2008)	X			X
Motiva (2001)	X	X	X	
Sierra (1998)	X	X		X
Tosco (1999)		X		
Valero (2007)	X	X		

The CSB determined that PHAs and PSSRs performed at both BP Texas City and Bayer were not sufficient. In both cases, the PHAs failed to address operating conditions involving bypassed or inoperative safety devices. At BP Texas City, the CSB determined that, "none of the PSSR procedural steps were undertaken for the ISOM startup." This is echoed in the Bayer case, as personnel improperly identified the PSSR as complete, and thus they proceeded with the methomyl unit startup even though equipment was not properly installed or calibrated.

At Bayer, longstanding operating procedure deficiencies played a significant role in the accident. As was the case in the BP incident, the CSB found that, "management did not effectively review the available computer records of [SOP] deviations and intervene to prevent future deviations." The staff should have corrected the operational problems before they proceeded with the unit restart. Furthermore, management did not enforce procedural compliance or proper application of MOC to ensure SOP errors were corrected. In all six CSB investigations that identified SOP problems, each incident involved SOP deviations that became “necessary violations” to get the job done (Hopkins, 2000).

5.1.4 OSHA PSM Chemical National Emphasis Program

Since the Process Safety Management of Highly Hazardous Chemicals standard was promulgated in 1992, OSHA has found that even employers with extensive written PSM programs may not effectively implement the programs on their covered processes. On July 27, 2009, OSHA issued a directive to implement a pilot national emphasis program (NEP) for chemical facilities covered by the PSM standard. The NEP directs certain OSHA regional offices to verify that the activities actually performed by employers are consistent with the employer’s written program and with the requirements of the standard. This NEP requires auditors to use investigative questions focused on a limited number of specific PSM program activities, rather than the traditional PSM program inspections that involved comprehensive, but broad, open-ended, and resource-intensive compliance evaluations. The NEP is intended to “allow for a greater number of inspections by better allocation of OSHA resources” [OSHA Directive 09-06 (CPL 02)]. It applies to planned inspections in the pilot regions, and unplanned inspections OSHA-wide. On July 8, 2010, OSHA superseded Directive 09-06 with Directive 10-05. The revision extended the NEP through September 2010 and encouraged State Plan adoption of the program. In October 2010, OSHA extended the directive in Regions 1, 7, and 10. OSHA continues evaluating the results of the pilot chemical industry NEP, and plans to make appropriate modifications to improve its effectiveness, and extend the NEP to all ten regional offices.

5.1.5 OSHA PSM Citations Follow-up Deficiencies

OSHA has issued many citations to companies for failure to comply with the PSM standard. Generally, the companies are required to submit written certifications to OSHA that assert the corrective actions have been implemented, as Bayer submitted in response to the citations that resulted from the 2005 planned inspection. Furthermore, OSHA can levy significant penalties when they determine that a company has a repeat violation, or has failed to abate workplace hazards cited in a previous inspection.

The CSB found, as did OSHA, that contrary to the certifications made by Bayer, some corrective actions were not implemented adequately. The CSB further found that OSHA does not always conduct follow-up field inspections to verify that companies have, in fact fully implemented agreed-upon corrective actions. OSHA field inspections that occur through planned inspections, complaints, referrals, or accident investigations do not necessarily examine the adequacy of corrective actions from previous inspections that a company has certified to be complete. Follow-up inspections specifically intended to confirm corrective action status are utilized only occasionally.

5.2 Environmental Protection Agency Risk Management Program

The EPA Risk Management Program (RMP) regulation (40 CFR 68), mandated by Section 112(r) of the Clean Air Act Amendments of 1990, regulates the use of highly hazardous chemicals at facilities (stationary sources). The purpose of the RMP is to prevent accidental offsite releases of these substances and ensure that the company and community are able to respond effectively in case of a release. The regulation applies to facilities that use or store regulated substances that exceed threshold quantities specified in the EPA regulations.

5.2.1 Application of the Bayer CropScience Risk Management Program

The Methomyl-Larvin unit and other units in the facility are subject to the RMP rule. The unit contained two listed toxic chemicals, methyl isocyanate (TQ = 10,000 pounds) and methyl mercaptan (TQ = 5,000 pounds). Bayer also reports six additional RMP regulated chemicals are used at the facility (Table 4).

Table 4. RMP covered chemicals in Bayer process units

Chemical	Threshold Quantity (pounds)
ammonia	10,000
chlorine	2,500
trichloromethane	20,000
methylamine	10,000
methyl mercaptan	5,000
phosgene	500
trimethylamine	10,000

The EPA requires the facility owner to assign to each covered process one of three “prevention program” levels based on offsite consequence analyses, incident history, and PSM program applicability. Program 1 is the lowest, simplest management program. Program 2 is an intermediate management level program with added program elements and basic documentation requirements. PSM-covered processes cannot be designated Program 2. Program 3 is the highest level management program. All PSM program activities and records are directly applicable to the Program 3 regulatory activities. Most PSM-covered processes fall into Program 3, as do the Bayer Institute facility processes that involve the seven RMP listed chemicals.

Each covered process must undergo a hazard assessment (40 CFR 68, Subpart B) in which the owner is required to prepare a “worst case release scenario” and an “alternative release scenario” for each covered process. Different analysis criteria apply based on whether the covered chemical is a toxic or flammable material. The hazard assessment also requires inclusion of the “five year accident history.” The results of the hazard assessment, along with other pertinent information for each covered process, must be submitted to the EPA. This Risk Management Plan (40 CFR 68, Subpart G) is prepared and submitted electronically and must be periodically updated by the facility owner.

The most recent Bayer CropScience Institute facility Risk Management Plan submittal preceding the August 2008 incident was dated July 2007. It states:

> The phosgene and MIC units [sic] on-site inventories have been minimized as far as practicable in order to minimize the potential impact in the event of a release. In 1992 and 1993, the phosgene process was rebuilt and the MIC process was modified to achieve these improvements following a thorough study of potential release scenarios.

The Risk Management Plan also discusses air emissions controls: “All of the processes covered by RMP utilize scrubbers and flares to destroy emissions from the process to minimize releases to the atmosphere.”

The five-year accident history for the RMP-regulated chemicals reports an accident that released approximately 15 pounds of phosgene (October 1999), another that released less than 1 pound of chlorine (May 2000), and a third that released approximately 3,000 pounds of liquid chloroform (August 2001). Each resulted in one or more worker exposures, and the phosgene release prompted a shelter-in place-alert. However, the company reports none of the releases involved offsite consequences.

5.2.2 EPA Inspections at the Bayer Institute Facility

The CSB searched the EPA Enforcement and Compliance History Online database for a record of EPA program audits or inspections at the Bayer facility. The database identified three evaluations of the Clean Air Act, Section 112(r), the first in 2005 and the second in 2006, which involved the MIC production unit. A third evaluation occurred in 2007.[54] None of the evaluations resulted in any enforcement action by the EPA.

5.2.3 EPA Office of Inspector General Risk Management Program Review

In 2008, the Office of Inspector General (OIG) of the U.S. Environmental Protection Agency conducted a review of the EPA implementation and oversight of the Risk Management Program (40 CFR 68). The OIG issued the final report, *EPA Can Improve Implementation of the Risk Management Program for Airborne Chemical Releases*, Report No. 09-P-0092 on February 10, 2009.

The OIG review found that EPA had not inspected or audited more than half (296 of 493) of the high-risk facilities. EPA Region 3, which includes West Virginia, had the highest RMP inspection rate of high-risk facilities (96 percent).

The report contained two significant recommendations to the EPA:

- Strengthen its inspection process to provide greater assurance that facilities comply with Risk Management Program requirements, and
- Develop inspection requirements to target higher-priority facilities for inspection and track its progress in completing inspections of these facilities.

The CSB also found during other incident investigations involving RMP covered processes that the EPA has seldom performed comprehensive audits or inspections of RMP programs at the facilities where the incident occurred.

In a May 2009 memorandum to the Office of Inspector General, EPA Office of Enforcement and Compliance Assurance agreed with the OIG recommendations. It revised the definition of a high-risk facility and reported that it would "work with the regions to develop an approach for targeting high risk facilities to make the best use of our limited inspection resources." EPA also revised the fiscal

[54] The EPA Enforcement and Compliance History Online database lists Bayer as the owner for the 2006 evaluation and Union Carbide Corporation as the owner for the 2005 and 2007 evaluation.

year 2010 National Program Managers Guidance to require the regions to ”require at least 10 percent of the total number of 112(r) inspections at defined high risk facilities.” Finally, EPA agreed to improve compliance inspection tracking of high-risk facilities.

5.3 State and Local Government Programs

5.3.1 Contra Costa County California Hazardous Materials Safety Ordinance

In 1999, the Contra Costa County, California Board of Supervisors approved an industrial safety ordinance[55] that established broad authority to the county health services department to oversee stationary sources in the refining and chemical industries in unincorporated areas in the county. The ordinance contains the following key elements:

- The owner shall prepare a Facility Safety Plan and submit it to the department. The Plan shall include:
  - Human factors and safety culture assessments
  - Consideration of inherently safer technologies in the PHA.
- The county health services department shall:
  - Conduct tri-annual audits of all submitted Safety Plans,
  - Hold public meetings on the facility safety plan,
  - Collect and maintain certain documents in a public information bank, and
  - Conduct an annual program performance review and issue a written report.
- The facility owner shall:
  - Allow the department to investigate an accident site and directly related facilities and submit an annual report of all accidents,
  - Document the decision made to implement or not implement all process hazard analysis recommended action items and the results of recommendations for additional studies, and
  - Periodically conduct a safety culture assessment.

[55] Contra Costa County, California, Ordinance Code Title 4 – Health and Safety, Division 450 – Hazardous Materials and Wastes, Chapter 450-8 – Risk Management.

The State also authorized the county to collect fees from each covered facility to fund the program. The department maintains a full-time staff of technical specialists who administer the program, perform the required audits, and conduct incident investigations. The City of Richmond adopted a similar ordinance in 2002 that mirrors the Contra Costa County ordinance.

The ordinance requires the Health Services department to conduct annual program reviews to evaluate the effectiveness of the program, discuss the results of audits completed by the department, and present various program metrics. The November 2009 annual audit[56] concluded:

> The number and severity of the Major Chemical Accidents or Releases have been decreasing since the implementation of Industrial Safety Ordinance. The implementation of the Industrial Safety Ordinance has improved and, in most cases, is being done as required by the ordinance. It is believed that by continuing implementation of the Industrial Safety Ordinance and strengthening the requirements of the Ordinance that the possibility of accidents that could impact the community has decreased.

The ordinance applies to three refineries and four chemical facilities in the county as reported in the audit. The audit report also includes the results of the City of Richmond ordinance, which includes one refinery and one chemical facility. The total fees assessed to the covered facilities in 2008 were less than $440,000. For the same period, the county reported that 4400 hours were charged in support of the ordinance. The report notes a significant decrease in the number of "major chemical accidents and releases" at covered facilities, from 11 incidents in 2001 to zero incidents in 2009.

As the CSB previously noted in its BP Texas City refinery investigation, the Contra Costa program has the benefit that covered facilities are regularly inspected for process

[56] http://cchealth.org/groups/hazmat/industrial_safety_ordinance.php, October 2010.

safety compliance every three years by a team of trained engineers employed by the county and funded through fee collection. By contrast, as the CSB and others noted, comprehensive OSHA and EPA safety inspections of high-hazard chemical facilities have historically been infrequent. OSHA and EPA process safety inspections do not occur on a regular schedule and often result only from a serious accident or complaint.[57]

5.3.2 New Jersey Toxic Catastrophe Prevention Act

The New Jersey state legislature enacted the Toxic Catastrophe Prevention Act (TCPA) in 1985 in response to the release of MIC in 1984 from the Union Carbide India Limited plant in Bhopal. The TCPA was one of the first regulatory programs in the nation to impose more stringent requirements on chemical facilities to reduce the risk of accidental releases. The TCPA is part of the New Jersey Department of Environmental Protection (DEP) Bureau of Release Prevention and has been accepted by the U.S. EPA for implementing the Risk Management Program regulation (40 CFR 68).

The TCPA is intended to protect the public from catastrophes caused by the release of Extraordinary Hazardous Substances (EHS) [58] and Reactive Hazard Substances (RHS).[59] Facilities covered under

[57] In 2007, the CSB recommended in its BP Texas City investigation that OSHA "strengthen the planned comprehensive enforcement of the OSHA Process Safety Management (PSM) standard" and "establish the capacity to conduct more comprehensive PSM inspections by hiring or developing a sufficient cadre of highly trained and experienced inspectors."

[58] An EHS is any substance or chemical compound used, manufactured, stored, or capable of being produced from on-site components in this State in sufficient quantities at a single site such that its release into the environment would produce a significant likelihood that persons exposed will suffer acute health effects resulting in death or permanent disability.

[59] An RHS is an EHS that is a substance, or combination of substances, which is capable of producing toxic or flammable EHSs or undergoing unintentional chemical transformations producing energy and causing an extraordinarily hazardous accident risk.

the act must submit a Risk Management Plan for all covered processes. Additionally, the DEP may require owners or operators to do the following under the TCPA:

- Immediately submit a risk management program for the DEP to review,
- Perform a safety review, hazard analysis, or risk assessment,
- Immediately take risk reduction actions or implement a risk reduction plan, and
- Cease operating until the identified risks have been abated.

The TCPA incorporates the EPA RMP list of toxic chemicals and threshold quantities; however, the TCPA EHS list contains several chemicals with lower thresholds than the RMP. The TCPA list also contains some chemicals for which the RMP does not apply. Facilities in New Jersey that process listed EHSs or RHSs in excess of the threshold quantities must submit a TCPA-specific Risk Management Plan to the DEP. The facility must also submit an EPA-specific Risk Management Plan as required by 40 CFR 68 Subpart G if the chemical is listed in the EPA RMP and the quantity exceeds the EPA threshold quantity.

Facilities with substances or mixtures containing substances on the RHS list must conduct a hazard assessment under the TCPA. The RHS list contains 30 specific reactive chemicals and 43 functional groups that exhibit reactive hazards such as water reactivity and pyrophoric or self-reacting properties. Operators must determine applicability of substances and mixtures to the RHS requirements by conducting calorimetry tests, literature reviews, or engineering calculations to determine the heat of reaction. The RHS threshold quantity ranges from 13,100 pounds for the lowest heat of reaction value (100 calories per gram) to 2400 pounds for a heat of reaction at, or above 1000 calories per gram.

In June 2008, the state amended the act to require facilities to conduct inherently safer technology (IST) reviews, to provide improved risk reduction. A team of qualified experts are required to conduct the IST reviews, as well as operations and union representatives. Each covered facility must determine whether IST is feasible and take into account environmental, health and safety, legal, technological, and economic factors into the analysis. The IST review must be submitted to the TCPA and updated on a 5-year basis, or with major process modifications.

As of March 2010, the TCPA has eliminated the less rigorous RMP Program 1and Program 2 criteria [40 CFR 68.10(b) and (c)]; it now requires all covered processes to be classified and managed in accordance with Program 3. It is the most rigorous toxic chemical environmental regulatory program in the United States.

5.3.3 Hazardous Materials Regulatory Oversight in West Virginia

Like Contra Costa County, the Kanawha valley has many facilities that handle large quantities of hazardous materials, some of which are acutely toxic. The EPA RMP database contains 15 facilities that report EPA Risk Management Program covered chemicals assigned as Program level 3 in Kanawha County. Statewide, the RMP database contains 54 facilities with Program level 3 plans. The region contains environmentally sensitive areas such as the Kanawha River, which is also an important transportation corridor. In addition to the serious incident at Bayer's Institute plant in 2008, the CSB is currently investigating a series of incidents that occurred in 2010 at the DuPont chemical plant in nearby Belle, West Virginia, including a fatal release of phosgene gas on January 23. Although the CSBs final report on the DuPont incidents remains to be completed, the incidents at DuPont also reveal process safety deficiencies that were not detected or corrected through existing regulatory enforcement mechanisms. In the Kanawha valley where both Bayer and DuPont are located, neither the state nor the local government has a program or regulation in place that requires or authorizes direct participation with facility safety planning and oversight even though many community stakeholders have long campaigned for such involvement.

The West Virginia Code Chapter 16, Public Health, charges the state public health agency with providing "Essential public health services" i.e., activities necessary to promote health and prevent disease, injury and disability for the citizens of the state." The code authorizes the commissioner of the bureau for public health “To make inspections, conduct hearings, and to enforce the legislative rules concerning occupational and industrial health hazards.” The Secretary of the state department of health and human resources may also propose “Fees for services provided by the Bureau for Public Health.”

If the West Virginia Department of Health and Human Services were to implement a program similar to the California safety ordinance, it would likely improve stakeholder participation and awareness, and improve emergency planning and accident prevention.

6.0 Key Findings

6.1 Process Hazard Analysis

1. The PHA team did not validate the assumptions in the PHA including accuracy of the SOP, conformance to the SOP, and control of process safeguards.
2. The residue treater layers of protection to prevent a runaway reaction were inadequate.
3. Previous PHA action items were not closed in a timely manner, including operator training and control of process safeguards.
4. The methomyl unit SOP was overly complex and not reviewed and approved prior to the methomyl unit startup.
5. The SOP did not include flasher tails methomyl concentration testing as required by the original construction process safety information package.

6.2 Pre-Startup Safety Review

1. The PSSR did not include a formal process involving multiple disciplines.
2. The PSSR did not verify the completion of modifications in the field, including:
   a. Methomyl-Larvin unit toxic gas monitoring system was not in service.
   b. Project engineers did not verify the functionality of critical DCS control and indication circuits.
   c. Operating equipment and instruments were not installed before the restart, some of which were discovered to be missing after the startup began.
3. Equipment checkouts as required by the pre-startup safety review were incomplete:
   a. Methomyl-Larvin unit toxic gas monitoring system was not in service.
   b. Project engineers did not verify the functionality of critical DCS control and indication circuits.
   c. Valve lineups were incomplete or incorrect.
4. Control system training was inadequate. The operators were not formally trained on the methomyl DCS and were not familiar with some of the changed units of measure used on the DCS displays.

6.3 Methomyl Unit Startup

1. Methomyl unit board operators were not provided with computer screen displays to effectively operate all assigned process and utility systems.
2. Multiple operational problems diverted the staff's attention:
    a. Only one of the two centrifuges was operating properly.
    b. The new Siemens operating system was not calibrated; consequently, the staff struggled with balancing the MIBK- hexane ratio in the crystallizers.
    c. Operators were pressured to start the MIBK solvent recovery system because the MIBK stockpile levels were getting low.
3. Operations personnel incorrectly assumed that methomyl was not being produced in the reactor even though the flasher feed sample lab results were available, which reported excessively high methomyl content in the process downstream from the reactor.
4. Operators and technical staff did not troubleshoot why the centrifuges did not contain methomyl cake.
5. Several required SOP steps were not completed during the methomyl unit startup:
    a. The residue treater was not pre-filled with solvent.
    b. The solvent was not circulated and heated to the minimum operating temperature.
    c. The 7 a.m. daily residue treater liquid sample was not collected and analyzed for methomyl concentration.
6. Management did not strictly enforce the safety matrix control policies. Bypassing the safety interlocks on the residue treater flasher bottoms feed valve allowed the empty residue treater to be filled with concentrated methomyl.
7. Oxime system startup problems diverted operators' attention, resulting in poor communication between methomyl board operators at shift change.

8. The residue treater relief system design basis was invalidated during the methomyl unit startup:

   a. The design basis assumed that the safety interlocks were active, but the interlocks were bypassed.

   b. The resident treater relief system design basis relied on administrative controls such as sample collection and analysis to prevent overcharging methomyl, but these controls were either incomplete or not implemented before startup.

9. A runaway methomyl decomposition reaction inside the residue treater overwhelmed the vent system and caused the vessel to violently explode.

6.4 MIC Day Tank Shield Structure Design

1. The blast blanket design basis did not consider an impact of a large object moving at high velocity. Had the residue treater traveled in the direction of the day tank and struck the shield structure near the top of the frame it might have resulted in an MIC release into the atmosphere (see Appendix C)

6.5 Emergency Planning, Response, and Communication

6.5.1 Bayer CropScience

1. The Bayer onsite emergency response did not conform to the unified command structure contained in the National Incident Management System (NIMS) protocols.

2. Bayer did not assign a Public Information Officer (PIO) to directly communicate with the Kanawha Putnam EOC and Metro 9-1-1.

3. Unknown to Bayer emergency personnel, the Methomyl-Larvin unit air monitor system that they relied on to determine and report airborne concentrations of possible toxic chemicals was not in service the night of the incident.

4. Bayer had only two distant fenceline air monitors to determine the extent of chemical contaminants traveling off site.

5. Although the Bayer IC recommended a shelter-in-place, the Bayer EOC did not notify Metro 9-1-1.

6. Bayer discontinued hot zone decontamination activities before all emergency responders were able to clean their safety gear.

6.5.2 Outside Responding Agencies

1. The overloaded telephone system prevented Bayer from promptly notifying the Metro 9-1-1 center of the incident.
2. County emergency responders established three separate EOCs in response to the incident, which resulted in duplication of effort, poor communication, and conflicting control.
3. First-responders working near the explosion and fire did not wear adequate respiratory protection and were not decontaminated.

6.5.3 Kanawha County Commission

1. The Kanawha Putnam Emergency Management Plan does not adequately address emergency response personnel responsibilities and communications between the facility IC and outside emergency response organizations when a facility owner is responsible for incident command during an on-site emergency involving hazardous chemicals.

6.6 Environmental Impact

1. MIC air monitoring devices in the Methomyl-Larvin unit were not functioning at the time of the incident, preventing the accurate measurement of any MIC release from piping or equipment that might have resulted from the explosion and fires.
2. Two fenceline monitors located hundreds of feet from the incident location were ineffective for detecting toxic chemicals that might be released into the atmosphere either from process equipment leaks or spills, or combustion products from a major fire.

6.7 Regulatory Oversight

1. Both the Occupational Safety and Health Administration (OSHA) and the Environmental Protection Agency (EPA) had conducted process safety related audits and inspections at the Bayer facility prior to the incident in August 2008. However, the inspections did not detect or correct all the serious, longstanding process safety problems that were revealed by investigations conducted after the incident.
2. OSHA cited Bayer for deficient process hazard analyses in 2005; however OSHA did not subsequently verify that corrective actions were fully implemented by Bayer. Deficient PHAs were a causal factor in the August 2008 incident.

7.0 Incident Causes

1. Bayer did not apply standard PSSR and turnover practices to the methomyl control system redesign project. Bayer restarted the unit before the equipment was properly tested and calibrated.

2. Operations personnel were inadequately trained to operate the methomyl unit with the new DCS control system.

3. Malfunctioning equipment and the inadequate DCS checkout prevented the operators from achieving correct operating conditions in the crystallizers and solvent recovery equipment.

4. The methomyl-solvent mixture was fed to the residue treater before the residue treater was pre-filled with solvent and heated to the minimum safe operating temperature.

5. The incoming process stream normally generated an exothermic decomposition reaction, but methomyl that had not crystallized due to equipment problems greatly increased the methomyl concentration in the residue treater, which led to a runaway reaction that overwhelmed the relief system and over-pressurized the residue treater.

8.0 Recommendations

The CSB makes recommendations based on the findings and conclusions of its investigations. Recommendations are made to parties that can effect change to prevent future incidents, which may include the companies involved; industry organizations responsible for developing good practice guidelines; regulatory bodies; and/or organizations that have the ability to broadly communicate lessons learned from the incident, such as trade associations and labor unions.

8.1 Bayer CropScience – Research Triangle Park, NC

2008-08-I-WV-R1 Revise the corporate PHA policies and procedures to require:

a. Validation of all PHA assumptions to ensure that risk analysis of each PHA scenario specifically examines the risk(s) of intentional bypassing or other nullifications of safeguards,

b. Addressing all phases of operation and special topics including those cited in chapter 9 of "Guidelines for Hazard Evaluation Procedures" (CCPS, 2008), and

c. Training all PHA facilitators on the revised policies and procedures prior to assigning the facilitator to a PHA team.

Ensure all PHAs are updated to conform to the revised procedures.

8.2 Bayer CropScience - Institute, West Virginia

2008-08-I-WV-R2 Review and revise, as necessary, all Bayer production unit standard operating procedures to ensure they address all operating modes (startup, normal operation, temporary operations, emergency shutdown, emergency operations, normal shutdown, and startup following a turnaround or emergency shutdown), are accurate, and approved.

2008-08-I-WV-R3	Ensure that all facility fire brigade members are trained in the National Incident Management System, consistent with municipal and state emergency response agencies.
2008-08-I-WV-R4	Evaluate the fenceline air monitor program against federal, state, and local regulations, and Bayer corporate policies, and upgrade and install air monitoring devices as necessary to ensure effective monitoring of potential releases of high-hazard chemicals at the perimeter of the facility.
2008-08-I-WV-R5	Commission an independent human factors and ergonomics study of all Institute site PSM/RMP covered process control rooms to evaluate the human-control system interface, operator fatigue, and control system familiarity and training. Develop and implement a plan to resolve all recommendations identified in the study that includes assigned responsibilities, required corrective actions, and completion dates.

8.3 Director of the Kanawha-Charleston Health Department

2008-08-I-WV-R6 Establish a Hazardous Chemical Release Prevention Program to enhance the prevention of accidental releases of highly hazardous chemicals, and optimize responses in the event of their occurrence. In establishing the program, study and evaluate the possible applicability of the experience of similar programs in the country, such as those summarized in Section 5.3 of this report. As a minimum:

a. Ensure that the new program:

   1. Implements an effective system of independent oversight and other services to enhance the prevention of accidental releases of highly hazardous chemicals
   2. Facilitates the collaboration of multiple stakeholders in achieving common goals of chemical safety; and,
   3. Increases the confidence of the community, the workforce, and the local authorities in the ability of the facility owners to prevent and respond to accidental releases of highly hazardous chemicals

b. Define the characteristics of chemical facilities that would be covered by the new Program, such as the hazards and potential risks of their chemicals and processes, their quantities, and similar relevant factors;

c. Ensure that covered facilities develop, implement, and submit for review and approval:

   1. Applicable hazard and process information and evaluations.
   2. Written safety plans with appropriate descriptions of hazard controls, safety culture and human factors programs with employee participation, and consideration of the adoption of inherently safer systems to reduce risks
   3. Emergency response plans; and,
   4. Performance indicators addressing the prevention of chemical incidents.

d. Ensure that the program has the right to evaluate the documents submitted by the covered facilities, and to require modifications, as necessary

e. Ensure that the program has right-of-entry to covered facilities, and access to requisite information to conduct periodic audits of safety systems and investigations of chemical releases;

f. Establish a system of fees assessed on covered facilities sufficient to cover the oversight and related services to be provided to the facilities including necessary technical and administrative personnel; and,

g. Consistent with applicable law, ensure that the program provides reasonable public participation with the program staff in review of facility programs and access to:

   1. The materials submitted by covered facilities (e.g., hazard evaluations, safety plans, emergency response plans);
   2. The reviews conducted by program staff and the modifications triggered by those reviews;

3. Records of audits and incident investigations conducted by the program;
4. Performance indicator reports and data submitted by the facilities, and;
5. Other relevant information concerning the hazards and the control methods overseen by the program.

h. Ensure that the program will require a periodic review of the designated agency activities and issue a periodic public report of its activities and recommended action items.

8.4 Secretary of West Virginia Department of Health and Human Services and the West Virginia Department of Environmental Protection

2008-08-I-WV-R7 Work with the Director of the Kanawha-Charleston Health Department to ensure the successful planning, fee collection, and implementation of the Hazardous Chemical Release Prevention Program as described in Recommendation 2008-08-WV-R6, above, including the provision of services to all eligible facilities in the State.

8.5 Kanawha-Putnam Emergency Planning Committee

2008-08-I-WV-R8 Work with the Kanawha and Putnam counties Emergency Response Directors to prepare and issue a revision to the Kanawha Putnam County Emergency Response Plan and Annexes to address facility emergency response and Incident Command when such functions are provided by the facility owner.

8.6 West Virginia State Fire Commission

2008-08-I-WV-R9 Revise the Fire Department Evaluation Administrative Section Matrix addressing the periodic inspection of local fire departments to include a requirement for inspectors to examine and identify the status of National Incident Management System fire department personnel training.

8.7 Occupational Safety and Health Administration

2008-08-I-WV-R10 In light of the findings of this report and the serious potential hazards to workers and the public from chemicals used and stored at the Bayer Institute site (such as phosgene, MIC, and methomyl), conduct a comprehensive Process Safety Management (PSM) inspection of the complex. Coordinate with the Environmental Protection Agency, as appropriate.

2008-08-I-WV-R11 Revise the Chemical National Emphasis Program and the targeting criteria to:

a. Expand the coverage to all 10 OSHA regions,

b. Include in the targeting criteria from which potential inspections are selected all establishments that have submitted certifications of completions of actions in response to previous PSM citations;

c. Require NEP inspections to examine the status of compliance of all previously cited PSM program items for which the company has submitted certifications of completion to OSHA.

8.8 Environmental Protection Agency

2008-08-I-WV-R12 In light of the findings of this report and the serious potential hazards to workers and the public from chemicals used and stored at the Bayer Institute site (such as phosgene, MIC, and methomyl), conduct a comprehensive Risk Management Program (RMP) inspection of the complex. Coordinate with the Occupational Safety and Health Administration, as appropriate.

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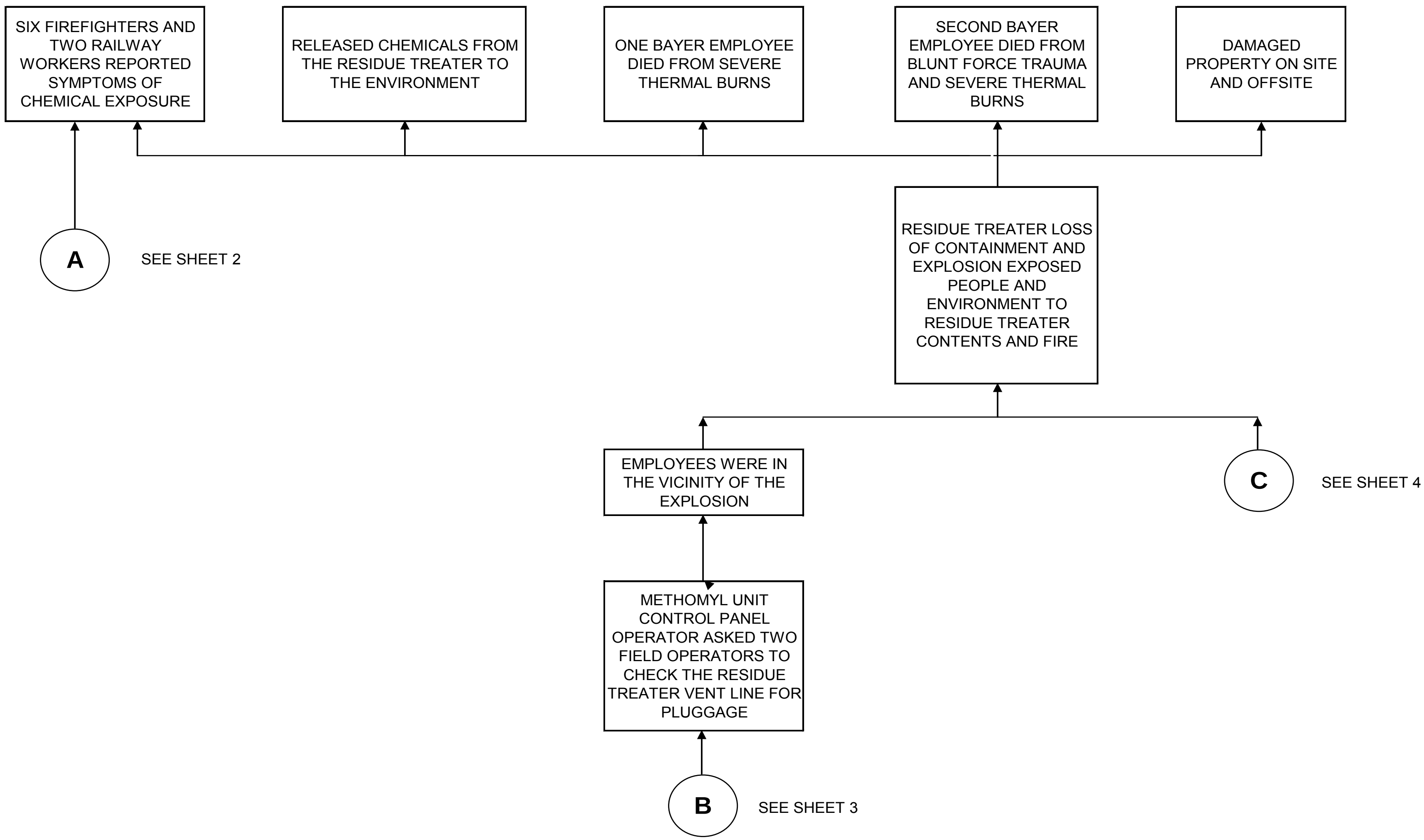
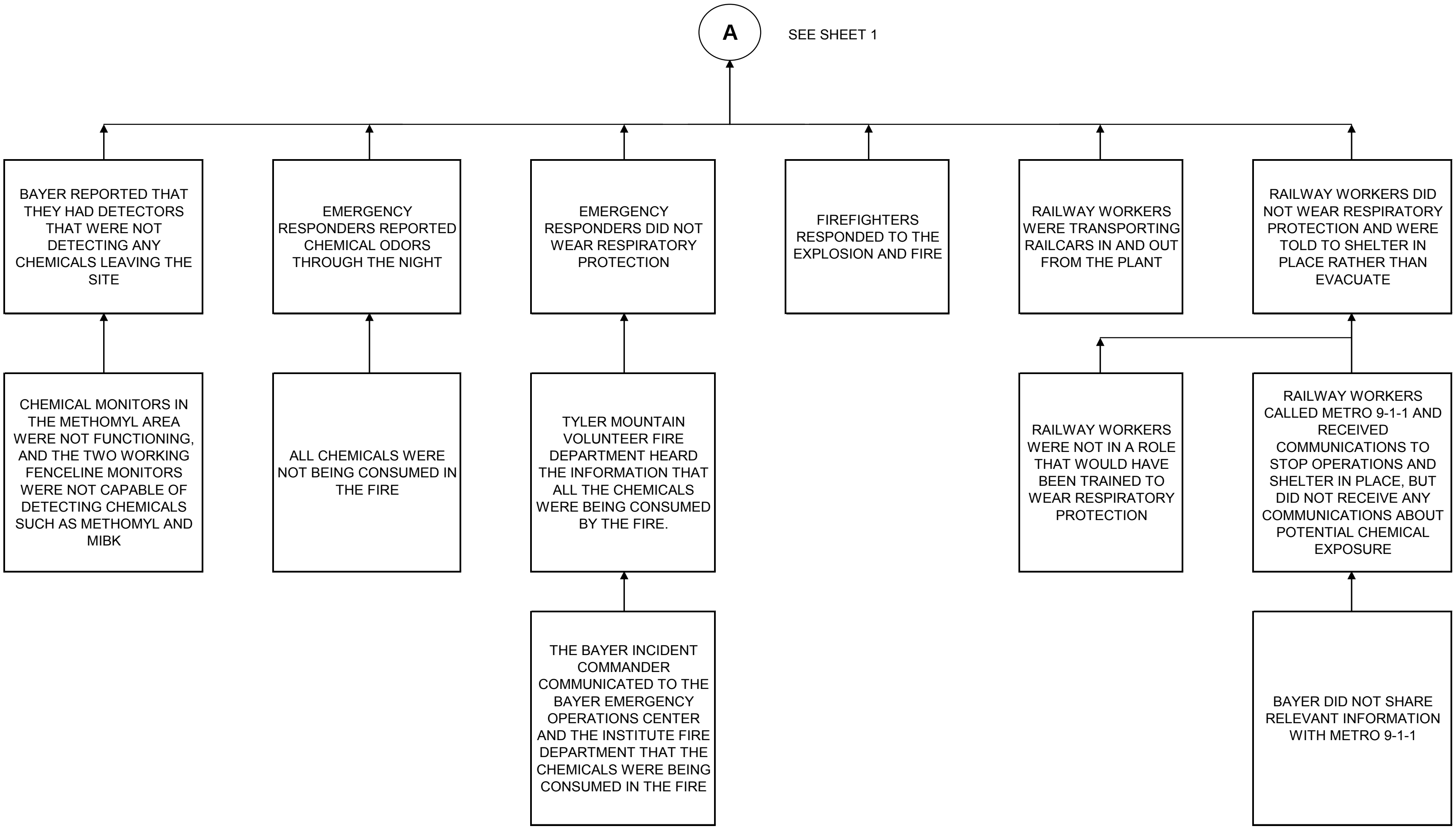
Appendix A – Causal Analysis Charts

Appendix A is a "Why Tree" diagram showing the events that led to the incident and its consequences. Each box in the Why Tree is from information discovered in the investigation, and is a statement of something that happened in the chain of events. To construct a Why Tree, the investigation team starts with a concise description of the on-site and off-site human health, environmental, and business impacts, and asks why each impact occurred. The team continues asking why each preceding event occurred until they determine that they have reached a root cause. The arrows show the direction of flow from the root causes to the final impacts. When the evidence shows that a particular hypothetical event did not happen, the box in the Why Tree has a diagonal line crossed through it and a statement next to the box describing the evidence that the event did not happen.

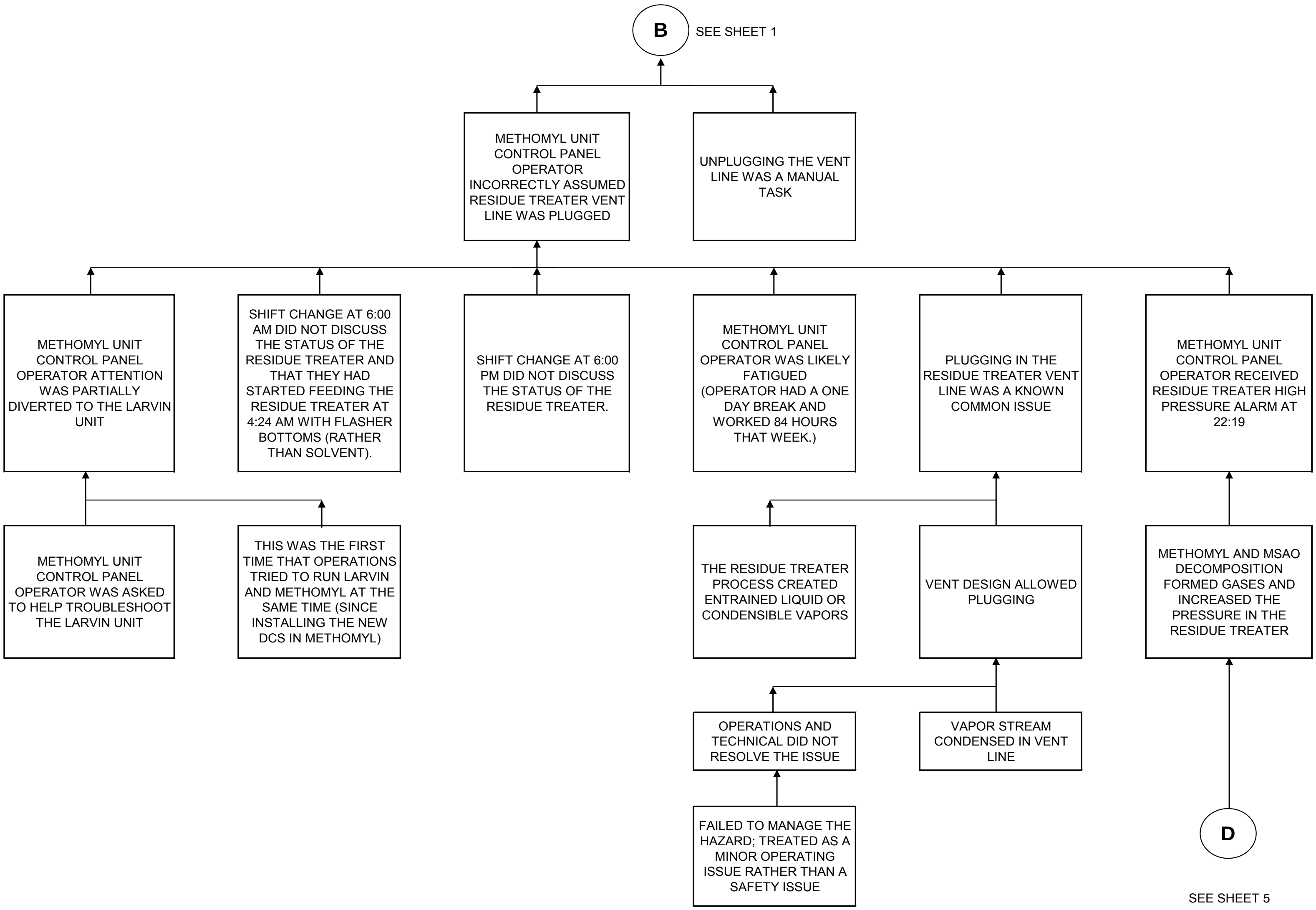
SHEET 1


SIX FIREFIGHTERS AND TWO RAILWAY WORKERS REPORTED SYMPTOMS OF CHEMICAL EXPOSURE
RELEASED CHEMICALS FROM THE RESIDUE TREATER TO THE ENVIRONMENT
ONE BAYER EMPLOYEE DIED FROM SEVERE THERMAL BURNS
SECOND BAYER EMPLOYEE DIED FROM BLUNT FORCE TRAUMA AND SEVERE THERMAL BURNS
DAMAGED PROPERTY ON SITE AND OFFSITE
A
SEE SHEET 2
RESIDUE TREATER LOSS OF CONTAINMENT AND EXPLOSION EXPOSED PEOPLE AND ENVIRONMENT TO RESIDUE TREATER CONTENTS AND FIRE
EMPLOYEES WERE IN THE VICINITY OF THE EXPLOSION
C
SEE SHEET 4
METHOMYL UNIT CONTROL PANEL OPERATOR ASKED TWO FIELD OPERATORS TO CHECK THE RESIDUE TREATER VENT LINE FOR PLUGGAGE
B
SEE SHEET 3

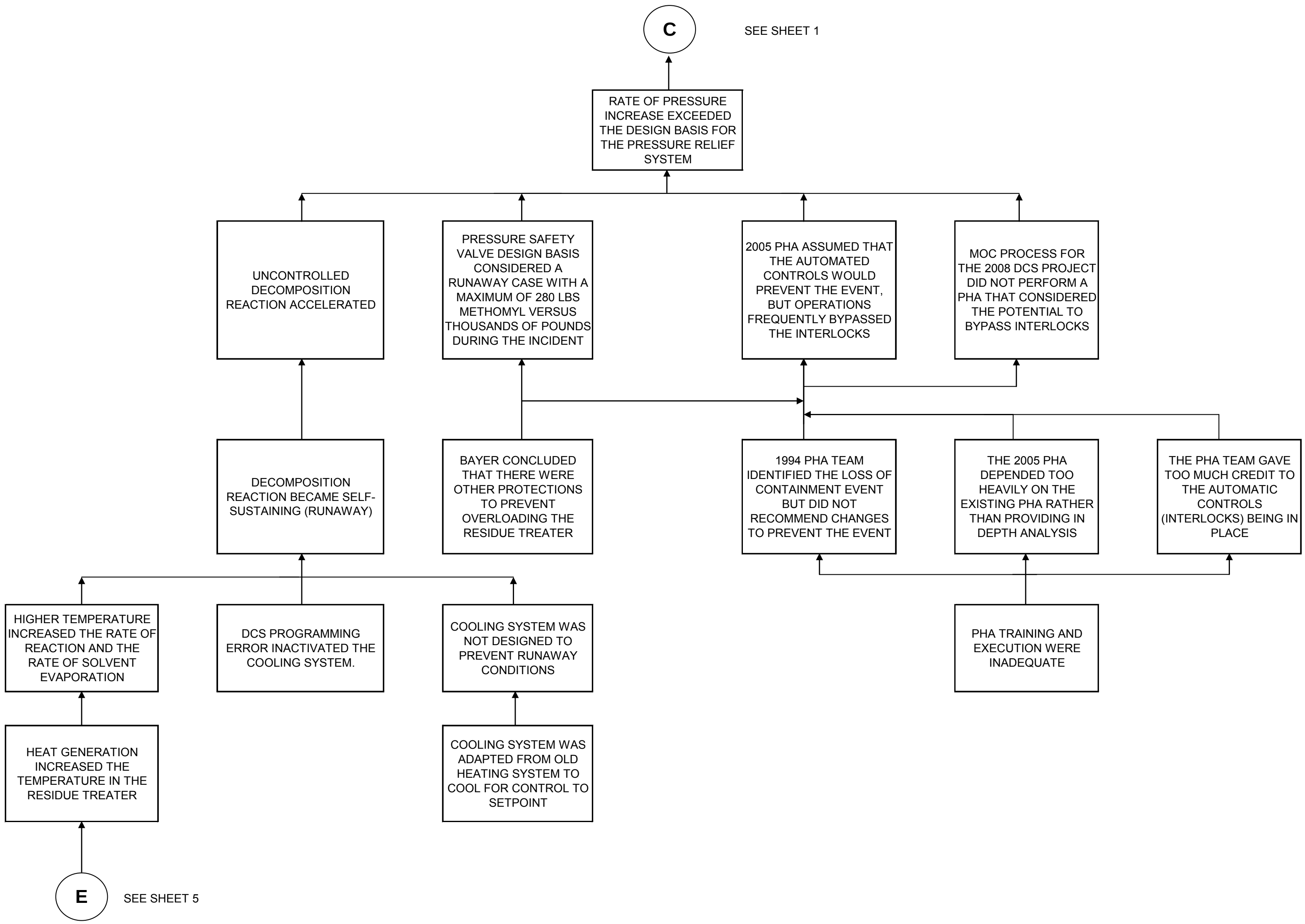
SHEET 2


A
SEE SHEET 1
BAYER REPORTED THAT THEY HAD DETECTORS THAT WERE NOT DETECTING ANY CHEMICALS LEAVING THE SITE
EMERGENCY RESPONDERS REPORTED CHEMICAL ODORS THROUGH THE NIGHT
EMERGENCY RESPONDERS DID NOT WEAR RESPIRATORY PROTECTION
FIREFIGHTERS RESPONDED TO THE EXPLOSION AND FIRE
RAILWAY WORKERS WERE TRANSPORTING RAILCARS IN AND OUT FROM THE PLANT
RAILWAY WORKERS DID NOT WEAR RESPIRATORY PROTECTION AND WERE TOLD TO SHELTER IN PLACE RATHER THAN EVACUATE
CHEMICAL MONITORS IN THE METHOMYL AREA WERE NOT FUNCTIONING, AND THE TWO WORKING FENCELINE MONITORS WERE NOT CAPABLE OF DETECTING CHEMICALS SUCH AS METHOMYL AND MIBK
ALL CHEMICALS WERE NOT BEING CONSUMED IN THE FIRE
TYLER MOUNTAIN VOLUNTEER FIRE DEPARTMENT HEARD THE INFORMATION THAT ALL THE CHEMICALS WERE BEING CONSUMED BY THE FIRE.
RAILWAY WORKERS WERE NOT IN A ROLE THAT WOULD HAVE BEEN TRAINED TO WEAR RESPIRATORY PROTECTION
RAILWAY WORKERS CALLED METRO 9-1-1 AND RECEIVED COMMUNICATIONS TO STOP OPERATIONS AND SHELTER IN PLACE, BUT DID NOT RECEIVE ANY COMMUNICATIONS ABOUT POTENTIAL CHEMICAL EXPOSURE
THE BAYER INCIDENT COMMANDER COMMUNICATED TO THE BAYER EMERGENCY OPERATIONS CENTER AND THE INSTITUTE FIRE DEPARTMENT THAT THE CHEMICALS WERE BEING CONSUMED IN THE FIRE
BAYER DID NOT SHARE RELEVANT INFORMATION WITH METRO 9-1-1

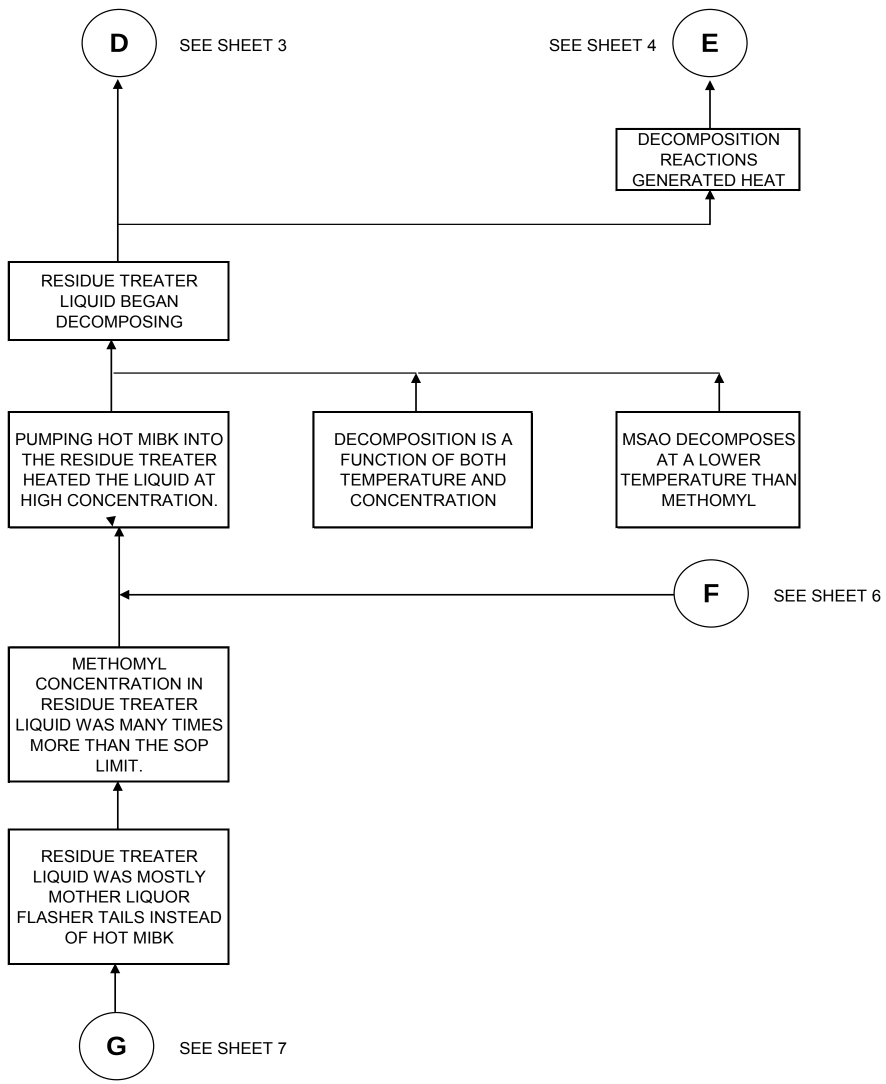
SHEET 3


B
SEE SHEET 1
METHOMYL UNIT CONTROL PANEL OPERATOR INCORRECTLY ASSUMED RESIDUE TREATER VENT LINE WAS PLUGGED
UNPLUGGING THE VENT LINE WAS A MANUAL TASK
METHOMYL UNIT CONTROL PANEL OPERATOR ATTENTION WAS PARTIALLY DIVERTED TO THE LARVIN UNIT
SHIFT CHANGE AT 6:00 AM DID NOT DISCUSS THE STATUS OF THE RESIDUE TREATER AND THAT THEY HAD STARTED FEEDING THE RESIDUE TREATER AT 4:24 AM WITH FLASHER BOTTOMS (RATHER THAN SOLVENT).
SHIFT CHANGE AT 6:00 PM DID NOT DISCUSS THE STATUS OF THE RESIDUE TREATER.
METHOMYL UNIT CONTROL PANEL OPERATOR WAS LIKELY FATIGUED (OPERATOR HAD A ONE DAY BREAK AND WORKED 84 HOURS THAT WEEK.)
PLUGGING IN THE RESIDUE TREATER VENT LINE WAS A KNOWN COMMON ISSUE
METHOMYL UNIT CONTROL PANEL OPERATOR RECEIVED RESIDUE TREATER HIGH PRESSURE ALARM AT 22:19
METHOMYL UNIT CONTROL PANEL OPERATOR WAS ASKED TO HELP TROUBLESHOOT THE LARVIN UNIT
THIS WAS THE FIRST TIME THAT OPERATIONS TRIED TO RUN LARVIN AND METHOMYL AT THE SAME TIME (SINCE INSTALLING THE NEW DCS IN METHOMYL)
THE RESIDUE TREATER PROCESS CREATED ENTRAINED LIQUID OR CONDENSIBLE VAPORS
VENT DESIGN ALLOWED PLUGGING
METHOMYL AND MSAO DECOMPOSITION FORMED GASES AND INCREASED THE PRESSURE IN THE RESIDUE TREATER
OPERATIONS AND TECHNICAL DID NOT RESOLVE THE ISSUE
VAPOR STREAM CONDENSED IN VENT LINE
FAILED TO MANAGE THE HAZARD; TREATED AS A MINOR OPERATING ISSUE RATHER THAN A SAFETY ISSUE
D
SEE SHEET 5

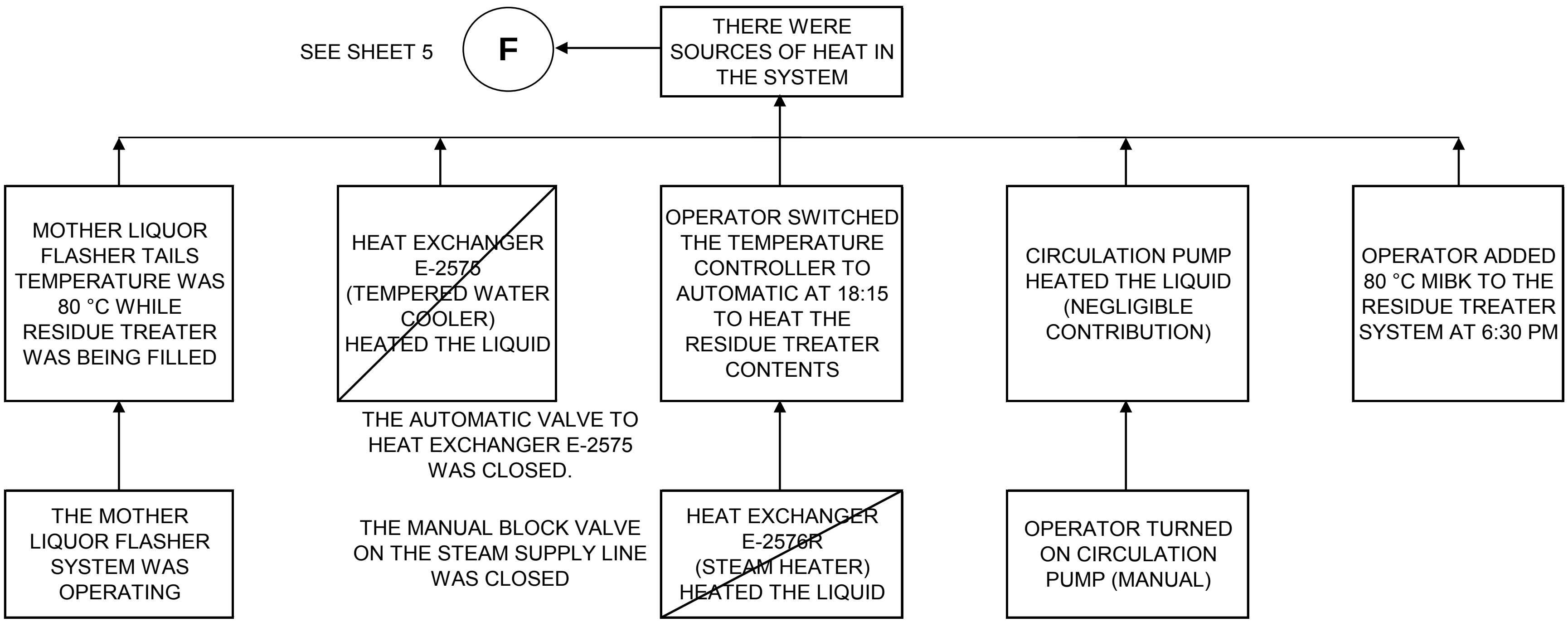
SHEET 4


C
SEE SHEET 1
RATE OF PRESSURE INCREASE EXCEEDED THE DESIGN BASIS FOR THE PRESSURE RELIEF SYSTEM
UNCONTROLLED DECOMPOSITION REACTION ACCELERATED
PRESSURE SAFETY VALVE DESIGN BASIS CONSIDERED A RUNAWAY CASE WITH A MAXIMUM OF 280 LBS METHOMYL VERSUS THOUSANDS OF POUNDS DURING THE INCIDENT
2005 PHA ASSUMED THAT THE AUTOMATED CONTROLS WOULD PREVENT THE EVENT, BUT OPERATIONS FREQUENTLY BYPASSED THE INTERLOCKS
MOC PROCESS FOR THE 2008 DCS PROJECT DID NOT PERFORM A PHA THAT CONSIDERED THE POTENTIAL TO BYPASS INTERLOCKS
DECOMPOSITION REACTION BECAME SELF-SUSTAINING (RUNAWAY)
BAYER CONCLUDED THAT THERE WERE OTHER PROTECTIONS TO PREVENT OVERLOADING THE RESIDUE TREATER
1994 PHA TEAM IDENTIFIED THE LOSS OF CONTAINMENT EVENT BUT DID NOT RECOMMEND CHANGES TO PREVENT THE EVENT
THE 2005 PHA DEPENDED TOO HEAVILY ON THE EXISTING PHA RATHER THAN PROVIDING IN DEPTH ANALYSIS
THE PHA TEAM GAVE TOO MUCH CREDIT TO THE AUTOMATIC CONTROLS (INTERLOCKS) BEING IN PLACE
HIGHER TEMPERATURE INCREASED THE RATE OF REACTION AND THE RATE OF SOLVENT EVAPORATION
DCS PROGRAMMING ERROR INACTIVATED THE COOLING SYSTEM.
COOLING SYSTEM WAS NOT DESIGNED TO PREVENT RUNAWAY CONDITIONS
PHA TRAINING AND EXECUTION WERE INADEQUATE
HEAT GENERATION INCREASED THE TEMPERATURE IN THE RESIDUE TREATER
COOLING SYSTEM WAS ADAPTED FROM OLD HEATING SYSTEM TO COOL FOR CONTROL TO SETPOINT
E
SEE SHEET 5

SHEET 5


D
SEE SHEET 3
SEE SHEET 4
E
DECOMPOSITION REACTIONS GENERATED HEAT
RESIDUE TREATER LIQUID BEGAN DECOMPOSING
PUMPING HOT MIBK INTO THE RESIDUE TREATER HEATED THE LIQUID AT HIGH CONCENTRATION.
DECOMPOSITION IS A FUNCTION OF BOTH TEMPERATURE AND CONCENTRATION
MSAO DECOMPOSES AT A LOWER TEMPERATURE THAN METHOMYL
F
SEE SHEET 6
METHOMYL CONCENTRATION IN RESIDUE TREATER LIQUID WAS MANY TIMES MORE THAN THE SOP LIMIT.
RESIDUE TREATER LIQUID WAS MOSTLY MOTHER LIQUOR FLASHER TAILS INSTEAD OF HOT MIBK
G
SEE SHEET 7

SHEET 6



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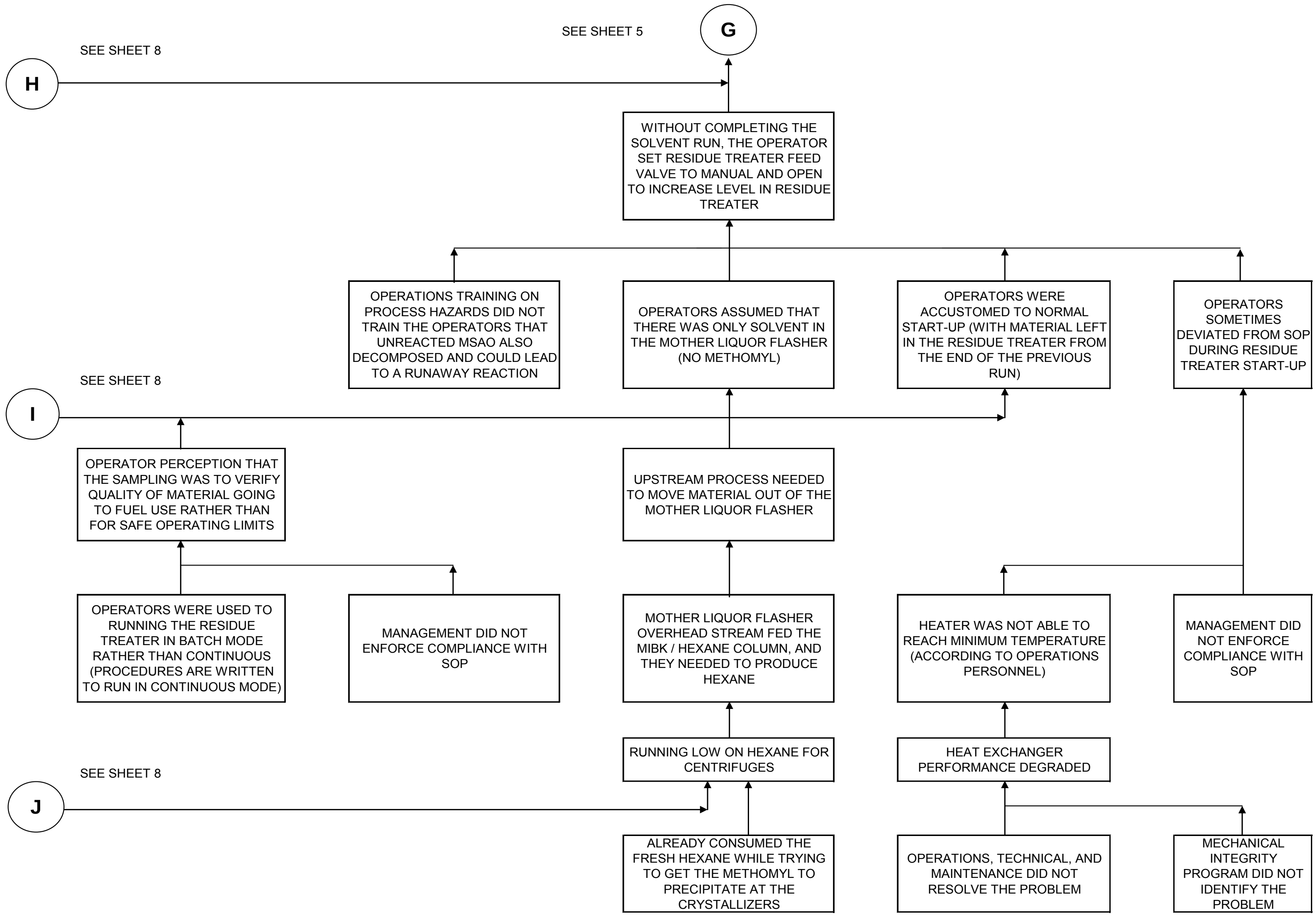
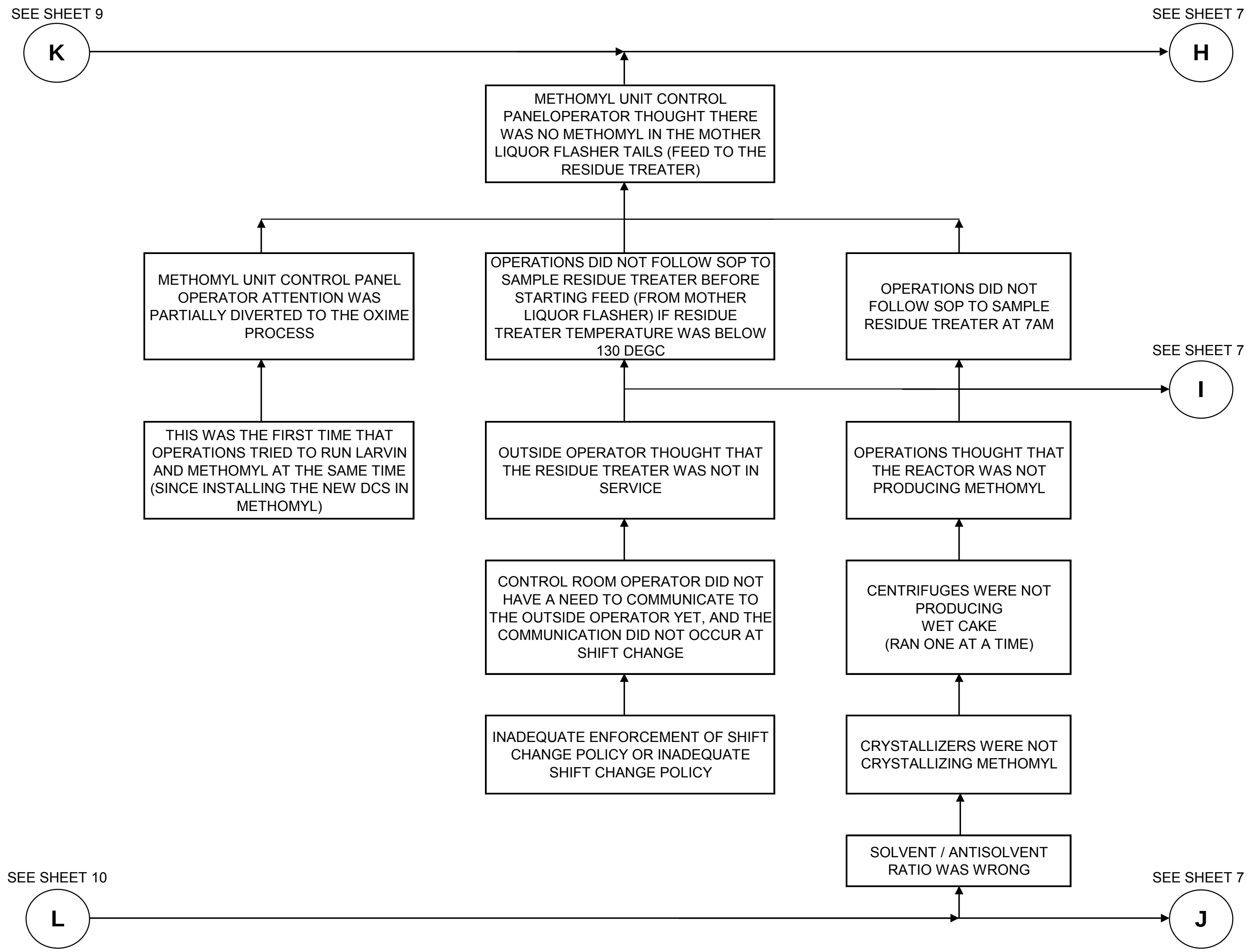
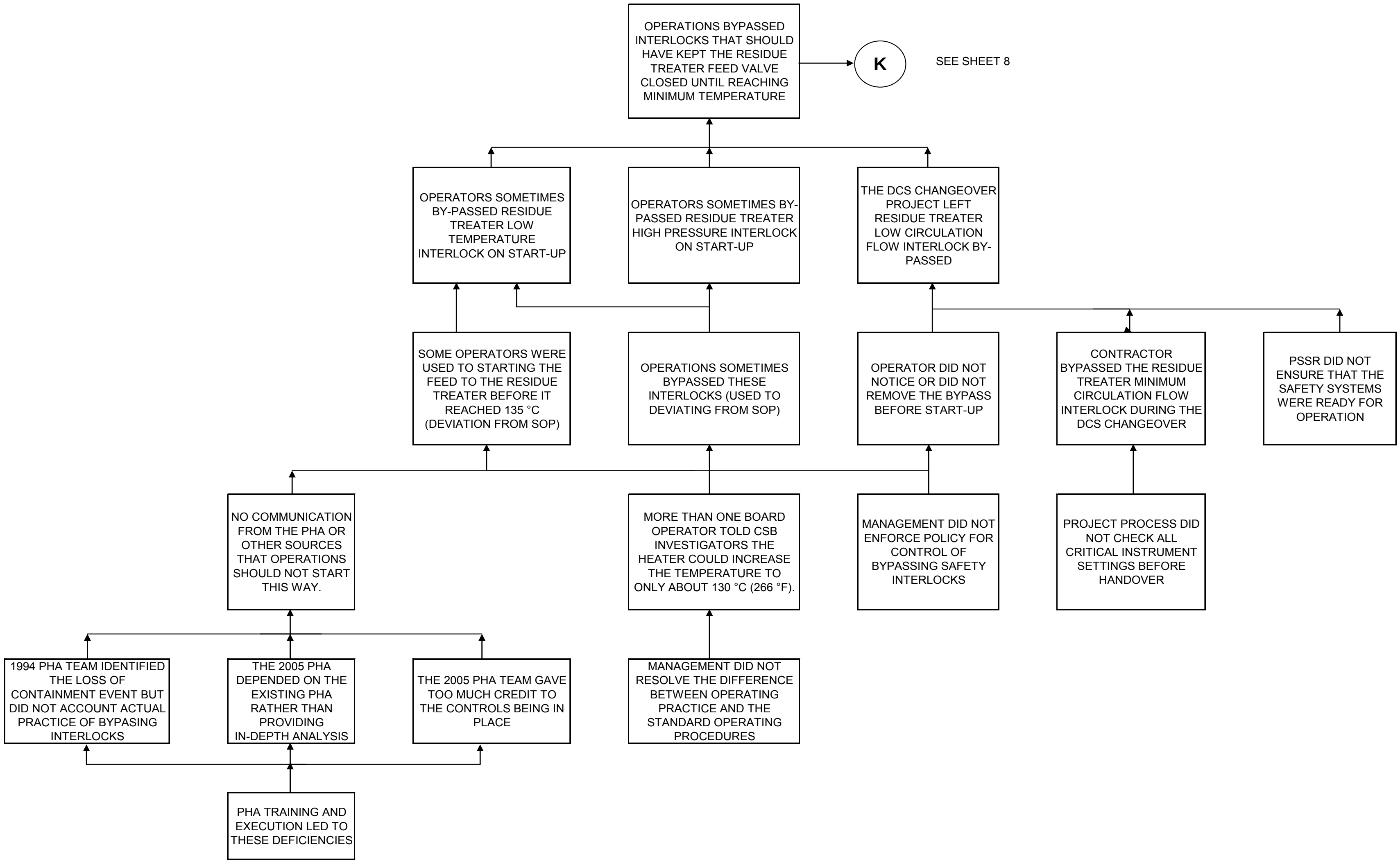
SHEET 7

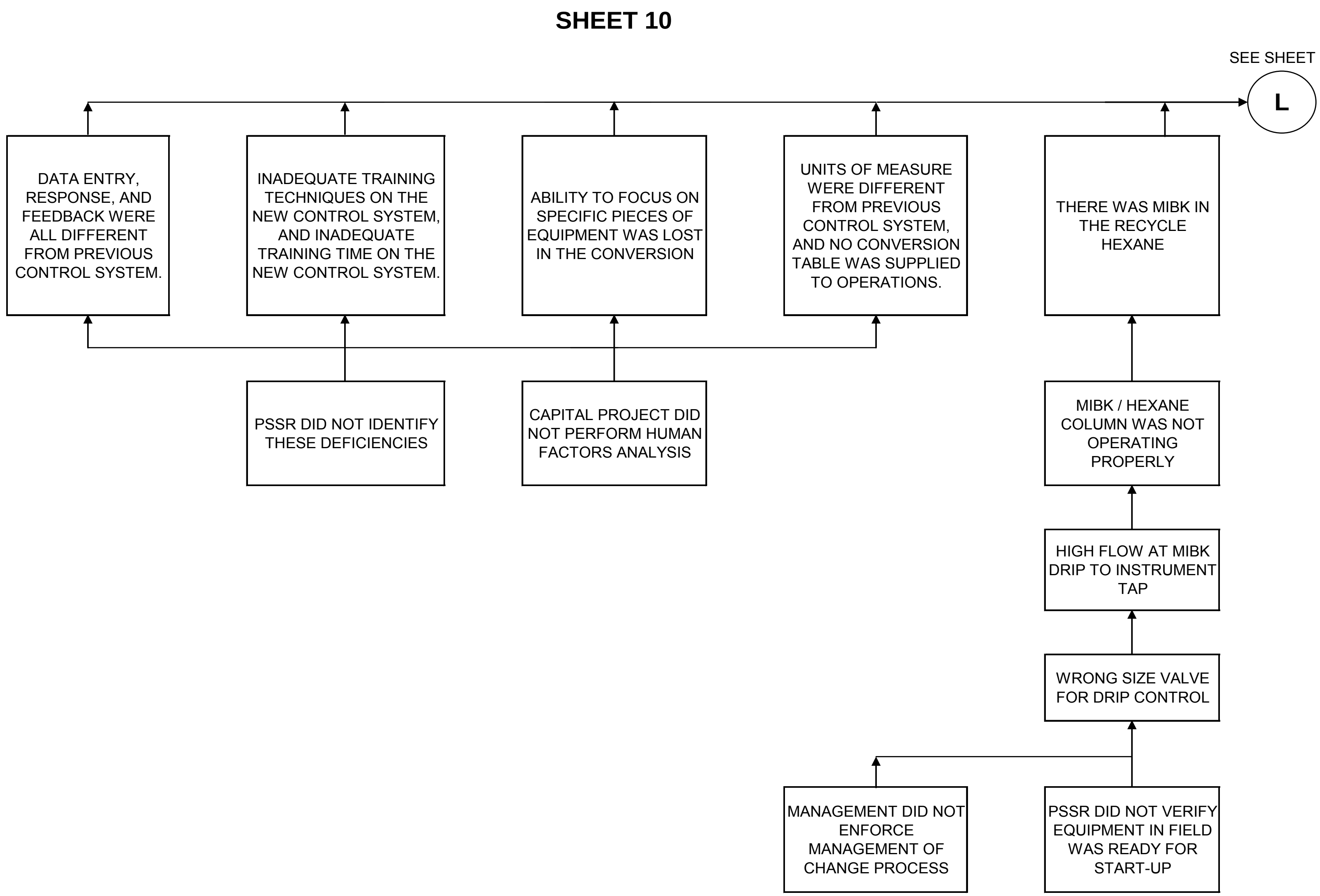

SEE SHEET 5
G
SEE SHEET 8
H
WITHOUT COMPLETING THE SOLVENT RUN, THE OPERATOR SET RESIDUE TREATER FEED VALVE TO MANUAL AND OPEN TO INCREASE LEVEL IN RESIDUE TREATER
OPERATIONS TRAINING ON PROCESS HAZARDS DID NOT TRAIN THE OPERATORS THAT UNREACTED MSAO ALSO DECOMPOSED AND COULD LEAD TO A RUNAWAY REACTION
OPERATORS ASSUMED THAT THERE WAS ONLY SOLVENT IN THE MOTHER LIQUOR FLASHER (NO METHOMYL)
OPERATORS WERE ACCUSTOMED TO NORMAL START-UP (WITH MATERIAL LEFT IN THE RESIDUE TREATER FROM THE END OF THE PREVIOUS RUN)
OPERATORS SOMETIMES DEVIATED FROM SOP DURING RESIDUE TREATER START-UP
SEE SHEET 8
I
OPERATOR PERCEPTION THAT THE SAMPLING WAS TO VERIFY QUALITY OF MATERIAL GOING TO FUEL USE RATHER THAN FOR SAFE OPERATING LIMITS
UPSTREAM PROCESS NEEDED TO MOVE MATERIAL OUT OF THE MOTHER LIQUOR FLASHER
OPERATORS WERE USED TO RUNNING THE RESIDUE TREATER IN BATCH MODE RATHER THAN CONTINUOUS (PROCEDURES ARE WRITTEN TO RUN IN CONTINUOUS MODE)
MANAGEMENT DID NOT ENFORCE COMPLIANCE WITH SOP
MOTHER LIQUOR FLASHER OVERHEAD STREAM FED THE MIBK / HEXANE COLUMN, AND THEY NEEDED TO PRODUCE HEXANE
HEATER WAS NOT ABLE TO REACH MINIMUM TEMPERATURE (ACCORDING TO OPERATIONS PERSONNEL)
MANAGEMENT DID NOT ENFORCE COMPLIANCE WITH SOP
RUNNING LOW ON HEXANE FOR CENTRIFUGES
HEAT EXCHANGER PERFORMANCE DEGRADED
SEE SHEET 8
J
ALREADY CONSUMED THE FRESH HEXANE WHILE TRYING TO GET THE METHOMYL TO PRECIPITATE AT THE CRYSTALLIZERS
OPERATIONS, TECHNICAL, AND MAINTENANCE DID NOT RESOLVE THE PROBLEM
MECHANICAL INTEGRITY PROGRAM DID NOT IDENTIFY THE PROBLEM

SHEET 8


SEE SHEET 9
K
SEE SHEET 7
H
METHOMYL UNIT CONTROL PANELOPERATOR THOUGHT THERE WAS NO METHOMYL IN THE MOTHER LIQUOR FLASHER TAILS (FEED TO THE RESIDUE TREATER)
METHOMYL UNIT CONTROL PANEL OPERATOR ATTENTION WAS PARTIALLY DIVERTED TO THE OXIME PROCESS
OPERATIONS DID NOT FOLLOW SOP TO SAMPLE RESIDUE TREATER BEFORE STARTING FEED (FROM MOTHER LIQUOR FLASHER) IF RESIDUE TREATER TEMPERATURE WAS BELOW 130 DEGC
OPERATIONS DID NOT FOLLOW SOP TO SAMPLE RESIDUE TREATER AT 7AM
SEE SHEET 7
I
THIS WAS THE FIRST TIME THAT OPERATIONS TRIED TO RUN LARVIN AND METHOMYL AT THE SAME TIME (SINCE INSTALLING THE NEW DCS IN METHOMYL)
OUTSIDE OPERATOR THOUGHT THAT THE RESIDUE TREATER WAS NOT IN SERVICE
OPERATIONS THOUGHT THAT THE REACTOR WAS NOT PRODUCING METHOMYL
CONTROL ROOM OPERATOR DID NOT HAVE A NEED TO COMMUNICATE TO THE OUTSIDE OPERATOR YET, AND THE COMMUNICATION DID NOT OCCUR AT SHIFT CHANGE
CENTRIFUGES WERE NOT PRODUCING WET CAKE (RAN ONE AT A TIME)
INADEQUATE ENFORCEMENT OF SHIFT CHANGE POLICY OR INADEQUATE SHIFT CHANGE POLICY
CRYSTALLIZERS WERE NOT CRYSTALLIZING METHOMYL
SOLVENT / ANTISOLVENT RATIO WAS WRONG
SEE SHEET 10
L
SEE SHEET 7
J

SHEET 9


OPERATIONS BYPASSED INTERLOCKS THAT SHOULD HAVE KEPT THE RESIDUE TREATER FEED VALVE CLOSED UNTIL REACHING MINIMUM TEMPERATURE
K
SEE SHEET 8
OPERATORS SOMETIMES BY-PASSED RESIDUE TREATER LOW TEMPERATURE INTERLOCK ON START-UP
OPERATORS SOMETIMES BY-PASSED RESIDUE TREATER HIGH PRESSURE INTERLOCK ON START-UP
THE DCS CHANGEOVER PROJECT LEFT RESIDUE TREATER LOW CIRCULATION FLOW INTERLOCK BY-PASSED
SOME OPERATORS WERE USED TO STARTING THE FEED TO THE RESIDUE TREATER BEFORE IT REACHED 135 °C (DEVIATION FROM SOP)
OPERATIONS SOMETIMES BYPASSED THESE INTERLOCKS (USED TO DEVIATING FROM SOP)
OPERATOR DID NOT NOTICE OR DID NOT REMOVE THE BYPASS BEFORE START-UP
CONTRACTOR BYPASSED THE RESIDUE TREATER MINIMUM CIRCULATION FLOW INTERLOCK DURING THE DCS CHANGEOVER
PSSR DID NOT ENSURE THAT THE SAFETY SYSTEMS WERE READY FOR OPERATION
NO COMMUNICATION FROM THE PHA OR OTHER SOURCES THAT OPERATIONS SHOULD NOT START THIS WAY.
MORE THAN ONE BOARD OPERATOR TOLD CSB INVESTIGATORS THE HEATER COULD INCREASE THE TEMPERATURE TO ONLY ABOUT 130 °C (266 °F).
MANAGEMENT DID NOT ENFORCE POLICY FOR CONTROL OF BYPASSING SAFETY INTERLOCKS
PROJECT PROCESS DID NOT CHECK ALL CRITICAL INSTRUMENT SETTINGS BEFORE HANDOVER
1994 PHA TEAM IDENTIFIED THE LOSS OF CONTAINMENT EVENT BUT DID NOT ACCOUNT ACTUAL PRACTICE OF BYPASING INTERLOCKS
THE 2005 PHA DEPENDED ON THE EXISTING PHA RATHER THAN PROVIDING IN-DEPTH ANALYSIS
THE 2005 PHA TEAM GAVE TOO MUCH CREDIT TO THE CONTROLS BEING IN PLACE
MANAGEMENT DID NOT RESOLVE THE DIFFERENCE BETWEEN OPERATING PRACTICE AND THE STANDARD OPERATING PROCEDURES
PHA TRAINING AND EXECUTION LED TO THESE DEFICIENCIES


SHEET 10
SEE SHEET 8
L
DATA ENTRY, RESPONSE, AND FEEDBACK WERE ALL DIFFERENT FROM PREVIOUS CONTROL SYSTEM.
INADEQUATE TRAINING TECHNIQUES ON THE NEW CONTROL SYSTEM, AND INADEQUATE TRAINING TIME ON THE NEW CONTROL SYSTEM.
ABILITY TO FOCUS ON SPECIFIC PIECES OF EQUIPMENT WAS LOST IN THE CONVERSION
UNITS OF MEASURE WERE DIFFERENT FROM PREVIOUS CONTROL SYSTEM, AND NO CONVERSION TABLE WAS SUPPLIED TO OPERATIONS.
THERE WAS MIBK IN THE RECYCLE HEXANE
PSSR DID NOT IDENTIFY THESE DEFICIENCIES
CAPITAL PROJECT DID NOT PERFORM HUMAN FACTORS ANALYSIS
MIBK / HEXANE COLUMN WAS NOT OPERATING PROPERLY
HIGH FLOW AT MIBK DRIP TO INSTRUMENT TAP
WRONG SIZE VALVE FOR DRIP CONTROL
MANAGEMENT DID NOT ENFORCE MANAGEMENT OF CHANGE PROCESS
PSSR DID NOT VERIFY EQUIPMENT IN FIELD WAS READY FOR START-UP

Appendix B – Emergency Response Timeline

The following is a key for the abbreviations used to denote the organizations agencies in the table below:

CAD	Computer Aided Dispatch
EOC	Emergency Operations Center
KCEAA	Kanawha County Ambulance Authority
KCSD	Kanawha County Sheriff's Department

Date	Time	Information	Source
8/28	**22:34**	**Explosion and Fire on Methomyl Unit**	
8/28	22:34	Metro to Jefferson fire department (FD): unknown source of explosion, receiving numerous calls	KCSD-1
8/28	22:35	EMS to Metro 911: wants address for explosion; Metro states it might be at Bayer CropScience, not sure	KCEAA
8/28	22:36	First report of explosion--caller to Metro	CAD Operations Report
8/28	22:36	Alarm--Tyler Mountain FD	Tyler Mountain FD
8/28	22:37	Metro to Dunbar and Institute FD--Explosion at Bayer plant, fireball 100 ft in air, numerous calls; no telephone or radio contact with plant at this time	KCSD-1
8/28	22:38	Dispatch to 1600 1st Ave South (Bayer); scene of incident confirmed to be at the center of the plant.	KCSD-1
8/28	22:38	Emergency alarm at Larvin unit	EOC Log
8/28	22:39	Metro calls Main Gate: gate guard says he has been instructed not to give out information; emergency alarm in progress	911 call Transcript
8/28	22:41	Haze coming towards Cross Lanes	KCEAA
8/28	22:41	EMS to Metro 911: ambulance staging outside Bayer	KCEAA
8/28	22:42	Metro contacts Bayer: gate guard requests ambulance immediately for a burn patient; will not provide additional information	911 call Transcript
8/28	22:42	Call from Metro to Dunbar FD to stand by for Institute Station 24. Large explosion reported at the Bayer plant. No contact with plant at this time; multiple calls to plant have been made	Dunbar Fire
8/28	22:43	Metro to EMS: a burn patient is at main gate	KCEAA
8/28	22:44	Need medics at gate for burn patient	CAD Operations Report
8/28	22:44	Bayer has not called Metro	KCEAA
8/28	22:44	Metro advises that burn patient is at the main gate	KCSD-1
8/28	22:44	"They're not giving us anything, I don't know if they've even called in from Bayer."	KCSD-1
8/28	22:45	Unit 245 on-scene command established	KCSD-1
8/28	22:45	EOC activated, Shift A and B ring-down	EOC Log

Date	Time	Information	Source
8/28	22:46	Metro calls Bayer, no answer; gate guard not giving information.	KCEAA
8/28	22:47	EMS enters plant	KCEAA
8/28	22:48	Talks to someone at the gate, he doesn't know what is going on but they need an ambulance at the front gate	KCEAA
8/28	22:49	Tyler FD arrives on scene	Tyler Mountain FD
8/28	22:51	ATF on way to scene	CAD Operations Report
8/28	22:51	Route 25 closed	Dunbar Police
8/28	22:53	Station 31, power line down at1014 Ellis Street. Pole and line in front of residence still smoking and leaning against a tree. Power still on to residence	St. Albans FD and Nitro FD
8/28	22:53	"Spoke to a gentleman in the plant and informed that the event is located in the Larvin unit. Told that the material involved is poisonous."	KCSD-1
8/28	22:54	Metro to Dunbar: No contact from plant, getting info from many different sources. Keep roads closed unless you hear otherwise from Metro 9-1-1 EOC only.	Dunbar Police
8/28	22:57	Cloud observed moving towards metro; seeks guidance on what cloud consists of.	St. Albans FD and Nitro FD
8/28	23:00	Notification to shut down river traffic	CAD Operations Report
8/28	23:00	St. Albans FD orders SIP unless hears otherwise about the cloud over explosion	CAD Operations Report
8/28	23:04	Still no contact from plant to Metro 911; Dunbar FD gathers a copy of evacuation plan just in case	Dunbar FD
8/28	22:52	"The explosion is in the Larvin unit; someone talked to a mechanic they know in the plant [and] it's poisonous."	KCEAA
8/28	23:04	Metro advises command that the unit involved is the Larvin	KCSD-1
8/28	23:06	No SIP per Chief 24 (Institute)	Dunbar Police
8/28	23:06	Burn victim in ambulance	EOC Log
8/28	23:13	KC-1 directed to Shawnee Park (designated as EOC)	KCSD-1
8/28	23:15	Bayer contacts Metro: a Bayer representative informs Metro that they "might want to alert the community that there is an emergency at the plant right now." The rep. does not confirm Larvin unit as source	911 call transcript
8/28	23:18	Secondary explosion noted	St. Albans FD and Nitro FD
8/28	23:24	SIP recommended for St. Albans and Nitro	EOC Log

Date	Time	Information	Source
8/28	23:33	NWAS issues SIP; informs media	CAD Operations Report
8/28	23:34	Bayer contacts Metro with update; Bayer representative tells Metro that Bayer CropScience still having emergency and is responding to it.	911 call transcript
8/28	23:34	Bayer informed that Metro Emergency Service director putting community SIP order for South Charleston, Dunbar, Nitro, St. Albans	911 call transcript
8/28	23:34	SIP declared for western portion of the county	St. Albans FD and Nitro FD
8/28	23:43	By order of the Kanawha County Office of Emergency Services, SIP ordered for all cities west of the City of Charleston (South Charleston, Dunbar, Nitro & St. Albans, specifically.)	KCSD-1
8/28	23:48	Individual transported to hospital	EOC Log
8/28	23:58	Status update: I-64 shut from Nitro to Dunbar; Rt. 25 from Dunbar to Putnam County line; Rt. 60 from South Charleston to Putnam County line; SIP for all areas west of South Charleston	KCSD-1
8/28		TV/radio announcement acknowledges SIP	SCPD
8/29	0:01	Praxair is SIP location	EOC Log
8/29	0:06	Bayer contacts Metro with update: still having emergency and is responding to it. Bayer rep. on way to Metro 911 center	911 call transcript
8/29	0:13	West of Larvin unit under toxic cloud; SIP in west end of plant	EOC Log
8/29	0:15	Norfolk Southern railroad personnel onsite with rash and itching goes to medical	EOC Log
8/29	0:21	One employee in medical with heat-related problems	EOC Log
8/29	0:25	Shawnee Park requests MSDS	EOC Log
8/29	0:35	Chemical in the explosion is highly toxic and flammable methomyl	Dunbar Police
8/29	0:37	MIC tank warming	EOC Log
8/29	0:40	Bayer contacts Metro with update: still having emergency and is responding to it	911 call transcript
8/29	0:55	EE sent to hospital is not decontaminated (HCN, Sulfide, Hexane, MIBK, methomyl residue)	EOC Log
8/29	1:10	Another emergency responder being transferred to medical (firefighter)	EOC Log
8/29	1:12	Bayer contacts Metro with update: still having an emergency and is responding to it	911 call transcript
8/29	1:12	Another emergency responder sent to medical for heat stress (firefighter)	EOC Log

Date	Time	Information	Source
8/29	1:20	SIP lifted in St. Albans	EOC Log
8/29	1:25	Another BCS employee to medical department with heat fatigue	EOC Log
8/29	1:27	Third BCS emergency responder sent to medical (heat stress)	EOC Log
8/29	1:32	Bayer makes official statement to media	EOC Log
8/29	1:40	SIP all clear accept Larvin unit	EOC Log
8/29	1:42	All community SIPs lifted; Metro notified	EOC Log
8/29	1:43	Bayer contacts Metro with update: still having emergency and is responding to it.	911 call transcript
8/29	1:47	Two heat stress and one injured knee in medical	EOC Log
8/29	1:55	Metro wants written request from BCS to lift SIP	EOC Log
8/29	2:04	Roadways re-opened, SIP lifted	Dunbar PD
8/29	2:08	Metro 911 to all units: be advised SIP has been lifted.	Dunbar Fire
8/29	2:08	SIP lifted; roadways being re-opened	St. Albans FD and Nitro FD
8/29	2:08	Department of Environmental Protection notified incident over	EOC Log
8/29	2:14	Firefighting operations to be released, and begin to return to quarters. The fire is out	KCEAA
8/29	3:01	Bayer contacts Metro with update: response team has situation under control, plant still in alarm state	911 call transcript
8/29	3:33	Bayer contacts Metro with update: response team has situation under control, plant still in alarm state	911 call transcript
8/29	4:07	Tyler FD leaves scene	Tyler Mountain FD
8/29	5:31	"Governor is now on scene"	EOC Log
8/29	5:50	Bayer contacts Metro with update: all clear except Larvin unit	911 call transcript

Appendix C – Methyl Isocyanate Day Tank Blast Shield Analysis

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1.0 Introduction

Methyl isocyanate (MIC) has been manufactured and used at the Institute site since at least the 1970s. Union Carbide Corporation (UCC) owned the facility when the equipment was designed and installed. Recognizing the acute toxic hazard associated with MIC, UCC specified a more rigorous design than what is often applied in chemical processes: redundant and backup instrument systems, augmented fire suppression systems, and an ammonia-steam emergency vapor suppression system. In addition, the bulk storage systems were more robust than a typical aboveground storage vessel. In particular, Union Carbide installed specialized blast-resistant structures around the aboveground MIC storage vessels to protect the vessels from projectiles in the event of an explosion in nearby equipment. The blast blankets also provided a thermal heat shield in the event of a nearby fire.

In 1994, the owner of the Institute facility, Rhone-Poulenc, increased the height of the blast shield on the MIC day tank in the Methomyl-Larvin unit. The added height protected the relief valve piping and the vent line that is attached to the top head of the vessel.

The August 2008 incident and Bayer’s subsequent effort to restrict public information about the proximity of the MIC day tank to the explosion resulted in renewed concern about MIC use and storage at the plant. This appendix presents a CSB analysis that evaluates whether the exploded residue treater could have damaged the MIC day tank and piping, if it had followed a hypothetical trajectory in that direction.

2.0 Methomyl and Carbofuran MIC Supply System

2.1 MIC Manufacturing

Bayer, the only user of large quantities of MIC in the U.S., manufactures MIC and at the time of the incident stored up to 200,000 pounds in large underground pressure vessels and smaller aboveground vessels. Liquid MIC was transferred from the MIC production unit about 2500 feet through an insulated piping system to an aboveground pressure vessel called a "day tank" located adjacent to the Methomyl-Larvin production unit. After refilling the day tank, operators removed all MIC from the transfer pipe and purged the pipe with nitrogen gas.

The transfer piping and storage vessel incorporated multiple layers of protection, both active and passive:

- The MIC recirculation system, carbofuran unit transfer line, and the cross-plant transfer line were equipped with emergency block valves that were operated from the control room;
- An emergency dump tank adjacent to the day tank was available to receive the contents of the MIC day tank and cross-plant transfer line; and
- The day tank and dump tank were installed on a concrete foundation and surrounded by a concrete dike wall with the capacity to contain the maximum MIC inventory in the day tank and transfer piping.

2.2 Production Storage

The MIC day tank was a 6,700-gallon-capacity stainless steel pressure vessel. Maximum inventory was approximately 37,000 pounds (4,400 gallons). The tank was designed, fabricated, and tested in accordance with the American Society of Mechanical Engineers Boiler and Pressure Vessel Code

Section VIII and was rated for lethal[60] service. Union Carbide specified the vessel to be designed with a maximum allowable working pressure of 100 psig, even though the MIC system would operate at only 1-2 psig; the rupture disk and relief valve were set at 20 psig. UCC also installed a dedicated nitrogen supply system to maintain an inert atmosphere in the tank and piping system.

The day tank was equipped with additional layers of protection. The refrigeration system chilled the MIC to about 0 °C (32 °F). A multiple stage chiller system first used ethylene glycol to cool methyl isobutyl ketone (MIBK). The MIBK was then used to cool MIC in a separate heat exchanger. This two-step cooling process prevented a possible MIC-water reaction should the ethylene glycol chiller system leak.[61] The MIBK system pressure was also maintained greater than the MIC system pressure, and the MIBK pressure in the MIBK-ethylene glycol heat exchanger was greater than the ethylene glycol pressure. This ensured that water could not enter the MIC system. Finally, emergency generators provided power to the refrigeration system in the case of normal plant electricity loss.

The day tank control system contained redundant pressure, temperature, and flow instruments including high-pressure, high-temperature, and refrigeration system failure alarms. The MIC system vents discharged into the process and emergency vent scrubber system.

The area around the tank was equipped with air monitors to detect MIC. Firewater monitors were located nearby to mitigate an MIC leak and suppress a fire that could threaten the tank. Surveillance cameras provided full-time visual display on video display panels inside the Methomyl-Larvin control room. A blast shield structure fully enclosed the day tank to protect it from flying debris and thermal radiation in the event of an explosion and fire.

[60] ASME defines lethal substance as a poisonous gas or liquid of such a nature that a very small amount of the gas or of the vapor of the liquid mixed or unmixed with air is dangerous to life when inhaled (ASME 2001). Lethal service rated vessels are designed and fabricated to a higher quality standard than non-lethal rated vessels.

[61] The coolant is a mixture of ethylene glycol and water.

2.3 Impact From the Explosion and Fire

The day tank contained approximately 13,700 pounds of MIC on the night of the residue treater explosion and fire. Neither the empty cross-plant transfer line nor the carbofuran unit transfer system, which was operating at the time of the incident, was damaged. Debris from the explosion struck the blast blanket surrounding the day tank (Figure C-1), and the blast blanket was exposed to radiant heat from the fires. However, the MIC day tank was not damaged.

Figure C-1. MIC tank blast shield post-incident

Power to the MIC refrigeration system was interrupted, so an emergency generator was put in service. The MIC temperature rose to 8.9 °C (48 °F) and the pressure rose to 12.7 psig, which were both less than the maximum allowed values of 30 °C (86 °F) and 20 psig, respectively. The day tank temperature was below 2 °C late the next day. The day tank was then depressurized and drained.

2.4 Day Tank Inspection and Return to Service

Bayer removed the blast blankets and removed the tank insulation, then inspected the tank, piping, and refrigeration system to verify that the explosion and fire did not damage the equipment. Bayer reinsulated the tank and piping systems and purchased and installed new blast blankets to replace those that were exposed to the fire. The blankets not directly exposed to the fire were reused. Finally, the MIC tank was returned to service to provide MIC to the carbofuran unit until the unit was shut down in August, 2010.

3.0 MIC Day Tank Blast Shield Analysis

When the day tank was installed in 1983, a wire rope blast blanket system was installed to protect it from flying debris. The blast blankets also provide a radiant heat shield from nearby fires. In 1994, the structure was extended up to completely surround the entire tank and top piping connections (Figure C-2). The original frame design considered static (blast blanket weight) and wind loads only, and did not analyze the structure for dynamic side loading, one of the functional purposes of the assembly.

Figure C-2. MIC day tank shield structure

3.1 Postulated Worst-Case Event Analysis

The shell and one head careened into the methomyl unit when the residue treater violently exploded. The other 800-pound head (Figure C-3) sheared off and came to rest near the installed location of the residue treater. A small piece of the vessel cylindrical shell separated and lodged between a catwalk and the shell of a distillation column (Figure C-4) some 15 to 20 feet from the residue treater installed location.

Figure C-3. 800-pound residue treater bottom head

Figure C-4. Residue treater shell fragment lodged in catwalk of adjacent distillation column

The blast shield showed no evidence of an impact by any significant projectile. However, because of the proximity of the residue treater to the structure, the CSB conducted a dynamic analysis of the shield structure and compared the results to a postulated residue treater impact with the structure. The analysis consisted of the following steps:

- Calculate the residue treater theoretical rupture pressure,[62]
- Calculate the TNT equivalent energy at the rupture pressure and temperature,
- Calculate the initial velocity of various size residue treater fragments,
- Calculate impact forces from residue treater fragment impacts with the shield structure,
- Calculate the forces required to deflect the shield structure into the MIC day tank or attached piping, and
- Compare the results of the fragment energies to the shield structure frame analysis.

3.2 Residue Treater Rupture Pressure and TNT Energy

The newly installed 4,500-gallon residue treater was an ASME Code-stamped, SA-240 316L stainless steel pressure vessel manufactured in 2008. It had a maximum allowable working pressure (MAWP) of 50 psi at 400 °F and the vessel hydrostatic test pressure was 68 psig. The following calculations estimate the burst pressure and TNT equivalency of the energy released in the August 2008 explosion.

The Faupel method (Faupel, 1956) is a theoretical method used to predict vessel burst pressures +/- 15 percent based on vessel geometry and yield and ultimate tensile strengths of the stainless steel. The formulas were developed from nearly 100 static cylinder tests. According to Faupel, if a cylinder

[62] The maximum pressure range of the control system residue treater pressure instruments was 0-50 psig. Therefore, the actual vessel pressure near the failure point was not recorded.

wall yields at a constant stress, it will burst at a pressure required to overstrain the wall[63]. The residue treater burst pressure, $P_{b,}$ is estimated using the following equation.

$$P_b = \frac{2\sigma_y}{\sqrt{3}} \ln R \left[2 - \frac{\sigma_y}{\sigma_u} \right]$$

where

σ_u, ultimate tensile strength = 70,000 psi
σ_y = yield strength = 25,000 psi
Cylinder wall ratio, R = b/a
a = inner radius (47.6875 in)
b = outer radius (48 in)
R = 1.0066

P_b = 310 psig

When the residue treater ruptured, the stored energy was released nearly instantaneously, creating a blast wave that spread over a distance from the vessel. The energy of the blast wave can be compared to a high explosive detonation through a TNT equivalency calculation using the conversion factor of 1.545×10^6 ft lbs/lb of TNT.

[63] Though the Faupel method is intended for thick-walled vessels, it can be applied to thin-walled vessels as well. All thin- and thick- walled equations derived in the Faupel method yield the same result as the cylinder wall ratio, R, approaches the value 1.0 (Faupel, 1034).

Using the calculated burst pressure, the blast energy and TNT equivalence (Cain, 1995) are:

$$W = \frac{P_1 V_1}{\gamma - 1}\left[1 - \left(\frac{P_2}{P_1}\right)^{\frac{\gamma-1}{\gamma}}\right]$$

where

W = total explosion energy

P_1 = 310 psia = 46,760 psfa

P_2 = 14.7 psia = 2117 psfa

V_1 = 295 ft^3 (volume above liquid level: 4500-gallon vessel @ 51% full)

γ = specific heat ratio of CO_2 = 1.23 (because CO_2 is a principal byproduct of methomyl decomposition)

$$W = 26.3\text{ e}^{6}\ \text{ft-lbs}$$

Using the TNT equivalency factor of 1.545 e ^{6} ft-lbs/lb, the mass of TNT required to generate the calculated explosion energy is:

$$\text{TNT} = \frac{26.3\quad \text{ft-lbs}}{1.545\quad \text{ft-lbs/lb}}$$

$$\text{TNT} = 17\text{ lbs}$$

The American Institute of Chemical Engineers, Center for Chemical Process Safety (CCPS) *Guidelines for Chemical Process Quantitative Risk Analysis* (AIChE, 2000) contains other methods for estimating the TNT equivalent energy from a pressure vessel explosion. The CSB compared the result from the Cain method with the methods contained in the CCPS publication. Table C-1 contains the summary of the results.

Table C-1. TNT equivalency values

Method	TNT (lbs)	Energy (ft-lbs)
Baum	13	20,690,000
Brode	36	57,000,000
Brown	44	69,900,000
Crowl	19	29,500,000
Cain	17	26,300,000

3.3 Fragment Kinetic Energy Estimates

The explosion caused the vessel to separate into three pieces: the bottom head, a small segment that embedded in the catwalk, and the main vessel shell with the top head attached. Initial velocities were calculated and applied to various trajectory departure angles in the direction of the MIC day tank. Aerodynamic drag coefficients were then applied to predict the velocity and kinetic energy of each fragment at impact with the day tank shield structure at the same elevation as the top of the day tank. The analyses ignored the pipe rack and other large structures between the residue treater and the day tank that would likely deflect the object, or absorb some of the kinetic energy.

3.3.1 Fragment Velocity Estimates

The energy released in an exploding pressure vessel is distributed among the energy consumed to fracture the steel vessel, shock wave, kinetic energy of the fragments, and heat energy. The energy distribution depends on the vessel failure characteristics (e.g., ductile vs. brittle fracture)[64] and can change throughout the explosion.

[64] Post-explosion visual examination of the new residue treater confirmed ductile failure of the shell and heads, as expected for stainless steel.

Assuming a complex expansion process (e.g., gas/liquid mixtures are contained in the pressure vessel), a simple kinetic energy calculation can be used to estimate the fragment upper limit velocity:

$$KE = \frac{1}{2} m v^2$$

$$\text{so } v = \sqrt{\frac{2KE}{m}}$$

where

KE = kinetic energy lbs (ft-lbs)

v = initial velocity (ft/s)

m = mass (lbs)

However, according to Baum (1988), less than 20 percent of the vessel expansion energy is transferred to projectiles. To improve the understanding of pressure vessel failure energies, the U.S. Air Force and U.S. Naval Surface Warfare Center commissioned the General Physics Corporation to develop a computer model to calculate fragment velocity and energy, called LIMIT-V, as part of the Pressure Vessel Burst Test Study (Cain, 1995). The study compared the Baum predicted values to actual fragment velocities measured from high-pressure, gas-filled pressure vessel burst tests.

Assuming a vessel axial split, which was similar to the residue treater failure, and assuming a burst pressure of 310 psig, the LIMIT-V program predicts that the fragment projectile energy and velocity for the main residue treater shell and top head are:

Fragment energy = 14.3 e ^{6} ft-lbs

Initial velocity = 81 ft/sec

The LIMIT-V method likely over-predicts the residue treater fragment velocity because the residue treater was approximately half-full of liquid rather than vapor filled, and the method does not consider a foamy gas-liquid mixture inside the pressure vessel. However, the results are reasonable to use for evaluating the MIC blast shield structure.

3.3.2 Fragment Range and Strike Velocities

TRAJ is a two-dimensional fragment trajectory model developed for the U.S. Naval Surface Warfare safety program to estimate fragment velocity and range at various angles. The program uses velocity and shape characteristics to plot fragment flight path height and range and accounts for aerodynamic drag and fragment ricochets off barriers or interferences in the fragment path. The program calculates the velocity and energy at the point of contact with a specified barrier or interference.

The residue treater vessel shell and top head scenario generated the greatest fragment kinetic energy that could impact the MIC day tank blast mat frame. Barriers representing the MIC day tank structure were input into TRAJ at a range of 70 feet and a height of 22 feet from the residue treater. Figure C-5 shows the path traveled by the vessel shell and top head having an initial velocity of 81 feet per second.

If a large, high velocity fragment strikes the shield structure at the elevation where the MIC tank piping passes through the grating with enough energy to deflect the structure more than about 4 inches horizontally, the piping could be damaged. The model predicts that the residue treater main fragment will strike the structure at this elevation (circled area on Figure C-5) when the departure trajectory angle from the explosion epicenter is about 30 degrees above horizontal. The fragment energy at impact is 137,000 foot-pounds.

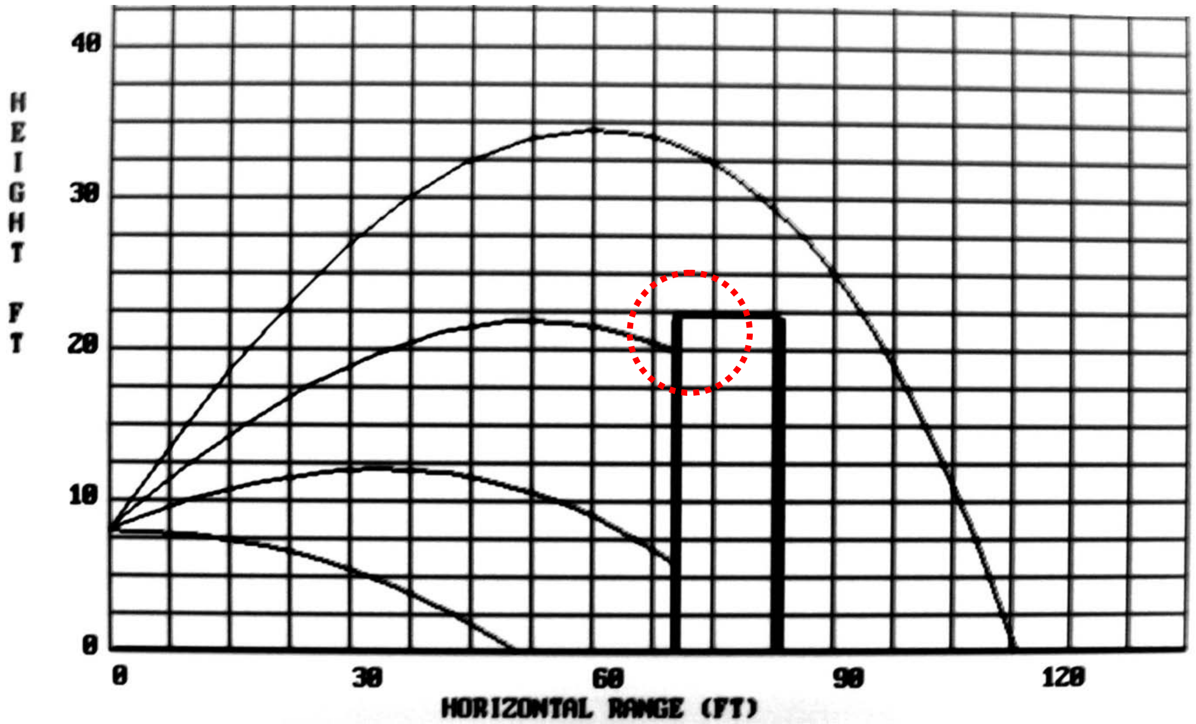

Figure C-5. TRAJ plot with fragment impact with the blast shield structure (vertical line at 75 feet range). The curves represent fragment departure angles of 0, 15, 30, and 45 degrees.

3.3.3 Shield Structure Dynamic Analysis

Union Carbide installed the blast shield structure in 1983. A 1994 modification added additional shielding above the MIC day tank. The assembly consisted of a structural frame bolted to the concrete foundation. Steel wire rope ballistic shield mats were suspended on all sides. The shield mats served multiple functions: prevent small projectile penetration or significantly reduce the projectile exit velocity, attenuate energy from an explosion generated pressure wave, and absorb heat from an explosion or fire. The structural frame supported the heavy steel mats.

A steel grating floor deck was installed a few inches above the top of the MIC day tank. The vessel relief valve piping passed through a circular opening in the floor deck. The clearance between the floor opening and the pipe was approximately 4 inches. Therefore, contact between the steel grating and the pipe will occur if the frame is deflected 4 inches horizontally. An MIC release was assumed to occur if the grating contacts the pipe—the analysis ignored the strength of the pipe and vessel nozzle. The analysis did not evaluate the additional fragment energy (greater impact velocity) that would be necessary to puncture or break the pipe and release MIC.

3.3.4 Blast Mat Design

The blast mat is a commercially available ballistic shield product that was originally intended to protect personnel from high-energy explosive detonations. The manufacturer worked with the Israeli Defense Force and the Southwest Research Institute to determine the ability of the blast mat to absorb potential debris or pressure waves from an explosion. Testing conducted using explosive devices showed that the shield is capable of containing very high energy explosions. The testing also demonstrated that the shield is capable of withstanding detonation pressures resulting from thousands of pounds of TNT more than 30 feet from the source of the detonation.

The CSB estimated that the residue treater exploded with the force of about 17 pounds of TNT equivalent, many orders of magnitude lower that the energy absorbing capacity of the ballistic shield. Therefore, the CSB concluded the shield mat would withstand any postulated explosion pressure wave from the residue treater.

3.3.5 Structural Frame Assembly Design

Frame assembly design records address only the capacity of the frame to support the deadweight of the installed mats, plus wind loads. The records do not include a frame dynamic analysis to demonstrate that the frame assembly was strong enough to protect the day tank from a large object strike at high velocity.

The CSB commissioned a structural analysis of the frame assembly to evaluate it for resistance to two load cases:

1. Blast wave overpressure from approximately 40 pound TNT equivalent explosion at 75 feet.
2. Impact force from the residue treater vessel.

The structural and civil drawings were used to analyze the assembly using GTStrudul,® a comprehensive structural analysis tool. Failure was assumed if the maximum calculated stresses exceeded the material strength of any primary component in the frame assembly, or if the frame structure deflected 4 inches horizontally at the elevation of the top floor grating, the space between the hole in the grating and the pipe. The results are shown in Table C-2.

Table C-2. Frame loading analysis results

Load condition	Frame component stress limit	Maximum Deflection
Blast overpressure	Baseplate overstressed	~ 1.8 inches (no contact with pipe)
Residue treater vessel impact	Baseplate, structural beams and braces overstressed	~ 4 inches (possible contact with MIC pipe)

The analyses are based on worst case conditions for the following reasons:

- They ignore any objects in the path between the residue treater and the MIC day tank including the pipe rack that might deflect or even stop the fragment before it strikes the shield structure (See Figure C-2);
- The blast mat is assumed to act as a rigid plate, which transmitted all forces directly into the frame (i.e., the calculation ignored attenuation of blast or impact energy by the blast mat);
- The frame is assumed to be oriented such that the east face was perpendicular to the path of the overpressure and vessel fragment trajectory; and
- The fragment analysis uses the absolute value of the velocity applied in the horizontal direction rather than the horizontal vector component of the calculated velocity at the incident angle.

The blast overpressure analysis indicates that the calculated frame deflection was less than half the available space between the grating and the relief valve pipe. Although the overpressure analysis suggested that the frame baseplates would have shown evidence of permanent structural deformation, post-incident visual examination did not identify any structural damage, confirming that the analysis results were very conservative.

The fragment impact analysis predicts that the frame might have sustained permanent and observable structural damage if the residue treater vessel had impacted the structure at maximum theoretical velocity near the top of the structure. Furthermore, the results show that the frame could contact a pipe connected to the MIC day tank. However, the same highly conservative assumptions used in the analysis likely results in the model over-predicting the maximum frame deflection.

3.3.6 Limitations of the Model

The CSB did not evaluate the likelihood that the residue treater would travel along any particular trajectory when it ruptured The direction the vessel traveled was the result of the physical characteristics of the vessel and attached piping and other factors that are difficult to model. Factors that influenced the direction of the fragments included:

- Piping connected to the residue treater, including the relief pipe attached to the top head;
- Orientation of the support legs and concrete anchor bolts; and
- The orientation of the head and shell welds, manway, and other significant attachments that strongly influenced where the vessel shell first was breeched.

Specific conditions would have been necessary for the largest residue treater fragment to strike the blast shield frame at the most vulnerable location. First, the trajectory angle would have had to approach 30 degrees above horizontal. A steep trajectory angle would also be necessary for the residue treater to pass over the elevated pipe rack that was directly in front of the day tank. The CSB did not attempt to quantify the likelihood of these conditions occurring; in the actual incident, the residue treater followed an essentially horizontal trajectory.

3.4 Blast Shield Analysis Conclusions

The blast mat provided highly effective protection to the MIC day tank against radiant heat from an external fire and penetration from very small projectiles traveling at near sonic velocity. The blast mat would also prevent penetration of a large fragment, such as the residue treater shell or head travelling nearly 55 miles per hour.

The original design of the structural frame used to support the blast mat considered only the weight of the blast mats and wind loading. The calculations did not consider dynamic loading from a high velocity large projectile impact. The CSB frame analysis concluded that the structure provided only marginal impact energy absorption protection from such a large fragment strike at velocities predicted to result from the residue treater rupture.

Had the residue treater traveled unimpeded in the direction of the day tank, and struck the shield structure just above the top of the MIC day tank, the shield structure might have moved enough to come in contact with the relief valve vent pipe. A puncture, or tear in the vent pipe or MIC day tank head would have released MIC vapor into the atmosphere above the day tank.

The CSB notes that the scenario did not occur and remains hypothetical. The vessel might have traveled in one of many trajectories; even under conservative assumptions, only a specific narrow set of trajectories could have potentially led to an MIC release. However, the analysis does emphasize the risks of locating large vessels containing extremely toxic substances within hazardous process areas that have the potential for explosions. As noted previously, following the August 2008 incident Bayer committed to eliminating all aboveground storage tanks of MIC.

Appendix D – Bayer CropScience Press Release Announcing Institute Facility MIC Storage Reduction

Bayer CropScience

News Release

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Bayer CropScience announces investment of $25 million for Institute site

Significant production changes planned

Institute, West Virginia (USA), August 26, 2009 – Bayer CropScience today announced an investment of $25 million for further enhancing operational safety at its Institute, W.Va. site. As part of these plans, the company will reduce methyl isocyanate (MIC) storage by 80 percent. This reduction will lead to the elimination of the transfer, use and storage of MIC at the site's West Carbamoylation Center within approximately one year. After completion of these measures, there will be no MIC storage above ground anywhere on the site.

Bayer CropScience President & CEO Bill Buckner said, "While MIC was not involved in the explosion at the Institute site in August last year, we have taken seriously the concerns of public officials and the site's neighbors, and we are making very substantial changes in how we operate our facility in the future."

A number of changes has already been implemented, including the hiring of an emergency services leader to interact with public emergency responders and new procedures, including dedicated phone lines and back-up radios, for communicating with Metro 911. Buckner added that the site also had participated recently in a successful emergency drill with the Kanawha Putnam Emergency Planning Committee.

"Within approximately one year we also will cease production of all MIC-based products currently manufactured in the West Carbamoylation Center," Buckner stated. As part of this, the company will not reconstruct the methomyl facility. To offset changes in Bayer CropScience's production, the industrial park will seek new tenants so to maintain a substantial business presence in the Kanawha Valley. Company officials said today they will work with state and federal officials to attract new businesses to the 465-acre site.

The company aims at implementing these changes to the site's production with the least amount of impact on the employees.

Beyond the changes announced today, Bayer CropScience will continue to evaluate the feasibility of further measures, which may also include the use of alternative process technologies.

In going forward, the company will also continue its dialogue and close cooperation with the community and governmental agencies involved.

About Bayer CropScience
Bayer is a global enterprise with core competencies in the fields of health care, nutrition and high-tech materials. Bayer CropScience AG, a subsidiary of Bayer AG with annual sales of about EUR 6.4 billion (2008), is one of the world's leading innovative crop science companies in the areas of crop protection, non-agricultural pest control, seeds and plant biotechnology. The company offers an outstanding range of products and extensive service backup for modern, sustainable agriculture and for non-agricultural applications. Bayer CropScience has a global workforce of more than 18,000 and is represented in more than 120 countries. This and further news is available at: www.press.bayercropscience.com.

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hjb (2009-0498E)

Forward-Looking Statements

This release may contain forward-looking statements based on current assumptions and forecasts made by Bayer Group or subgroup management. Various known and unknown risks, uncertainties and other factors could lead to material differences between the actual future results, financial situation, development or performance of the company and the estimates given here. These factors include those discussed in Bayer's public reports which are available on the Bayer website at www.bayer.com. The company assumes no liability whatsoever to update these forward-looking statements or to conform them to future events or developments.

U.S. CHEMICAL SAFETY AND HAZARD INVESTIGATION BOARD

INVESTIGATION REPORT

DONALDSON ENTERPRISES, INC.

FIREWORKS DISPOSAL EXPLOSION AND FIRE

(5 Fatalities, 1 Injury)

WAIKELE SELF STORAGE

WAIPAHU, HAWAII

APRIL 8, 2011

KEY ISSUES:

- HAZARDS OF FIREWORKS DISPOSAL AND THE ACCUMULATION OF EXPLOSIVE FIREWORKS COMPONENTS
- LACK OF REGULATIONS AND INDUSTRY STANDARDS ADDRESSING FIREWORKS DISPOSAL
- INSUFFICIENT CONTRACTOR SELECTION AND OVERSIGHT REQUIREMENTS FOR HAZARDOUS ACTIVITIES

REPORT NO. 2011-06-I-HI
JANUARY 2013

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Acronyms and Abbreviations

AE	Ammunition and Explosives
AIHA	American Industrial Hygiene Association
ANSI	American National Standards Institute
APA	American Pyrotechnics Association
ATF	Bureau of Alcohol, Tobacco, Firearms and Explosives
BAI	Thomas E. Blanchard & Associates, Inc.
CBP	U.S. Customs and Border Protection
CCR	Central Contractor Registration
CLIN	Contract Line Item Number
CO	Contracting Officer
CSB	U.S. Chemical Safety and Hazard Investigation Board
CURT	Construction Users Roundtable
DAR	Daily Activity Report
DDESB	Department of Defense Explosives Safety Board
DEI	Donaldson Enterprises, Inc.
DFARS	Department of Defense Acquisition Regulation Supplement
DHS	U.S. Department of Homeland Security
DLIR	Department of Labor and Industry Relations
DoD	Department of Defense
DOH	State of Hawaii Department of Health
DOT	U.S. Department of Transportation
DTAP	Department of Treasury Acquisition Procedures
DTAR	Department of Treasury Acquisition Regulation System
EOD	Explosive Ordnance Disposal
EPA	U.S. Environmental Protection Agency
ESD	Electrostatic Discharge
FAR	Federal Acquisition Regulation
HAR	Hawaii Administrative Rules
HAZWOPER	Hazardous Waste Operations and Emergency Response
HFD	Honolulu Fire Department
HIOSH	Hawaii Occupational Safety and Health Division

HPD	Honolulu Police Department
HSPM	Health and Safety Program Manager
ICC	International Code Council
ICE	U.S. Immigration and Customs Enforcement
ICE/HSI	U.S. Immigration and Customs Enforcement Homeland Security Investigations
MOC	Management of Change
NFPA	National Fire Protection Association
OPE	Department of the Treasury Office of the Procurement Executive
OSHA	Occupational Safety and Health Administration
PHA	Process Hazard Analysis
PPE	Personal Protective Equipment
PSM	Process Safety Management
RCRA	Resource Conservation and Recovery Act
QCM	Quality Control Manager
SBA	Small Business Association
SOP	Standard Operating Procedure
SPE	Senior Procurement Executive
SSHO	Site Safety and Health Officer
SOW	Statement of Work
TEOAF	Treasury Executive Office for Asset Forfeiture
TEP	Temporary Emergency Permit
TFU	Thermal Flash Unit
TFF	Treasury Forfeiture Fund
TSDF	Treatment, Storage, and Disposal Facility
VSE	VSE Corporation
UXO	Unexploded Ordnance

Executive Summary

On April 8, 2011, at approximately 8:50 am, an explosion and fire occurred at a magazine[1] located at Waikele Self Storage in Waipahu, Hawaii, that was leased and used by Donaldson Enterprises, Inc. (DEI) for seized fireworks storage and disposal-related activities. Five DEI personnel in the magazine at the time of the incident were fatally injured.

DEI is an unexploded ordnance[2] (UXO) remediation company based on Oahu that employs fewer than 20 full-time workers. Pursuant to a federal seized property management contract with the Treasury Executive Office for Asset Forfeiture (TEOAF), federal government contractor VSE Corporation (VSE) awarded DEI a subcontract in early 2010 to dispose of imported fireworks seized in Honolulu, Hawaii, by federal law enforcement personnel. Three fireworks shipments were seized as contraband[3] because they were labeled as consumer grade fireworks but, upon inspection, appeared physically consistent with more hazardous commercial display grade fireworks.

Federal contractor selection regulations did not require VSE procurement personnel to conduct a safety-related review of DEI prior to awarding the company the subcontract, nor did VSE procurement personnel involved in awarding this subcontract have training and experience related to fireworks disposal. VSE's procurement office selected DEI as the fireworks disposal subcontractor because DEI was already storing the seized fireworks at the time under a separate subcontract with VSE, and because DEI submitted the lowest-cost and most time-efficient bid, which VSE determined to be the best overall value for the government. VSE procurement personnel were unaware that DEI had no prior fireworks disposal experience when it awarded the subcontract.

Because seized fireworks requiring disposal are considered hazardous waste in the United States, DEI was required to obtain an environmental permit from the State of Hawaii Department of Health (DOH). In June 2010, DOH issued DEI a 90-day emergency hazardous waste permit authorizing "thermal treatment"[4] of the fireworks at a local shooting range, and DEI began its disposal work soon after. The permit did not evaluate or address fireworks disassembly or diesel soaking. To dispose of the first seizure of fireworks, DEI personnel separated individual firework tubes from their original configuration and soaked the firework tubes whole in 55-gallon diesel-filled steel drums inside the magazine. DEI then transported the soaked fireworks to a local shooting range to burn them in either drums or a portable incinerator.

The U.S. Chemical Safety Board (CSB) learned that because DEI was experiencing minor explosions with some types of fireworks while burning the initial shipment of seized fireworks, the company altered

[1] A "magazine" is "any building or structure, other than an explosives manufacturing building, used for storage of explosive materials." Commerce in Explosives, 27 CFR §555.11 (2003).
[2] "Unexploded ordnance" is an explosive weapon such as a grenade, bomb, or land mine that has not exploded and poses a risk of detonation. It can be located on the ground, partially buried in the ground, under bushes or other vegetation, and in water.
[3] Goods that have been imported illegally.
[4] Burning.

its fireworks disposal methodology in summer 2010. As a result of the altered methodology, DEI personnel began cutting open, or disassembling, individual firework tubes by hand on a loading dock just outside the magazine entrance and separating out the individual explosive fireworks components, the black powder[5] and aerial shells,[6] which are both susceptible to ignition from sparks, friction, and static electricity. The accumulated explosive powder from the fireworks, referred to as "black powder," was stored in a plastic container lined with a plastic garbage bag. To improve diesel permeation of the shells and minimize explosions, DEI personnel cut one-inch slits in the aerial shells. They then soaked the shells in diesel and burned them at the shooting range. VSE personnel were aware of this procedure change, but did not question or express concern about it. DEI completed disposal of the initial seizure in late fall 2010 without incident.

DEI began work on the next fireworks seizure in December 2010. In early 2011, DEI again altered the fireworks disposal process to increase the fireworks destruction rate by maximizing the amount of aerial shells that could be burned at once. Expanding upon the modification DEI developed when disposing of the initial seizure, DEI personnel disassembled the firework tubes outside the magazine by hand and separated the individual explosive components, the black powder and aerial shells, into cardboard boxes. The cardboard boxes containing the black powder were lined with plastic garbage bags to minimize leakage. DEI personnel stacked and stored boxes containing aerial shells and black powder within the magazine and simultaneously soaked aerial shells in diesel. DEI notified VSE of this change in methodology via email in March 2011, but VSE again did not question the change.

Although DEI wrote a brief document presenting a hazard review of its fireworks disposal activities when it was awarded the subcontract, this analysis did not consider the safety implications of cutting into the fireworks and accumulating their explosive components. Because the Occupational Safety and Health Administration (OSHA) Process Safety Management (PSM) standard does not apply to activities conducted under the umbrella of fireworks disposal,[7] DEI was not required to conduct a formal Process Hazard Analysis (PHA) of its fireworks disposal activities or a formal Management of Change (MOC) analysis when it modified its disposal process.

At the time of the incident, DEI personnel had abruptly halted their disassembly work due to rain and had taken the materials involved in the process to just inside the magazine entrance. Boxes containing aerial shells, black powder, and partially disassembled firework tubes were stacked inside the magazine near the entrance along with tools, a metal hand truck, and chairs. Once the materials were moved into the

[5] Black powder is a mixture of charcoal, sulfur, and potassium nitrate. The standard composition typically contains 75% potassium nitrate, 10% sulfur, and 15% charcoal. Turcotte, R., Turcotte, A.M., Fouchard, R., and Jones, D.E.G. Thermal Analysis of Black Powder. *Journal of Thermal Analysis and Calorimetry.* Canadian Explosives Research Laboratory, Natural Resources Canada, Ottawa, Ontario, Canada. 2003; Vol. 73, p 105.

[6] An "aerial shell" is "a cartridge containing pyrotechnic composition, a burst charge, and an internal time fuse or module, that is propelled into the air from a mortar and that is intended to burst at or near apogee [highest point]." National Fire Protection Association (NFPA) 1124. *Code for the Manufacture, Transportation, Storage, and Retail Sales of Fireworks and Pyrotechnic Articles,* Section 3.3.1, 2006.

[7] PSM only applies to activities associated with fireworks manufacturing; it does not apply to fireworks disposal. http://www.osha.gov/pls/oshaweb/owadisp.show_document?p_table=INTERPRETATIONS&p_id=22524 (accessed December 29, 2012)

magazine, the DEI project supervisor stepped outside to make a phone call. While he was on the phone, a large explosion occurred inside the magazine near its entrance.

The CSB determined that changes in DEI's fireworks disposal process resulted in the accumulation of a large quantity of explosive components just inside the magazine entrance, creating the essential elements for a mass explosion.[8] Insufficient federal contractor selection and safety oversight requirements for hazardous activities, a significant gap in regulatory and industry standards pertaining to fireworks disposal, and a lack of hazard management by DEI personnel, enabled DEI to introduce significant hazards to its fireworks disposal process without those hazards being adequately identified or effectively controlled.

The CSB investigation into this incident identified the following key findings:

Technical Findings

1. DEI's hazard analysis of its fireworks disposal process was insufficient. The company failed to identify key hazards of handling, disassembling, and storing contraband commercial display fireworks, and did not adequately control the identified and evaluated hazards.

2. DEI personnel disposing of the fireworks lacked the training, experience, and knowledge of procedural safeguards for the safe conduct of the fireworks disposal.

3. DEI's modifications to the fireworks disposal process accumulated substantially large quantities of explosive material in boxes, greatly increasing the potential explosion hazard. This change to the disposal process was not adequately reviewed for safety implications.

4. The CSB, along with the Bureau of Alcohol, Tobacco, Firearms, and Explosives (ATF) and the Hawaii Occupational Safety and Health Division (HIOSH), identified a number of possible ignition sources in the magazine at the time of the incident, including sparking tools, a metal hand truck, a rolling office chair, and plastic bags capable of producing static discharge.

Contractor Selection and Oversight Findings

5. The Federal Acquisition Regulation (FAR), which governs federal agencies' acquisition of goods and services, does not specifically require a federal contracting officer to consider safety performance measures and qualifications when determining the "responsibility" of a potential government contractor or subcontractor to handle, store, and dispose of hazardous materials such as fireworks.

[8] A mass explosion is "one which affects almost the entire load instantaneously." 49 CFR §173.50 (b)(1) (2003).

6. The Department of the Treasury Acquisition Regulation (DTAR), the Department of the Treasury's supplement to the FAR, does not impose sufficient requirements for safe practices and subcontractor selection and oversight with respect to the unique hazards associated with handling, storing, and disposing of hazardous materials.

7. VSE's procurement office conducted a non-technical review of DEI and the competing offeror for the fireworks disposal subcontract that did not address health and safety.

8. VSE did not use personnel with the technical background or expertise to properly select and oversee subcontractors performing work with hazardous materials such as fireworks, nor did it consult with or hire anyone with that expertise.

Regulatory and Industry Safety Standard Findings

9. The CSB found a lack of regulations or industry standards that adequately address safe fireworks disposal. Federal or local codes, regulations, or industry standards do not establish safety requirements, provide guidance on proper ways to dispose of fireworks, or address the hazards associated with the disassembly of fireworks and the accumulation of explosive fireworks components.

10. While OSHA's PSM standard applies to fireworks manufacturing, OSHA has determined that the regulation does not apply to work activities related to fireworks disposal. Therefore, DEI was not required to implement a more robust PSM system for its fireworks disposal process. For example, DEI's change to its disposal process led to the accumulation of material that created a mass explosion hazard. PSM elements such as Management of Change (MOC) would have required a safety review of this change.

11. Emergency hazardous waste disposal permits are granted in Hawaii and throughout the country to entities seeking to dispose of seized contraband fireworks because they are considered an imminent threat to human health and the environment. However, the Resource Conservation and Recovery Act (RCRA) does not incorporate PSM-type elements in its hazardous waste permitting process, despite the extremely hazardous nature of the materials covered by these permits.

As a result of this investigation, the CSB makes recommendations to

- The Federal Acquisition Regulatory Council
- The Department of the Treasury Office of the Procurement Executive (OPE)
- Treasury Executive Office for Asset Forfeiture (TEOAF)
- VSE Corporation
- The National Fire Protection Association (NFPA)
- The U.S. Environmental Protection Agency (EPA)
- The Bureau of Alcohol, Tobacco, Firearms and Explosives (ATF)

Section 9.0 of this report details the recommendations.

1.0 The Incident

On April 8, 2011, at approximately 8:50 am, an explosion and fire occurred at a magazine known as "A-21" located at Waikele Self Storage in Waipahu, Hawaii. Five Donaldson Enterprises, Inc. (DEI) employees were fatally injured and a sixth sustained minor injuries.

DEI, a small unexploded ordnance (UXO) clearance company based on the island of Oahu, was using the magazine to store seized contraband fireworks and prepare them for disposal. On the morning of the incident, five DEI personnel were disassembling one-inch contraband firework tubes on a cement loading dock located directly in front of the magazine entrance, while a sixth remained inside the magazine cleaning and organizing (Figure 1). To accomplish the disassembly work, DEI personnel cut into the individual firework tubes by hand using a PVC pipe cutter or knife and separated the individual explosive components contained within each tube, the aerial shells and the black powder (which functions as a lift charge[9]) into cardboard boxes.

According to witness statements, around 8:30 am it began to rain heavily, and the DEI workers quickly moved materials involved in the disassembly process – including tools, chairs, and boxes containing aerial shells, black powder, and partially disassembled firework tubes – to just inside the magazine entrance. While five of the workers remained inside, the project supervisor went outside to the front left corner of the loading dock to make a phone call. While he was on the phone, an explosion occurred inside the magazine, and a fire ensued.

The five individuals located inside the magazine at the time of the incident did not survive. Three DEI employees sustained fatal burn injuries while two succumbed to carbon monoxide poisoning. The project supervisor sustained minor injuries.

[9] A lift charge is a "pyrotechnic composition used to propel a component of a mine or shell device into the air. Lift charge is limited to black powder (potassium nitrate, sulfur, and charcoal) or similar pyrotechnic composition without metallic fuel." APA Standard 87-1. *Standard for Construction and Approval for Transportation of Fireworks, Novelties, and Theatrical Pyrotechnics*, Section 2.10, 2001.

Figure 1. DEI work area outside of the A-21 magazine at Waikele Self Storage

2.0 Fireworks

2.1 Explosive Classification of Fireworks

The American Pyrotechnics Association[10] (APA) defines fireworks as "[a]ny device, other than a novelty or theatrical pyrotechnic article, intended to produce visible and/or audible effects by combustion, deflagration,[11] or detonation."[12,13] Fireworks require a source of combustible material for energy such as black powder, which acts as a lift charge to propel the device into the air. A chemical substance known as a burst charge[14] contained within the aerial shell emits brightly colored light once the firework is propelled into the air. According to industry literature, black powder is extremely sensitive to ignition from small sparks, which can be emitted from static electricity, friction, and electrical contacts, and may explode violently when ignited.[15]

The U.S. Department of Transportation (DOT) hazard classification system regulations classify fireworks as Class 1 explosives due to the hazardous nature of the chemical compositions they contain.[16] Under DOT regulations, all explosives must be formally approved for transportation and assigned an EX Number before they can be transported within the U.S.[17]

The DOT system classifies explosives into divisions 1.1 through 1.6, of which fireworks typically fall into two: 1.3 and 1.4.[18] Division 1.1 has the largest potential hazard, with each subsequent division representing a lower hazard category. Division 1.3 (1.3G[19] Display Fireworks – UN0335) "consists of explosives that have a fire hazard and either a minor blast hazard or a minor projection hazard or both, but

[10] The American Pyrotechnics Association (APA), founded in 1948, is a fireworks industry trade association whose goal is to promote safe design and use of all types of fireworks and responsible regulation of the fireworks industry. www.americanpyro.com (accessed July 14, 2012).
[11] Deflagration is a reaction in which the speed of the reaction front propagates through the unreacted mass at a speed less than the speed of sound in the unreacted medium. Crowl, Daniel A. *Understanding Explosions,* A CCPS Concept Book, 2003; p. 204.
[12] A detonation is a reaction in which the speed of the reaction front propagates through the unreacted mass at a speed greater than the speed of sound in the unreacted medium. *Ibid*.
[13] APA Standard 87-1, Section 2.7, 2001.
[14] According to APA Standard 87-1 Section 2.5, a burst charge is a "chemical composition used to break open a fireworks device after it has been propelled into the air, producing a secondary effect such as a shower of stars. Burst charge is also sometimes referred to as expelling charge or break charge…[b]urst charge for use in 1.3G fireworks is limited to black powder (potassium nitrate, sulfur, and charcoal) or similar pyrotechnic composition without metallic fuel for approval under provisions of this standard."
[15] Malitz, I. "Black Powder Manufacturing, Testing & Optimizing." *American Fireworks News* (AFN), Dingmans Ferry, PA, 2003; p. 16.
[16] 49 CFR §173.50(a) (2003).
[17] 49 CFR §173.56 (2003).
[18] 49 CFR §172.101 provides a Hazardous Materials Table that includes Identification Numbers for fireworks under each appropriate hazard classification/Division. 1.3 fireworks have the Identification Number of UN0335, and 1.4 fireworks have the identification number UN0336. Identification Numbers that start with the prefix "UN" are appropriate for both domestic and international transportation.
[19] The "G" following the explosive classification number pertains to the compatibility group of the substance. 49 CFR §173.52(a) (2011). Compatibility group "G" indicates pyrotechnic substances. 49 CFR §173.52(b) (2011).

not a mass explosion hazard."[20,21] The Bureau of Alcohol, Tobacco, Firearms and Explosives[22] (ATF) regulates 1.3G fireworks under 27 CFR Part 555, Commerce in Explosives, which subjects the fireworks to significant controls regarding storage, permitting, and marking requirements.

To be considered a 1.3G UN0335 device, an aerial shell contained within the firework cannot exceed 10 inches in diameter.[23] Otherwise, the firework would be considered a division 1.1 explosive with the ability to mass explode.[24] In addition, black powder, an explosive mixture of charcoal, sulfur, and potassium nitrate that is often a component of aerial shells and the primary explosive for the lift charge inside each firework tube, is considered to be a 1.1 explosive on its own under the DOT classification system. [25]

Division 1.4 (1.4G Consumer Fireworks – UN0336) "consists of explosives that present a minor explosion hazard."[26] The DOT rates the transportation hazard of these materials as "minimum." Because of the limited amount of pyrotechnic composition permitted in each individual piece, their explosive effects are expected to be largely confined to the package, and they are consequently exempt from regulations under 27 CFR Part 555.[27] Consumer fireworks intended for use by the general public are typically Division 1.4G UN0336 explosives.[28]

APA Standard 87-1, *Standard for Construction and Approval for Transportation of Fireworks, Novelties, and Theatrical Pyrotechnics*, provides manufacturers, importers, and distributors of fireworks and novelties with relevant information to manufacture, test, ship, and label their products in accordance with federal law and good manufacturing practices. This standard requires that aerial mine and shell devices that are classified as Division 1.4 (i.e., consist of a single heavy cardboard or paper tube attached to a base and filled with pyrotechnic composition) should not contain more than 60 grams of total chemical composition, including the lift charge, burst charge, and the visible/audible composition, and the components that create a noise should be limited to 130 mg.[29] When a device comprises multiple tubes, the total weight of all explosive or pyrotechnic components within the device cannot exceed 200 grams. Fireworks containing greater amounts of explosives are classified as either Division 1.3G UN0335 or Division 1.1G UN0333.[30]

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[20] 49 CFR §173.50(b)(3) (2003).
[21] A mass explosion is "one which affects almost the entire load instantaneously." 49 CFR §173.50 (b)(1) (2003).
[22] ATF works to protect communities from violent criminals and criminal organizations by investigating and preventing the illegal use and trafficking of firearms, the illegal use and improper storage of explosives, acts of arson and bombings, and the illegal diversion of alcohol and tobacco products. www.atf.gov (accessed November 26, 2012). ATF regulates the importation, manufacturing, dealing in, receiving, and storage of display fireworks under 27 CFR Part 555.
[23] APA Standard 87-1, Section 4.1.1, 2001
[24] *Ibid.*
[25] 49 CFR §172.101 Table (1990).
[26] 49 CFR §173.50(b)(4) (2003).
[27] 27 CFR §555.141(a)(7) (2006).
[28] Division 1.4 can be further broken down into 1.4G and 1.4S subcategories.
[29] APA Standard 87-1, Section 3.1.2.5, 2001.
[30] 49 CFR §172.101 Table (1990).

2.2 Importing Fireworks

Since the 1970s, the U.S. has greatly increased its importation of fireworks, due in part to lower labor costs overseas and increased federal regulation of fireworks manufacturing.[31] Fiscal year 2011 U.S. International Trade Commission statistics obtained and published by the APA show that 98 percent of all consumer fireworks and 75 to 80 percent of commercial display fireworks used in the U.S. are manufactured in and imported from China. Of the 440 million pounds of consumer and display fireworks consumed in the U.S. in 2010 and 2011, only approximately 1.5 percent (6.7 million pounds) was produced domestically.[32]

The importation of illegal fireworks[33] has also been rising throughout the country.[34] This increase has resulted in efforts by a network of government agencies, not-for profit organizations, and other entities to improve the quality and safety of imported fireworks through screening, inspecting, testing, seizing, and when necessary, disposal. Federal law enforcement agencies, including ATF, U.S. Customs and Border Protection[35] (CBP), and U.S. Immigration and Customs Enforcement[36] (ICE), work to prevent the illegal importation of fireworks by inspecting, seizing, and testing firework shipments at major cities and ports of entry throughout the country. To illustrate the extent of the illegal fireworks importation issue in the U.S., between October 1, 2008, and November 30, 2012, the CBP Office of Field Operations[37] conducted a total of 69 firework seizures at cities considered to be major ports of entry including Boston, Chicago, Houston, Los Angeles, Miami, New York, and San Francisco. The largest individual commercial seizure conducted by CBP during the first half of 2012 contained nearly 18 tons of fireworks.[38] In Honolulu,

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[31] Yang, Xiyun. China's Fireworks: A Trusted Import. *Washington Post,* [Online] **2007,** http://www.washingtonpost.com/wp-dyn/content/article/2007/07/03/AR2007070302188.html (accessed July 12, 2012).

[32] American Pyrotechnics Association (APA). *APA U.S. Fireworks Consumption Figures 2000-2011*. http://www.americanpyro.com/pdf/Fireworks-Consump-Figures-2000-11.pdf *(*accessed July 14, 2012).

[33] Imported fireworks may be deemed "illegal" or "contraband" under federal law if they have been imported without the requisite license or permit; if they have been mislabeled; if they have been smuggled or attempted to be smuggled into the U.S.; or if they exceed the maximum allowable explosive filler weight or charge weight, or maximum grams of explosives permitted.

[34] Yang, Xiyun. China's Fireworks: A Trusted Import. *Washington Post,* [Online] **2007,** http://www.washingtonpost.com/wp-dyn/content/article/2007/07/03/AR2007070302188.html (accessed July 12, 2012).

[35] CBP exists within the U.S. Department of Homeland Security and works to secure U.S. borders and facilitate trade to and from the U.S. www.cbp.gov (accessed November 27, 2012).

[36] ICE is the principal investigative arm of the U.S. Department of Homeland Security. Its primary mission is to "promote homeland security and public safety through the criminal and civil enforcement of federal laws governing border control, customs, trade, and immigration." www.ice.gov (accessed November 27, 2012).

[37] The CBP Office of Field Operations is "the largest component of CBP and is responsible for securing the U.S. border at ports of entry while expediting lawful trade and travel." http://www.cbp.gov/xp/cgov/about/organization/assist_comm_off/field_operations.xml (accessed December 7, 2012).

[38] "Watch Out for Illegally Imported Fireworks: CBP seizes dozens of illegal fireworks shipments on behalf of partner agencies." July 3, 2012. http://www.cbp.gov/xp/cgov/newsroom/news_releases/national/07032012.xml (accessed December 4, 2012).

Hawaii, CBP and ICE Homeland Security Investigations[39] (ICE/HSI) together have conducted nine separate fireworks seizures between 2006 and 2012, including the seizure involved in the incident.

These quantities are significant, as these fireworks pose substantial safety challenges once they are seized. Due to the unknown composition of seized fireworks and the hazards that may be involved, illegally imported and seized fireworks are typically destroyed; a major issue for all entities involved becomes how to properly and safely destroy them.

2.3 Seized Fireworks Disposal

2.3.1 History

Through the early 1980s, the standard practice in the U.S. was to use U.S. Military Explosive Ordnance Disposal[40] (EOD) technicians to dispose of fireworks confiscated by local and federal law enforcement, reflecting the military's mission to support those agencies and their work. However, the CSB learned that a July 29, 1980, explosion and fire at Fort Rosecrans in San Diego, California, that killed three EOD technicians and injured another caused the military to eliminate seized firework disposal activities.

The incident involved disposing of homemade firework "poppers" illegally imported from Mexico. EOD technicians were loading fireworks, which federal law enforcement personnel had seized and stored in plastic bags, from a holding unit onto a military truck for destruction at Fort Irwin, California, when one of the bags on the truck began to pop and fizz. As an EOD technician grabbed the bag to throw it off the truck, it exploded. Three EOD technicians moved to the back of the storage unit and shut the door to isolate themselves from the explosion and resulting fire. However, they became trapped in the unit as the rest of the fireworks within the unit were set off, and all three were killed.

The military's decision not to handle seized fireworks highlights the risk involved in storing, transporting, and disposing of contraband fireworks, because they are unpredictable and hazardous. Typically, no quality assurance controls are used in contraband fireworks manufacture. Mislabeled fireworks are by definition uncharacterized. Their unknown composition makes them dangerous to an EOD technician tasked with their disposal. Ultimately, this change shifted seized firework, storage, transportation and disposal responsibilities from EOD technicians within the military to permitted commercial entities and federal, state, and local law enforcement agencies.

[39] ICE/HSI exists within ICE and is responsible for investigating immigration crime, human rights' violations and smuggling of humans, narcotics, weapons, and other types of contraband. http://www.ice.gov/about/offices/homeland-security-investigations/ (accessed December 4, 2012).

[40] Explosive Ordnance Disposal involves the rendering safe and disposal of all hazardous items containing explosives, including bombs, grenades, and mines.

2.3.2 Present Fireworks Disposal Framework

A small number of commercial[41] treatment, storage, and disposal facilities (TSDFs) across the country have the requisite environmental permitting to accept and dispose of explosives, including commercial and consumer fireworks. These facilities utilize various methods of disposal, including incineration,[42] open burning,[43] and microbiological destruction.[44]

While these commercial facilities are available for disposal work, the CSB learned from local law enforcement agencies throughout the country that many local agencies have undertaken the task of disposing of seized fireworks themselves because contracting the work out to these facilities is too time-consuming and costly. And some state and local law enforcement agencies have had difficulty disposing of seized fireworks due in part to stringent state environmental regulations and policies that prevent them from burning the fireworks. The CSB has learned the extensive time and cost necessary to ship the fireworks elsewhere has, unfortunately, resulted in the growing accumulation of illegal consumer and display fireworks in magazines in states across the country.

2.4 Federal Government Seizure Programs

The approach federal agencies use for storing, transporting, and disposing of illegally imported and seized fireworks involves subcontracting to commercial vendors under an overarching, multi-million dollar federal seized property management contract. The U.S. has two separate and distinct federal forfeiture programs, one within the U.S. Department of Justice and one within the U.S. Department of the Treasury (Treasury).

[41] Permitted to receive third party waste.
[42] For example, General Dynamics operates a facility located in Joplin, Missouri, that contains two Resource Conservation and Recovery Act (RCRA) permitted incinerators specifically designed to incinerate explosive materials and devices. www.ebveec.com (accessed November 26, 2012). Heritage-WTI, Inc, located in East Liverpool, Ohio, is another incineration system capable of receiving 60,000 tons per year of hazardous waste. www.heritage-wti.com (accessed November 28, 2012).
[43] For example, Clean Harbors operates a RCRA permitted facility that accepts and treats over 300 kinds of explosive and reactive wastes, including consumer and commercial display fireworks. Clean Harbors practices the method of open burning, usually soaking the fireworks in diesel and burning them on concrete slabs in a large open space the size of a football field. www.cleanharbors.com (accessed November 27, 2012).
[44] Heritage Disposal and Storage (HDS) operates a 24,000 square foot recycling facility for energetic materials, including fireworks. The HDS energetic materials recycling process is a proprietary process utilizing microbiological technology to recycle propellants, energetic materials, and ammunition into agricultural use products. HDS has treated approximately 2 million pounds of explosives for U.S. Government agencies. HDS documents indicate that in 2004, the Nebraska Department of Environmental Quality (NDEQ) evaluated the HDS processes and studied the final products and determined that the HDS process meets the definition of true recycling as outlined in NDEQ Title 128, Nebraska Hazardous Waste Regulations. HDS possesses an ATF Explosive Manufacturing License and is able to modify explosive materials for either safe disposal or resale. HDS considers the energetic materials it recycles to be "Highly Hazardous Materials" and has implemented management systems for all technical operations involving ammunition and explosives in accordance with PSM goals identified in 29 CFR §1910.119 Appendix C, Compliance Guidelines and Recommendations for Process Safety Management (Nonmandatory). HDS documents indicate that no separating or disassembling of explosive components is done at this facility. www.heritagedisposalandstorage.com (accessed November 26, 2012).

The program relevant to this investigation is the Treasury Executive Office for Asset Forfeiture (TEOAF) seizure and forfeiture program. TEOAF administers the Treasury Forfeiture Fund[45] (TFF), which is the receipt account for the deposit of non-tax forfeitures made pursuant to laws enforced or administered by participating law enforcement agencies. Under this federal program, TEOAF procures general seized property management services, including storage and disposal, to support the seizure, forfeiture, and blocking programs of the Treasury and U.S. Department of Homeland Security (DHS) participating agencies.[46] Participating agencies seize a broad range of items, such as cars, horses and other livestock, handbags and jeans, perfume, and explosives (including fireworks), as well as other hazardous materials.

[45] The Treasury Forfeiture Fund was established in 1992 as the successor to the Customs Forfeiture Fund. The mission of the Treasury Forfeiture Fund is to "affirmatively influence the consistent and strategic use of asset forfeiture by participating agencies to disrupt and dismantle criminal enterprises." http://www.treasury.gov/about/organizational-structure/offices/Pages/The-Executive-Office-for-Asset-Forfeiture.aspx (accessed June 6, 2012).

[46] TFF participating agencies include the Internal Revenue Service, Criminal Investigation (IRS-CI); ICE; CBP; U.S. Secret Service (USSS); and the U.S. Coast Guard (USCG). http://www.treasury.gov/about/organizational-structure/offices/Pages/The-Executive-Office-for-Asset-Forfeiture.aspx (accessed June 6, 2012).

3.0 Pre-Incident

3.1 Federal Seized Property Management Contract

On August 1, 2006, TEOAF awarded a ten-year contract (federal prime contract) to VSE Corporation (VSE) to support its Seized and Forfeited Property Program. VSE employs roughly 2,500 individuals and provides diverse services to the government and military, including reverse engineering, supply chain management, management consulting, and process improvement.[47] VSE's responsibility under the federal prime contract was to secure services for the receipt, storage, handling, transportation, consignment, or disposal of all seized, blocked, or forfeited general property[48] through the subcontracting of vendors. Among other things, the federal prime contract required VSE, as the contractor, to ensure the safety of the public, workers, and property of others.

The ten-year federal prime contract was protested[49] and terminated by an agreement between Treasury and VSE. On September 28, 2010, TEOAF awarded VSE a seven-month interim contract[50] for the continuation of services being provided under the earlier awarded federal prime contract. This interim contract was in place at the time of the incident.

According to VSE officials, it was instrumental to the company in obtaining the federal prime and interim contracts that it had a separate subcontract with the management company Thomas E. Blanchard & Associates, Inc. (BAI). BAI utilizes a team of retired federal law enforcement personnel located throughout the U.S. who provide VSE with field services such as acceptance, transportation, and inspection of seized property, on an as-needed basis.[51] According to VSE, subcontracting with BAI enabled VSE to submit a lower-cost proposal to TEOAF that provided for national coverage without VSE incurring day-to-day expenses such as travel and per diem. Review of the subcontract shows there was no requirement that BAI make available field representatives with relevant safety experience, as their primary responsibility was tracking of inventory.

3.2 Federal Fireworks Disposal Subcontract

Between 2007 and 2010, federal law enforcement agents conducted three separate firework seizures in Honolulu, Hawaii, intercepting the fireworks during importation from China.[52] These shipments were

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[47] www.vsecorp.com (accessed June 20, 2012).
[48] The federal prime contract defined seized, blocked, or forfeited property as "seized, blocked, or forfeited tangible property that is not real property, money or investments, including aircraft; vehicles; vessels; machinery and equipment; antiques and collectables; and livestock."
[49] Pursuant to 4 CFR Part 21 (1996).
[50] The contract was later extended to one year.
[51] BAI provides field services solutions to companies and government agencies throughout the United States. http://blanchardai.com (accessed June 21, 2012).
[52] CBP seized one fireworks shipment on December 10, 2007. ICE/HSI seized one fireworks shipment on February 4, 2009, and one on January 13, 2010.

labeled as 1.4G UN0336 consumer fireworks, but the fireworks contained within the shipments had physical characteristics of more hazardous 1.3G UN0335 display fireworks (See Appendix A). The fireworks involved in the incident[53] (referred to as "primary seizure") were seized in 2010 and consisted of multi-tube devices known as cake fireworks, which are made up of individual firework tubes linked by pyrotechnic fuse. Each firework tube contains a lift charge and aerial shell (Figure 2).

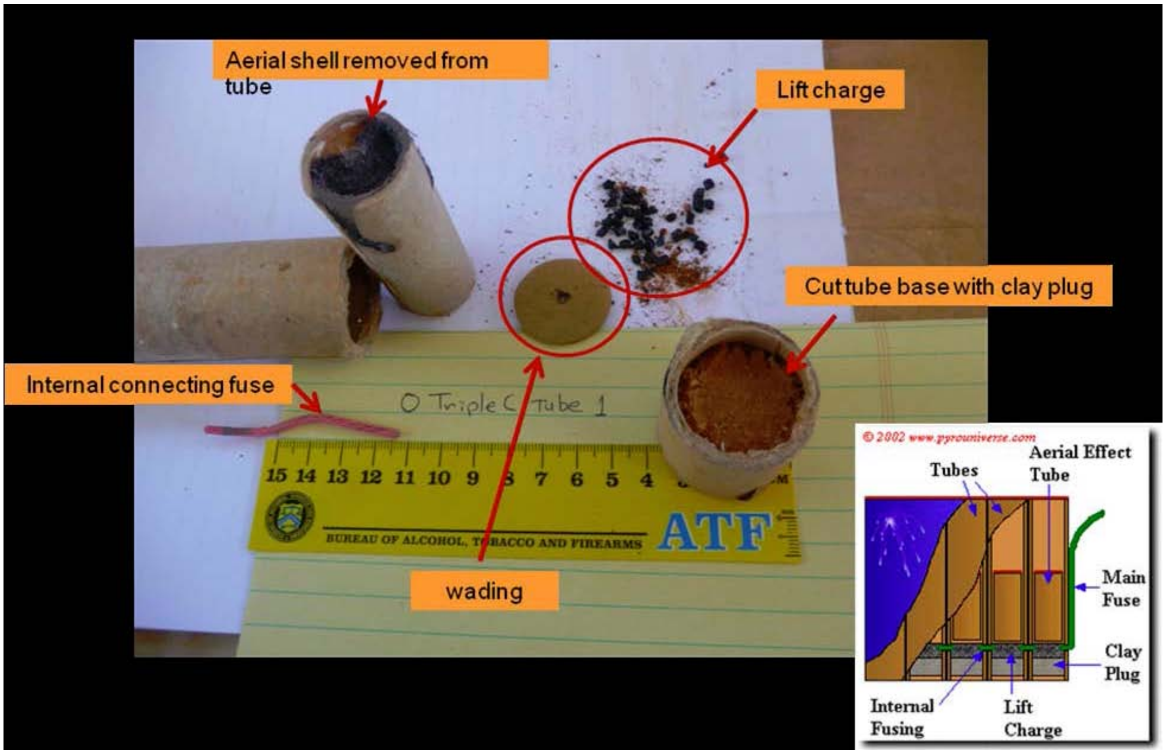

Figure 2. Cake firework tube, lift charge, and aerial shell configuration (photo courtesy of ATF)

Because CBP and ICE/HSI both participate in the Treasury Forfeiture Fund, VSE was responsible, as the prime federal contractor, for locating vendors to transport, store, and ultimately destroy the shipments when instructed to do so by the seizing agency. In March 2010 VSE awarded a subcontract to Donaldson Enterprises, Inc. (DEI) to dispose of the seized fireworks. Figure 3 shows the chain of contractual relationships relevant to this incident (Section 6.0 discusses VSE's selection and oversight of DEI).

[53] The third fireworks seizure (number 2010-3205-000-012-01) was seized on January 13, 2010. This seizure is referred to as the "primary seizure" as it contained the fireworks that resulted in the explosion on the day of the incident.

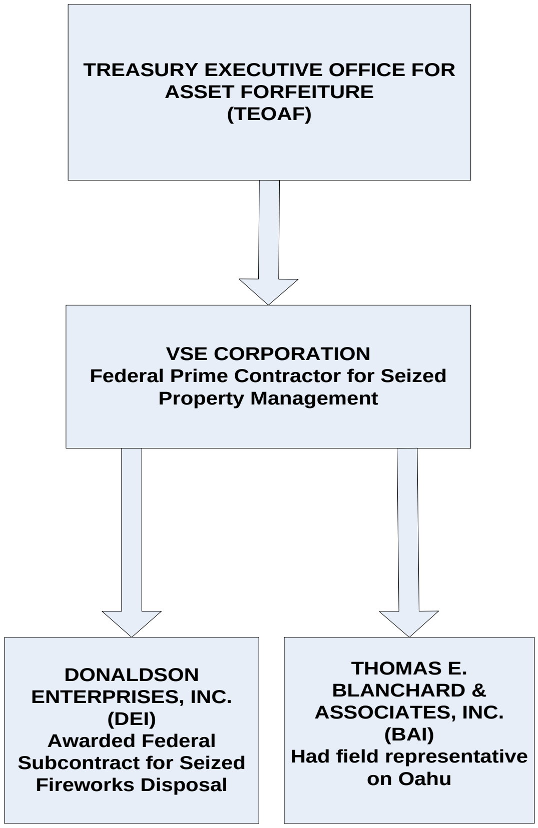

Figure 3. Contractual Relationships

3.3 Donaldson Enterprises, Inc.

DEI is a small company that was founded in 1988 and provides environmental and UXO mitigation services throughout the Pacific basin. DEI employs a staff with experience in both military and civilian UXO clearance operations. During World War II and the Vietnam War, the military used areas throughout Hawaii for live munitions training. Many of these areas have been returned to civilian use, but may still have UXO present. Individuals and companies hire DEI to determine the presence and extent of UXO in an area or at a site and provide UXO escort services.[54] When UXO is located, DEI personnel typically clear the UXO by installing explosives and remotely initiating an explosion to safely destroy the UXO. DEI also assists in the development of UXO clearance plans and provides training to

[54] "The UXO Escort is responsible for the safe escort of non-UXO qualified personnel who are not directly involved in specific UXO clearance site work, but have activities to perform within restricted/exclusion areas…the escort function involves hazard recognition and avoidance only, not the execution of UXO search or clearance actions..." http://www.dol.gov/whd/regs/compliance/wage/p29494.htm#.UN-QFm_BGSo (accessed December 29, 2012).

others in UXO identification and avoidance. Prior to being awarded the subcontract by VSE, DEI's work did not include the disposal of fireworks.

3.4 Waikele Self Storage

DEI leased magazine A-21 at Waikele Self Storage, Ltd. in Waipahu, Hawaii, to store unexploded ordnance.[55] Waikele Self Storage consists of 120 storage units cut into a solid rock hillside that were built during World War II and used by the Navy as ammunition storage bunkers. These magazines are tunnel-like structures, each approximately 250 feet long, with concrete floors, walls, and domed ceilings. Each magazine has a loading dock and ramp leading to one entrance with steel doors.

The A-21 magazine is 250 feet long, 16 feet wide, and 12 to 14 feet high. Its entrance is secured with a steel door that is 6.1 feet wide by 9.4 feet high, and split into two segments (Figure 4).

Figure 4. Magazine A-21 (and loading dock), Waipahu, Hawaii

DEI told the CSB that its personnel stored the three fireworks shipments, which consisted of boxes wrapped in plastic stacked on wood pallets, towards the rear of the magazine. DEI personnel pulled out boxes individually when they were ready to prepare the fireworks for disposal.

[55] According to the lease for the A-21 magazine, it appeared that the storage of fireworks was also permitted. While the lease contained boilerplate language prohibiting the storage of explosives and fireworks, this language had been struck through on the executed contract.

3.5 DEI Initial Fireworks Disposal Activities

DEI began its fireworks disposal work on the initial seized fireworks shipment[56] (initial seizure) in summer 2010. According to DEI's Standard Operating Procedure (SOP), its disposal process involved soaking individual whole firework tubes that had been separated from the cake in diesel-filled 55-gallon steel drums located within the magazine for a minimum of 24 to 48 hours, removing the fireworks from the diesel soaking drum, and transporting the diesel soaked fireworks to the Koko Head firing range (Koko Head) to burn the fireworks in a drum or in DEI's portable incinerator (a Thermal Flash Unit (TFU)). Diesel is sometimes used to soak and burn fireworks because it desensitizes the material to spark, friction, impact, and temperature and should result in a slow burn rather than an explosion.

As Section 7.0 discusses, seized fireworks are considered hazardous waste under the Resource Conservation and Recovery Act (RCRA) and, as such, require a RCRA permit for treatment and disposal. DEI notified the State of Hawaii Department of Health (DOH), Hawaii's state environmental agency responsible for implementing and enforcing federal environmental regulations, of its intended burn operations at Koko Head via letter in May 2010. On June 8, 2010, DOH issued DEI a 90-day Emergency Hazardous Waste Permit[57] authorizing DEI personnel to "conduct specific hazardous waste management activities at a designated site at Koko Head Range and proper storage of the waste fireworks."

According to DOH, the actions authorized in the permit were based on information DEI provided when it requested the permit, and DEI's activities were limited to those the permit authorized. The permit stated that DEI would dispose of approximately 5,000 pounds of confiscated class "C" type[58] illegal fireworks by thermal treatment, using empty 55-gallon containers or a mobile incinerator, at Koko Head. The permit expired 90 days after it was issued. Upon conclusion of the permitted activities, DEI was required to provide a closure report to the DOH Solid and Hazardous Waste Branch and the RCRA Facilities Management Office at EPA Region IX in San Francisco, California. The permit did not discuss diesel soaking or fireworks disassembly.

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[56] The initial seizure (number 2008-3201-000-013-01) was seized on December 10, 2007, and consisted of 11 pallets of fireworks and included "Maylar Tubes," "Assortment Shells," and "Singing Oriole/Dancing Swallows."
[57] DOH has the authority under 40 CFR §270.61 and Hawaii Administrative Rules (HAR) §11-270-61 to issue temporary emergency permits to non-RCRA permitted, and RCRA permitted, persons or facilities seeking to engage in hazardous waste treatment, storage, or disposal activities where there is an "imminent and substantial endangerment to human health or the environment." The burden is on the applicant to prove that such an imminent threat exists.
[58] 1.4G fireworks were classified as "Type C" fireworks prior to 1991. 1.3G fireworks were previously classified as "Type B." 49 CFR §173.53 (2001).

3.6 Modifications to the Fireworks Disposal Process

3.6.1 Initial Modification

DEI management later told the CSB that during the disposal of the initial seizure, some of the fireworks were exploding during burning operations, even after the diesel soaking time had been increased to one week. DEI believed this was due to inadequate diesel permeation of the aerial shells contained in these fireworks. To resolve this issue, DEI personnel used blades to disassemble the fireworks by cutting open the individual firework tubes by hand and taking apart their explosive components (the aerial shells and black powder lift charge) (Figures 5 and 6). They then cut a one-inch slit into each aerial shell (Figure 7), soaked the aerial shells in diesel-filled drums (Figures 8 and 9), and burned them at Koko Head (Figures 10 and 11). The black powder lift charge from the tubes was collected in plastic containers lined with plastic garbage bags.

DEI completed its disposal of the initial seizure in December 2010. However, it did not dispose of the black powder lift charge collected from the disassembly work. The powder was being stored in containers in the back of the magazine at the time of the incident.[59]

Figure 5. Photo of DEI personnel disassembling initial fireworks seizure in 2010

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[59] DEI completed its disposal work on the initial seizure in December 2010. The DOH 90-day Emergency Hazardous Waste Permit expired on September 5, 2010, and was not renewed. As discussed in Section 7.3.2, the CSB determined that DEI's failure to renew the Emergency Hazardous Waste Permit for its fireworks disposal activities was not causal to the incident.

Figure 6. Fireworks cake being disassembled

Figure 7. Slit aerial shell from DEI's first destruction

Figure 8. 55 gallon steel drum and inner liner used for diesel soaking

Figure 9. Aerial shells removed from the firework tubes and placed in an inner liner for diesel soaking

Figure 10. Fireworks burning in incinerator (TFU)

Figure 11. Fireworks burning in drums

3.6.2 Second Modification

DEI began work on its second disposal job under the subcontract in December 2010 and in early 2011 again altered its fireworks disposal process. According to an email from DEI management to VSE, this modification was designed to increase the destruction rate of the third shipment of seized fireworks (later referred to as the "primary seizure," as this was the seizure involved in the incident). To maximize the quantity of explosives that could be burned at one time, DEI personnel again disassembled the fireworks by cutting open individual firework tubes by hand and separating the individual explosive firework components, black powder lift charge and aerial shells, into cardboard boxes. The boxes containing black powder were lined with plastic garbage bags to minimize leakage.

More precisely, DEI took three boxes of fireworks at a time out of the magazine and broke them down into three boxes of firework components: one box, lined with a plastic garbage bag, contained the black powder lift charge; one box contained the accumulated aerial shells; and one box contained the cardboard tubes and packaging material. Periodically, the plastic bags containing black powder were relocated from the cardboard boxes into plastic containers and were stored towards the middle of the magazine.

DEI's plan was to soak the aerial shells in diesel in the steel drums and burn them; however, the company had no plan to dispose of the accumulated black powder.

3.7 Morning of the Incident

On April 8, 2011, at approximately 7:15 am, a team of six DEI personnel (a project supervisor, four UXO Level I Technicians,[60] and one general laborer) arrived at the magazine to begin their disassembly work for the day. They prepared their outside work area by setting up a pop-up tent, table, and chairs on the magazine loading dock located directly in front of the magazine entrance.

According to witness testimony, DEI personnel previously stacked fifteen remaining boxes of whole one-inch firework tubes from the primary seizure in the front left corner of the magazine (Figure 14). Each box contained 152 one-inch Sky Festival tubes that had been separated from a cake (Figure 12).[61] DEI

[60] A UXO Level I Technician (UXO Tech I) has successfully completed 200 hours of training on Munitions and Explosives of Concern (MEC) and Material Potentially Presenting an Explosive Hazard (MPPEH), and 40 hours of Hazardous Waste Operations and Emergency Response (HAZWOPER). A UXO Technician is qualified for and fills a Department of Labor, Service Contract Act, Directory of Occupations contractor position of UXO Technician I, II, and III. See the Department of Defense Explosives Safety Board (DDESB). *Minimum Qualifications for Unexploded Ordnance (UXO) Technicians and Personnel*; Technical Paper (TP) 18, Section 3.1.1, 2004; this paper provides the minimum qualification standards for personnel conducting UXO-related operations in support of the Department of Defense. According to the DDESB, a UXO Tech I may not handle or transport UXO or discarded military munitions, including military pyrotechnic items, without the direction and supervision of UXO-qualified personnel, which include UXO Tech IIs, UXO Tech IIIs, UXO Safety Officers, UXO Quality Control Specialists, and Senior UXO Supervisors. *Ibid* at Section C2.1.2, 2004.

[61] ATF evaluated the Sky Festival fireworks as part of the seizure enforcement process. Each of the 96 seized boxes of contraband Sky Festival fireworks contained 4 individual cakes containing 156 firework tubes, or shots. An individual cake contained 150 small tubes, and 6 large tubes. ATF kept one box to sample and test for evidence purposes, leaving 95 boxes. DEI removed all of the tubes from the cakes and boxed the 2,280 large tubes and

personnel initially transferred three boxes of whole firework tubes to the outside working area. They then began their normal disassembly process: two UXO technicians cut the tubes using a PVC cutter or knife, while the project supervisor and the two additional technicians broke the tubes apart and separated the internal explosive components into one of the three cardboard boxes.

The general laborer remained inside the magazine during this work, performing cleaning and organizing tasks. When the DEI personnel were finished disassembling and separating this first round of firework tubes, they then pulled out three more boxes of whole firework tubes and took them to the outside work area to disassemble.

Figure 12. Sky Festival cake firework (from the primary seizure) contains 150 small tubes and 6 large tubes; large tubes located on the right side of the box were being disassembled on the day of the incident.

The team was able to disassemble six to seven boxes of fireworks before 8:30 am when according to the project supervisor, it began to rain heavily. The team stopped work and used a metal hand truck to move the boxes containing black powder, aerial shells, and partially disassembled tubes, and stack them just

57,000 small tubes separately. DEI determined that individual disassembly of the small tubes to remove the explosive components did not offer a sufficient advantage during the diesel soaking and burning process, so these tubes were not disassembled, and remained intact. According to witness statements, this resulted in 15 boxes of large tubes. According to CSB calculations, each box contained 152 large Sky Festival tubes.

inside the magazine entrance. They also brought in the table, camp chairs, and a rolling office chair, leaving the pop-up tent outside on the dock. Figures 13 and 14 show the approximate location of materials within the magazine just prior to the incident. This information is based on witness statements to the CSB.

While the team of personnel remained inside the magazine, the project supervisor left and got his phone from his truck, which was parked in front of the magazine dock. He then walked to the front left corner of the magazine dock to make a phone call. While he was on the phone, a large explosion occurred inside the magazine and a fire ensued, fatally injuring all five DEI personnel who were located inside the magazine at the time of the incident. Only one of those five was able to escape the magazine during the event, and he succumbed to his burn injuries later that day.

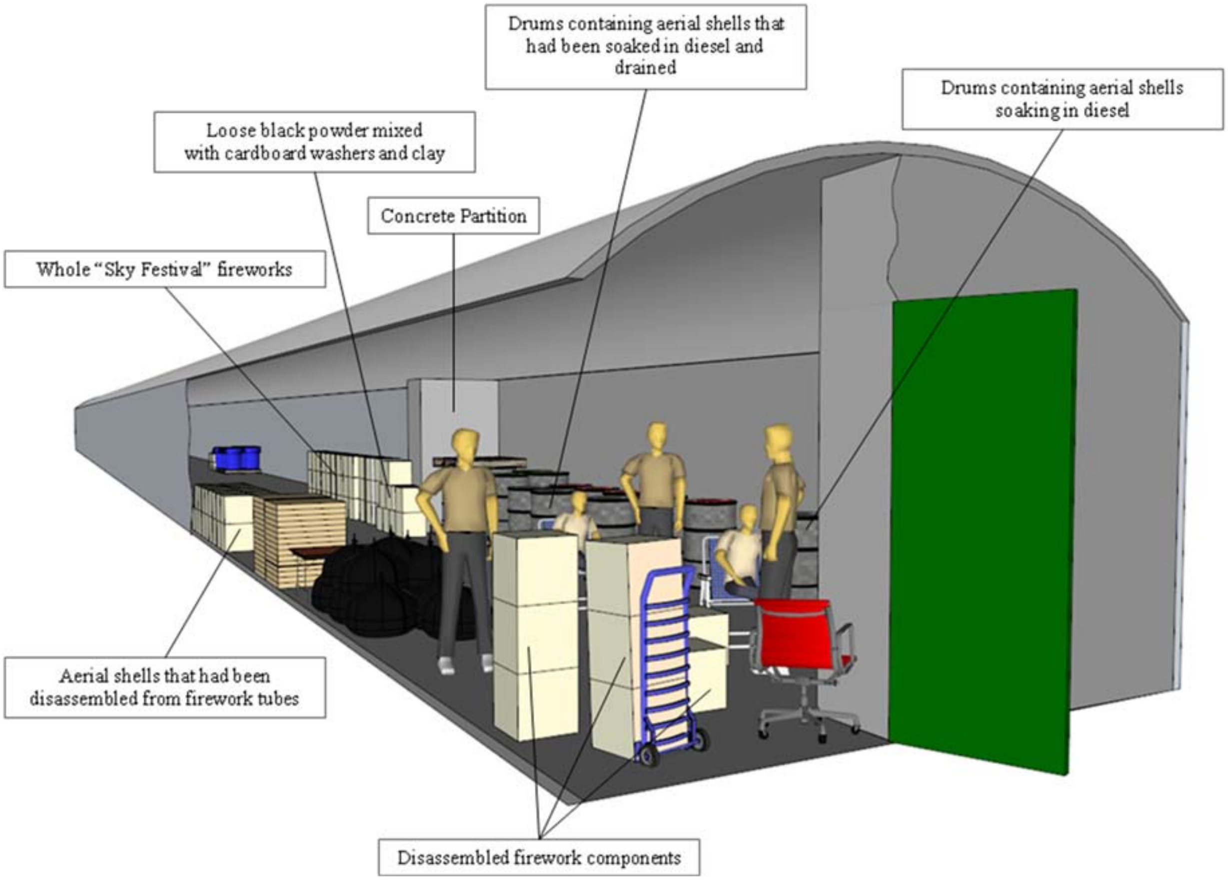

Figure 13. Magazine layout at the time of the incident

Figure 14. Side aerial view of magazine at the time of the incident

4.0 Technical Analysis

The CSB investigation team arrived at the incident scene the morning of April 11, 2011. The team interviewed DEI personnel, examined the incident scene and physical evidence, and collected and reviewed relevant documentation.

Investigation activity was coordinated with a number of other organizations:

- ATF
- Hawaii Occupational Safety and Health Division (HIOSH)
- U.S. Occupational Safety and Health Administration (OSHA)
- Honolulu Police Department (HPD)
- Honolulu Fire Department (HFD)

4.1 Site Inspection and Evaluation

Following an examination of the incident scene, the CSB determined the explosion was a deflagration that originated inside the magazine near the entrance. Damage indicators included chipping and scorching of the magazine walls, burned 55-gallon drums, and scorching on the lower portions of the ventilation duct within the magazine near the entrance. The other side of the concrete partition located in the middle portion of the magazine sustained little to no damage and the ventilation duct toward the rear had minimal marking. The very rear of the magazine still contained fully intact fireworks, with slight melting of the plastic wrapping (Figures 15 through 18).

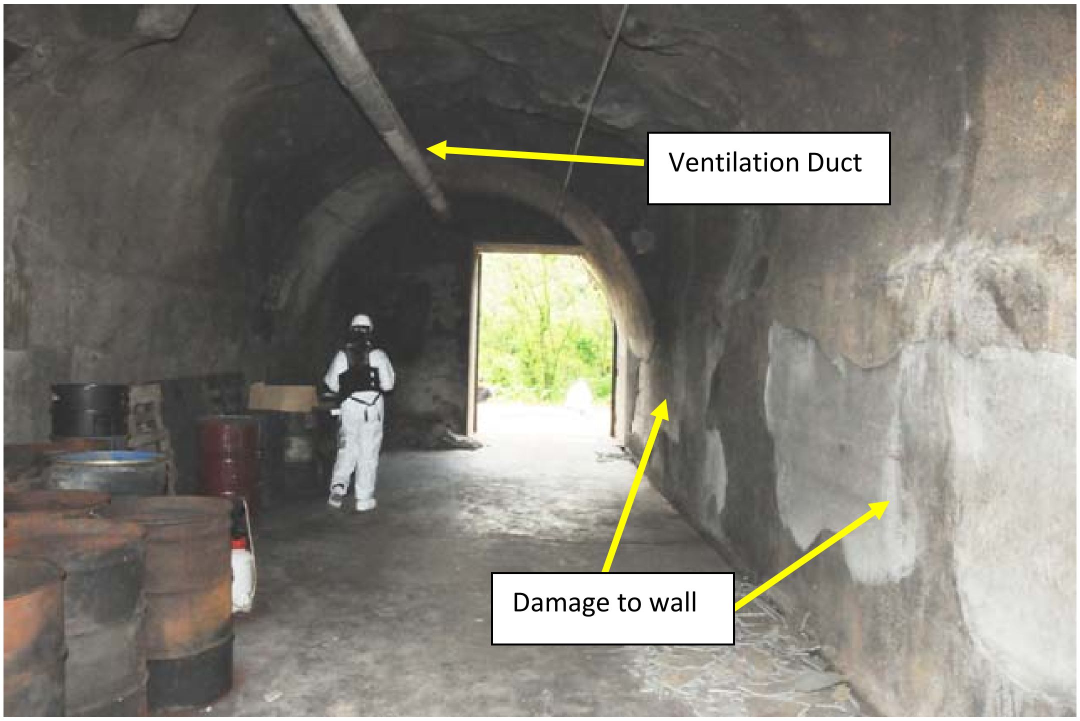

Figure 15. Damage to the magazine wall

Figure 16. Interior of the magazine post-incident

Figure 17. Rear interior of magazine, behind concrete partition, post-incident

Figure 18. 2009 Seizure (second seizure) at rear of magazine, relatively undamaged with some melting of the plastic wrapping following the explosion and fire near the front of the magazine.

The steel hand truck (Figure 19) used to move the boxes in and out of the magazine was propelled more than 100 feet from the magazine door into vegetation located across a road in front of the magazine. The rolling office chair was found in the same area near a stream (Figure 20). The GMC Sierra truck, parked approximately 30 feet in front of the magazine entryway, was forced away from the magazine, its rear cab rotated approximately 10 feet away from its original position (Figure 21). The CSB was told that the truck was not running at the time of the incident.

Figure 19. Steel hand truck found in vegetation (courtesy of Honolulu Fire Department)

Figure 20. Rolling office chair found blown out of the magazine

Figure 21. Prior to incident, this GMC truck was parked just in front of the silver car. The force of the explosion moved the rear of the truck to the right as indicated by the arrow.

4.2 Disassembly Activities

CSB analysis of DEI's activities on the day of the incident indicates that the act of disassembling the Sky Festival firework tubes from the primary seizure and separating out the explosive components into boxes increased the mass of explosive materials within a single container by a factor of 456.[62]

Type of Firework	Mass of lift charge per individual firework tube (grams)	Mass of aerial shell explosives per individual firework tube (grams)	Mass of lift charge DEI accumulated in a single container (grams)	Mass of aerial shell explosives DEI accumulated in a single container (grams)	Scale-Up Factor
Sky Festival Fireworks disassembled by DEI on the Day of the Incident	3.3	4.7	1,505	2,143	456

Table 1. DEI disassembly process on the day of the incident increased the mass of explosives within a container by a factor of 456.

DEI decided to disassemble these larger tubes in order to remove the black powder lift charges and aerial shells. As Table 1 shows, DEI's disassembly activities, which accumulated large quantities of black powder (a 1.1 explosive on its own)[63] and aerial shells into boxes, greatly increased the risk to DEI personnel working that day by creating the potential for a mass explosion.

[62] Factor/Scale-up Factor calculation is based on starting with the amount of explosives in a single large tube from the Sky Festival cake fireworks after DEI workers separated the large tubes from the original cake. ATF determined that each large tube contained approximately 3.3 grams of black powder lift charge and 4.7 grams of a perchlorate explosive pyrotechnic mixture in the aerial shell. The disassembly process had evolved over time, and on the day of the incident was such that 3 boxes of fireworks were removed from the magazine and taken out to the loading dock. The three boxes contained a calculated total of 456 large firework tubes. When DEI personnel disassembled these fireworks, they accumulated all of the black powder lift charge in one box; all of the aerial shells in a second box; and the remaining non-explosive materials in a third box. The CSB calculated that the box of accumulated black powder lift charges contained 1,505 grams of black powder and the box of accumulated aerial shells contained 2,143 grams of explosive pyrotechnics, which was 456 times more than a single large tube from the 1.3(G) contraband Sky Festival fireworks contained.

[63] The table located in 49 CFR §172.101 states that 1.1 explosives have the ability to mass explode.

4.3 Testing

4.3.1 ATF Testing of Firework Samples

On January 16, 2010, ATF officials conducted a detailed examination of four samples[64] collected from the primary seizure (Appendix A). ATF concluded from its analysis that the amount of pyrotechnic material contained within all four samples exceeded the allowable quantities for a 1.4G UN0336 consumer firework. Laboratory analysis of the explosive components from the larger Sky Festival tubes being disassembled on the day of the incident identified the lift charge as black powder and the burst charge (contained within the aerial shells) as a perchlorate explosive mixture.

4.3.2 CSB Testing of Firework Samples

Physical testing of samples from the four types of fireworks contained in the primary seizure, including the Sky Festivals, is being performed to identify the likely means of accidental ignition of the fireworks. The results of this testing were not completed at the time this report was issued; the results will be published on www.csb.gov when available.

Composition testing, conducted to determine which chemical components most likely contributed to the energetic properties of the fireworks and whether any chemicals were added to the fireworks to make them particularly energetic, had not yet been performed at the time of this report's release. The results will be published on www.csb.gov when available.

4.3.3 HIOSH Testing of Tools

National Fire Protection Association (NFPA) good practice industry standards and ATF explosive regulations recognize the importance of minimizing ignition sources near explosives. For example, NFPA 1124, *Code for the Manufacture, Transportation, Storage, and Retail Sales of Fireworks and Pyrotechnics Articles* states that "[m]etal tools other than nonferrous conveyors shall not be stored in magazines."[65]

Post-incident, HIOSH collected 12 separate tools found inside the magazine near the entrance: three cutting tools, pruning shears, a shovel/dust pan, loppers,[66] a push broom, a pair of miter saws, scissors, tin snips, and a battery-powered diesel pump. Metallurgical testing was conducted to determine if the tools were sparking and thus likely capable of initiating an explosion within the magazine.

[64] The four sampled fireworks were taken from the following: a. O Triple C 8/1; b. HALAWA 8/1; c. Sky Festival 4/1; and d. Krazy Kids 8/1.
[65] National Fire Protection (NFPA) 1124. *Code for the Manufacture, Transportation, Storage, and Retail Sales of Fireworks and Pyrotechnic Articles,* Section 5.4.8.1, 2006.
[66] A "lopper" is a pruning shear with long handles.

Two tests were performed on each of the 12 tools. The first test identified what metal components were made of steel and the type of steel in each component. The second test demonstrated whether the tools' steel components were "spark resistant." A spark-resistant wrench was used as the control. Each tool was applied to a grinding wheel to produce particles of the material being tested; these particles were then directed towards a flammable material to determine if they could be an ignition source. In every case except one (the non-ferrous dust pan), when the metal tested on these tools emitted visible sparks, the flammable material caught fire. The conclusion was that each of the tools, other than the non-ferrous dustpan, was capable of producing a spark, and therefore being an ignition source within the magazine.[67]

4.4 Conclusions on Ignition

ATF concluded in its investigative report on the incident that the explosion was likely triggered when loose explosive pyrotechnic powder, initially generated as the fireworks were disassembled outside, spilled or leaked from the boxes onto the storage magazine floor and was ignited due to friction or a metal-to-metal spark as DEI employees moved materials around inside the magazine. ATF concluded that the ignition likely propagated to one or more of the boxes of the accumulated explosives located near the magazine entrance, resulting in a large explosion.

CSB explosion analysis concurred with ATF's conclusion. The CSB adds that the ignition of the explosive powder could have resulted from any of the following uncontrolled ignition sources: sparks generated by the movement of the metal hand truck (either by knocking it over or dragging the metal lip on the floor); dropping or knocking over a removable steel drum lid onto the floor; or friction from the office chair rolling over explosive pyrotechnic powder.

While less likely, static electricity from the plastic garbage bags used as liners for the cardboard boxes could have also caused the ignition. Ordinary plastic garbage bags are sometimes charged with static electricity as part of the manufacturing process in order for the bags to be tightly folded; as such, they are not appropriate for storing explosives.[68] At the site, ATF investigators used special anti-static plastic bags to contain explosive components they collected as evidence (Figure 22).

[67] OSHA. *Report on Donaldson Enterprises, Inc.;* April 9, 2012.
[68] National Aeronautics and Space Administration (NASA). *Safety Standard for Explosives, Propellants, and Pyrotechnics;* NSS 1740.12, Section 525(b)(2)(b), 1993.

Figure 22. Left photo (courtesy of ATF) shows anti-static bag used by ATF post-incident; right photo shows a roll of plastic garbage bags found following the incident.

While the CSB cannot definitively identify the source of ignition that led to the explosion, the physical evidence shows that the explosion initiated a rapid reaction, consuming significant quantities of explosive firework components, cardboard tubes, and boxes that had been accumulated within the magazine near its only entrance and exit, and prevented escape by a majority of the DEI workers who were inside the magazine at the time of the incident.

5.0 Incident Analysis

The CSB analyzed DEI's firework disposal activities and its Standard Operating Procedure (SOP), an "evergreen"[69] document which contained an "Activity Hazard Analysis" created by DEI management, and determined that DEI would have greatly benefitted from Process Safety Management (PSM) principles and concepts of inherent safety.[70] For instance, rather than minimizing and controlling the amount of hazardous materials present, the DEI fireworks disassembly process increased and concentrated the hazard by removing explosive components from within individual firework cardboard containers and accumulating large quantities of these explosives in boxes. This process greatly compounded the total amount of explosive energy within each box, creating the conditions that allowed for the mass explosion.

5.1 Process Safety Management Standard

OSHA provides at 29 CFR §1910.109(k)(3) that the manufacture of pyrotechnics must meet the requirements of 29 CFR §1910.119, also known as OSHA's PSM standard. The preamble states that "OSHA remains convinced that the hazards associated with the manufacture of explosives and pyrotechnics have the potential of resulting in a catastrophic incident, and pose a significant risk to employees and that the manufacture of explosives and pyrotechnics should be covered by the provisions of the final process safety management rule."[71] Appendix A of the PSM standard lists toxic and reactive highly hazardous chemicals that present a potential for a catastrophic event at or above the threshold quantity. However, OSHA considers explosives and blasting agents to be so hazardous that they have no minimum threshold quantity to trigger the requirements of the PSM standard.

Despite the recognized hazardous nature of fireworks and explosives, a February 4, 1998, OSHA "Letter of Interpretation" narrows OSHA's jurisdiction over those materials and defines the manufacture of explosives to mean the "mixing, blending, extruding, synthesizing, assembling, disassembling and other activities involved in the making of a chemical compound, mixture or device which is intended to explode,"[72] an interpretation further promulgated by the Hawaii Occupational Safety and Health Division (HIOSH), part of the Department of Labor and Industrial Relations (DLIR). Following the DEI incident, HIOSH evaluated DEI's disposal process and determined it would not fall under the standard because DEI's disassembly work was done under the umbrella of fireworks disposal rather than manufacturing.

Had PSM been applicable to DEI's fireworks disposal process, DEI would have been required to conduct a formal Process Hazard Analysis (PHA) on its disassembly procedure that explicitly identified a) the

[69] An evergreen document is a document that is updated on an ongoing basis to reflect changes to a system or procedure.
[70] Inherent Safety is a "concept, an approach to safety that focuses on eliminating or reducing the hazards associated with a set of conditions." Center for Chemical Process Safety (CCPS). *Inherently Safer Chemical Processes: A Life Cycle Approach;* 2nd ed., 2009; p.11.
[71] Preamble to 29 CFR Part 1910. Section 3 – III. Summary and Explanation of the Final Rule (1992).
[72] OSHA Letter of Interpretation. *Applicability of PSM Standard to Explosive and Pyrotechnic Manufacturing,* February 4, 1998.

hazards of the disassembly process; b) any previous incidents involving DEI that had a likely potential for a catastrophic consequence in the workplace; c) engineering and administrative controls applicable to the hazards; d) consequences of the failure of these controls; e) justification and risk assessment associated with facility siting; and f) a human factors analysis of the proposed process.[73] DEI would have also been required to conduct a formal management of change (MOC) analysis of its proposed disposal methodology before changes were made, to identify and control hazards introduced by the change.[74]

5.1.1 Process Hazard Analysis

According to the PSM standard, a PHA is conducted to "identify, evaluate, and control the hazards involved" in a process associated with highly hazardous chemicals.[75] DEI's Corporate Health and Safety Plan required DEI's Quality Control Manager (QCM) and Corporate Health and Safety Program Manager (HSPM) to analyze and control risks associated with DEI activities by identifying explicit risks associated with specific and implied tasks, determining the hazards causing these risks and the magnitude of risks, making risk acceptance decisions by balancing risk benefits against risk assessments, eliminating unnecessary risks, integrating specific controls into plans, and training and enforcing controls and standards. As such, upon developing its original fireworks disposal plan pursuant to the fireworks disposal subcontract, DEI management personnel produced an SOP that contained a two-page "Activity Hazard Analysis" to evaluate its fireworks disposal activities. The Activity Hazard Analysis, however, did not robustly identify hazards associated with the disassembly process and was not evaluated by outside entities such as VSE, or DOH during the permitting process. Furthermore, safeguards DEI management listed to mitigate identified hazards, such as flame-retardant clothing and non-sparking tools, were not implemented, as evidenced by the HIOSH testing of the tools found within the magazine and physical evidence indicating workers were not wearing personal protective equipment (PPE) at the time of the incident.

5.1.1.1 Process Safety Information

To conduct a thorough PHA, DEI personnel would have had to compile certain process safety information to help identify and understand the hazards of their disposal process. Safety information critical to the DEI process would include thermal and chemical stability as well as physical, toxicity, and reactivity data. None of these data were available to DEI workers, however, because these fireworks were brought into the country as contraband, and there were no company, contractual, or regulatory requirements to obtain the data prior to initiating disposal operations. Because contraband fireworks are generally uncharacterized, a better safety approach would have been to assume that they were extremely energetic and highly sensitive to potential ignition and to develop procedures and protocols to dispose of them as if they were at the highest level of potential hazard. This is consistent with the approach OSHA requires for

[73] 29 CFR §1910.119(e) (2002).
[74] 29 CFR §1910.119(l) (2002).
[75] 29 CFR §1910.119(e) (2002).

Hazardous Waste and Emergency Response, where workers who may need to enter an insufficiently characterized environment must prepare as though it presented the highest level of potential hazard, such as wearing a very high level of personal protective equipment (PPE).[76]

5.1.1.2 Identifying, Evaluating, and Controlling Hazards

The Activity Hazard Analysis in place at the time of the incident[77] identified five operations being performed by DEI personnel while conducting fireworks disposal activities:

1. Separating and cutting fireworks
2. Establishing SOPs to desensitize fireworks to prepare for their destruction by burning
3. Destroying fireworks by burning
4. Standing in front of the TFU, and
5. Standing near the TFU

The Activity Hazard Analysis identified heat, shock, and friction as possible hazards of separating and cutting fireworks that could lead to fire, severe burns, detonation, or death. The recommended controls for these activities were to use non-sparking tools, refrain from dragging boxes of fireworks across cement, and prepare fireworks outside the magazine; however, wearing the proper PPE such as flame resistant clothing was not listed. DEI personnel allowed sparking tools, steel drums, a steel hand truck, and a rolling office chair inside the magazine, hazards that could have been eliminated if tools and other items manufactured with non-spark-producing materials had been used.

The Activity Hazard Analysis also did not identify hazards of separating explosive firework components that are sensitive to shock, friction, and static, such as black powder, and accumulating them in large quantities, creating a mass explosion hazard. No safety analysis was done that focused on minimizing the amount of hazardous material that was being accumulated during the disposal process, nor did the analysis identify or evaluate hazards stemming from the use of regular plastic garbage bags to store black powder rather than utilizing anti-static bags.

To prevent possible injury or exposure to fumes from the TFU during burn operations, the Activity Hazard Analysis instructed DEI personnel not to stand downwind of the TFU and to wear proper PPE, but specific PPE requirements were not given. DEI's Corporate Health and Safety Plan states that PPE must be worn when work activities involve known or suspected atmospheric contamination; when vapors, gases, or airborne particulate matter may be generated; or when direct contact with skin-affecting substances may occur. Records show that DEI purchased rubber gloves, face shields, eye protection, and fire-retardant clothing for its personnel conducting the disposal work. But on the day of the incident,

[76] 29 CFR §1910.120 (C)(5)(iii) (2012).
[77] DEI developed an initial hazard analysis in 2010 prior to disposal of the initial seizure; it was updated on an unknown date prior to the incident to include separating and cutting the fireworks as operations being conducted, and heat, shock, and friction as hazards of this operation, that could result in death.

workers wore only ordinary street clothes, including cotton shorts and t-shirts, which are not flame resistant.

The magazine had only one means of ingress and egress. Yet DEI work practices allowed for explosive and combustible materials to effectively block this exit. The only life-saving provision afforded DEI workers who might be trapped inside the magazine were three small portable fire extinguishers attached to the magazine wall: one near the entrance, one towards the middle of the magazine, and one in the rear. No provision for emergency breathing air or fire protection clothing was provided. The only worker able to escape from the magazine after the explosion exited with his clothing in flames, and he sustained fatal burn injuries. Two workers succumbed to carbon monoxide poisoning inside the magazine. Had the proper PPE and emergency provisions such as breathing air been available and used, the severity of the injuries might have been reduced and lives could have been saved.

5.1.2 Management of Change (MOC) Review

Under PSM, proposed changes to a process must be analyzed to determine their technical basis, required authorizations, and impact on health and safety.[78] As DEI activities were not covered under PSM, DEI altered its original fireworks disposal process twice without conducting an MOC-type review. The CSB has found no evidence suggesting that DEI conducted a detailed analysis of the risks associated with disassembling the fireworks and creating the potential for a mass explosion by accumulating explosive fireworks components.

5.2 Principles of Inherent Safety

Inherent safety focuses on eliminating or reducing hazards associated with a process. That is, a process can be made inherently safer by eliminating or reducing the hazards associated with materials and operations.[79] The four principles of inherent safety are to minimize, substitute, moderate, and simplify.[80] To minimize is to reduce the quantity of material or energy contained in a process.[81] However, rather than minimize hazards, DEI's fireworks disposal process increased the quantity of hazardous energy and created the potential for a mass explosion when explosive components were removed from individual firework tubes, concentrated in a box, and allowed to accumulate.

One approach to minimizing hazards that DEI could have used would have been to immediately soak the aerial shells in diesel as each firework tube was disassembled. If a process to effectively destroy the black powder lift charge as each tube was disassembled was not feasible, DEI should have developed an alternative disposal process that did not require the disassembly of the individual firework tubes.

[78] 29 CFR §1910.119(l) (2012).
[79] Center for Chemical Process Safety (CCPS). *Inherently Safer Chemical Processes: A Life Cycle Approach;* 2nd ed., 2009; p.11.
[80] *Ibid* at 29.
[81] *Ibid* at 30.

5.3 Relevant Training and Experience

DEI's main practice as a company was to conduct UXO identification and clearance activities through remote ignition (Section 3.3). While the company did employ individuals with military explosives backgrounds, many of whom held management-type positions, this experience was not sufficient to safely handle or disassemble contraband commercial display fireworks.

5.3.1 DEI Management

DEI's firework disposal team included a project manager, a senior supervisor, a site safety and health officer (SSHO), and a project supervisor. This team collaborated to develop DEI's fireworks disposal methodology and the SOP, which included the two-page Activity Hazard Analysis (Section 5.1.1.2). The DEI project manager was responsible for communicating with VSE, executing all instructions, managing all aspects of the project, overseeing the overall performance of those on the project team, coordinating all contract and subcontract work, and resolving any problems. The senior supervisor planned, coordinated, and supervised all operations, and communicated on a regular basis with VSE personnel. The SSHO implemented the overall safety program during the project and was responsible for implementing all Accident Prevention Plan and onsite training requirements, and changes to the level of PPE as site conditions warranted. The project supervisor oversaw the lower-level UXO technicians employed by DEI, performed on-site activities (such as fireworks disassembly), and maintained control of team and daily activities. DEI personnel involved in the fireworks disposal activities under the fireworks disposal subcontract lacked the requisite training and experience needed to safely identify and control the hazards of this type of hazardous work.

5.3.2 Experience

DEI management told the CSB that DEI personnel had significant experience dealing with explosives from their time served in the military as EOD technicians; however, there is no evidence that this experience pertained to disposing of commercial fireworks. As discussed in Section 2.0, military EOD policy does not support military EODs handling contraband commercial fireworks.

5.3.3 Training

The DEI Corporate Health and Safety Plan required that all DEI field personnel undergo the initial 40-hour "Hazardous Waste Operations and Emergency Response" (HAZWOPER) course prior to participating in field activities. This training covers medical surveillance requirements; safety, health, and other hazards present on the site; selection and use of appropriate PPE; work practices to minimize risks from potential hazards; and the safe use of test equipment and engineering controls.[82] In addition, all DEI managers and supervisors were required to have at least eight extra hours of specialized OSHA supervisor training prior to job assignment.

Four of the six DEI personnel involved in the incident were certified UXO Level I Technicians and received their UXO training[83] and credentials from commercial schools in Hawaii and Texas; however, this training does not provide information on commercial fireworks or disassembly activities. In addition, according to the Department of Defense Explosives Safety Board (DDESB), a UXO Level I Technician may not handle or transport UXO or discarded military munitions, including pyrotechnics, without the direction and supervision of UXO-qualified personnel.[84] UXO-qualified personnel include UXO Level II Technicians, UXO Level III Technicians, UXO Safety Officers, UXO Quality Control Specialists or Senior UXO Supervisors.[85] The four UXO Level I Technicians involved in the incident had not been adequately trained to handle and dispose of commercial contraband fireworks, and required direction and supervision at the magazine from the project supervisor to conduct the disposal work.

The CSB's interviews with DEI management, and analysis of DEI's disposal process and hazard analysis show that despite their military EOD experience, these individuals were not experienced or adequately trained to comprehend the hazards associated with this kind of work. In addition, the CSB could not identify the existence of training available to civilians covering fireworks disposal.

5.4 Relevant Incidents

The following incidents provide valuable lessons regarding the hazards of handling and disposing of fireworks and the importance of identifying and properly managing those hazards.

5.4.1 Enschede Fireworks Incident

On May 13, 2000, a fireworks explosion and fire at the SE Fireworks[86] Depot in Enschede, Netherlands, killed 23 and injured 947. This incident involved stored fireworks labeled as 1.4G consumer fireworks. As with DEI, an investigation into the incident concluded that although the fireworks were labeled as 1.4G consumer fireworks, these fireworks were consistent with 1.3G display fireworks and the mass explosion was consistent with 1.1G explosives. The report on this incident highlights that aerial shells, when taken from their packaging, must be treated as a 1.1G explosive with the potential to mass

[82] 29 CFR §1910.120(e)(2) (2006).
[83] UXO Technician Level I training consists of a four-week course that provides students with training in the safe detection, location, identification, and disposal of unexploded ordnance. http://teex.org/teex.cfm?pageid=training&area=teex&templateid=14&Division=publicsafety&Course=UXO200&navdiv=publicsafety (accessed September 17, 2012).
[84] DDESB. Technical Paper (TP)18, *Minimum Qualifications for Unexploded Ordnance (UXO) Technicians and Personnel*, Section C2.1.2, 2004.
[85] *Ibid.*
[86] SE Fireworks was a major importer of fireworks from China and a supplier for concerts and events in the Netherlands.

explode.[87] This conclusion is critical for anyone conducting firework disposal activities, as separating and accumulating explosive firework components can introduce the possibility of a mass explosion.

5.4.2 Lansing, Kansas Incident

On July 4, 2012, a volunteer was killed when he and other local volunteers, some of whom worked with the local fire department, were disposing of fireworks that had not discharged during a fireworks display show for the City of Lansing, Kansas. The state-licensed fireworks display operator had been conducting this show annually for more than ten years. He told the CSB that each year during his shows as many as ten percent of the fireworks do not properly discharge and must be disposed of. In this incident, volunteers were disposing of undischarged three-inch diameter aerial shells by digging a pit several feet deep, starting a fire to burn the cardboard containers from cake fireworks, and throwing the defective firework aerial shells into the pit one at a time (Figures 23 and 24). This had been the common disposal method for this display operator for the last several years and was specifically developed to avoid past incidents when unexploded fireworks discharged on the back of a pickup truck during transportation, as well as in a garbage dumpster hours after the show was completed. The display operator had developed this disposal technique based on experience working for a fireworks manufacturing company.

Just prior to this incident, following a verbal instruction for everyone to take cover, a chain of three-inch spherical aerial shells was thrown into the fire pit. At least one of the shells was ejected from the pit and exploded, fatally injuring a volunteer who had taken cover 40 to 50 feet away behind sand troughs constructed to stabilize the mortar tubes during the show.

As Section 7.0 discusses, a significant regulatory and industry standards gap exists surrounding fireworks disposal in the U.S. This incident is yet another reflection of that gap, and illustrates the lack of guidance for disposing of fireworks, both contraband and non-contraband.

[87] National Fire Service of the Netherlands. *Final Consideration.* National Fire Service Documentation Center, p. 8. http://www.nbdc.nl/cms/servlet/nl.gx.nibra.client.http.GetFile?id=498631&file=Final_consideration_(Slotbeschouwing_Engels).pdf (accessed Nov 16, 2012).

Figure 23. Burn pit used for fireworks disposal (courtesy of the Office of the Kansas State Fire Marshal)

Figure 24. Sand troughs built to stabilize mortar tubes for the display show, behind which volunteers took cover during disposal activities as aerial shells were thrown into the burn pit (yellow rectangle) (courtesy of the Office of the Kansas State Fire Marshal)

6.0 Contractor Selection and Oversight

The procurement process TEOAF and VSE utilized, which is governed by the Federal Acquisition Regulation (FAR), the Department of the Treasury Acquisition Regulation System (DTAR), the Department of the Treasury Acquisition Procedures (DTAP), and bureau-level procurement policies and procedures, does not explicitly address safety, and lacks sufficient selection and oversight requirements for the prime contractor VSE and its subcontractors for the unique hazards associated with fireworks disposal.

6.1 Federal Acquisition Regulation

The FAR,[88] a broad set of regulations governing the federal agencies' acquisition of goods and services, covers both the selection of contractors and in many cases the selection of subcontractors under federal contracts. These regulations deal with the types of contracts available to procure and the factors to consider when determining the qualifications of a prospective contractor or subcontractor. As such, the FAR governed the TEOAF federal prime seized property management contract and the process for awarding subcontracts under the prime contract.

6.1.1 Determining Responsibility

FAR Subpart 9.104-4[89] requires prime contractors to determine the "responsibility" of their subcontractors before awarding a subcontract.[90] To be deemed "responsible" under the FAR, a prospective contractor or subcontractor must "a) [h]ave adequate financial resources to perform the contract…[;] b) [b]e able to comply with the required or proposed delivery or performance schedule…[;] c) [h]ave a satisfactory performance record[91]…[;] d) [h]ave a satisfactory record of integrity and business ethics…[;] e) [h]ave the necessary organization, experience, accounting and operational controls, and technical skills, or the ability to obtain them (including…quality assurance measures and safety programs…)[;] f) [h]ave the necessary production, construction, and technical equipment and

[88] 48 CFR Chap. 1 (2012).
[89] 48 CFR §9.104-4 (2005).
[90] 48 CFR §9.104-1 discusses requirements for determining the responsibility of a prospective contractor. 48 CFR §9.104-4 extends those requirements to determining the responsibility of prospective subcontractors.
[91] According to the FAR, "[a] prospective contractor that is or recently has been seriously deficient in contract performance shall be presumed to be nonresponsible…[p]ast failure to apply sufficient tenacity and perseverance to perform acceptably is strong evidence of nonresponsibility. Failure to meet the quality requirements of the contract is a significant factor to consider in determining satisfactory performance." 48 CFR §9-104-3(b). (2005). *See also* 48 CFR §42.15, Contractor Performance Information: "Past performance information is relevant information, for future source selection purposes, regarding a contractor's actions under previously awarded contracts. It includes, for example, the contractor's record of conforming to contract requirements and to standards of good workmanship; the contractor's record of forecasting and controlling costs; the contractor's adherence to contract schedules, including the administrative aspects of performance; the contractor's history of reasonable and cooperative behavior and commitment to customer satisfaction; the contractor's reporting into databases…the contractor's record of integrity and business ethics, and generally, the contractor's business-like concern for the interest of the customer (2002).

facilities…[;] and g) [b]e otherwise qualified and eligible to receive an award under applicable laws and regulations."[92] FAR Subpart 9.104-2 states that, when necessary, a contracting officer (CO) may develop special standards of responsibility, especially when unusual expertise is needed for adequate contract performance.[93] Pursuant to these sections, VSE contract procurement personnel are required to determine a potential subcontractor's "responsibility" before awarding any subcontract; as such, they would have to have the ability to assess any prospective subcontractor's technical qualifications relevant to the work involved.

FAR Subparts 9.104-1 and 9.104-4, however, do not specifically require prime contractors to include any safety performance metrics and qualifications criteria in their review of a prospective subcontractor's responsibility, despite the fact that the work of federal agencies can be hazardous. As discussed in the CSB's Xcel Investigation Report, issued in August 2010, several organizations and industry associations, including the Construction Users Roundtable[94] (CURT), the American National Standards Institute[95] (ANSI), and the American Industrial Hygiene Association (AIHA), have developed guidelines and recommended practices addressing the use of safety criteria for selecting and prequalifying contractors. CURT has stated that demonstrated safety performance is a "critical criterion used in the [contractor] prequalification process."[96] CURT guidance lists staff qualifications, accident history, a contractor's safety program, and an owner's previous experience as potential criteria for safety prequalification of a contractor. ANSI Standard Z-10, "Occupational Health and Safety Management Systems," also recommends that the contractor prequalification process include consideration of safety criteria for successful contractor safety performance management.[97]

6.2 Supplements to the FAR

Over the years, federal agencies have developed supplements to the FAR containing regulations and policies that are more specific to an agency's activities and needs. The courts have ruled that agency supplements, like the FAR itself, have "the force and effect of law."[98] The U.S. Department of Defense

[92] 48 CFR §9.104-1 (2005).
[93] 48 CFR §9.104-2 (2005).
[94] CURT is an industry organization that promotes advocacy by users of construction services on national issues that includes "developing industry standards and owner expectations with respect to safety, training and worker qualifications" http://www.curt.org/2_0_about_curt.html (accessed September 27, 2012). CURT is composed of 66 member companies, organizations, and government entities that represent some of the largest industrial corporations and users of construction services in the U.S. including ExxonMobil, Dow Chemical, Intel, Duke Energy, Shell, the U.S. Army Corp. of Engineers, U.S. Department of State, U.S. Federal Bureau of Prisons, and the U.S. General Services Administration.
[95] ANSI is as private, non-profit organization that "oversees the creation, promulgation and use of thousands of norms and guidelines that directly impact businesses in nearly every sector…[and] is also actively engaged in accrediting programs that assess conformance to standards…" http://www.ansi.org/about_ansi/overview/overview.aspx?menuid=1 (accessed December 20, 2012). ANSI is comprised of nearly 1,000 businesses, professional societies and trade associations, standards developers, government agencies, and consumer and labor organizations.
[96] CURT, *Construction Safety: The Owner's Role, UP-802*, 2004, p.6.
[97] ANSI/AIHA. ANSI/AIHA Z-10, *American National Standard for Occupational Health and Safety Management Systems*, 2012; p.18.
[98] *Davies Precision Machining, Inc. v. U.S.*, 35 Fed Cl. 651 (1995).

(DoD), for example, developed the Defense Federal Acquisition Regulation Supplement (DFARS),[99] which, among other things, reflects the nature of the DoD's hazardous work and its commitment to protecting the public and workers by requiring more rigorous contractor and subcontractor selection and oversight practices to ensure safety is effectively managed. However, the Treasury supplement (the DTAR) does not explicitly require the consideration of health or safety in its selection and oversight provisions, despite the fact that subcontractors are engaging in hazardous work pursuant to the TEOAF federal prime contract.

6.2.1 Department of the Treasury

The DTAR establishes uniform policies for all acquisition activities throughout Treasury, including the TEOAF. [100] The Treasury Office of the Procurement Executive (OPE), which is responsible for evaluating, reviewing, and issuing all departmental acquisition regulations and guidance, directly oversees and controls the DTAR.[101] The Senior Procurement Executive (SPE) is the director of OPE and may approve all individual and class contract FAR and DTAR deviations.[102] The SPE has also published a companion policy guide to the DTAR, the DTAP, which must be used in conjunction with the DTAR and FAR to ensure adherence to all Treasury policy and federal procurement regulations.[103]

Although the TEOAF is responsible for managing participating agencies' seized and forfeited property, which may include explosive and hazardous materials, provisions contained within the DTAR do not reflect the importance of occupational health and safety when conducting hazardous activities. The DTAR and DTAP lack explicit safety provisions, and do not provide for additional contractor and subcontractor selection and oversight procedures when contracting for the handling, storage, or disposal of hazardous materials such as fireworks.

6.2.2 Department of Defense

The DoD's DFARS Section 223, "Environment, Energy and Water Efficiency, Renewable Energy Technologies, Occupational Safety, and Drug-Free Workplace,"[104] considers additional safety and contractor oversight for all DoD acquisitions involving the use of ammunition and explosives[105] (AE), including handling or loading, assembling, transportation, storage, and disposal.[106] Section 223 requires

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[99] 48 CFR Chapter 2 (Sections 200 to 299) (last updated May 29, 2012).
[100] 48 CFR Chapter 10 (Sections 1000 to 1052) (2011).
[101] 48 CFR §1001.304 (2011).
[102] 48 CFR §1001.403 and 1001.404 (August 2011).
[103] *See* Department of the Treasury Acquisition Procedures (DTAP) (June 1, 2011) http://www.treasury.gov/about/organizational-structure/offices/Mgt/Documents/DTAP%2006-01-2011.pdf (accessed September 18, 2012).
[104] 48 CFR §223 (May 29, 2012)
[105] "Ammunition and Explosives" is defined as "liquid and solid propellants and explosives, pyrotechnics, incendiaries and smokes in the following forms: (i) Bulk; (ii) Ammunition; (iii) Rockets; (iv) Missiles; (v) Warheads; (vi) Devices; and (vii) Components of (i) through (vi), except for wholly inert items." 48 CFR §252.223-7002, Safety Precautions for Ammunition and Explosives (May 1994).
[106] 48 CFR §223.370-1(a) (May 29, 2012).

contracting officers to incorporate DoD Manual 4145.26M, *DoD Contractor's Safety Manual For Ammunition and Explosives* (*DoD Safety Manual*),[107] into all contracts under which AE are handled (AE procurement actions).[108]

The *DoD Safety Manual* provides safety requirements, guidance, and information to minimize potential accidents that "could interrupt DoD operations, delay DoD contract production, damage DoD property, cause injury to DoD personnel, or endanger the public during DoD contract work or services involving AE."[109] These requirements apply to DoD contractors and subcontractors handling AE and provide additional contractor selection and safety oversight information.

For example, Section C1.5 requires that DoD safety personnel conduct pre-award safety surveys to evaluate each potential contractor's ability to comply with contract safety requirements. A potential contractor must provide the CO with any site plans; its safety and fire prevention programs; descriptions of proposed facilities; its safety history; proposed operations and equipment (including a process flow narrative/diagram, proposed hazard analysis and proposed procedures for all phases of AE operations); and information on any subcontractor the contractor plans to utilize to perform AE work.[110] The policy states that DoD safety personnel will then assess whether the prospective contractor has sufficient programs in place before awarding an AE contract.

Under Section C1.6, DoD has the authority to conduct an additional "pre-operational survey" under certain circumstances, such as when a contract has been awarded to a contractor with "limited experience," or following a "major modification," both of which were significant factors in the DEI incident.[111]

Section C1.7 states that, post-award, a contractor must comply with all requirements of the *DoD Safety Manual* in addition to following all applicable local, state, and federal codes, standards, and regulations. The contractor also must implement a demonstrable safety program to prevent AE-related accidents, designate qualified individuals to administer the safety program, and prepare and keep available for review all hazard analyses.[112]

Chapter 3 provides general safety requirements for all AE operations addressed within the manual. They reflect the "cardinal principle of AE safety," which is to "limit exposure to a minimum number of personnel, for a minimum amount of time, to the minimum amount of the hazardous material consistent with safe and efficient operations."[113] It includes minimum requirements for 1) SOPs; 2) training and housekeeping; 3) controlling and monitoring subcontractors, including the method the contractor uses to determine whether subcontractors are qualified to perform work safely; [114] and 4) handling and storing

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[107] DoD Contractor's Safety Manual for Ammunition and Explosives. DoD 4145.26-M. (March 13, 2008).
[108] 48 CFR §223.370-3(b) (2012).
[109] DoD 4145.26-M Section C1.1. *Purpose*. (March 13, 2008).
[110] *DoD 4145.26-M* Section C1.5. *Pre-Award Safety Survey*. (March 13, 2008).
[111] DoD 4145.26-M Section C1.6. *Pre-Operational Safety Survey*. (March 13, 2008).
[112] DoD 4145.26-M Section C1.7. *Post-Award Contractor Responsibilities*. (March 13, 2008).
[113] DoD 4145.26-M Section C3.2.1. *Personnel and Material Limits.* (March 13, 2008).
[114] DoD 4145.25-M Section C3.3.5. *Control and Monitoring.* (March 13, 2008).

explosives waste in operating areas (including a requirement that black powder must be stored in containers with water).[115]

Chapter 11, which includes a sample matrix used for guidance, [116] requires that all contractors have a risk identification and management system and perform a hazard analysis that evaluates processes, materials, equipment, and personnel hazards.[117] (Appendix B includes excerpts from the *DoD Safety Manual*).

As discussed in Section 6.3, VSE's selection and oversight of DEI as a subcontractor as well as DEI's fireworks disposal process reflect a lack of safety focus throughout the entire contracting process. All parties involved would have greatly benefited from contract safety provisions similar to those found in the *DoD Safety Manual*, including those that required pre- and post-award safety surveys of subcontractors, the creation and review of risk assessments and hazard analyses, the implementation of a safety program, and provisions that emphasize the importance of minimizing hazards.

6.3 Subcontractor Selection

6.3.1 VSE Procurement Selection Methodology for Subcontractors

VSE procurement personnel assigned to work under the TEOAF prime and interim contracts have varied training and technical backgrounds and are responsible for subcontracting to vendors to manage a wide array of projects. While explosives and hazardous materials are periodically seized and must be managed, VSE procurement personnel responsible for selecting and overseeing vendors to conduct these activities, including storage and disposal, lacked the requisite backgrounds or expertise necessary to understand the risks of managing this type of property – nor does VSE employ or consult with experts to assist in selecting vendors capable of properly managing hazardous and explosive materials.

6.3.1.1 Initial Solicitation

In early 2010, VSE procurement personnel assigned to work under the TEOAF federal prime contract began the task of securing a vendor to dispose of the contraband fireworks that CBP and ICE/HSI had seized in Honolulu. Based on initial market research, on February 16, 2010, VSE sent a request for a firm-fixed-price[118] quotation[119] to five vendors, including DEI. VSE requested a quote from DEI for one

[115] DoD 4145.25-M Section 3.6. *Explosives Waste in Operating Areas.* (March 13, 2008).
[116] DoD 4145.25-M Section C11.2.2.2 and Table C11.T1. (March 13, 2008).
[117] DoD 4145.25-M Chapter 11. *Risk Identification and Management*. (March 13, 2008).
[118] According to FAR Subpart 16.202-1, "[a] firm-fixed-price contract provides for a price that is not subject to any adjustment on the basis of the contractor's cost experience in performing the contract. This contract type places upon the contractor maximum risk and full responsibility for all costs and resulting profit or loss. It provides maximum incentive for the contractor to control costs and perform effectively and imposes a minimum administrative burden upon the contracting parties…"
[119] VSE required a firm-fixed-price bid to dispose of the contraband fireworks because VSE procurement personnel understood that the terms of the federal prime contract required a firm-fixed-price for all purchase orders. The CSB learned that VSE understood that firm fixed price contracts are best suited for situations where the subcontractors'

main reason: DEI was already storing the fireworks through a separate subcontract with VSE, and VSE had a stated preference for a "one-stop shopping" subcontractor. Two solicited suppliers, DEI and Liberty Disposal (Liberty), a fireworks disposal company in Michigan,[120] responded with firm fixed-price quotations. DEI's quotation estimated a total of 400 hours of labor and projected a cost of $157,579.73 for disposal of 40 pallets of fireworks. According to DEI management, the price was based on assumptions that certain facilities, such as Koko Head, could be used for burning and that the timelines they provided were accurate. The quotation did not detail how DEI would dispose of the fireworks or include possible permitting requirements. The CSB has found no evidence that VSE procurement personnel discussed these matters with DEI when analyzing the quotation.

Liberty, which provided a more detailed quotation to VSE that explained how the company would dispose of the fireworks (via incineration in Ohio) and what permitting would be necessary, estimated its total to be $268,372.56.

6.3.1.2 Subcontractor Selection – Determining Responsibility

Once VSE procurement specialists received the two price quotations from DEI and Liberty they began their analysis by researching both companies on the Central Contractor Registration[121] (CCR) website to ensure that neither was on the excluded parties list, and then compared each company's Small Business Administration[122] (SBA) profile. VSE procurement specialists also perused company websites to get an idea of the type of work each vendor did. No additional analysis was done to determine prior work history, proposed disposal methodology, or the vendor's technical skills to safely and responsibly dispose of explosives. VSE procurement personnel also failed to discover if DEI had prior fireworks disposal experience; instead, VSE procurement personnel told the CSB that because they were not the subject matter experts, they deferred to DEI as the expert based on the company's website and what DEI said its capabilities were.

VSE procurement analysis found DEI's proposal to be the lowest-cost and most time-efficient, and therefore determined it to be the best overall value for the government. According to VSE, this, along with the fact that DEI was a local company already storing the fireworks, led VSE procurement to select DEI as the subcontractor. VSE procurement's lack of health and safety focus during the procurement process resulted in a flawed responsibility determination and the award of the subcontract to DEI on March 17, 2010.

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scope of work is fully understood. The protocols associated with seized property do not allow a subcontractor bidding on the seized fireworks disposal subcontract to open boxes containing the fireworks and verify their contents to help in their cost estimation process.

[120] http://libertydisposalinc.com (accessed July 6, 2012).

[121] The Central Contractor Registration (CCR) is the primary vendor database for the U.S. Federal Government. It collects, validates, stores and disseminates data in support of agency acquisition mission. Government vendors are required to register in CCR in order to be awarded contracts by the government. http://www.osdbu.dot.gov/related/ccr.cfm (accessed September 27, 2012)

[122] The Small Business Administration (SBA) provides financing, contracts, counseling sessions and other forms of assistance to small businesses, http://www.sba.gov/about (accessed September 27, 2012). Both DEI and Liberty are SBA certified.

6.4 Fireworks Disposal Subcontract Provisions

The lack of safety focus is also apparent when reviewing the context of the fireworks disposal subcontract itself. The subcontract awarded to DEI contained a Statement of Work (SOW) and a *Subcontractor Property Management Handbook* (*Property Management Handbook*); both were generic, related to the management of general property, and did not address hazards associated with handling or disposing of explosive hazardous materials, including fireworks.

The SOW's stated intent was to "facilitate the transportation, storage, and destruction of seized general property as well as hazardous waste materials in Hawaii." Its objectives were "General Property Management Services in accordance with the Property Management Handbook" and "destruction of property via the use of a hazardous waste landfill or landfill." Under "description of work" the SOW stated that the vendor must "have the capacity to transport, store, and destroy general property as well as hazardous waste materials…must locate a facility that is a fully-regulated hazardous waste land fill or a land fill…dispose of property in accordance with all federal, state, and local laws, codes, ordinances, and regulations...[and that] a waste-to-energy facility [was] preferable…" Nothing within this SOW provided any technical detail of DEI's proposed fireworks disposal methodology or the risks involved. When asked about the general language contained within the SOW, VSE procurement personnel told the CSB that this was a standard language SOW except for specifics that had been inserted such as the state where the work was being conducted. These individuals told the CSB this was because the person writing the SOW was unfamiliar in terms of what to include specific to fireworks disposal, as that person did not understand the process.

The *Property Management Handbook* included guidance on a seizure's life cycle, property collection, chain of custody, property manipulation, property transportation, property storage, and property removal from storage. However, the language and instructions related to seized general property; explosives, fireworks, or other hazardous materials, or the risks of working with such items, were not discussed.

6.5 Subcontractor Oversight

6.5.1 Initial DEI Fireworks Disposal Plan

After DEI was awarded the fireworks disposal subcontract, DEI submitted a fireworks disposal plan to VSE for review and approval. DEI management personnel developed the fireworks disposal plan and told the CSB that, as they could find no guidance regarding fireworks disposal, they relied solely on military manuals and on-the-job military EOD training and experience to develop the initial disposal methodology. The CSB has been unable to verify the use of those military manuals.

Post-award, the VSE Regional Office in California (Regional Office) became the main VSE day-to-day contact for DEI. While this office received DEI's daily activity reports (DARs) and maintained contact with DEI management, CBP, and the BAI representative in Hawaii, its personnel lacked necessary expertise or training to understand the risks associated with handling and disposing of explosives, including fireworks. Regional Office Personnel also indicated to the CSB that they did not understand the kind of permitting DEI required to conduct its disposal work and why such permitting was needed.

The initial DEI fireworks disposal plan, "DEI Disposal of Commercial Grade Fireworks Plan," (disposal plan) detailed DEI's intended disposal methodology and was written for the "VSE Regional Office and those who will need to oversee the destruction of the commercial grade fireworks via services provide[d] by DEI." The disposal plan provided for DEI to carry out a series of burn operations using a DEI portable incinerator (TFU) that was capable of holding 40 to 50 pounds of fireworks. DEI noted the following steps in its plan:

1. DEI would ask the VSE Regional Office to reserve the Koko Head range at least two weeks before the actual burn operation,
2. DEI would pre-soak fireworks in diesel fuel for a minimum of 48 hours to ensure "complete desensitization,"
3. Desensitized fireworks would be loaded into 55-gallon steel drums and transported to Koko Head,
4. The TFU would be ignited and preheated for 15 to 20 minutes,
5. The pre-soaked fireworks would be fed down a chute one at a time,
6. Photos would be taken and provided to the VSE Regional Office upon request, and
7. DEI personnel would sign and date CBP Form 7605 block 8[123] and submit to the VSE Regional Office.

The Regional Office used the information to create a VSE Property Destruction Plan for submission to VSE Risk Management for review and approval. The Property Destruction Plan mischaracterized DEI's initial disposal plan by stating that the diesel fuel would "neutralize" rather than "desensitize" the fireworks.[124] As noted, diesel is used to desensitize explosives to spark, friction, impact, and temperature, and should result in a slow burn. The explosives are not "neutralized," and no chemical changes occur when diesel is added. The plan also indicated that a BAI field representative would be present to "oversee destruction." However, the CSB later learned that the BAI field representative lacked the expertise to oversee DEI's practices, and VSE had ultimately approved DEI's conduct of the work without BAI's daily oversight. In short, this plan overstated the safeguards in place to ensure that disposal was being done safely. VSE Risk Management approved the Property Destruction Plan on April 28, 2010.

6.5.2 Property Destruction Plan Review and Approval

The VSE Risk Management analyst who reviewed the Property Destruction Plan lacked the expertise or relevant training to adequately assess a plan for fireworks disposal. After receiving the plan, this analyst told the CSB that he first reviewed the very brief disposal methodology consisting of a few lines, which

[123] Certification of Destruction.
[124] As noted, diesel is used to desensitize explosives to spark, friction, impact, and temperature and should result in a slow burn.

described soaking the fireworks in diesel fuel to “neutralize” them and then destroying them by incineration. The analyst told the CSB that he deferred to DEI’s expertise when reviewing this section because of his lack of knowledge about fireworks, and he conducted no further research on DEI’s proposed methodology. Section IV of the Property Destruction Plan required the analyst to check either “Yes” or “No” for whether DEI was qualified to destroy the fireworks. Because VSE’s Procurement Office had already assessed DEI’s qualifications and selected DEI as the subcontractor, the Risk Management analyst checked “Yes” without researching DEI’s qualifications, experience, or proposed methodology. The analyst did search for adverse events involving DEI in VSE’s adverse incidents database and, finding no such history, approved and returned the Plan to the Regional Office.

6.5.3 VSE Regional Office

The approach taken by the VSE Regional Office echoed the stated position adopted throughout VSE: company personnel lacked expertise in handling fireworks or other explosives and hazardous materials and therefore deferred to DEI as the “expert” on fireworks disposal. The decisions on which VSE deferred to DEI included DEI’s two deviations from the original fireworks disposal plan to begin disassembling the fireworks by hand. Regional Office staff confirmed to the CSB that when DEI significantly altered its disposal methodology in March 2011, VSE was simply informed in a notification email. However, VSE Regional Office personnel would not have recognized the hazards associated with disassembling fireworks and accumulating boxes of explosive components. Because VSE trusted that DEI was an expert that would recognize and address any risks involved, VSE did not question any changes or express concern.

6.5.4 BAI

As discussed, VSE relied on BAI field representatives to provide field services such as property inspections and storage on an as-needed basis. A BAI representative in Hawaii came to the magazine occasionally and served as VSE’s observer during DEI’s disposal process. He also took photos of the disassembly process (Figures 5 and 6). The subcontract between VSE and BAI did not require the BAI representative to oversee safety, which the representative could not have done effectively because he had no experience with fireworks and explosives and therefore would be unable to offer any valuable insight. The CSB concurs with ATF’s conclusion that the BAI field representative did witness some disposal work where unsafe practices would have been apparent to observers with expertise in explosive disposal operations.

6.6 Conclusion

Neither VSE nor BAI used personnel with the necessary backgrounds and expertise to recognize the hazards associated with DEI’s fireworks disposal work. All deferred to DEI as the “expert” regarding fireworks disposal and were unaware of the hazards of disassembling the fireworks by hand, accumulating explosive materials in cardboard boxes, and storing them in a magazine along with potential spark- and static-producing items.

To improve the subcontractor selection and oversight process under the TEOAF seized property management contract, government acquisition regulations must emphasize safety system management. The FAR should be strengthened to require the analysis of safety performance measures and qualifications when determining the "responsibility" of prospective contractors and subcontractors handling explosive and hazardous materials. Federal agencies such as Treasury, that require contractors and subcontractors to deal with explosives and other hazardous materials, should adopt and implement stringent safety-related contractor and subcontractor selection and oversight provisions similar to those found within the DFARS. In addition, entities tasked with implementing safety-related contracting requirements must have the personnel or consultants in place with the necessary technical expertise to sufficiently evaluate and oversee contractors and subcontractors to ensure the work is being conducted safely.

7.0 Regulatory and Industry Standards Analysis

Within Hawaii, ATF, HIOSH, and the State of Hawaii Department of Health (DOH) all have regulatory oversight over various aspects of fireworks manufacturing, storage, handling, and disposal. National Fire Protection Association (NFPA) industry standards also include good practices pertaining to fireworks manufacturing and storage. However, the CSB found a significant gap with regulatory and industry standards pertaining to the safe disposal of fireworks in the U.S.

7.1 Hawaii Occupational Safety and Health Division

7.1.1 Jurisdiction

Hawaii is one of 26 jurisdictions OSHA approved to operate its own state safety and health program under the Occupational Safety and Health Act (OSH Act) Section 18(b).[125] HIOSH administers Hawaii's OSHA State Plan Program and has adopted Federal OSHA standards in their entirety, contained within the Hawaii Administrative Rules (HAR).

OSHA's Explosives Standard, 29 CFR §1910.109,[126] and HAR Title 12, Subtitle 8, Part 2 (General Industry Standards) cover the storage and handling requirements of explosives and pyrotechnics. However, Section 4(b)(1) of the OSH Act precludes OSHA from any enforcement activity over a working condition if another federal agency exercises its statutory authority.[127] In this case, HIOSH's authority to regulate most manufacturing, distribution, handling, and storage of fireworks in Hawaii, including DEI's activities, would be preempted should ATF have chosen to exercise its statutory authority under ATF's Federal Explosives Law and Regulations, found at 18 U.S.C. Chapter 40 and 27 CFR Part 555.[128]

OSHA Directive Number CPL 02-01-053, Compliance Policy for Manufacture, Storage, Sale, Handling, Use and Display of Pyrotechnics,[129] clarifies situations in which OSHA may issue citations for hazards related to fireworks and conditions during which the OSH Act General Duty Clause can be applied to address hazards not specifically covered by OSHA standards.[130] Because ATF's regulations in 27 CFR Part 555 specifically address working conditions associated with storing explosives, including commercial 1.3G UN0335 display fireworks, they preempt OSHA's storage requirements for explosives in §1910.109(c). However, storing 1.4G UN0336 consumer fireworks in their finished state falls under

[125] 29 U.S.C. §667 (1970).
[126] 29 CFR §1910.109, Explosives and Blasting Agents (1998).
[127] 29 U.S.C. §653 (1970).
[128] Organized Crime Control Act of 1970, Title XI, Chapter 40. Importation, Manufacture, Distribution and Storage of Explosive Materials. (October 22, 1986). 27 CFR Part 555, Commerce in Explosives (2007).
[129] CPL 02-01-053, Policy for Manufacture, Storage, Sale, Handling, Use and Display of Pyrotechnics (October 27, 2011).
[130] CPL 02-01-053, Executive Summary (Oct. 27, 2011).

OSHA's and HIOSH's authority.[131] Hazards such as ignition sources, including static electricity hazards associated with storage and handling of explosive materials not covered by ATF, may also be cited under §1910.109(b)(1) and correlating HAR standards.[132]

7.1.2 HIOSH Investigation of the Incident

On September 30, 2011, HIOSH announced that it had completed its investigation of the DEI incident. HIOSH identified 11 potential causes for the explosion, each of which carries a separate penalty. HIOSH issued four serious, seven willful, and one other citation against DEI, alleging DEI's serious violation of 29 CFR §1910.36(b)(2)[133] and HAR §12-71.1 by blocking the magazine's only exit; willful violation of HAR §12-61-2(a)(3) that exposed employees to explosion hazards (the presence of sources of static electricity as potential ignition sources) while they worked with explosive materials; willful violation of 29 CFR §1910.109(b)(1) and HAR §12-74.1 by separating pyrotechnic materials in close proximity to other explosives, storing ferrous[134] tools inside the magazine, and permitting spark-producing devices near the magazine; and willful violation of 29 CFR §1910.132(d)(1)(i)[135] and HAR §12-64.1 for the lack of appropriate PPE.

As discussed in Section 5.1, because DEI's disassembly activities were under the umbrella of disposal rather than manufacturing, HIOSH was unable to cite DEI for PSM-related violations. In addition, while HIOSH did cite DEI for various alleged health and safety violations, no OSHA or HIOSH guidance specifically relates to fireworks disposal.

7.2 ATF

As discussed above, 27 CFR Part 555, Commerce in Explosives, regulates the importation, manufacturing, distribution, and storage of explosive materials, including commercial display 1.3G UN0335 fireworks. Under Subpart D, anyone intending to import, manufacture, or deal in explosive materials must obtain an ATF license.[136] However, a separate license is not required for storage facilities operated by the licensee as an integral part of one business premises.[137] Because DEI had a

[131] CPL 02-01-053 Section B(2), Enforcement of 29 CFR §1910.109 (Oct. 27, 2011).
[132] CPL 02-01-053 Section B(3), Enforcement of 29 CFR §1910.109 (Oct. 27, 2011).
[133] 29 CFR §1910.36(b)(2) states "[m]ore than two exit routes must be available in a workplace if the number of employees, the size of the building, its occupancy, or the arrangement of the workplace is such that all employees would not be able to evacuate safely during an emergency." 29 CFR §1910.36(b)(2). The number of exit routes must be adequate (Nov. 7, 2002).
[134] Of or containing iron.
[135] 29 CFR §1910.132(d)(1) states that an employer must "assess the workplace to determine if hazards are present, or are likely to be present, which necessitate the use of personal protective equipment (PPE). If such hazards are present, or likely to be present, the employer shall… (i) Select, and have each affected employee use, the types of PPE that will protect the affected employee from the hazards identified in the hazard assessment…" 29 CFR §1910.132(d)(1)(i) (June 8, 2011).
[136] 27 CFR §555.41(a)(1) (2005).
[137] 27 CFR §555.41(a)(2)(i) (2005).

manufacturing license from ATF as a result of its UXO activities, its personnel were approved to store the three fireworks seizures in the A-21 magazine without ATF inspection. At the time of the incident, no ATF staff had inspected the magazine although, according to DEI management, a day and time were being set up for this; the goal was to have it classified under ATF regulations as a Type 1 magazine,[138] which is authorized under ATF regulations to store high explosives.[139]

ATF storage regulations include requirements for storage within Types 1, 2, 3, and 4 magazines. These regulations state that explosive materials cannot be placed directly against interior walls and, except for fiberboard or other nonmetal containers, containers of explosive materials cannot be unpacked or repacked inside a magazine or within 50 feet of a magazine.[140] Tools used to open containers of explosives must be of non-sparking materials, except that metal slitters can be used to open fiberboard containers.[141] Magazines are required to be kept clean and dry; free of grit, paper, empty packages, trash, and containers; and floors are to be regularly swept with brooms or other items with non-sparking parts. Volatile materials are required to be kept at least 50 feet from outdoor magazines.[142] ATF regulations do not provide guidance on fireworks disposal or disassembly activities.

7.3 Regulation of Hazardous Waste

7.3.1 Resource Conservation and Recovery Act

The Resource Conservation and Recovery Act (RCRA) is a federal law that regulates non-hazardous and hazardous solid waste. RCRA Subtitle C implements the Hazardous Waste Permit Program, which regulates the generation, handling, transportation, storage, and disposal of hazardous waste from cradle to grave. RCRA requires a permit[143] for the treatment,[144] storage,[145] and disposal[146] of any hazardous waste as identified or listed in 40 CFR Part 261.[147]

[138] 27 CFR §555.203(a). (1981).
[139] "High Explosives" are explosive materials which can be caused to detonate by means of a blasting cap when unconfined." 27 CFR §555.2-2(a) (1998).
[140] 27 CFR §555.214 (a) and (c) (1981).
[141] 27 CFR §555.214 (d) (1981).
[142] 27 CFR §555. 215 (1981).
[143] A permit includes a permit by rule (270.60), emergency permit (270.61), and standardized permit (subpart J of this part). 40 CFR §270.2 (2006).
[144] Treatment means "any method, technique, or process, including neutralization, designed to change the physical, chemical, or biological character or composition of any hazardous waste so as to neutralize such wastes, or so as to recover energy or material resources from the waste, or so as to render such waste non-hazardous, or less hazardous; safer to transport, store, or dispose of; or amenable for recovery, amenable for storage, or reduced in volume." 40 CFR §270.2 (2006).
[145] Storage means "the holding of hazardous waste for a temporary period, at the end of which the hazardous waste is treated, disposed, or stored elsewhere." 40 CFR §270.2 (2006).
[146] Disposal means "the discharge, deposit, injection, dumping, spilling, leaking, or placing of any hazardous waste into or on any land or water so that such hazardous waste or any constituent thereof may enter the environment or be emitted into the air or discharged into any waters, including ground water." 40 CFR §270.2 (2006).
[147] 40 CFR §270.1(c) (2006).

Under RCRA, no material is a hazardous waste unless it is first deemed a solid waste.[148] RCRA places hazardous waste into two categories: 1) listed wastes, which appear on one of the four hazardous waste lists established by regulations;[149] or 2) characteristic wastes, which exhibit one or more of four features: ignitability;[150] corrosivity;[151] reactivity;[152] and/or toxicity.[153] Confiscated, seized, or forfeited fireworks (when a solid waste) are considered regulated hazardous waste under RCRA because they are ignitable,[154] reactive,[155] and potentially toxic solid wastes.[156]

Standard RCRA operating permit applications include two parts (A and B)[157] and are comprehensive. Permit application requirements include a description of the facility and procedures, structures, or equipment used at the facility to prevent hazards in unloading operations, and to prevent undue exposure to hazardous waste (for example, protective clothing);[158] a description of precautions to prevent accidental ignition or reaction of ignitable, reactive, or incompatible wastes as required to demonstrate compliance with 40 CFR §264.17;[159] and an outline of training programs by owners or operators to prepare workers to operate in a safe manner.[160] RCRA permit applicants must also comply with the facility standards in 40 CFR Part 264, including personnel training requirements[161] and requirements for handling ignitable,

148 "Solid waste" is defined under 40 CFR §261.2 as a "discarded material which is A) Abandoned…or; B) Recycled…; or C) Considered inherently waste-like…; or D) A military munition…" 40 CFR §261.2 (2010). "Hazardous waste" is defined under 40 CFR §261.3 as a solid waste that exhibits any of the characteristics of hazardous waste identified in subpart C or that is listed in subpart D of this part. 40 CFR §261.3 (2006).
149 40 CFR §261.31-33 (2011).
150 40 CFR §261.21 (2011).
151 40 CFR §261.22 (2011).
152 40 CFR §261.23 (2011).
153 40 CFR §261.24 (2011).
154 Characteristic of ignitability: "(a) A solid waste exhibits the characteristic of ignitability if a representative sample of the waste has any of the following properties: (2) It is not a liquid and is capable, under standard temperature and pressure, of causing fire through friction, absorption of moisture or spontaneous chemical changes and, when ignited, burns so vigorously and persistently that it creates a hazard…" 40 CFR §261.21(a)(2) (2011).
155 Characteristic of reactivity: "(a) A solid waste exhibits the characteristic of reactivity if a representative sample of the waste has *any* of the following properties: (1) It is normally unstable and readily undergoes violent change without detonating. (2) It reacts violently with water. (3) It forms potentially explosive mixtures with water. (6) It is capable of detonation or explosive reaction if it is subjected to a strong initiating source or if heated under confinement. (7) It is readily capable of detonation or explosive decomposition or reaction at standard temperature and pressure. (8) It is…a Division 1.1, 1.2, or 1.3 explosive as defined in 49 CFR §§ 173.50 and 173.53." 40 CFR §261.23(a) (2011).
156 Toxicity characteristic: "(a) A solid waste…exhibits the characteristic of toxicity if, using the Toxicity Characteristic Leaching Procedure, test Method 1311 in 'Test Methods for Evaluating Solid Waste, Physical/Chemical Methods'…the extract from a representative sample of the waste contains any of the contaminants listed in table 1 at the concentration equal to or greater than the respective value given in that table." 40 CFR §261.24(a) (2011).
157 RCRA application Part A and Part B requirements are contained within 40 CFR §§270.13 and 270.14, respectively.
158 40 CFR §270.14(b)(8)(v) (1983).
159 40 CFR 270.14(b)(9) (1983).
160 40 CFR §270.14(b)(12) (1983).
161 40 CFR §264.16 (2006).

reactive, or incompatible wastes.[162] RCRA permits are effective for a fixed term not to exceed 10 years.[163]

Under 40 CFR §270.61,[164] persons or facilities seeking to engage in hazardous waste treatment, storage, or disposal activities may obtain an emergency hazardous waste permit if the waste is determined to be an "imminent and substantial endangerment to human health or the environment."[165] Emergency permits may be oral or written and are effective for 90 days once issued.[166] They are significantly less detailed and robust than traditional RCRA permits and require substantially less work on the part of the applicant and the permit writer. Throughout the U.S., seized fireworks are sometimes disposed of pursuant to these emergency permits due to the hazardous characteristics of firework components.

Although not applicable to this incident, RCRA regulations also have a complete exemption from all permits, including emergency permits, for all qualified responders to "an immediate threat to human health, public safety, property, or the environment, from the known or suspected presence of military munitions, other explosive material, or an explosive device, as determined by an explosive or munitions emergency response specialist as defined in 40 CFR §260.10."[167]

7.3.2 State of Hawaii Department of Health (DOH)

DOH is Hawaii's state environmental agency, and implements federal environmental regulations that have been adopted under the HAR, including RCRA regulations. As such, DOH has the authority under 40 CFR §270.61 and HAR §11-270-61(a) to issue emergency hazardous waste permits to RCRA and non-RCRA permitted persons or facilities. According to DOH policy, DOH views "illegal fireworks as hazardous wastes that exhibit an unusual risk to the public and the environment"[168] and therefore issues emergency permits to those who wish to treat or dispose of contraband fireworks.

As discussed in Section 3.4, DOH issued DEI an emergency hazardous waste disposal permit on June 8, 2010, for fireworks disposal activities. 40 CFR §270.61(b)(3) requires that the emergency permit "clearly specify the hazardous wastes to be received, and the manner and location of their treatment, storage, or disposal." According to DOH policy, the specific conditions authorized in an emergency permit depend on analysis of facts provided by the applicant. However, the policy also provides that DOH's "basic

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[162] 40 CFR §264.17 states that an owner or operator must take precautions to prevent accidental ignition or reaction of ignitable or reactive waste. This waste must be separated and protected from sources of ignition or reaction, including but not limited to open flames, smoking, cutting and welding, hot surfaces, frictional heat, sparks (static, electrical, or mechanical), spontaneous ignition (e.g., from heat-producing chemical reactions), and radiant heat. (2006).
[163] 40 CFR §270.50 (1985).
[164] 40 CFR §270.61 (1996).
[165] 40 CFR §270.61 (1996).
[166] 40 CFR §270.61 (b)(1) and (2) (1996).
[167] 40 CFR §§264.1(g)(8)(i)(D) (2006) and 40 CFR 270.1(c)(3)(i)(D) (1997).
[168] State of Hawaii Department of Health, Environmental Management Division, Solid and Hazardous Waste Branch. *Temporary Emergency Permits to Treat, Store or Dispose of Hazardous Waste,* November 29, 2010. http://hawaii.gov/health/environmental/waste/hw/pdf/tempemergpermit.pdf (accessed July 10, 2012).

template for TEP [temporary emergency permit] conditions is designed with the temporary, emergency nature of the situation in mind and under no circumstances should it be overly burdensome on the permittee."[169]

The emergency hazardous waste disposal permit that DOH issued to DEI required that DEI complete the disposal within 90 days of the date issued. DOH instructed DEI via email that no extensions would be provided. This time limit proved to play a significant role in the incident, as DEI's first disposal job exceeded the 90-day time limit, and emails written by DEI management in fall 2010 indicated that for all future fireworks disposal jobs, DEI would disassemble the firework tubes prior to obtaining a permit in order to maximize the available time for burning. These efficiency improvements resulted in the accumulation of large quantities of explosive firework components, which created a mass explosion hazard.

In its permit application letter, DEI stated it intended to destroy approximately 5,000 pounds of illegal "Class 1.3 and 1.4 fireworks" including "firecrackers, poppers, sparklers, and aerials," through burning activities at Koko Head. Emails show that DOH requested DEI's fireworks disposal plan, which detailed diesel soaking and burning activities, prior to awarding the permit. However, DOH wrote the permit to include only the burn activities. The CSB has found no evidence that DOH personnel conducted additional analysis to better understand DEI's disposal plan. In fact, evidence suggests that safety was not a factor in DOH's review process, and DOH personnel told the CSB that their focus was on environmental protection, not safety. In addition, DOH personnel lacked the requisite background to analyze DEI's proposed disposal methodology, experience, and qualifications when issuing this permit.

Safety is an important aspect of hazardous waste disposal; the legislative history supports the argument that RCRA is intended to address environmental implications of hazardous waste treatment and disposal and also those of health and safety. In fact, RCRA was created in part to provide "for the safe disposal of discarded materials…"[170] (Emphasis added). Congress also noted in enacting RCRA that "disposal of solid waste and hazardous waste in or on the land without careful planning and management can present a danger to human health and the environment…"[171]

RCRA regulations also support the consideration of safety. For example, 40 CFR §264.17 requires that an owner or operator take precautions to prevent accidental ignition or reaction of ignitable or reactive waste. In addition, 40 CFR §264.16 requires that facility personnel complete classroom or on-the-job hazardous waste training that at a minimum ensures they are able to respond effectively to emergencies.[172] These regulations illustrate that RCRA and comparable state regulations, such as the HAR, can and should address environmental protection as well as the safety and health of workers and the public. This is especially important for the emergency permitting process, which requires a much less

[169] State of Hawaii Department of Health, Environmental Management Division, Solid and Hazardous Waste Branch. *Temporary Emergency Permits to Treat, Store or Dispose of Hazardous Waste*, November 29, 2010. http://hawaii.gov/health/environmental/waste/hw/pdf/tempemergpermit.pdf (accessed July 10, 2012).
[170] A Legislative History of the Solid Waste Disposal Act. Pub. L. no. 94-580, 90 Stat 2795 (1976).
[171] A Legislative History of the Solid Waste Disposal Act. Pub. L. no. 94-580, 90 Stat 2797 (1976).
[172] 40 CFR §264.16 (2006).

substantial review of permit applicants even though the materials involved are extremely hazardous and pose an imminent safety, health, and environmental threat.

To reflect the importance of public and worker safety, an emergency permit applicant seeking to dispose of explosive hazardous materials such as fireworks should be reviewed extensively. RCRA should incorporate PSM-type elements such as PHA and MOC into its regulations to provide for a more robust safety program for entities conducting activities that are not covered by OSHA's PSM standard, such as fireworks disposal. Increasing the focus on safety will help ensure that activities being performed pursuant to a RCRA emergency hazardous waste permit are done so safely and responsibly.

7.4 Industry Standards

7.4.1 National Fire Protection Association

The NFPA works to prevent fire-related hazards and advocates for public safety by developing, publishing, and disseminating good practice standards intended to minimize risks. This includes fireworks and explosives-related standards, which are developed by NFPA's Pyrotechnics Committee. However, NFPA has no standard or guidance for the safe disposal of fireworks. NFPA standards are voluntary unless adopted by federal, state, or local agencies as part of regulations.

7.4.1.1 NFPA 495

NFPA 495, *Explosive Materials Code*, covers the manufacture, transportation, storage, sale, and use of explosive materials and emphasizes the importance of training for persons handling explosive materials and developing a hazards analysis for processes involving manufacturing, movement, storage, testing, or developing energetic materials.[173] However, this standard does not apply to any type of fireworks.[174]

7.4.1.2 NFPA 1123

NFPA 1123, *Code for Fireworks Display*, applies to constructing, handling, and using fireworks and equipment intended for outdoor fireworks display and operation of the display.[175] This standard provides for the flooding of a fireworks mortar shell with water within 15 minutes if the firework fails to fire.[176] The standard also states that any storage, handling, assembly, testing, or transportation of fireworks materials and devices intended for outdoor display – prior to their delivery to the display site – must comply with NFPA 1124, 18 U.S.C. Chapter 40; and 27 CFR Part 55. For fireworks disposal, Section 8.2.10.2 states that suppliers will provide disposal instructions and those instructions will be followed.

[173] NFPA 495. *Explosive Materials Code*. 2010 ed.
[174] NFPA 495, Section 1.3.4.
[175] NFPA 1123. *Code for Fireworks Display*. 2010 ed.; Section 1.1.1.
[176] NFPA 1123, Section 8.2.10.1.1.

This would not be applicable to seized contraband fireworks, and it does not appear that NFPA 1123 provides any other guidance on fireworks disposal.

7.4.1.3 NFPA 1124

NFPA 1124, *Code for the Manufacture, Transportation, Storage, and Retail Sales of Fireworks and Pyrotechnic Articles*, applies to manufacturing facilities and to the storage of display fireworks and black powder at facilities other than display sites – but the standard does not apply to disposal.[177] This standard requires that all tools used to open containers of explosive materials be non-sparking,[178] and that magazines must be used exclusively for storage of explosive and pyrotechnic materials.[179] As noted, DEI did not utilize the magazine exclusively for storage: DEI also soaked fireworks in diesel-filled steel drums, which the CSB would consider to be part of a process. In addition, a number of sparking items were found within the magazine or blown out of the magazine post-incident, including steel drums, a metal hand truck, metal chair, and metal tools.

While some sections within NFPA 1124 provide relevant safety guidance for fireworks storage activities, this standard does not provide any guidance on fireworks disposal. In addition, nowhere are the hazards of fireworks disassembly and the accumulation of explosive fireworks components discussed.

7.4.2 Review of Current Fireworks Disposal Practices

The CSB had informal discussions with a number of fireworks manufacturers and state and local law enforcement agencies to better understand their firework disposal methodologies. The responses varied, illustrating that manufacturers have developed their own disposal procedures in the absence of industry guidance.

7.4.2.1 Fireworks Operators

Disposal methods were inconsistent across these operators and ranged from procedures that incorporate stringent PSM guidelines to those that simply burn the fireworks in a pit, sometimes after soaking them in diesel. Several operators indicated that the best method to dispose of undamaged fireworks is to shoot them off as intended and strongly stated their opposition to disassembling or soaking fireworks in diesel prior to burning. Some operators said that they contract the disposal of 1.3G UN0335 fireworks to third-party companies (in Louisiana, Pennsylvania or Ohio) or turn them over to the local fire marshal or law enforcement.

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[177] NFPA 1124. *Code for the Manufacture, Transportation, Storage, and Retail Sales of Fireworks and Pyrotechnic Articles*, 2006 ed.; Section 1.1.
[178] NFPA 1124, Section 5.4.7.
[179] NFPA 1124, Section 5.4.8.

7.4.2.2 Local Law Enforcement Agencies

Fire departments and local law enforcement agencies are also inconsistent in their handling, storage, and disposal of fireworks. For example, the State of California Office of the State Fire Marshal seizes and takes possession of all contraband fireworks in the state. Its personnel told the CSB that they do not disassemble seized fireworks or soak them in diesel prior to burning them. The Office sometimes provides 1.3G UN0335 display fireworks to bomb technicians for training, and disposes of 1.4G UNO336 consumer fireworks in approved burn pits or ships them to an authorized disposal contractor in Louisiana. However, its personnel concede that cost and budget constraints have resulted in a large inventory of hundreds of thousands of pounds of seized fireworks being stored in magazines within California.

The San Francisco Fire Department confiscates mostly type 1.4G UNO336 fireworks, wets them down, grinds them, and then discards them. They do not have a procedure for 1.3G UN0335 fireworks.

Finally, the Houston Fire Department confiscates primarily type 1.4 G UNO336 fireworks, stores them in magazines, and then either sends them to the bomb squad for disposal, turns them over to the local police department for training, or burns them without first soaking them in diesel.

7.5 Conclusion

The wide array of disposal techniques across the country; incidents such as the one in Lansing, Kansas; and the lack of existing regulations and standards that provide safety requirements and guidance to those disposing of fireworks, all support the conclusion that a regulatory gap exists in this country pertaining to fireworks disposal. Closing this gap to prevent fatal incidents requires a combined effort by ATF, EPA, NFPA, state and local agencies, and the fireworks industry to create standards and guidance that clearly indicate the dangers of handling and disposing of fireworks, and discuss how to properly and effectively manage the hazards and safely conduct this work.

8.0 Causal Analysis

For the DEI Investigation, the CSB team developed an accident map (AcciMap) (Figure 24), a multi-layered causal diagram that allows for the evaluation of higher level causes at the governmental, regulatory, and societal levels. This diagram is especially useful for developing broadly applicable recommendations for accident prevention,[180] and includes five levels:

1. *Physical Events, Conditions, and Outcomes:* the immediate causes of the incident as displayed in a traditional logic tree;
2. *DEI:* company rules and policies; and conduct of fireworks disposal work;
3. *VSE*: primary government contractor responsible for subcontractor selection and oversight;
4. *Industry Codes and Standards:* good practice guidelines provide safety standards; and
5. *Government:* laws and legislation are developed to regulate federal contracting and the handling, storage, and disposal of explosive hazardous materials.

8.1 Physical Events, Conditions, and Outcomes

Five workers were fatally injured due to a fire and explosion inside a magazine. The fire and explosion were a result of the accumulation of explosive black powder and aerial shells inside the magazine near its only entrance, and multiple ignition sources were present. The fire developed near the only entrance and exit, and prevented workers' escape from the magazine. All of these physical outcomes and conditions were the result of DEI's high-risk fireworks disposal activities.

8.2 DEI

DEI developed a fireworks disposal methodology that evolved into disassembling seized fireworks and separating and accumulating their explosive components – black powder and aerial shells – into cardboard boxes. By accumulating these explosive components, the DEI process created a much larger explosive hazard than the original fireworks represented. In addition, DEI's Activity Hazard Analysis and procedures failed to identify and control the key explosive hazards involved in this process. DEI personnel also had a lack of fireworks training and experience.

[180] The AcciMap tool was developed by Jens Rasmussen and popularized by Andrew Hopkins. Rasmussen, J., &. A. Hopkins. "Risk Management in a Dynamic Society: A Modeling Problem." *Safety Science*, 27 (2.3), 1997; pp 183-213.

8.3 VSE

The main federal seized-property management contractor, VSE, did not use individuals with the requisite technical and explosives expertise in its subcontractor selection and oversight process. VSE procurement personnel lacked explosives and fireworks experience and were not qualified to assess the technical differences between the two proposals they received to dispose of the fireworks. Even though DEI had never conducted a firework disposal operation, VSE procurement staff selected DEI as the subcontractor to dispose of contraband fireworks because DEI was already storing the fireworks, and its proposal was determined to be the lowest-cost and most time-efficient bid for the government, resulting in attractive "one-stop shopping." In addition, no VSE personnel or representatives aware of DEI's disposal process had the expertise to identify or evaluate any hazards associated with the activities being conducted.

8.4 Industry Codes and Standards

No Industry Codes or Standards exist that provide safety guidance on fireworks disposal.

8.5 Government

There is a regulatory gap that exists pertaining to fireworks disposal in the United States.

RCRA emergency permits lack safety management provisions. The State of Hawaii DOH awarded DEI an emergency hazardous waste permit to dispose of the contraband fireworks without reviewing its qualifications or proposed disposal methodology. As the DEI firework disposal operation evolved and major hazards were introduced from disassembling and accumulating firework components, the emergency hazardous waste permit included no requirements to review the safety aspects of these critical changes.

Neither the FAR, the DTAR, nor the DTAP explicitly address safety, and lack sufficient selection and oversight requirements for the prime contractor and its subcontractors with respect to the unique hazards associated with the disposal of hazardous materials, including fireworks.

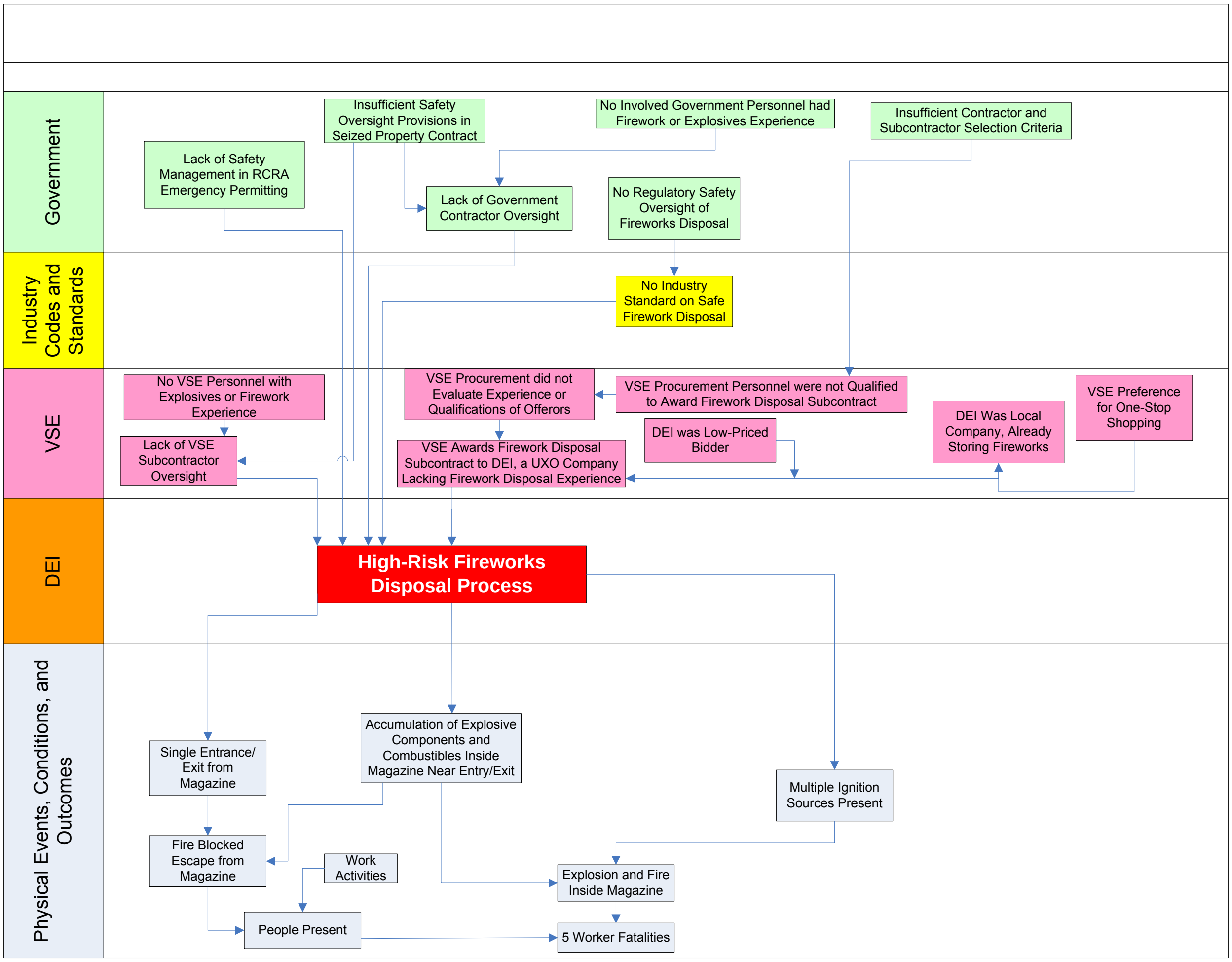

Figure 24. DEI Investigation AcciMap

9.0 Recommendations

The CSB makes recommendations based on the findings and conclusions of the investigation. Recommendations are made to parties that can affect change to prevent future incidents, which may include the company, contractors, industry organizations responsible for developing good practice guidelines, regulatory bodies, and/or organizations that have the ability to broadly communicate lessons learned from the incident, such as trade associations.

Federal Acquisition Regulatory (FAR) Council

2011-06-I-HI-R1

Establish an additional contractor responsibility determination requirement under Subpart 9.104-1 of the Federal Acquisition Regulation (FAR) addressing contractor safety performance. The analysis under this requirement should focus on incident prevention, and environmental and system safety. At a minimum, the language should specifically require the review of a prospective contractor's:

- Environmental and safety programs;
- Safety record and incident history;
- Ability to use safe methods for any work involving hazardous materials (including explosives); and
- Suitable training and qualifications for the personnel involved in the work including prior relevant safety experience.

Department of the Treasury Office of the Procurement Executive (OPE)

2011-06-I-HI-R2

Establish formal policy requiring that:

- Solicitations for contracts dealing with the storage, handling, and disposal of explosive hazardous materials, including fireworks, incorporate rigorous safety-related contractor selection provisions such as those provided in the DoD's Contractor's Safety Manual for Ammunition and Explosives, Section C1.5, "Pre-Award Safety Survey"; and
- Contracts dealing with the storage, handling, and disposal of explosive hazardous materials, including fireworks, include a provision requiring that any subcontract (regardless of tier) for the storage, handling, and disposal of explosives (including fireworks) be selected based on rigorous

safety-related contractor selection provisions such as those provided in the DoD's *Contractor's Safety Manual for Ammunition and Explosives,* Section C1.5, "Pre-Award Safety Survey."

2011-06-I-HI-R3

Establish a formal policy requiring that contracts and subcontracts dealing with the storage, handling, and disposal of explosive hazardous materials, including fireworks, incorporate rigorous safety-related contractor oversight provisions such as those provided in the DoD's *Contractor's Safety Manual for Ammunition and Explosives*, Section C1.6, "Pre-Operational Safety Survey" and C1.7, "Post-Award Contractor Responsibilities" to provide effective oversight of subcontractors handling and disposing of explosives and hazardous materials.

2011-06-I-HI-R4

When the NFPA guidance developed by the National Fire Protection Association for the safe disposal of fireworks as recommended under recommendation 2011-06-I-HI-R7 is completed, incorporate this document by reference into the formal policies established by 2011-06-I-HI-R2 and 2011-06-I-HI-R3.

Treasury Executive Office for Asset Forfeiture (TEOAF)

2011-06-I-HI-R5

Require additional provisions within the TEOAF seized property management contract, such as a contract line item number (CLIN), that provide for the prime contractor to use expert(s) to assist the prime contractor's personnel in the selection and oversight of subcontractors who handle, store, or dispose of explosive hazardous materials, including fireworks, pursuant to the main contract.

VSE Corporation

2011-06-I-HI-R6

Use experts to:

- Assist VSE procurement in selecting vendors to properly handle, store, and dispose of explosive hazardous materials, including fireworks, pursuant to prime contract requirements; and,
- Assist VSE personnel in overseeing the work to ensure it is being conducted safely.

National Fire Protection Association (NFPA)

2011-06-I-HI-R7

Develop a new standard, or incorporate within an existing standard, best practices for the safe disposal of waste fireworks that are consistent with environmental requirements. At a minimum this guidance or standard should:

- Discourage the disassembly of waste fireworks as a step in the disposal process;
- Minimize the accumulation of waste explosive materials, and encourage practices that reduce, recycle, reuse, or repurpose fireworks; and
- Incorporate input from ATF, EPA, and other agencies, experts, and available resources on fireworks disposal methodologies.

2011-06-I-HI-R8

Once fireworks disposal best practices under recommendation 2011-06-I-HI-R7 is completed, develop and implement an outreach plan to promptly communicate the new NFPA practices to relevant government agencies and private entities that dispose of waste fireworks.

U.S. Environmental Protection Agency (EPA)

2011-06-I-HI-R9

Revise the Resource Conservation and Recovery Act (RCRA) Subtitle C regulations to require a permitting process with rigorous safety reviews to replace the use of emergency permits under 40 CFR §270.61 for the disposal of explosive hazardous materials, including fireworks. At a minimum, the new process should require the use of best available technology, safe disposal methodologies, as well as safety management practices, such as those required by OSHA's Process Safety Management Standard (PSM), 29 CFR §1910.119 (e.g., hazard analysis and control, management of change).

2011-06-I-HI-R10

Until recommendation 2011-06-I-HI-R9 can be implemented, develop and issue a policy guidance document to provide a regulatory process with rigorous safety reviews to replace the use of emergency permits under 40 CFR §270.61 for the disposal of explosive hazardous materials, including fireworks. At a minimum, the new process should require the use of best available technology, safe disposal methodologies, as well as safety management practices, such as those required by OSHA's Process Safety Management Standard (PSM), 29 CFR §1910.119 (e.g., hazard analysis and control, management of change). Ensure its effective communication to all EPA regional administrators, state environmental agencies, and organizations within the fireworks industry.

2011-06-I-HI-R11

Effectively participate in the National Fire Protection Association's standard development process to develop guidance on the safe and environmentally sound disposal of fireworks, as recommended under recommendation 2011-06-I-HI-R7.

Bureau of Alcohol, Tobacco, Firearms, and Explosives (ATF)

2011-06-I-HI-R12

Effectively participate in the National Fire Protection Association's standard development process to develop guidance on the safe disposal of fireworks, as recommended under recommendation 2011-06-I-HI-R7.

BY THE

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Rafael Moure-Eraso
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Date of Approval January ___, 2013.

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Appendix A: Hawaii Firework Seizures

Between 2007 and 2010, CBP and ICE/HSI agents in Hawaii conducted three separate seizures of fireworks that were being imported from China into Honolulu, due to suspicion that they were illegally labeled for consumer use.

Seizures

Initial Seizure

On December 10, 2007, CBP seized a shipment of fireworks (initial seizure) in Honolulu[181] and declared these fireworks forfeited on February 12, 2008.[182] This shipment consisted of 11 pallets of fireworks and included "Maylar Tubes," "Assortment Shells," and "Singing Oriole/Dancing Swallows."

Second Seizure

On February 4, 2009, ICE/HSI seized a second shipment of fireworks in Honolulu[183] (second seizure) illegally imported from China. The property, consisting of 5,480 pieces contained in 1,370 cartons/39 pallets, was forfeited on July 6, 2009, for knowingly smuggling goods into the United States.[184] This seizure was being stored in the rear of the magazine at the time of the incident.

Primary Seizure

On January 13, 2010, ICE/HSI seized a third shipment of fireworks in Honolulu[185] (primary seizure) during its importation from China. The property was forfeited on March 22, 2010, for introducing merchandise contrary to law[186] and knowingly smuggling goods into the U.S.[187] DEI was in the process of disassembling the primary seizure on the day of the incident.

This shipment consisted of eight cardboard containers holding 296 boxes or 17 pallets of fireworks marked "Fireworks 1.4G" with the Identification Number UN0336 and DOT approval number EX2008060273. The four different products contained within this shipment were 65 boxes/519 pieces of "O Triple C"; 65 boxes/519 pieces of "Halawa"; 96 boxes/383 pieces of "Sky Festival"; and 70 boxes/559 pieces of "Krazy Kids." The total value of this shipment was over $30,000.00. Table 2 below details specific fireworks in the seizure and samples requested by CBP.

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[181] Seizure Number 2008-3201-000-013-01.
[182] For introducing merchandise contrary to law under 19 U.S.C. §1595A(c) and knowingly receiving explosive materials without a license or permit under 18 U.S.C. §842(a)(3)(A).
[183] Seizure Number 2009-3201-000-052-01.
[184] Under 18 U.S.C. §545 (1996).
[185] Seizure Number 2010-3205-000-012-01.
[186] 19 U.S.C. §1595a(c) (2008).
[187] 18 U.S.C. §545 (1996).

U.S. Dept. of Homeland Security (Disposition Order)				VSE (Chain of Custody)		
Line Item#	**Description**	**Unit of Measure**	**Quantity**	**Count was:**	**Count now:**	**Sample pulled**
001-A001	CC Halawa	CTNS	64	65 (519 pieces)	64	1
002-A001	KK Krazy Kids	CTNS	69	70 (559 pieces)	69	1
003-A001	RR O Triple C	CTNS	64	65 (519 pieces)	64	1
004-A001	SF Sky Festival	CTNS	95	96 (383 pieces)	95	1

Table 2. Seizures and Samples[188]

All four of these fireworks are multi-shot devices, often referred to as "cakes" in the industry, [189] and are designed to produce a succession of effects. According to the APA, each tube in a multi-shot device is typically 0.6" – 1.38" in diameter. A single igniter is generally used to initiate the first effect; a timed fuse, the spacing of the tubes, and the total number of tubes determine subsequent ignition of the tubes and the overall duration of the device. The tubes typically incorporated in these devices can include comets, mines, small aerial devices, audible effects, and any combination thereof.[190] In the instantaneous version of these devices, all tubes ignite simultaneously.

<u>ATF testing and analysis of Primary Seizure</u>

ATF conducted a detailed analysis of the primary seizure and concluded that

1. The *CC Halawa* fireworks consisted of a multi-tube device (shot cake) comprising 25 tubes. The shot cakes were packaged eight per carton and the tubes within each device were spaced less than 0.5 inches apart. Each shot cake contained two types of tubes, half of which contained shells with stars. For laboratory analysis, one of each type of tube was randomly selected, weighed, and disassembled. The lift charge for the tubes (with and without stars) consisted of 5.15 grams of black powder. The shells contained a 1-gram lift charge; 10.83 grams of pyrotechnic stars; and a burst charge, identified as perchlorate explosive mixture, of either 2.47 or 5.79 grams. The cake contained a total of 374.32 grams of explosives and pyrotechnics material. The ATF observed that, while the carton displayed a marking

[188] CTNS = Cartons (boxes).
[189] http://www.fireworks.us/Fireworks-Multi-Shots-Cakes-s/7.htm (accessed April 22, 2012).
[190] American Pyrotechnics Association (APA). *Generic Close Proximity Product Types: Pyrotechnics Used Before a Proximate Audience*, March 1, 2009; p 12.
http://www.americanpyro.com/pdf/APACloseProxDescriptionsFinal.pdf (accessed November 1, 2012).

indicating that it contained 1.4G UN0336 fireworks, the individual shot cakes were unmarked; the ATF therefore concluded that the product violated APA 87-1, paragraph 3.5.2. The DOT hazard classification for multiple tube devices with less than 0.5-inch tube separation is limited to 200 grams. This product also exceeded the maximum allowable explosive filler weight of 130 milligrams permitted in consumer fireworks by 27 CFR §555.151 (a)(7) and the maximum permitted charge weight of 130 milligrams for devices that are intended for sale to the public and produce an audible charge effect (APA 87-1, paragraph 3.373). The ATF therefore opined that the *CC Halawa* fireworks were classified as explosives (Class 1.3 or higher) and subject to regulations under 27 CFR Part 555, Commerce in Explosives.

2. The *KK Krazy Kids* fireworks also consisted of a 25-tube shot cake packaged eight per carton, with the tubes spaced less than 0.5 inches apart. Each tube contained 3.75 grams of a black powder lift charge. The shell contained 1-gram black powder lift charge; 9.01 grams of pyrotechnic stars; and 2.28 grams perchlorate explosive lift charge. The entire multi-tube assembly contained a total of 400.25 grams of explosives and pyrotechnics material. The ATF observed that, while the carton displayed a marking indicating that it contained 1.4G UN0336 fireworks, the individual shot cakes were unmarked and therefore concluded that the product violated APA 87-1, paragraph 3.5.2. The DOT hazard classification for multiple tube devices with less than 0.5-inch tube separation is limited to 200 grams. This product also exceeded the maximum allowable explosive filler weight of 130 milligrams permitted in consumer fireworks by 27 CFR §555.141(a)(7) and the maximum permitted charge weight of 130 milligrams for devices that are intended for sale to the public and produce an audible charge effect (APA 87-1, paragraph 3.7.3). The ATF therefore opined that the *KK Krazy Kids* fireworks were classified as explosives (Class 1.3 or higher) and subject to regulations under 27 CFR Part 555, Commerce in Explosives.

3. The *RR O Triple C* fireworks also consisted of a multi-tube device (shot cake) comprising 25 tubes packaged eight per carton. The tubes were spaced less than 0.5-inch apart. A tube was selected randomly from a single multi-tube device, weighed, disassembled, and submitted to the laboratory for analysis. Each tube contained 5.15 grams of a black powder lift charge; 10.5 grams of pyrotechnic stars; and 6.18 grams of a perchlorate explosive burst charge. Each shot cake contained a total of 570.25 grams of explosives and pyrotechnics material. The ATF observed that, while the carton displayed a marking indicating that it contained 1.4G UN0336 fireworks, the individual shot cakes were unmarked; thus, ATF concluded that the product violated APA 87-1, paragraph 3.5.2. The DOT hazard classification for multiple tube devices with less than 0.5-inch tube separation is limited to 200 grams. This product also exceeded the maximum allowable explosive filler weight of 130 milligrams permitted in consumer fireworks by 27 CFR §555.141 (a)(7) and the maximum permitted charge weight of 130 milligrams for devices that are intended for sale to the public and produce an audible charge effect (APA 87-1, paragraph 3.7.3). The ATF therefore opined that the *RR O Triple C* fireworks were classified as explosives (Class 1.3 or higher) and subject to regulations under 27 CFR Part 555, Commerce in Explosives.

4. The *SF Sky Festival* fireworks consisted of a 156-tube shot cake packaged four per carton. The cake contained six large tubes, and 150 smaller tubes spaced less than 0.5 inches apart. One of each type of tube was randomly selected, weighed, disassembled, and submitted for analysis. The large tubes contained 3.3 grams of a black powder lift charge and 4.7 grams of a perchlorate explosive burst charge, while the small tubes contained 0.96 gram of black powder lift charge and 1.22 grams of pyrotechnic stars. Each shot cake contained a total of 375 grams of explosives and pyrotechnic material. The ATF observed that, while the carton displayed a marking indicating that it contained 1.4G UN0336 fireworks, the individual shot cakes were unmarked; thus, ATF concluded that the product violated APA 87-1, paragraph 3.5.2. The DOT hazard classification for multiple tube devices with less than 0.5-inch tube separation is limited to 200 grams. This product also exceeded the maximum allowable explosive filler weight of 130 milligrams permitted in consumer fireworks by 27 CFR §555.141 (a)(7) and the maximum permitted charge weight of 130 milligrams for devices that are intended for sale to the public and produce an audible charge effect (APA 87-1, paragraph 3.7.3). The ATF therefore opined that the *RR O Triple C* fireworks were classified as explosives (Class 1.3 or higher) and subject to regulations under 27 CFR Part 555, Commerce in Explosives.

ATF analysis of samples from the subject seizure, collected from undamaged cartons found near the rear of the magazine after the subject explosion, provides photographic documentation of individual tubes for each type of these fireworks. The analysis concluded that a) the aerial component within the Halawa cakes were consistent with star shells and contained approximately 13.4 grams of powder; b) the aerial shells within the Krazy Kids cakes contained between 5.7 and 12.1 grams of material that appeared to be consistent with a flash powder; c) the aerial component within the O Triple C cakes contained approximately 5.9 grams of material consistent with flash powder; and d) the aerial shells within the Sky Festival cakes contained comets and approximately 4.3 grams of material that appeared to be consistent with flash powder.

Case Processing and Management

Post-seizure, a CBP Fines, Penalties and Forfeitures Officer (FP&F) at Port of Honolulu oversaw the seized property program and aspects of case processing. CBP issued disposition orders (CBP Form 7605) to VSE as TEOAF's primary federal contractor to secure storage for the seizures, coordinate their destruction, monitor and control storage costs, and inspect the storage facilities.

Storage

Initial Seizure

On December 11, 2007, CBP issued a disposition order to VSE to store the initial seizure. VSE subcontracted to Timberline Environmental Services[191] (Timberline) to locally store the fireworks at Waikele Storage. At some point, Timberline entered into a separate agreement with DEI to store the seizures. For unknown reasons, VSE did not renew their storage contract with Timberline and instead, in late 2008, directly subcontracted with DEI to store the firework seizures. On December 12, 2008, CBP issued a new disposition order to VSE to transfer the initial seizure from Timberline to DEI as the "new vendor for storage." DEI began storing the seizure at Waikele Storage on February 17, 2009.

[191] Timberline provides unexploded ordinance (UXO) services, including vegetation clearance, target removal, scrap management and large scale soil sifting operation on live ranges http://www.uxoservices.com (accessed November 29, 2012).

Second Seizure

On February 19, 2009, CBP issued a disposition order to VSE to store the second seizure. DEI had stored this seizure in the back of the magazine, where it was at the time of the incident.

Primary Seizure

On January 13, 2010, CBP issued a disposition order to VSE to store the primary seizure. On or around March 29, 2010, these fireworks were transferred to the A-21 magazine for storage.

Destruction

Initial Seizure

On February 10, 2010, CBP issued a disposition order to VSE to destroy the initial seizure. CBP issued a second disposition order on April 16, 2010. DEI obtained the requisite permitting to begin the disposal process on June 8, 2010.

CBP Form 7605 states that DEI completed its destruction of the initial seizure on December 1, 2010.

Second Seizure

Post-incident, on July 20, 2011, CBP issued a disposition order to VSE to destroy the second seizure. However, these 39 pallets of cake fireworks have not yet been destroyed and are being stored in the magazine where the incident occurred.

Primary Seizure

On April 16, 2010, CBP issued a disposition order to VSE, set to expire June 16, 2010, for destruction of the primary seizure.

The incident occurred while DEI was completing its disassembly of these fireworks; it had destroyed approximately 35 percent of this seizure at the time of the incident.

Appendix B. Department of Defense *Contractor's Safety Manual*

Pertinent Sections.

DoD 4145.26-M, March 13, 2008

C1.1. PURPOSE

C1.1.1. This Manual provides safety requirements, guidance and information to minimize potential accidents that could interrupt Department of Defense (DoD) operations, delay DoD contract production, damage DoD property, cause injury to DoD personnel, or endanger the public during DoD contract work or services involving ammunition and explosives (AE). The Manual contains the minimum contractual safety requirements to support DoD objectives. These requirements are not a complete safety program, and this Manual does not relieve a contractor from complying with Federal, State, interstate, and local laws and regulations.

C1.2. APPLICABILITY. When included in or properly incorporated into their contracts, subcontracts, purchase orders, or other procurement methods and made applicable to the contractor (or to their subcontractors), these safety requirements apply to contractors and subcontractors handling ammunition or explosives. Nothing in this Manual should be construed as making the Department of Defense a controlling employer under Occupational Safety and Health Administration (OSHA) regulations and standards.

C1.5. PRE-AWARD SAFETY SURVEY

C1.5.1. The PCO will request a DoD pre-award safety survey to help determine contractor capability. DoD safety personnel conduct pre-award surveys to evaluate each prospective contractor's ability to comply with contract safety requirements. While the pre-award safety survey is an opportunity for the contractor to request clarification of any safety requirement or other AE issue that may affect the contractor's ability to comply, any such clarification must be issued by the contracting officer. During pre-award surveys, the contractor shall provide:

C1.5.1.1. Site plans conforming to subparagraphs C1.8.5.1. through C1.8.5.5. for proposed facilities to be used in contract performance.

C1.5.1.2. Evidence of implementation of a safety program containing at least the mandatory requirements described in Chapter 3 of this Manual.

C1.5.1.3. General description of proposed contract facilities, including size, building layouts, construction details, and fire resistive capabilities.

C1.5.1.4. Fire prevention program and available firefighting resources, including local agreements or other documentation demonstrating coordination.

C1.5.1.5. Copies of required licenses and permits or demonstration of the ability to obtain approvals necessary to support the proposed contract.

C1.5.1.6. A safety history including accident experience; safety survey or audit reports by insurance carriers or Federal, State, and local authorities; and any variances, exemptions, or waivers of safety or fire protection requirements issued by Federal, State, or local authorities.

C1.5.1.7. Proposed operations and equipment to include process flow narrative/diagram, proposed facility or equipment changes, proposed hazard analysis, and proposed procedures for all phases of AE operations.

C1.5.1.8. Subcontractor information.

C1.5.8.1. Identification of all subcontractors proposed for the AE work.

C1.5.8.2. Proposed methods used to evaluate the capability of the subcontractor to comply with the requirements of this Manual.

C1.5.8.3. Proposed methods used to ensure subcontractor compliance.

C1.6. PRE-OPERATIONAL SAFETY SURVEY

C1.6.1. The Department of Defense reserves the right to conduct a pre-operational survey after contract award in these situations:

C1.6.1.1. Contractor has limited experience with the item.

C1.6.1.2. After major new construction.

C1.6.1.3. After major modifications.

C1.6.1.4. After an AE accident.

C1.6.2. When these situations occur, the contractor shall provide sufficient notification to the ACO and Defense Contract Management Agency (DCMA) contract safety personnel, to provide adequate time for the Department of Defense to schedule and perform a preoperational survey.

C1.7. POST-AWARD CONTRACTOR RESPONSIBILITIES. The contractor shall:

C1.7.1. Comply with the requirements of this Manual and any other safety requirements contained within the contract.

C1.7.2. Develop and implement a demonstrable safety program, including operational procedures, intended to prevent AE-related accidents.

C1.7.3. Designate qualified individuals to administer and implement this safety program.

C1.7.4. Prepare and keep available for review all hazard analyses used to justify alternative methods of hazards control implemented in order to comply with the mandatory requirements in this Manual.

C1.7.5. Provide access to facilities and safety program documentation to DoD safety representatives.

C1.7.6. Report and investigate AE accidents in accordance with Chapter 2 of this Manual.

C1.7.7. Provide identification and location of subcontractors to the ACO for notification or approval in accordance with terms of the contract.

C1.7.8. Establish and implement management controls to ensure AE subcontractors comply with paragraphs C1.7.1. through C1.7.7. of this section.

C3.5. <u>HOUSEKEEPING IN HAZARDOUS AREAS</u>

C3.5.1. Contractors shall keep structures containing AE clean and orderly.

C3.5.2. Contractors shall establish a regular cleaning program to maintain safe conditions. Personnel shall not perform general cleaning concurrently with hazardous operations.

C3.5.3. Explosives and explosive dusts shall not be allowed to accumulate on structural members, radiators, heating coils, steam, gas, air or water supply pipes, or electrical fixtures.

C3.5.4. Contractors shall use proper design of equipment, training of employees, and catch or splash pans to prevent spillage of explosives and other hazardous materials. Operators shall promptly remove spillage of explosives and hazardous materials following proper procedures established per section C8.4.

C3.5.5. Personnel shall use cleaning methods, such as hot water, steam, etc., that do not create ignition hazards for cleaning floors in buildings containing explosives. When these methods are impractical, personnel may use nonabrasive sweeping compounds that are compatible with the explosives involved. Flammable compounds shall not be used. Combustible sweeping compounds (closed cup flash point less than 230ºF) are acceptable for use. Personnel shall not use sweeping compounds containing wax on conductive floors if the wax can reduce conductivity. Personnel shall not use cleaning agents containing alkalis in areas with nitrated organic explosives, since these materials are incompatible and can form sensitive explosive compounds.

C3.5.6. Cleaning methods may use nonferrous wire brushes to clean explosives-processing equipment only when other methods of cleaning are ineffective. A thorough inspection should follow such cleaning to ensure that no wire bristles remain in the equipment. This also applies to cleaning magnesium ingot or other metal molds used in explosives processing. Cleaning methods should substitute fiber brushes for hairbrushes to reduce generation of static.

C3.5.7. Contractors shall dispose of all loose explosives swept up from floors of operating buildings. Responsible personnel shall thoroughly inspect and determine disposition of explosives recovered from sources other than ammunition breakdown operations and equipment.

C3.9. SAFETY HAND-TOOLS

C3.9.1. Unless a hazard analysis indicates otherwise, only hand tools constructed of wood or non-sparking metals such as bronze, lead, and “K” Monel shall be used for work in locations and on equipment that contain exposed explosives or hazardous concentrations of flammable dusts, gases, or vapors that are susceptible to mechanical spark. Hand tools shall be cleaned and inspected prior to use. Be aware that nonferrous metals used in so-called non-sparking tools may produce sparks. If the use of ferrous metal tools is required because of their strength and wear characteristics, the contractor’s safety office shall approve their use.

C3.9.2. If their strength makes the use of ferrous metal hand tools necessary during maintenance and repair operations, exposed explosives and other highly flammable and combustible materials shall be removed from the area. In addition, explosives operations in the immediate vicinity shall be discontinued to guard against accidental ignition of materials by flying sparks, and potential contact surfaces should be oiled or covered to reduce the likelihood of sparks.

C3.11. PROTECTIVE CLOTHING

C3.11.1. All AE operations require a hazard assessment to determine the need for protective clothing and personal protective equipment. The assessment shall include an evaluation of all hazards and factors contained in paragraph C3.11.2.

C3.11.2. The contractor shall provide a changing area for employees who must remove their street clothes to wear protective clothing, such as explosive plant clothing, anti-contamination clothing, or impervious clothing. To minimize the risk of exposure to unrelated personnel, AE operators shall not remove contaminated clothing from the AE areas. Employees shall not wear any static-producing clothing in areas where electrostatic discharge (ESD) is a hazard.

C3.11.3. Explosives plant clothing, generally referred to as powder uniforms, shall have nonmetallic fasteners and be easily removable.

C3.11.4. When sending explosives-contaminated clothing to an off-plant laundry facility, the contractor is responsible for informing the laundry of the hazards associated with the contaminants and any special laundering or disposal requirements.

C7.12. DISASSEMBLY

C7.12.1. Equipment and tooling that require disassembly during the manufacturing process should be designed to prevent metal-to-metal contact and trapping of explosive material.

C7.12.2. Non-routine disassembly of equipment and tooling, such as that necessary for equipment repair, shall not be started until potential hazards from trapped material or process residuals have been evaluated and controls or safeguards have been implemented to mitigate the hazard.

SAFETY REQUIREMENTS FOR MANUFACTURING AND PROCESSING PYROTECHNICS

C8.1. GENERAL. The safety precautions for manufacturing and processing pyrotechnics are similar to those required for many types of explosives and other energetic materials. However, pyrotechnics exhibit many different characteristics because they are formulated for different purposes. Knowledge of the various pyrotechnic properties is critical to the establishment of proper hazard controls. Pyrotechnics can be divided into several general categories including: initiators (igniters), illuminants, smokes, gas generators, sound generators, heat producers, and timing compositions. Each of these categories has its own characteristics and attendant processing requirements. Knowledge of these characteristics is necessary to assure safety in processing. The range of characteristics associated with pyrotechnics includes compositions that are easily initiated, including compositions that burn in seconds at temperatures exceeding 5000 degrees Fahrenheit (°F) [2760 degrees Celsius (°C)] through compositions that require substantial energy for initiation and have relatively low output temperatures. As examples, the auto-ignition temperature for smoke compositions is typically about 356°F [180°C], while for illuminants it is about 932°F [500°C]. Illuminants burn approximately 2.7 times faster than smokes and the heat of reaction is 1.5 times as great. Infrared (IR) flare compositions are both hotter and faster burning than illuminants. Many of the compositions in the igniter or initiator class are as sensitive to ESD, friction, or impact as are initiating explosives such as lead azide and lead styphnate. Initiation thresholds to stimuli such as impact, friction, and ESD and energy output of initiator compositions shall be determined and understood to ensure adequate safety controls are implemented to provide personnel safety in specific processes. In addition to the safety precautions generally required for the handling of explosives and other energetic materials, section C8.2. provides specific guidance pertinent to pyrotechnic operations.

C8.3. PROCESS REQUIREMENTS

C8.3.1. Housekeeping and Cleanliness Guidelines. Pyrotechnic operations require stringent housekeeping and cleanliness due to the sensitive nature of the ingredients and compositions; the dangerous effects of contamination, including cross contamination of oxidizers and fuels; and the amount of open or exposed ingredients and mixtures. Materials control and cleanliness are mandatory not only to reduce the likelihood of accidental initiations, but also to minimize the effects of an accident.

C8.3.1.1. Do not allow ingredient or composition dusts to accumulate, whether on the exterior work surfaces or the interior of process equipment and ventilation systems. Accident investigations frequently identify dust buildups as the source of initiation when items are dropped on or scraped across them. Dust accumulations also can provide a propagation path from the initiation of a small quantity to a much larger quantity, thereby increasing the magnitude of an accident.

C8.3.1.2. Vapor recovery methods or ventilation shall prevent the accumulation of volatile vapors, and ignition sources shall be eliminated or controlled to prevent the initiation of a solvent vapor cloud. Where volatile flammable solvents are part of the process, solvent vapors in ventilation systems, hallways, conduits, or pipes may also provide a propagation path from the initiation of a small quantity to larger quantities.

C8.3.2. Static Control Systems. As many pyrotechnic ingredients, mixtures, or the solvents used in their production are highly susceptible to initiation by static electricity, static control systems are mandatory where hazard analysis indicates a need. Static control systems include conductive floors or mats, shoes, wrist straps, grounding of equipment, etc.

C8.3.3. Hazard Analysis and Risk Assessment. For all pyrotechnic operations, a documented hazard analysis and risk assessment is mandatory to validate the layout of operations, selection of materials and equipment, and process control parameters. (See Chapter 11 of this Manual.)

C9.4. UNPACKAGED AE ITEMS AND DAMAGED CONTAINERS

C9.4.1. Unpackaged AE items shall not be stored in magazines containing AE in their original shipping container, but may be stored in separate magazines.

C9.4.2. Damaged containers of AE should not be stored in a magazine with serviceable containers of AE. Such containers should be repaired or the contents transferred to new or serviceable containers. All containers of AE in magazines shall be closed with covers securely fastened. Containers that have been opened shall be properly closed before restoring them. Stored containers should be free from loose dust and grit.

C9.4.3. Do not permit loose powder, grains, powder dust, or particles of explosive substances from broken AE or explosive substance containers in magazines. In addition, clean up any spilled explosive substance as soon as possible following proper procedures established per section C8.4. and suspend all other work in the magazine until accomplished.

RISK IDENTIFICATION AND MANAGEMENT

C11.1. GENERAL. AE operations involve many hazards and risks. These include the type of hazards associated with any industrial enterprise, e.g., AE reactivity, lifting, slipping, tool use, toxic chemicals, potential exposures to environmental extremes.

C11.1.1. The evaluation of hazards and risk of accidents addressed in this section relate to processes, not end products. The safety of operations is a contractor responsibility.

C11.1.2. A basic risk identification and management system is a necessary element of a comprehensive AE safety program. The purpose of this chapter is to address risk identification and management for all AE processes.

C11.2. RISK MANAGEMENT SYSTEM. Contractors shall have a risk identification and management system and perform a hazard analysis resulting in the evaluation of processes, materials, equipment, and personnel hazards. This analysis will aid in the development of a written SOP for AE contract operations. The analysis may include such factors as: initiation sensitivity; quantity of AE; heat output, burn rate, potential ignition and initiation sources; protection capabilities of shields; personnel protective equipment and clothing; fire protection; and personnel exposure with special considerations (such as toxic or corrosive chemicals). The contractor shall document the analysis and keep it as long as the SOP is active. The risk analysis should identify normal and abnormal (planned and unplanned) energy input into the AE, documenting the comparison between energy input and the sensitivity of the AE.

C11.2.1. The contractor shall perform risk analyses using personnel knowledgeable in the process, materials, equipment, and relevant safety requirements.

C11.2.2. A hazard is any condition, which, by itself or by interacting with other variables, may result in death or injury to personnel or damage to property. Controls only reduce the likelihood or severity of hazards. Controls do not eliminate hazards.

C11.2.2.1. After identifying a hazard, qualified contractor personnel shall determine the associated risk. The risk analysis of a potential accident shall address both the severity and the probability of occurrence of an accident.

C11.2.2.2. Evaluation of the hazard provides information useful for ranking the degree of risk associated with a hazard. The degree of risk indicates which hazardous conditions should receive priority for corrective action when compared to other hazardous conditions. One technique for ranking hazardous conditions is the assignment of a risk assessment code. The evaluation of the hazard results in the assignment of a narrative or numerical risk assessment that enables management to evaluate the seriousness of the risk before and after action is taken to control it.

Final

FINAL INVESTIGATION REPORT

CARIBBEAN PETROLEUM TANK TERMINAL EXPLOSION AND MULTIPLE TANK FIRES

CARIBBEAN PETROLEUM CORPORATION (CAPECO)

BAYAMÓN, PUERTO RICO

OCTOBER 23, 2009

KEY ISSUES:

TANK OVERFILL PREVENTION

COMMUNITY IMPACT

HAZARD ASSESSMENT

SAFETY MANAGEMENT SYSTEM

REGULATION GAPS:

- NO RISK ASSESSMENT CONSIDERING PROXIMITY TO COMMUNITIES
- NO ADHERENCE TO RAGAGEP
- NO REDUNDANT OR INDEPENDENT SAFEGUARDS TO PREVENT OVERFILLING A TANK

REPORT NO. 2010.02.I.PR
U.S. CHEMICAL SAFETY AND HAZARD INVESTIGATION BOARD

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Acronyms and Abbreviations

ALARP	As low as reasonably practicable
AOPS	Automatic Overfill Prevention System
API	American Petroleum Institute
AST	Aboveground Storage Tank
ATF	Bureau of Alcohol, Tobacco, Firearms and Explosives
ATG	Automatic Tank Gauge
Bbls	Barrels
bbls/hr	Barrels per hour
BSTG	Buncefield Standards Task Group
CA	Competent Authority
CAA	Clean Air Act
CAAA	Clean Air Act Amendments
CAPECO	Caribbean Petroleum Company
cbm/hr	Cubic meter per hour
CCPS	Center for Chemical Process Safety
CERCLA	Comprehensive Environmental Response, Compensation, and Liability
CH	Critical high level
COMAH	Control of Major Accident Hazards
CSB	U.S. Chemical Safety and Hazard Investigation Board
CWA	Clean Water Act
DFA	Direct Federal Assistance
DOH	Department of Health
DOJ	Department of Justice
EPA	Environmental Protection Agency
ESF	Emergency Support Function Annexes
FEMA	Federal Emergency Response Agency
FRP	Federal Response Plans
HAZOP	Hazard and Operability Study
HH	High-high level
HSE	Health and Safety Executive
ICC	International Codes Council
IFC	International Fire Code
IFR	Internal Floating Roof
ILTA	International Liquid Terminals Association
IOC	Indian Oil Corporation (IOC) Petroleum Oil Lubricants
IPL	Independent Protection Layer

IPAA	Independent Petroleum Association of America
ISA	International Society for Automation
JIC	Joint Incident Command
kPa	Kilopascal
LOC	Level of concern
MIIB	Major Incident Investigation Board
MOC	Management of Change
Mph	Miles per hour
MW	Maximum Working Level
NASA	National Aeronautics and Space Administration
NIMS	Incident Command System/National Incident Management
NFPA	National Fire Protection Association
OPA	Oil Pollution Act
OPP	Overfill Prevention Process
OSHA	Occupational Safety and Health Administration
PREPA	Puerto Rico Electric Power Authority
PHA	Process Hazard Analysis
PR DNR	Puerto Rico Department of Natural Resources
PR OSHA	Puerto Rico Occupation Safety Health and Administration
PREMA	Puerto Rico Emergency Management Agency
Psi	Pounds per square inch
Psia	Pounds per square inch absolute
PSM	Process Safety Management
RAGAGEP	Recognized and Generally Accepted Good Engineering Practices
RCRA	Resource Conservation and Recovery Act
RMP	Risk Management Program
SBA	Small Business Administration
SCO	State Coordinating Officer
SIF	Safety Instrumented Functions
SIL	Safety Integrity Levels
SIS	Safety Instrumented System
SOPs	Standard Operating Procedures
UCP	Unified Command Post
UK	United Kingdom
USCG	US Coast Guard
USFWS	US Fish and Wildlife Service
WWT	Wastewater treatment

1.0 EXECUTIVE SUMMARY

1.1 Incident Summary

On the night of October 23, 2009, a large explosion occurred at the Caribbean Petroleum Corporation (CAPECO) facility in Bayamón, Puerto Rico, during offloading of gasoline from a tanker ship, the *Cape Bruny*, to the CAPECO tank farm onshore. A 5-million gallon aboveground storage tank (AST) overflowed into a secondary containment dike. The gasoline spray aerosolized, forming a large vapor cloud, which ignited after reaching an ignition source in the wastewater treatment (WWT) area of the facility. The blast and fire from multiple secondary explosions resulted in significant damage to 17 of the 48 petroleum storage tanks and other equipment onsite and in neighborhoods and businesses offsite. The fires burned for almost 60 hours. Petroleum products leaked into the soil, nearby wetlands and navigable waterways in the surrounding area.

1.2 Public Impact and Emergency Response

The blast created a pressure wave registering 2.9 on the Richter scale[1] and damaging approximately 300 homes and businesses up to 1.25 miles from the site. In particular, the nearby Fort Buchanan military facility suffered over $5 million in damages; air and vehicle transportation was interrupted; and thousands of gallons of oil, fire suppression foam, and contaminated runoff were released to the environment. (Figures 9 and 10 show a map of communities neighboring the CAPECO facility and community damage.) CAPECO and the local fire department lacked the appropriate equipment or training to extinguish multiple tank fires, prolonging the environmental effects of the incident. The accident resulted in an emergency declaration for assistance from President Obama for the affected municipalities.

1.3 CSB Investigation

The CSB team arrived at the incident scene two days after the October 23, 2009, incident. The investigation team photo-documented the incident site, inventoried key evidence, interviewed witnesses, and assessed community damages. The team consulted tank experts and researched previous tank overfill incident investigations. Using several analytical tools, including timeline construction (Appendix A) and logic tree and AcciMap analysis[2] (Appendix C), the team

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[1] Puerto Rico Seismic Network. *Informe Especial, Explosión de Caribbean Petroleum en Bayamón, PR, 23 de octubre de 2009.* University of Puerto Rico Mayagüez Campus.

[2] AcciMap analysis is a causal diagram showing how factors remote from the immediate accident sequence contribute to the accident. Hopkins, A. An AcciMap of the Esso Australia Gas Plant Explosion. Australian

determined the root and systemic causes of this incident. The CSB investigators coordinated their work with the Puerto Rico Occupational Safety and Health Administration (PR OSHA) and the US Environmental Protection Agency (EPA).

1.4 CSB Findings

The CSB finds US regulations fail to consider bulk petroleum storage tank terminals similar to CAPECO as high-hazard facilities. Insufficient regulatory requirements for a hazard assessment, an unreliable level control and monitoring system, inadequate independent or redundant level alarms, and a poor safety management system led to CAPECO operating a high-hazard facility without the safeguards[3] necessary to prevent overfill. In addition, the CSB found the local Puerto Rico fire department was unprepared to address a vapor cloud explosion and multiple tank fires. This incident demonstrates that bulk aboveground tank terminals near residential populations are high-hazard facilities, and therefore regulations requiring a risk assessment and multiple layers of protection to prevent overfilling a tank, are necessary to protect workers and the public.

1.5 Key Findings

Physical Cause

1) During an operation to transfer gasoline from the vessel *Cape Bruny* tanker ship, Caribbean Petroleum Tank 409 overflowed with gasoline, resulting in a vapor cloud that encompassed 107 acres of the CAPECO tank farm.
2) The topography of the tank farm allowed the gasoline vapor cloud to migrate through open dike valves to low-lying areas of the tank farm and to the storm water retention pond in the wastewater treatment area, where it ignited.
3) Multiple physical causes likely contributed to Tank 409 overfill:
    - Malfunctioning of the tank side gauge or the float and tape apparatus during filling operations led to recording of inaccurate tank levels;
    - Normal variations in the gasoline flow rate and pressure from the *Cape Bruny* without the facility's ability to identify and incorporate the flow rate change in real time into tank fill time calculations may have contributed to the overfill;
    - Potential failure of the tank's internal floating roof due to turbulence and other factors may have contributed to the overfill.

National University. Obtained from http://www.qrc.org.au/conference/_dbase_upl/03_spk003_Hopkins.pdf (accessed January 2012).

[3] Safeguards are any device, system, or action that would likely interrupt the chain of events following an initiating event.

Control and Monitoring Failures

1) Inadequate tank filling procedures.
2) CAPECO's normal filling operations required that operators partially open the intake valve to a tank while filling another tank, because the pressure in the pipeline from the dock made manually opening a fully closed valve difficult. This inefficiency increased the potential error in fill time calculations. Refer to Section 6.9.4.
3) Unreliable tank gauging equipment.

Safety Management Systems

1) Tanks were not equipped with an independent high-level alarm system.
2) Tanks were not equipped with an independent Automatic Overfill Prevention System for terminating transfer operations.

Human Factors

1) The design of the dike valve system made it difficult to distinguish between open and closed valve positions
2) Insufficient lighting in the tank farm areas hindered operators from observing the overfilling of Tank 409 and the subsequent vapor cloud formation.

Lack of Reporting Requirements

1) An incomplete national incident database for assessing the frequency of specific types of incidents at bulk petroleum storage tank terminals inhibits the development and implementation of more tailored regulatory requirements, industry consensus standards, and best practices in this sector.

Emergency Response Findings

1) CAPECO and the local fire department lacked sufficient firefighting equipment to effectively fight and control a fire involving multiple tanks because they are not required to conduct a risk analysis where they have to consider and plan for the potential of a vapor cloud explosion involving multiple tanks.
2) CAPECO did not preplan with local emergency responders or adequately train facility personnel to deal with a fire involving multiple tanks.
3) Local fire departments lacked sufficient training and resources to respond to industrial fires and explosion.
4) A lack of coordination among the 43 federal, commonwealth and nongovernmental organizations that responded to the CAPECO incident further complicated the emergency response.

Regulatory Findings

1) The US regulatory system does not consider bulk aboveground storage tank terminals storing flammable liquid to be highly hazardous, even those near communities. Although the EPA characterizes facilities like CAPECO as substantial harm facilities, under the Facility Response Plan requirements, the risk assessment required for these facilities do not consider the potential of multiple tank releases as a worst case scenario.
2) Due to a lack of regulatory coverage under the Occupational Safety and Health Administration's (OSHA) Process Safety Management (PSM) standard and the Environmental Protection Agency's (EPA) Risk Management Plan (RMP), tank terminal facilities are not required to conduct risk assessments to address flammable hazards on site or to follow Recognized and Generally Accepted Good Engineering Practices (RAGAGEP).
3) A high-level alarm system or high-integrity overfill prevention system are not required by OSHA's Flammable and Combustible Liquids standard, the EPA's Spill Prevention Control and Countermeasure (SPCC) requirements. While facilities covered under SPCC must certify a SPCC plan by a Professional Engineer, only the EPA FRP plans meeting the substantial harm criteria are approved by the EPA. Furthermore, under SPCC facilities similar to CAPECO do not have to report overfill incidents unless oil is discharged to navigable waters.

Industry Standards

1) Despite past incidents in the US and internationally, the response of US industry, trade associations, professional associations, and standard-setting organizations has been inadequate to prevent similar incidents in the US.
2) NFPA 30 only requires one layer of protection on storage tanks, at minimum consistent gauging without requirement for an independent or redundant level alarm or an automatic overfill prevention system.
3) ANSI/API 2350 only requires an automatic overfill prevention system for remotely operated facilities and does not offer substantial guidance on conducting a risk assessment that considers the complexity of site operations, the type of flammable and combustible liquids stored at the facility or proximity to nearby communities when considering the necessary safeguards to protect the public. In addition, there is a lack of one comprehensive industry standard to address tank terminal operations, including tank filling operations and overfill prevention.
4) ICC does not require an independent audible or visual alarm to indicate rising liquid levels.

To prevent a similar incident from occurring, the CSB recommends policy changes to the following regulatory agencies, consensus, and industry standard-making bodies:

- United States Environmental Protection Agency (EPA)

- United States Occupational Safety and Health Administration (OSHA)
- American Petroleum Institute (API)
- International Code Council (ICC)
- National Fire Protection Association (NFPA)

2.0 CARIBBEAN PETROLEUM CORPORATION

2.1 Company History

Petroleum refining operations first began at the CAPECO site in Bayamón, Puerto Rico in 1955. Ownership changed several times in the decades following the purchase of the refinery by Gulf Oil Corporation in 1962 and Chevron Corporation in 1984. First Oil Corporation acquired the refinery in 1987 and operated it as a 48,000 barrel-per-day petroleum refining facility until 2000,[4] when the refinery closed. After filing for bankruptcy in 2001, the company reorganized and reduced operations to the terminal and 170 Gulf service stations throughout Puerto Rico. CAPECO filed for bankruptcy in 2001 and reorganized in 2003 to operate solely as a petroleum storage terminal and distribution facility.

2.2 Status of CAPECO

In August 2010, CAPECO declared bankruptcy. (See Section 5.7.) On May 11, 2010, Puma Energy Caribe, LLC acquired the Bayamón facility and other CAPECO assets under a broader EPA settlement. The settlement required cleanup activities under the Comprehensive Environmental Response, Compensation, and Liability Act (CERCLA),[5] Resource Conservation and Recovery Act (RCRA),[6] and Oil Pollution Act (OPA).[7]

2.3 Site Description

The CAPECO site covered 179 acres, 115 of which were developed into four areas: a tank farm, the decommissioned refinery, an administration area, and a wastewater treatment (WWT) plant. (See Figure 1.) The facility also owned and operated a loading dock on San Juan Bay in Guaynabo, 2.5 miles northeast of the site. (See Figure 2.) At the time of the incident, CAPECO employed 65 people.

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[4] *Documentation of Environmental Indicator Determination RCRA Corrective Action Environmental Indicator (EI) RCRIS Code (CA725), Current Human Exposures Under Control* (U.S. Environmental Protection Agency, 1999).

[5] Congress enacted CERCLA, commonly known as Superfund, in 1980 to provide tax collected money to federal authorities to respond directly to releases or threatened releases of hazardous substances that may endanger public health or the environment. *CERCLA Overview* (Washington, DC: U.S. Environmental Protection Agency). http://www.epa.gov/superfund/policy/cercla.htm (accessed December 19, 2014).

[6] RCRA, enacted in 1976, gives EPA the authority to control hazardous waste from "cradle to grave." U.S. Environmental Protection Agency. http://www2.epa.gov/aboutepa/new-law-control-hazardous-wastes-end-open-dumping-promote-conservation-resources (accessed December 19, 2014).

[7] Signed into law in August 1990, the OPA improved the nation's ability to prevent and respond to oil spills by establishing provisions that expand the Federal government's ability and provide money and resources necessary to respond to oil spills. *Oil Pollution Act Overview* (Washington, DC: U.S. Environmental Protection Agency). http://www.epa.gov/osweroe1/content/lawsregs/opaover.htm (accessed December 19, 2014).

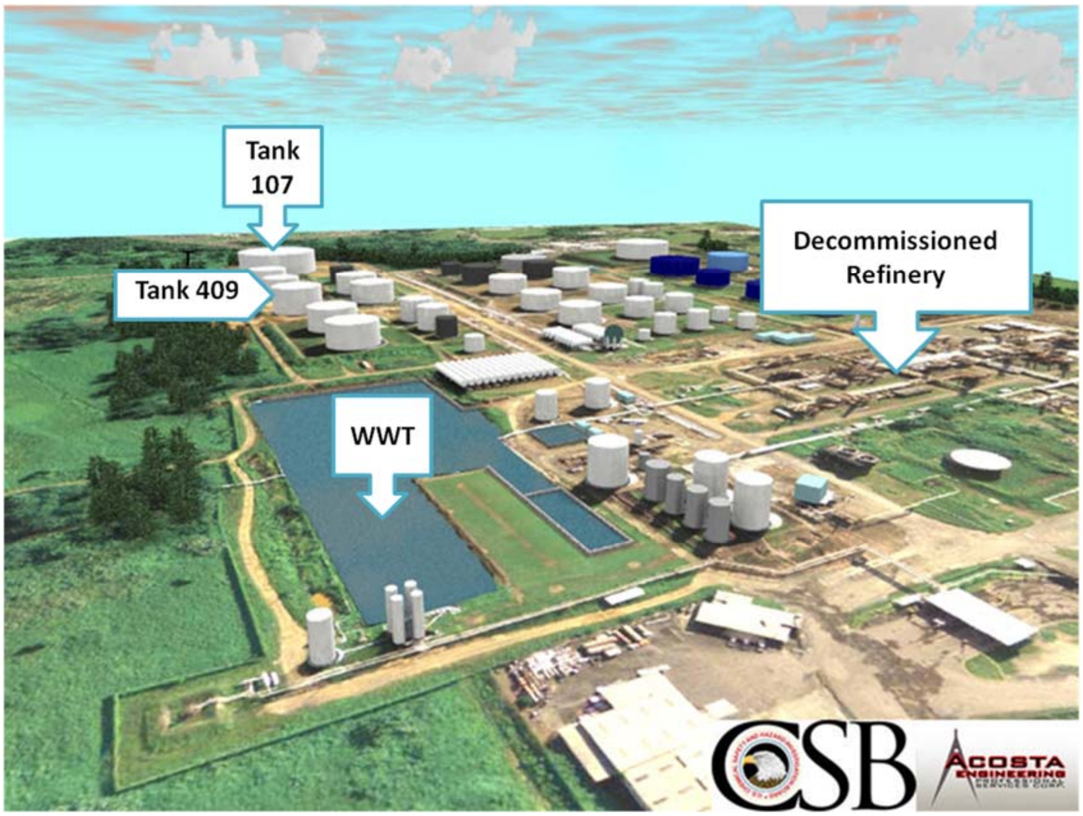

Figure 1: CAPECO tank farm, WWT, and decommissioned refinery overview

3.0 SITE OPERATIONS

CAPECO operated as a storage and distribution facility for gasoline, fuel oil, jet, and diesel fuel. The site was capable of storing approximately 90 million gallons of product.[8]

Figure 2: CAPECO Pipeline to Gulf Oil Dock where gasoline is offloaded from ships

3.1 Normal Site Operations

During normal site operations, vessels connected to the facility's pipeline at the dock in San Juan Bay and pumped petroleum products to one or more of the facility's aboveground storage tanks. Onsite, pumps transferred fuels between tanks, to the onsite truck loading facility, to the Puerto Rico Electric Power Authority (PREPA), and to the airport. Tanker trucks also received fuel onsite at the facility loading station for distribution across Puerto Rico.

3.2 Tank Farm Operations

Two tank farm operators, one WWT operator, and one shift supervisor conducted normal site operations staffing work on three 8-hour rotating shifts at the facility, from 6 a.m. to 2 p.m., 2 p.m. to 10 p.m., and 10 p.m. to 6 a.m.

Tank farm operators recorded tank levels every morning during a regular shift. Taking instructions from the facility's Planning Department, tank operators manually executed onsite

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[8] C. Jimenez, K. Glenn, G. Denning. *International Oil Spill Conference Proceedings, 2011 (1)* (Washington, DC, 1999). http://ioscproceedings.org/doi/pdf/10.7901/2169-3358-2011-1-90 (accessed December 19, 2014).

fuel transfers, blending gasoline with methanol, pumping products to PREPA and the airport via the pipeline, and receiving shipments from the dock in San Juan Bay.

3.3 Storm Water and Oil Runoff Management

Normal operations at the tank farm required that one operator inspect the secondary containment area for accumulating storm water and oil. Operations staff managed the secondary containment valves that drained storm water through storm water pipes to the storm water retention pond in the WWT plant. The morning operator closed the dike valves after rainstorms, and the evening WWT operator (2 p.m. to 10 p.m.) verified the valves were closed. Operators then recorded the secondary containment valve position in a valve inspection log. When oil was present in secondary containment, operators used a vacuum truck to remove it. (See Section 6.9.1.)

3.4 Ship Unloading and Tank-Filling Operations

The CAPECO Planning and Economics Department (Planning Department) was integral to the operations of the tank farm and management of fuel transfer operations.[9] Its staff coordinated fuel deliveries with the company and its fuel suppliers and instructed operators on which tank to fill, specified the volume of materials, and determined the filling schedule during unloading operations.

Similar to other tank terminals, the CAPECO Planning Department directed operations in the tank farm. After obtaining tank levels from the night-shift operations staff, the Planning Department rented tank space to various petroleum vendors interested in storing gasoline, jet fuel, or fuel oil.

Prior to product delivery, the Planning Department, the petroleum vendor, and the fuel distributor, in this case the *Cape Bruny*, negotiated a fee schedule for charging CAPECO based on the length of time to complete tank-filling operations at the terminal. The purchase terms, fee schedules and delivery contracts contained credits and penalties for all parties involved in offloading operations. If CAPECO operators completed filling operations in less than the allotted time, the *Cape Bruny* would refund CAPECO fees for the unused time. If filling operations took longer, the *Cape Bruny* could charge CAPECO the negotiated rate for the additional time. The Daily Operation Report from the Planning Department contained all filling instructions,

[9] Transfer operations for receiving a product into a tank encompasses all associated activities, including notification (verbally, electronically, or by other means) of a potential tank overfill and termination of flow into the tank (shutdown or diversion of product). American Petroleum Institute. *ANSI/API Standard 2350*. Fourth edition (Washington, DC: American Petroleum Institute, May 1, 2012).

including the level of product the tank should receive and the time it should take to fill the tank to the appropriate level. The Planning Department calculated the time based on the capacity of the pipeline and the volume discharged from the ship. CAPECO operations personnel were required to report any discrepancies in filling time to the Planning Department.

3.5 Communication

Due to the manual nature of operations, communication was essential to the success of the unloading process. During unloading operations, the operators remained in communication via radio with the WWT operator or the shift supervisor to ensure all necessary valve alignments and efficient switching between tanks occurred. Tank sizes varied at the CAPECO tank terminal, and only one tank, Tank 107 (Figure 1), was large enough to receive a full shipload of gasoline from the *Cape Bruny* tanker ship. In addition, due to storage limitations only a few designated tanks held gasoline. Because of this arrangement, CAPECO tank operators commonly switched flow among multiple tanks during unloading operations of a single shipment, requiring constant contact between tank operators and the shift supervisor.

3.6 Process Description

3.6.1 Level Measurements

CAPECO and cargo ship suppliers used multiple checks to ensure the correct amount of gasoline was unloaded and stored. Tank level measurement on a receiving tank occurred several times during filling operations. First, the tank farm operator recorded hourly readings by observing the level gauge on the side of the tank or the computer in the operator office displaying the same data. Then the tank farm operator and independent inspector placed car seals[10] on the appropriate receiving tank valves. Finally, the independent inspector[11] manually gauged the tank before and after filling operations and recorded it on gauge tickets shared with both the supplier and CAPECO. This dual verification measurement of tank levels was required for all material transfers involving a change of ownership.

[10] Car Seal: A security device consisting of a thin strip of metal cable usually attached to tank valve or hopper car closures. A broken seal indicates possible tampering or unauthorized tank entry.
[11] The independent, third-party inspector, employed by Intertek Caleb Brett, was responsible for determining the tank levels before and after filling operations to ensure that the correct amount of product was discharged to the tank. Caribbean Petroleum Corporation, Bayamón, PR. Communication, 2009.

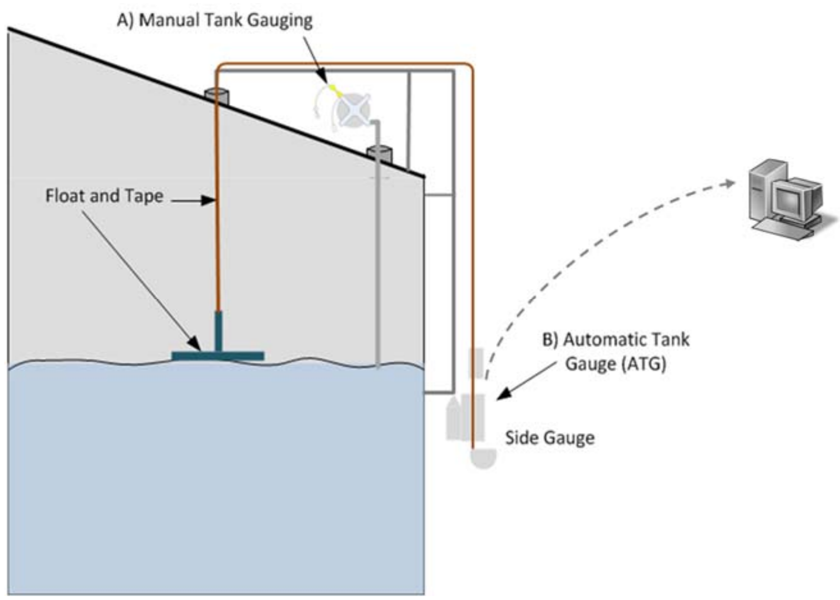

Figure 3: Manual and Automatic Tank Gauging. (A) Manual Gauging requires an operator to use a tape and measure to determine the liquid levels inside the tank. (B) Automatic Tank Gauging (ATG) requires an operator to read a level measurement from a tank gauge mounted to the side of the tank.

3.6.2 Manual Tank Gauging

Prior to the start and end of filling operations, the independent inspector manually measured the fuel tank levels by lowering a gauging tape[12] into the tank. (Figure 3.) A CAPECO operator

[12] The gauging tape used to measure tank liquid levels is similar to a common household measuring tape; it coils and has markings in feet and inches. Because gasoline and other fuels float on water, the operator coats the tape with special pastes to measure both the depth of water in the bottom of the tank and the fuel above it. Knowing the depth of the two liquids, the independent inspector and tank operators read the total liquid volume and the water volume from the strapping table. The operators subtracted the volume of water from the total volume to calculate the amount of fuel in the tank. When properly executed, this system accounted for the water volume and determined the fuel amount in a tank. Caribbean Petroleum Corporation, Bayamón, PR. Communication, 2009.

verified the measurements by comparing the tank liquid level to the strapping table[13] for that tank. The independent inspector and the operator placed car seals on various block valves of receiving tanks to prevent flow into or out of the tank before measuring the level in the tank and recording the readings on a form called a tank gauge ticket. This tracking method assured the transfer of an accurate volume of purchased product to the specified tank.

3.6.3 Manual and Automatic Tank Gauging

In addition to manual gauging by the independent inspector, operators used a float and tape gauge[14] mounted to the side of a tank, which automatically measured and displayed the tank level prior to the transfer, during transfer, and after product transfer termination.[15] *ANSI/API Standard 2350: Overfill Protection for Storage Tanks in Petroleum Facilities (2012)*[16] defines using float and tape level measurement instrumentation in this manner as an automatic tank gauging (ATG) system. (See Figure 4 and Section 6.5.)[17]

A typical float and tape gauge consists of depth-indicating dials, a motor, a long metal tape, and a sealed hollow cylinder called a float, which floats on the surface of the liquid in the tank. One end of the long metal tape attaches to the float, while at the other end, a motor winds the tape into a coil to maintain constant tension on the tape. As the liquid level in the tank falls, the weight of the float pulls the tape, and the motor allows the tape to extend farther into the tank. As the liquid level in the tank rises, the motor senses looseness in the tape and winds the tape into a coil to maintain the required tension. As the tape winds and unwinds, the mechanical dial rotates to indicate the total depth of liquid in the tank and displays the value on the side gauge (Figure 4).[18] Section 6.5 analyzes the failure of the ATG system in the incident.

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[13] Strapping table is a tabular record of a tank's volume versus height to convert measurements obtained from a tape (or strap) to liquid volumes. It is also known as a gauging table. *Access Engineering*, McGraw Hill. http://accessengineeringlibrary.com/search?q=strapping+table (accessed March 2012).

[14] The Shand and Jurs level instrument used by CAPECO is actuated by a float and stainless steel tape that measures tank levels recorded on a digital counter mounted to the side of a tank, allowing operators to read the tank liquid levels. *Automatic Tank Level Gauge Model 92021*. Product Data Sheet. Shand & Jurs: Hillside, IL.

[15] Termination refers to stopping flow of a product into a tank. American Petroleum Institute. *ANSI/API Standard 2350, Fourth edition* (Washington, DC: American Petroleum Institute, May 1, 2012).

[16] *ANSI/API Standard 2350-2012: Overfill Protection for Storage Tanks in Petroleum Facilities*. Fourth edition (Washington, DC: American Petroleum Institute, May 2012).

[17] This system is similar to the level measurement system that led to the CSB investigation of the explosion and fire at the Barton Solvents Wichita facility in Valley Center, Kansas. *CSB Barton Solvents Case Study. Static Spark Ignites Explosion Inside Flammable Liquid Storage Tank. No. 2007-06-I-KS* (Washington, DC: U.S. Chemical Safety Board, 2008). http://www.csb.gov/assets/1/19/CSB_Study_Barton_Final.pdf (accessed December 18, 2014).

[18] B. V Enraf. *The Art of Tank Gauging*. *http://enraf.ru/userfiles/File/4416650_rev4.pdf* (accessed January 2012).

3.6.4 Computer Monitoring of Tank Level

In 2004, CAPECO installed transmitter cards on the float and tape gauges that transmit the liquid depth to a computer in the operator's office, the shift supervisor's office, and the Planning Department. The computer instantaneously indicated the values for the liquid depth, the total volume based on the strapping table, and the flow rate into or out of the tank as it graphed the values over time and calculated the fill rate. When the computer data were unavailable, the shift supervisor and tank farm operator used information from the Planning Department, the start time of filling, and the strapping table, to calculate the estimated tank fill time. Refer to Section 6.5 for analysis of the automatic overfill prevention system and Section 6.7 for analysis of overfill prevention safeguards in place to prevent overfilling a tank.

Figure 4: Side gauge: mounted on the side on a tank and displaying the amount of liquid in the tank

4.0 INCIDENT DESCRIPTION

4.1 Physical Cause

On Wednesday, October 21, 2009, the *Cape Bruny* cargo ship arrived at the CAPECO dock in San Juan Bay to unload CAPECO's near-weekly shipment of more than 11.5 million gallons of unleaded gasoline. CAPECO assigned four personnel and three contract employees to assist in offloading gasoline from the *Cape Bruny* to various tanks on site.

Only Tank 107 with a capacity of 21 million gallons was large enough to hold a full shipment of gasoline, but it was already holding product. As a result, CAPECO planned to pump the gasoline shipment to four smaller storage tanks (405, 504, 409, and 411) and the balance to Tank 107, expecting the filling to take more than 24 hours (Figure 1). One CAPECO operator was overseeing transfer operations at the dock, while another was monitoring the gasoline delivery at the terminal. See Appendix A, Incident Timeline.

According to testimony and CAPECO records, shortly after noon on October 22, Tank 411 valve was fully opened but operations staff closed the valve to Tank 504 after observing the level gauge was physically stuck. Operators then fully opened the valve on Tank 409 and partially cracked the valve on Tank 411 directing more than 7,000 gallons of gasoline per minute into Tank 409 and allowing a small flow into Tank 411.

At approximately 6:30 p.m., the operator manually calculated that Tank 409 would reach maximum fill sometime between 9 p.m. and 10 p.m., during shift change. To avoid complications during shift change, the operator fully opened the valve on Tank 411 and almost completely closed the valve on Tank 409.

CAPECO operators often did not rely on the information displayed on the computer because the transmitters were frequently out of service. Therefore, under normal operation, operators manually recorded the hourly readings. On the night of the incident, the transmitter on Tank 409 was not sending level data measurements to the computer.

At 10 p.m., as Tank 411 reached maximum capacity and was closed, operators fully opened the valve on Tank 409. One operator then read the level on the Tank 409 side gauge and reported it to his supervisor, who estimated that the tank would be full at 1 a.m.

At the 11 p.m. walk-around, the tank farm operator observed the side gauge on Tank 409 during his hourly check. The operator called the level into the supervisor who calculated once again that the tank should be full at 1 a.m.; however, between the 11 p.m. and 12 a.m. check, Tank 409 began to overflow. At the 12 a.m. check, operations staff noticed a fog on the ground and on the road along Tanks 504, 411 and 409. Fuel gushed from the vents, creating a spray of gasoline that formed a vapor cloud and pooled in the secondary containment dike.

At midnight, the tank farm operator started to perform the hourly check of Tank 409, but before reaching the tank, he observed a vapor cloud and a strong smell of gasoline. He contacted the dock operator to halt the flow of gasoline to the tank and notified the WWT operator and his supervisor to meet at the western edge of the terminal. Despite the lack of illumination, they observed a white fog approximately three feet above the ground but could not hear or see gasoline overflowing from the vents on Tank 409 due to lack of lighting and the topography of the tank farm.[19] As they approached the fog, the men noticed the air cool as the fog condensed on their hands, despite the 79ºF temperature. Noting the potential danger, the supervisor sent one operator to the security gate, while the supervisor and another operator drove around the facility attempting to find the source of the leak and developing vapor cloud.

At 12:23 a.m., on October 23, 2009, security cameras at CAPECO and neighboring facilities recorded the ignition of the vapor cloud in the WWT area. About seven seconds after ignition, the vapor cloud exploded, creating a pressure wave that damaged hundreds of homes and businesses up to 1.25 miles from the site. The fire propagated through the vapor cloud and ignited multiple subsequent tank explosions registering 2.9 on the Richter scale.[20]

After the explosion, fuel in the damaged tanks burned for over two days while emergency responders fought to control the fire and prevent other tanks from igniting. The large fire demanded emergency personnel and resources from across the Commonwealth of Puerto Rico and the US mainland. Local fire departments with assistance from an industrial firefighting company took 66 hours to extinguish the fire after the explosion. As a result, 17 of the 48 tanks burned. (See Figures 5 and 6.)

[19] A CSB-commissioned topography study and visual modeling of the perspective from ground level on the night of the incident found that it would have been impossible for the operators and supervisor to observe the overflowing vents of Tank 409 because they were located a significant distance from the tank and at a lower elevation..

[20] Puerto Rico Seismic Network. *Informe Especial, Explosión de Caribbean Petroleum en Bayamón, PR, 23 de octubre de 2009.* University of Puerto Rico, Mayagüez Campus.

Figure 5: CAPECO multiple tank farm fire, October 23, 2009.

Figure 6: Impact of the explosion and multiple tank fires after the October 23, 2009 incident

4.2 Tank Overflow

Based on information from the *Cape Bruny* and CAPECO, the CSB calculated that Tank 409 overflowed for an estimated 26 minutes before the vapor cloud ignited (Table 1).

Table 1	
Estimated Volume of Gasoline Overfilling from Tank 409 during Filling Operations at CAPECO	
Tank	Estimated Volume of Gasoline into Tank
Tank 405	4,411bbls
Tank 504	62,984bbls
Tank 411	74,198 bbls
Tank 409	115,667 bbls
Total Offloaded Capacity	257,260 bbls
Total Offloaded from the Cape Bruny	261,878 bbls
Volume of Overfill	4,618 bbls
Volume of Overfill	193,974 gallons
*Overfill Duration	26 minutes
*Estimated flow rate 10,500 bbl/hr	
All calculations are approximations based on the tank gauging tickets and strapping tables from CAPECO.	

The CSB determined nearly 200,000 gallons of gasoline,[21] the equivalent of 20 fully loaded gasoline tanker trucks, rushed out of six vents in the tank. With a light breeze of about 5 mph[22] on a 79ºF night, the escaped gasoline formed a low-lying vapor cloud that encompassed an area equivalent to 107 acres.

The CSB found several possible scenarios could explain the tank overflow: malfunctions with the tank's internal floating roof, increased gasoline flow rate from the ship, and a malfunction

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[21] This calculated value was obtained using the tank gauging tickets, strapping tables for each tank involved in offloading operations and the estimated flow rate based on the pump pressure from the Cape Bruny.

[22] According to the Beaufort Scale (Wind Speed), a light breeze is defined as 5-7 miles/hour. On October 22 and 23, 2009, the average wind speed in San Juan, PR (12 miles from Bayamon, PR) was 5 miles/hour. Beaufort Scales (Wind Speed). http://www.unc.edu/~rowlett/units/scales/beaufort.html (accessed June 2012). Weather Underground, http://www.wunderground.com/history/airport/TJSJ/2009/10/14/MonthlyHistory.html?MR=1 (accessed June 2012).

with the side gauge in addition to many systemic failures in CAPECO's safety management system. See Section 6.0 for incident analysis.

4.3 Vapor Cloud Formation and Migration

Tanks 409 and 410 were located within the same secondary containment dike.[23] Similar to the Buncefield incident,[24] during the overflow, gasoline sprayed from the tank vents, hitting the Tank 409 wind girder and aerosolized,[25] forming a vapor cloud.[26] A CSB topographic survey of the site shows that Tanks 409 and 411 were located at the highest point within the tank farm area, allowing the vapor cloud to spread to lower lying areas in the direction of the WWT (Figure 7). See Figure 14, Tank 409 Specifications.

[23] Federal aboveground storage tank (AST) requirements mandate that facilities storing a large amount of petroleum product construct secondary containment to hold the contents of the largest tank/container with sufficient freeboard for rain and be sufficiently impervious to contain discharged oil. Secondary containment must be impermeable to the stored materials and have a manually controlled sump pump to collect rainwater. 40 CFR 112.8(c)(2) states a facility "may empty diked areas by pumps or ejectors; however, you must manually activate these pumps or ejectors and must inspect the condition of the accumulation before starting, to ensure no oil will be discharged." Drainage must be addressed in accordance with 40 CFR 112.8(b)(1-5) and 112.8(c)(3) i-iv *Above Ground Storage Tank Requirements*, *Code of Federal Regulations, Part 112, Title 40*, 2002.

[24] The British Health and Safety Executive (HSE) performed a study to demonstrate the mechanism and rate of vapor formation after a similar gasoline tank overflow and subsequent vapor cloud explosion at the oil storage depot in Buncefield, England, in December 2005. The HSE study found that aerosolization occurs during free fall. As the gasoline splashes against the side of the tank and wind girder, the vapor formation rate increases. (A wind girder is a metal ring welded around the middle exterior circumference of a tank that reinforces its structural integrity.)

[25] Aerosolization is the production or dispersal of an aerosol from a solid or liquid.

[26] *Vapour Cloud Formation Experiments and Modelling.* RR908 (Harpur Hill, UK: Health and Safety Executive, 2012). http://www.hse.gov.uk/research/rrhtm/rr908.htm (accessed July 2012).

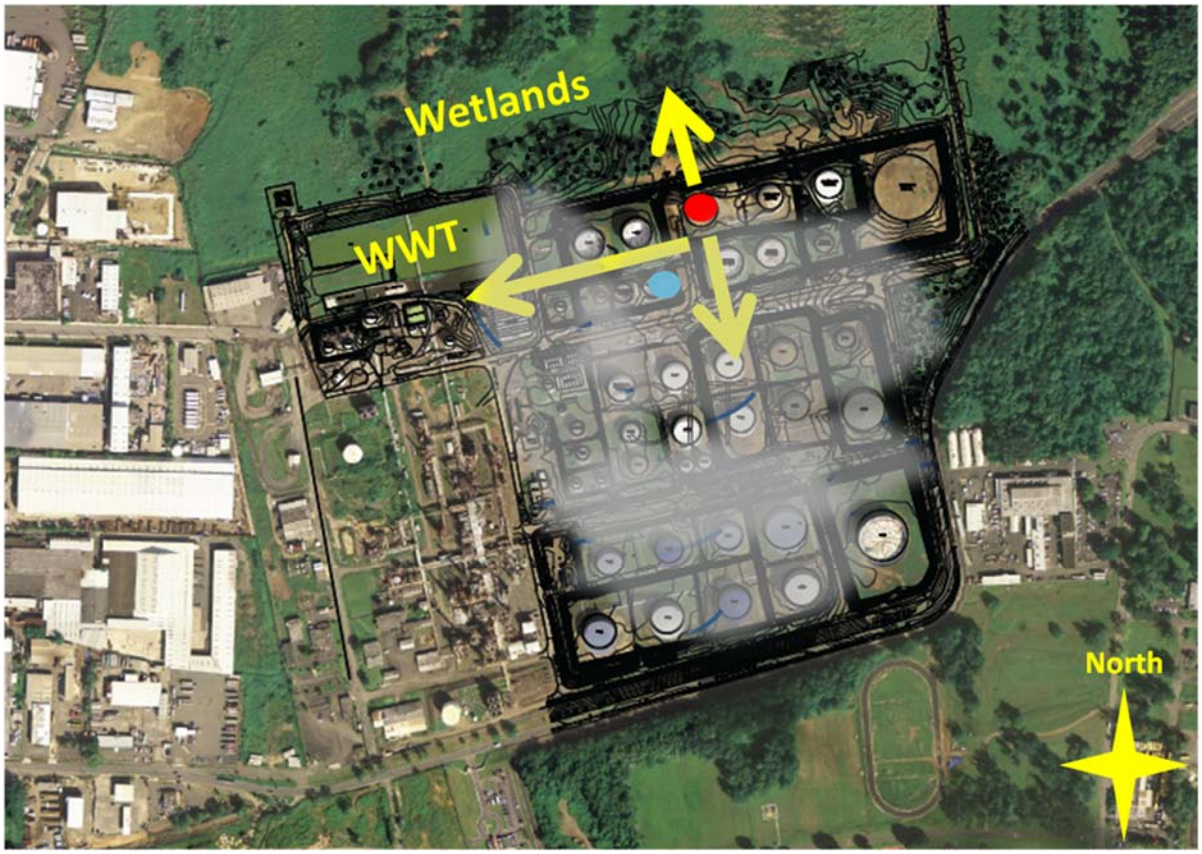

Figure 7. Topographic Survey of CAPECO Tank Farm showing the gasoline vapor cloud migration from higher elevation (Tank 409-Red and Tank 411-Blue) toward low-lying areas by the WWT plant, the south eastern end of the refinery and wetlands to the north. The cloud indicates the approximate area where the vapor cloud migrated based on surveillance footage.

4.4 Open Dike Drain Valves

Although the October 22, 2009, secondary containment valve inspection log indicated that the dike valve for Tank 409 was closed, the CSB determined that the valve was open after the incident.[27] The open dike valve directed gasoline to the storm water retention pond located in the WWT area where the large surface area pond provided a second location for gasoline to collect and vaporize. Refer to Section 6.9 for dike valve and human factors analysis.

[27] CSB investigators tested the dike valve after the incident by pouring water into the dike area of Tank 409 and observed the flow to the storm water retention pond in the WWT area through the underground storm water channel.

4.5 Ignition

The developing vapor cloud expanded from east to west toward the WWT area, north toward the wetlands area and the highway, south toward an east-west CAPECO site road, and east toward the neighboring Fort Buchanan (Figure 7). Onsite security video captured the ignition and initial flash fire in the WWT area occurring seconds before the explosion (Figure 8). The open secondary containment valves allowed the gasoline pool to extend to the storm water retention pond in the WWT area, which is not electrically classified.[28] The CSB did not determine the exact source of the ignition, but the areas where the vapor cloud traveled contained multiple potential ignition sources.

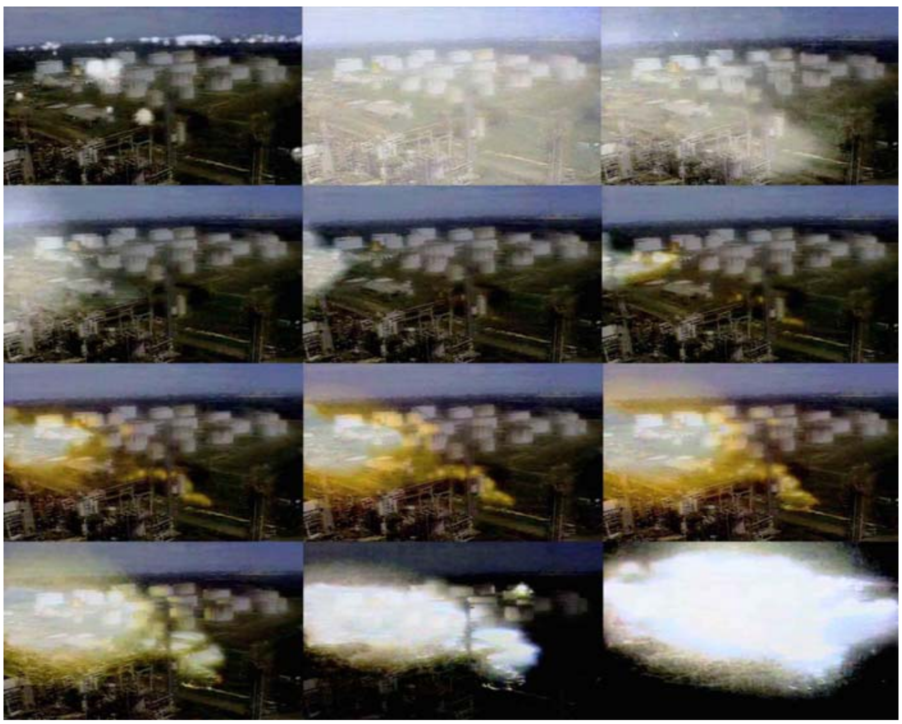

Figure 8: CAPECO surveillance footage of flame propagation during October 23, 2009 CAPECO explosion

[28] NFPA 70 defines hazardous (Electrically Classified) locations as areas where a fire or explosion hazard may exist because of the presence of flammable gases or vapors, flammable liquids, combustible dust, or ignitable fibers. *Electrical Classification: Using NFPA 70 and NFPA 499 to Classify Hazardous Locations*. http://www.oshainfo.gatech.edu/comb-dust/elec-classification.pdf (accessed December 17, 2014).

5.0 EMERGENCY RESPONSE

5.1 Response Description

Forty-three organizations responded to the incident, including federal, commonwealth, and nongovernmental organizations. The large number of responding agencies made communication difficult because the incident commander and the Unified Command Post changed frequently when different agencies claimed priority jurisdiction. The Bayamón and Cataño Fire Departments first arrived at the front gate of CAPECO at approximately 12:30 a.m. on October 23, 2009. At that time the fire had extended to approximately 103 acres (1,500 feet by 1,500 feet) of the tank farm, but firefighters were prohibited from entering the site until CAPECO safety personnel and the site fire chief arrived approximately 45 minutes later. Upon entering the facility, firefighters discovered that CAPECO lacked the necessary firefighting equipment to fight multiple tank fires at once. They found worn or missing fire hoses, stationary fire monitors without sufficient pressure to reach the tops of tanks, and insufficient equipment to provide the large quantities of foam necessary to control a fire of this magnitude.

Furthermore, CAPECO personnel and local firefighters were trained only for a worst-case scenario involving one tank on fire, rather than 11 tank fires at the same time caused by a vapor cloud explosion. Without sufficient equipment or training, local responders attempted to fight the multiple tank fires but failed as the fire encompassed more tanks.

The incident caused the governor of Puerto Rico to request federal assistance, and on October 24, 2009, the President signed an emergency declaration[29] providing assistance for the municipalities of Bayamón, Cataño, Guaynabo, San Juan, and Toa Baja (Figure 9). The federal emergency declaration activated 17 FEMA Emergency Support Function Annexes (ESF)[30] and enabled FEMA to provide logistical support, Direct Federal Assistance (DFA), and public assistance grants to state and local municipalities.[31] Logistical support included setting up a more

[29] On October 24, 2009, President Obama signed FEMA-3306-EM-PR for Category B (emergency measures) Direct Federal Assistance (DFA).

[30] During an Emergency Declaration, FEMA has jurisdiction to release funding under its 17 FEMA Emergency Support Function Annexes. The ESFs provides structure and support for coordinating a federal interagency response to an incident. *Emergency Support Function Annexes* (Washington, DC: U.S. Federal Emergency Management Agency, 2008).

[31] Through the Emergency Declaration request, Puerto Rico also requested DFA because it lacked the resources to handle the event. Under the Stafford Act, DFA states that the President can authorize 100% federal funding for emergency work: debris cleanup and/or removal; provision of food, water, ice, and other consumable commodities; and other emergency protective measures, under sections 403 and 407. The President also authorized the state and municipalities affected by the incident to be reimbursed for emergency protection measures through FEMA's Public Assistance (PA) grant programs.

than 400-person Incident Command Post to assist state and federal agencies and to circulate information to the media and respond to public inquiries. In addition to the 530 firefighters and other responding agencies, approximately 900 National Guard personnel provided support in firefighting efforts, transportation, security, and environmental assessments. These efforts continued until Sunday, October 25, 2009, at 11:30 a.m., when the fires were extinguished.[32] Ultimately, FEMA provided over $3.4 million[33] to 27 entities for response efforts during and after the incident.

5.2 Response Assessment

The CSB found the following shortcomings in the emergency response to the CAPECO incident, many of which were also identified in the FEMA After Action Report,[34] compiled after the incident.

- *Insufficient equipment*. Tank terminals like CAPECO are not considered high-hazard facilities under existing EPA and OSHA regulations;[35] therefore, they are not required to conduct a risk analysis where they consider the potential of a vapor cloud explosion and multiple tank fires. Neither CAPECO nor the fire department had the requisite amount of foam and adequate equipment to effectively fight and control a fire involving multiple tanks.

- *Insufficient preplanning with local fire departments or firefighter training at the site level*. CAPECO did not preplan with local emergency responders, set up mutual aid with other hazardous materials sites, or adequately train facility personnel to address a tank farm fire involving multiple tanks. The CSB found that after the refinery shut down in 2000, the facility curtailed investment into its firefighting operations on-site. In fact, training for CAPECO personnel was limited only to fighting a fire involving one tank, not an incident involving multiple tanks.

- *Limited emergency preparedness*. Local fire departments did not have sufficient training or resources to respond to industrial fires and explosions, which resulted in firefighting delays from insufficient foam and equipment. The limited training and resources of the local fire

[32] The PR Fire Department extinguished the fires with assistance from a contractor that specialized in tank farm firefighting.
[33] *Summary of Declaration Report: Public Assistance Program* (Washington, DC: U.S. Federal Emergency Management Agency, June 11, 2012).
[34] *Caribbean Petroleum Corporation (CaPeCo) / Gulf Refinery Explosion After Action Report (AAR)*. FEMA 3306-EM-PR. October 23-26, 2009 (Washington, DC: U.S. Federal Emergency Management Agency, 2010).
[35] EPA considers facilities as CAPECO as a “significant and substantial harm facility” under the Facility Response Plan regulations. See Section 8.6.6 for further discussion.

departments resulted in an inefficient firefighting operation. The fires were not extinguished until an industrial firefighting company suppressed the last of the tank fires. FEMA's After Action Report identified additional training and exercises for the Incident Management Team on an all-hazards approach to improve the initial multiagency response and recovery.

- *Overlapping multi-agency, multi-jurisdictional response*. Forty-three federal, commonwealth, and nongovernmental organizations responded to the incident.[36] As new agencies arrived, the person in the Incident Commander role changed without following the Incident Command System/National Incident Management System (ICS/NIMS). For example, the Puerto Rico Emergency Management Agency (PREMA) operated using ICS/NIMS, whereas the PR National Guard conducted operations using military standards.[37] FEMA's After Action Report also identified poor integration of Unified Command with the National Guard and PREMA after the Governor's office declared the emergency. The report further emphasized the need for additional joint training and exercises to improve the integration of the ICS with the NIMS. The FEMA report also calls for the development of Mass Fatality and Mass Casualty plans to address catastrophic incidents.

5.3 Incident Impact

5.3.1 Community Impact

Despite approximately 1,600 people residing adjacent to the CAPECO facility in the Puente Blanco community[38] and about 48,500 residents living in Cataño three miles from the incident site (Figure 9), the 2009 explosion and fires did not result in any fatalities. However, shrapnel and glass from the blast caused minor injuries to three people at Fort Buchanan. Nearby residents of the surrounding communities were awakened by the blast and ensuing fire. The CSB learned, regulatory authorities in Puente Blanco issued unclear evacuation orders by bullhorn as they drove through the community. With no planned evacuation routes or shelters, residents crowded into the narrow streets. Some members of other nearby communities evacuated voluntarily to escape damaged homes and potential health effects from the smoke and vapors generated by the fire.

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[36] *Caribbean Petroleum Corporation (CaPeCo) / Gulf Refinery Explosion After Action Report (AAR)*. FEMA 3306-EM-PR, October 23-26 2009 (Washington, DC: U.S. Federal Emergency Management Agency, 2010): 9.9.
[37] Ibid., p.6.
[38] Ibid., p.4.

Fort Buchanan experienced the most severe damage—suffering an estimated $5 million in repair costs. Community impact assessments[39] found most of the structural damage occurred in the Puente Blanco neighborhood where PREMA and the Department of Housing (DOH) found damage to 232 of the 266 homes assessed; 139 were repaired and six were demolished by November 2009.[40] The Puente Blanco community also experienced environmental contamination to several surface water bodies, including federally protected wetlands and streams surrounding the CAPECO site. After assessing 289 homes damaged by the explosion in the Cataño community, the Small Business Administration (SBA)[41] designated 25 single-family homes as destroyed or severely damaged at or beyond 40% of their fair market value. (See Figure 10.)

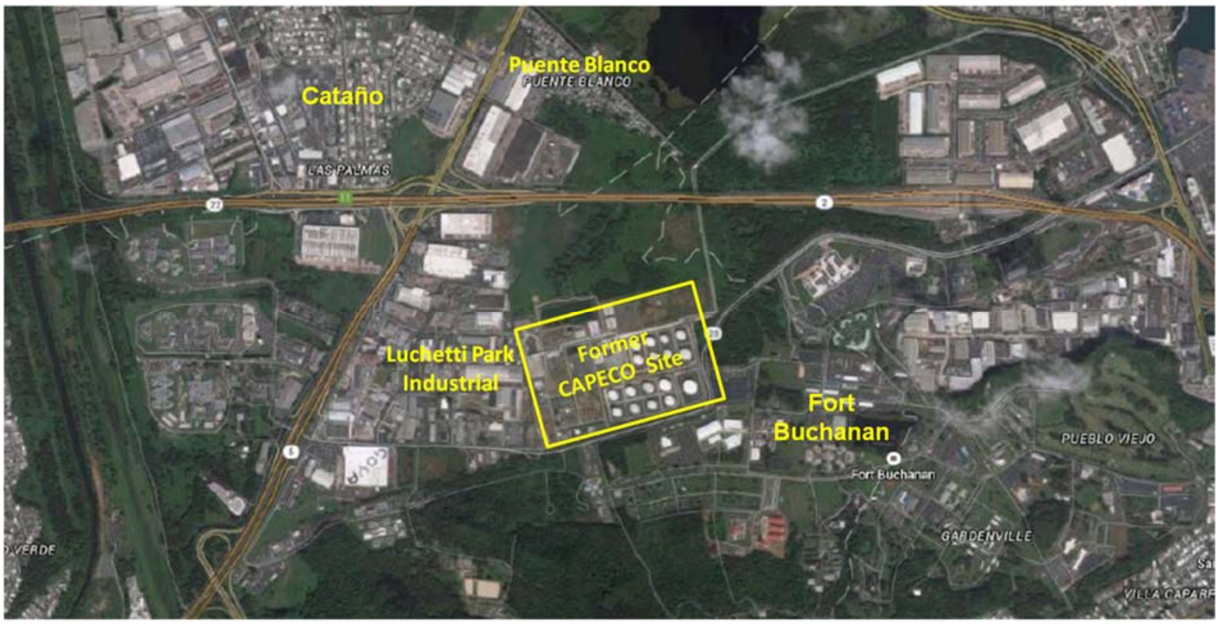

Figure 9: Communities neighboring the CAPECO facility

[39] The Small Business Administration (SBA), in conjunction with the PR Emergency Management Agency (PREMA) and the PR Department of Housing (DOH), conducted community assessments after the incident.

[40] Federal Emergency Management Agency. Caribbean Petroleum Corporation (CaPeCo) / Gulf Refinery Explosion After Action Report (AAR). FEMA 3306-EM-PR. October 23 – 26, 2009 *Incident Recovery Activities Summary: Caribbean Petroleum Corporation Fuel Explosion* (November 18, 2009).

[41] The SBA's mission is to help disaster-stricken communities through direct loans to businesses, homes, and non - profit organizations. SBA Disaster Recovery Plan. https://www.sba.gov/content/disaster-recovery-plan (accessed December 19, 2014).

Figure 10: Community damage surrounding the CAPECO facility

Figure 11: Oil Spill into nearby wetlands (photo from NOAA.gov) and in a local community drain after CAPECO explosion and tank fires

5.4 Impact to the Commonwealth

The incident forced the Commonwealth government and local officials to evacuate approximately 3,000 people in a nearby prison and other government facilities. Changing wind patterns caused the governor to prepare for the evacuation of over 30,000 individuals likely affected by particulate fallout from the smoke plume that extended miles out to sea. Overall, approximately 600 people used the shelters in Cataño, Guaynabo, and Toa Baja.[42]

5.5 Environmental Impact

The CAPECO incident released thousands of gallons of oil, fire suppression foam, and contaminated runoff to Malaria Creek, which traverses the Puente Blanco community to the San Juan Bay. CAPECO and the EPA collected and shipped offsite an estimated 171,000 gallons of oil and 22 million gallons of contact water.[43, 44] Overall, approximately 30 million gallons of petroleum was released via storm water channels, on-site and off-site surface water bodies, and neighboring wetlands to San Juan Bay.[45] Environmental assessments jointly conducted by the EPA, the US Fish and Wildlife Service (USFWS), and the Puerto Rico Department of Natural Resources (PR DNR) found dead wildlife and both aquatic and avian species, including several legally protected species, covered in oil.[46] (Figure 11.)

5.6 Impact to Transportation and Commerce

The incident also disrupted commerce and transportation corridors on the ground and in the air in the San Juan area. A main interstate, PR-22, was closed for three days, limiting access to work and shopping malls and interrupting transportation of goods to and from the main port. The smoke plume also resulted in airspace interruptions and temporary flight restrictions for the Luis Muñoz Marín International Airport. The explosion caused many tourists in the San Juan area to

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[42] *Caribbean Petroleum Corporation (CaPeCo) / Gulf Refinery Explosion After Action Report (AAR).* FEMA 3306-EM-PR. October 23-26, 2009. (Washington, DC: U.S. Federal Emergency Management Agency, 2010): 11.

[43] Contact water contains petroleum product.

[44] C. Jimenez, K. Glenn, G. Denning. *International Oil Spill Conference Proceedings*, *2011 (1).* http://ioscproceedings.org/doi/pdf/10.7901/2169-3358-2011-1-90 (accessed December 19, 2014).

[45] Environmental Protection Agency. Securing Cleanup from ashes at the Puma Energy Caribe Site. 2014. http://www2.epa.gov/enforcement/case-study-cleanup-puma-energy-caribe-site-puerto-rico (accessed May 4, 2015).

[46] C. Jimenez, K. Glenn, G. Denning. *International Oil Spill Conference Proceedings*, *2011 (1).* http://ioscproceedings.org/doi/pdf/10.7901/2169-3358-2011-1-90 (accessed December 19, 2014).

flee, affecting the local economy. The total economic and psychological effects of these major disruptions have not been determined.[47]

5.7 Impact of Overfill Incident on CAPECO

In May 2010, CAPECO was required to pay more than $8.2 million for environmental liabilities associated with the Bayamón petroleum distribution facility and the 170 service stations it owned and leased under a settlement agreement.[48] In the same month, the EPA issued a Notice of Federal Assumption to take responsibility for the remaining cleanup at the CAPECO site.[49]

6.0 INCIDENT ANALYSIS

6.1 Systemic Failure at CAPECO Led to Failure of the Overfill Prevention System

The CSB determined that numerous technical and systemic failures contributed to the explosion and multiple tank fires at the CAPECO tank terminal. The CSB found that multiple layers of protection failed within the level control and monitoring system at the same time. In addition a lack of independent safeguards contributed to the overfill. James Reason's Swiss Cheese Model best demonstrates these systemic failures that led to the accident.[50] Reason postulates that an accident results from the breakdown of the "interaction between latent failures[51] and a variety of local triggering events (active failures)"[52] and although rare, the "adverse conjunction of several

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[47] Ibid.

[48] *United States Announces Bankruptcy Settlement with Oil Company in Wake of October 2009 Explosion and Fire.* (Washington, DC: U.S. Department of Justice, 2011) http://www.ju.tice.gov/opa/pr/2011/May/11-enrd-657.html (accessed December 19, 2014).

[49] C. Jimenez, K. Glenn, G. Denning. *International Oil Spill Conference Proceedings*, *2011 (1)* http://ioscproceedings.org/doi/pdf/10.7901/2169-3358-2011-1-90 (accessed December 19, 2014).

[50] Reason postulated that "a multiplicity of overlapping and mutually supporting defenses" both hard and soft, allow complex systems to function despite a single technical or human failure. Hard defenses include technical devices such as automated engineered safety features, physical barriers, alarms and annunciators, interlocks, keys, personal protective equipment, non-destructive testing, and improved system design (Reason, 1997). Soft defenses rely heavily on a combination of paper and people, i.e., legislation, regulatory surveillance, rules and procedures, training, drills and briefings, administrative controls, licensing, certification, supervisory oversight, front-line operators (Reason, 1997).

[51] Latent Failures arise from strategic and other top-level decisions made by governments, regulators, manufacturers, designers, and organizational managers. They include poor design, supervisory gaps, undetected manufacturing defects, maintenance failures, unworkable procedures, poor automation, inadequate training, and insufficient or inadequate tools and equipment. These failures can lay dormant in an organization for years and, if undetected or unfixed, can contribute to active failures by creating deviation from procedures (Reason, 1997).

[52] Active failures are unsafe acts committed by those at the human-system interface or the sharp end of the system by personnel. They are immediate and have short-lived effects (Reason, 1997).

causal factors" from various layers.[53] The deficiencies or holes at each layer of protection are constantly increasing or decreasing based on management decisions and operational deviations.[54]

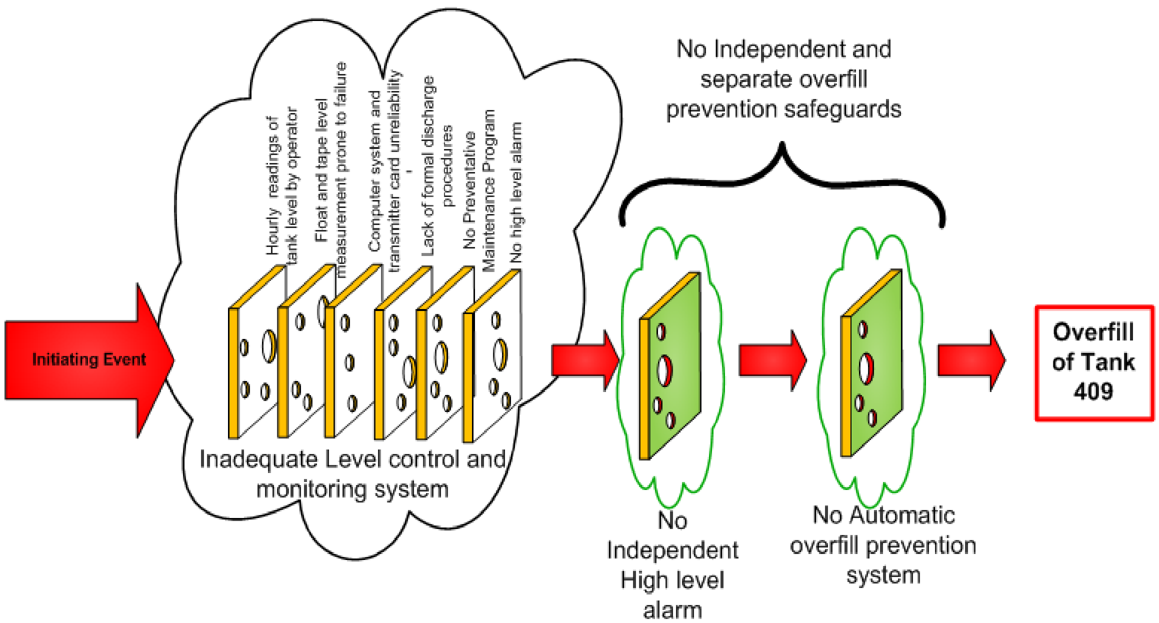

Figure 12: Contributing to the October 2009 overfill incident at CAPECO were multiple failures of the level control and monitoring system in addition to a lack of safeguards like a high level alarm, an independent level alarm and an automatic overfill prevention system that allows for automatic shutdown or diversion.

6.1.1 Inadequate Safety Management System

The CSB found that the CAPECO overfill incident resulted from a combination of multiple deficiencies in the safety management system, including the breakdown in the level control and monitoring system within an inadequate safety management system and a lack of safeguards,[55] such as an independent high-level alarm and an automatic overfill prevention system. In terminals, the level control system includes procedures and equipment used to control tank-filling operations. For many tank operations, the level control system is the operator and the alarm system, which together are able to control the fuel receiving process. In some cases, the

[53] J. Reason. *Human Error*. (United Kingdom: Cambridge University Press, 1990).
[54] J. Reason. *Managing the Risks of Organizational Accidents* (Brookfield: Ashgate, 1997).
[55] Safeguards are any device, system, or action that would likely interrupt the chain of events following an initiating event.

level control system is an automatic level controller functioning to restrict flow into the tank. The CSB finds that systemic failures at CAPECO included:

- a history of poorly maintaining terminal operations;
- an inherent financial pressure to fill the tanks within the Planning Department's stipulated time, which was at odds with safety;
- a failure to learn from previous overfill incidents at the facility;
- a lack of preventative maintenance for the malfunctioning float and tape device, automatic tank gauge transmitters;
- an unreliable computer for calculating tank fill times;
- a lack of overfill prevention safeguards as an independent alarm;
- a lack of formal procedures for tank-filling operations for operators and managers;
- an insufficient mechanical integrity program for safety critical equipment;
- poor adherence to human factors principles for safety critical equipment.

6.2 CAPECO History of Poorly Maintaining Terminal Operations

The CSB found that CAPECO had a history of poorly maintaining its terminal operations. EPA inspection records from 1992 to 2004 indicate a lack of investment in tank valves, maintenance of secondary containment around the tank farm, and appropriate level gauges and engineering controls. For the 12-year period, SPCC inspections revealed problems with leaking transfer valves, leaking product lines, insufficient secondary containment, failure to lock valves that could release content, and oil sheen present in dikes and adjacent dikes, indicating the migration of oil from a leak or spill through the dike drain valves that were unaddressed in subsequent inspections. Although these deficiencies were noted for smaller tanks holding less than 10,000 gallons of liquid and asphalt tanks not in the main tank farm, the SPCC records offer additional insight into how CAPECO management historically maintained the facility. Refer to Section 8.6.2 for CAPECO SPCC deficiencies.

6.3 Previous Spill Incidents at CAPECO

The CSB learned CAPECO had multiple overfills and spills during transfer operations. CAPECO records show a history of 15 separate incidents involving tanks of varying sizes from 1992 to 1999 and 3 others after 2005, when spills or overfills occurred during filling, draining, or transferring operations. Among the 15 incidents, 8 were overfills and 7 were spills. Incidents resulted from valves in the open position, tank gauge malfunctions, or corrosion of pipes or tank shells.

6.4 Normal Practice to Fill Tanks to Maximum Levels at Odds with Safety

The CSB found that despite the lack of computer-displayed tank levels, CAPECO operators received instructions from the Planning Department to fill the tanks to their maximum fill level during the October 21-23, 2009 filling operations, exposing the tank farm to the eventual incident. The Planning Department coordinated fuel deliveries with fuel suppliers and instructed operators on which tank to fill, specified the volume of materials, and determined the filling schedule during unloading operations. (See Section 3.4.) The contractual obligation to fill the specified tanks in the allotted time or at a faster rate was at odds with safely conducting filling operations.

6.5 Unreliable Safety Critical Equipment

The CSB found that CAPECO purchased the least effective level-measurement system and employed an inadequate maintenance program to care for that system. These shortfalls in safety critical equipment in the level control and monitoring system, including the transmitters on the side gauge and the float and tape device in the tank, prevented operators from determining tank levels during filling operations. Figure 10 illustrates the issues with the level control system at CAPECO.

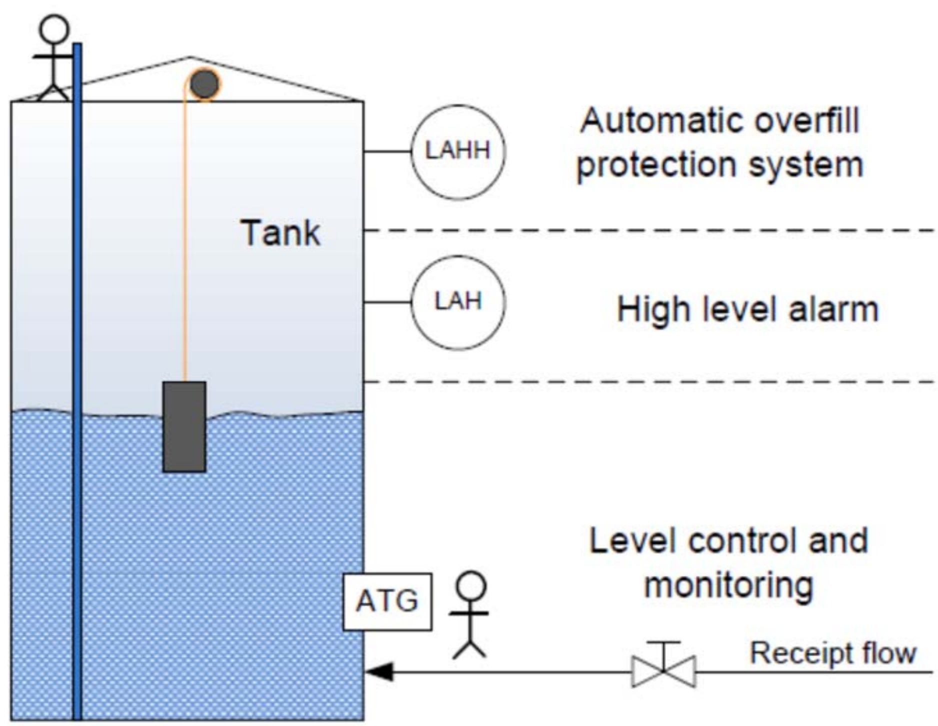

Figure 13: A comprehensive overfill prevention system includes the ATG, high-level alarm (LAH), and automatic overfill protection system (LAHH), in addition to the operator and facility procedures that govern, monitor, and control the flow of fuel into a tank.

6.5.1 Unreliable Level Control and Monitoring Systems

CAPECO lacked a reliable automatic level control and monitoring system for measuring tank levels. (See Figure 13.) The automatic gauging system at CAPECO, described in Section 3.6.3, had a history of repeated failures and prolonged out-of-service periods. On the night of the incident, the float and tape device inside Tank 504 became stuck and the transmitters for Tanks 107 and 409 were not receiving data from the side gauge on Tank 409; therefore, data on the tank liquid level and a calculated fill rate into 409 were not available in real time on the computer. The computer monitoring system was often compromised by outages from lightning strikes and accidental breakage of the computer cables after maintenance activities in the tank farm area. In addition, the transmitters[56] that sent the data to the computer were also susceptible to electromagnetic interference and frequently needed replacing after lightning storms.

Records show, CAPECO took weeks to replace the faulty transmitters. Therefore, CAPECO operators found the computer monitoring system to be unreliable. After completing hourly rounds, the operator reported the tank level back to the shift supervisor, who then manually calculated the time it would take to fill the tank. The CSB learned that CAPECO operators had been calculating the tank levels by hand for decades. This method of monitoring the level in the tanks was unreliable given the 15 prior tank spill incidents at the facility and the extended time that the level detection equipment remained out of service due to failure.

6.5.2 Float and Tape Gauges Prone to Failure

Float and tape gauges, which the aboveground storage tank industry has used for many years, are also prone to failure due to historically well-known design flaws.[57] Mechanical friction in pulleys, spring motors, and indicators degrade measurement reliability, causing the system to indicate the liquid depth inaccurately.[58] In addition, the gear mechanism attached to the indicator and transmitter can disengage, resulting in inaccurate readings, and can disrupt synchronization of the transmitter.[59] The float tape gauge is also subject to "excessive wear and tear,"[60] resulting from continuous and sudden movement from turbulence generated by the fuel in the tank.[61]

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[56] In accordance with *ANSI/API Overfill Protection for Storage Tanks in Petroleum Facilities (ANSI/ANSI/API 2350)*, operators recalibrate the level transmitter when they note more than a 3-inch discrepancy in tank levels between the physical gauge reading and the float and tape reading recorded at the side gauge. (See section 8.10 for API discussion.)
[57] B. V. Enraf. *The Art* of *Tank Gauging*. http://enraf.ru/userfiles/File/4416650_rev4.pdf (accessed January 2012).
[58] Ibid.
[59] Ibid.
[60] Ibid.
[61] Ibid.

6.5.3 Poor Float and Tape Gauge Maintenance

The CSB found the float and tape gauges installed on CAPECO tanks were poorly maintained. Installed in February 2004, the float and tape gauges were frequently out of service for multiple tanks at the same time. The CSB learned that just nine months after initial installation, CAPECO hired L&J Engineering to service the level transmitter due to "volume discrepancies," and one month prior to the 2009 explosion, CAPECO hired contractors to calibrate the side gauge on numerous tanks in the tank terminal.

The CSB found CAPECO's lack of preventative maintenance[62] resulted in the failure to repair the tank gauging system. A review of CAPECO maintenance logs found no status update on maintenance activities addressing a broken float tension on Tank 411 in July 2009, or on fixing strapping problems with Tanks 405 or 411 in early October 2009. During October 2009, the level transmitter for Tank 409 was out of service from the week prior, and maintenance personnel were waiting for repair parts. Despite frequent outages, CAPECO management did not replace the level transmitter on any of the tanks and relied only on the float and tape gauge located on the side of the tank to obtain tank levels.

The CSB found many of CAPECO's tank gauging practices were contrary to the recommended practices in API Manual of Petroleum Measurement Standards (MPMS) Chapter 3.1A,[63, 64] which might have contributed to inaccurately calculating liquid levels in Tank 409. Volume discrepancies in a tank could also arise from using a specific tank gauge, relying on a strapping table to calculate tank levels, and using unslotted still pipes.

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[62]CCPS Guidelines for Safe Process Operations and Maintenance: "Preventative maintenance seeks to reduce the frequency and severity of unplanned outages by establishing a fixed schedule of routine inspection and service. The chief advantage of a preventative maintenance program is that it gives maintenance management the flexibility to plan and execute required equipment service with a minimum disruption of essential plant operations. The importance of preventative maintenance to process safety management cannot be overemphasized." American Institute of Chemical Engineers, Center for Chemical Process Safety. *Guidelines for Safe Process Operations and Maintenance* (New York: Wiley & Sons, 1995).

[63] American Petroleum Institute. *Manual of Petroleum Measurement Standards*, Chapter 3.1A, Standard Practice for the Manual Gauging of Petroleum and Petroleum Products, 3rd edition (August 2013).

[64] *The Manual of Petroleum Measurement Standards*, Chapter 3.1A applies to liquids with a Reid vapor pressure. Reid vapor pressure is the property of a liquid fuel that defines its evaporation characteristics and a common measure of and generic term for gasoline volatility. http://www.epa.gov/otaq/fuels/gasolinefuels/volatility/index.htm.) of less than 103 kPa. A Pascal is the SI-derived unit of pressure, internal pressure, stress, Young's modulus, and tensile strength. 1 Kilopascals (kPa) ≡ 1000 Pa. or 15 psia.

- *Type of gauge:* CAPECO did not use an innage gauge, as recommended by the MPMS Chapter 3.1A, but relied on an outage gauge[65] to obtain tank levels. The MPMS Chapter 3.1A recommends the use of innage gauges over outage gauges due to movement of the tank gauge reference point, but recognizes circumstances when outage gauges are more applicable. The MPMS Chapter 3.1A also recommends that facilities inspect both manual tape-and-bob assembly and portable electronic gauging devices daily for inconsistencies that may introduce error, and that they verify for accuracy at least annually. It also requires operations personnel to check the detection signal from the sensor/probe annually. The CSB did not find any inspection records demonstrating daily or annual float and tape checks at CAPECO.

- *Strapping table inaccuracies*: API MPMS Ch. 3.1A advises that a volume discrepancy can arise from the inherent inaccuracies in strapping tables, which can lead to overestimating or underestimating of tank quantity, among other problems.

- *Calculating tank volume in the critical zone*: According to API MPMS Ch. 3.1A, "computing tank volume in the critical zone[66] is subject to considerable error." Inaccuracies can also arise from strapping tape calibration or thermal expansion, tension of the strapping tape, correction of shell expansion due to liquid head (static head), measurement of shell plate thickness and calculation of deadwood.[67]

- *Using still pipes without slots*: The independent inspector used a gauge hatch on the fixed roof and a gauging funnel on the floating roof to obtain liquid levels in Tank 409 but used an 8-inch still pipe[68] to physically gauge Tank 107. According to API MPMS Ch. 3.1A, still pipes without slots can lead to "serious liquid height measurement, temperature determination, and sampling errors."

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[65] An innage gauge is a direct measurement of the linear distance along a vertical path from the datum plate or tank bottom to the surface of the liquid being gauged. An outage gauge is an indirect measurement of the linear distance along a vertical path from the surface of the liquid being gauged to the tank reference gauge point.

[66] The critical zone is the area where liquid is partially displaced by the roof between the point where the liquid just touches the lowest section of the roof and the point where the roof floats freely.

[67] Deadwood refers to the ducted weight of all parts of a floating roof, including the swing joint, the drain and other items attached to the tank shell or bottom that are resting on the roof supports when the floating roof is immersed in liquid.

[68] Still pipe is used to gauge liquid levels inside a tank. The reference gauge point is located on the upper lip, and the datum plate is located at the lower lip. Still pipes may have slots or be solid.

6.6 Lack of Formal Procedures for Tank Terminal Operations

The CSB learned that CAPECO's standard operating procedures only addressed activities requiring a permit to work and did not cover terminal operations. When CAPECO became a fuel storage depot, it was no longer required to follow standards that would require regularly updated standard operating procedures (SOPs), such as OSHA PSM or EPA RMP. CAPECO last updated refinery SOPs to comply with PSM in 1999. In August 2009, CAPECO updated procedures that resulted in work permits (hot work, cold work, confined space, and lockout/tagout) but failed to update or write terminal operating procedures. The terminal often had activity outlines and checklists, but it did not have SOPs to instruct employees how to perform daily activities, such as discharging from a vessel or barge, gauging tanks, or operating dike drain valves. For example, CAPECO had a two-page document listing the activities to discharge from a vessel or barge, but the document did not provide details on how to perform the activities, who would be in charge, or what to do in an emergency. In addition, CAPECO lacked procedures dictating how to load multiple tanks at the same time. The normal practice of partially opening the tank valves of the next tank in line to be filled (See Section 6.9.4) directly influenced the tank fill rate, but the facility lacked procedures addressing the influence of valve cracking on calculating the tank fill time. As a result of the incident, the Puerto Rico Occupational Safety and Health Administration (PR OSHA) issued a serious violation to CAPECO for lacking tank filling procedures during transfer operations. See PR OSHA Section 8.8.

6.7 Lack of Additional Safeguards such as High-Level Alarms and an Automatic Overfill Prevention System

The CSB found that CAPECO tanks lacked effective safeguards to prevent a tank overfill. In addition to an accurate automatic tank gauging system with a reliable computer monitoring system, potential safeguards include independent high-level alarms, which give a visual or auditory indication when material in the tanks reach a specific high level, and an automated overfill prevention system,[69] which allows for shutoff or flow diversion to prevent overfill. Tank 409 lacked an independent high level alarm.[70] Without safety alarms and associated critical response procedures, CAPECO tank farm operators were left with a faulty level control and monitoring system to detect an overfill in Tank 409.

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[69] *ANSI/ANSI/API 2350* defines an automated overfill prevention system (AOPS) as an overfill prevention system not requiring the intervention of operating personnel to function.

[70] High-high level alarm: An alarm generated when the product level reaches the high tank level. American Petroleum Institute. *ANSI/API Standard 2350-2012: Overfill Protection for Storage Tanks in Petroleum Facilities*, fourth edition (Washington, DC: American Petroleum Institute, May 2012).

6.8 Other Potential Contributing Factors

The CSB found that other factors might have contributed to the accident, such as the construction and limitations of the Tank 409 internal floating roof and the variable flow rates and line pressures into Tank 409.

6.8.1 Internal Floating Roof Construction and Limitations

The destruction of the Tank 409 internal floating roof in the explosion prevented the CSB from determining if it failed during filling operations. Therefore, internal floating roof failure might have contributed to the overfilling of Tank 409. The roof construction of Tank 409 was subject to numerous operational limitations. Tank 409 had a fixed cone roof with an aluminum internal floating roof (IFR), and a freeboard[71] of 12 feet (24,157 bbls). (See Figure 14 for Tank 409 specifications.) Aluminum IFRs are prone to corrosion when exposed to caustic liquids but sufficient for petroleum and organic materials. An internal floating roof can fail by means of turbulence,[72] roof submersion,[73] seal issues, and fatigue.[74]

API MPMS Ch. 3.1A discusses the impact of the floating roof on tank volume. On the night of the incident, the final reading likely occurred when the floating roof was floating freely. When floating roofs are in the free-floating position, they displace the amount of liquid equal to the weight of the roof and attached deadwood. The only accurate way to obtain volume in the critical zone is by a liquid calibration procedure. API MPMS Ch. 3.1A advises that facilities calculate roof displacement by considering the roof weight, temperature, and density of the liquid of tank contents in the critical zone. CAPECO did not calculate the roof displacement of Tank 409.

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[71] Freeboard is the vertical distance between the maximum liquid level and the top of the tank.
[72] Turbulence: high velocity of receipt fluid sufficient to generate waves at the surface of the liquid causing floating roofs to shake, move, and vibrate. Turbulence usually results from excessive receipt rates when the liquid level is low in the tank.
[73] Roof Submersion: Part or the entire roof becomes covered with the stored tank product.
[74] Fatigue is the creation of initiating cracks at discontinuities in steel structures resulting from stresses magnified by "stress risers" or discontinuities from corrosion.

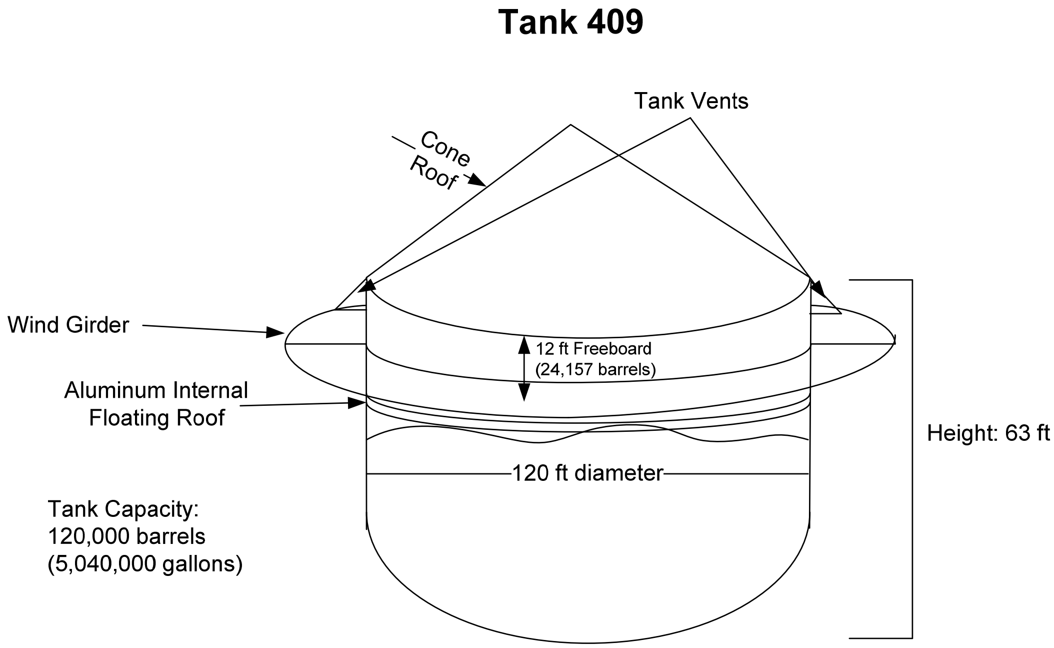

Figure 14: Tank 409 Specifications

6.8.2 Variable Flow Rates and Line Pressure into Tank

The CSB found that the fuel discharge flow rate to the terminal was controlled only by personnel from the *Cape Bruny*. CAPECO and the *Cape Bruny* had to complete filling operations in the allotted time negotiated by the Planning Department or face a financial penalty. (See section 3.4).

The CSB found it was normal for flow rates to vary from the barge to the tanks during filling operations. However, CAPECO lacked the ability to obtain product line flow rate information from the *Cape Bruny* to the CAPECO tank terminal via real time flow monitors, thus preventing CAPECO staff from accurately calculating the tank fill time and likely contributing to the overfill of Tank 409. The gasoline flow rate from the *Cape Bruny* to the terminal was determined before filling operations started in a pre-transfer meeting on the ship. Both CAPECO and *Cape Bruny* personnel determined the initial transfer limit to be 4,400 bbls/hr and a bulk transfer rate of 12,000 bbls/hr. Normal transfer operations from the *Cape Bruny* established a minimum allowable backpressure at 100 psig with a maximum discharge rate of 18,870 bbls/hr during transfer operations. However, CAPECO requested the discharge pressure to be 125 psig. At the time of the incident, CAPECO's manifest showed gasoline was pumped at a rate of 10,000-11,000 bbl/hr at a pressure of 100-110 psi, corresponding to about 7000-7700 gallons per minute. Despite the predetermined transfer rate and backpressure, CAPECO operators lacked information on the flow rate into the tanks during filling operations.

To change the ship pumping pressure during filling operations, CAPECO tank farm operators communicated with the dock operator via radio. The dock operator then contacted the ship to increase or reduce the pressure of fuel pumped from the ship to the terminal. However, CAPECO personnel testified that stopping pumping from the ship was rare and only occurred if the tank farm lacked sufficient tank space onsite. Ship discharge records show the line pressure at the dock started at 50 psig on October 21, 2009, at 1 a.m. and increased by approximately 5-10 psig every three hours. At 11 p.m., approximately one hour before the incident, on October 22, 2009, the dock pressure was 115 psig, within the agreed-upon pump pressure. As the line pressure increased, the tank operator manually switched from Tank 405 (line displacement) to Tank 504 then to Tank 411, and cracked the valve on Tank 409 to contain the gasoline. However, it was difficult for operators to determine the exact flow rate into the tanks after cracking the valves because gasoline flow rate was also dependent on the pipe diameter. Operators often went to the tank 10-30 minutes prior to the calculated filling time to switch the lines and address any discrepancy in flow rates. The lack of flow indicators coupled with various pipe diameters, the tank-switching process, and an unreliable gauging system all contributed to the overfilling of Tank 409.

6.9 Human Factors

Human factors-related deficiencies[75] also contributed to the breakdown in the safety management system, including issues with dike valve designs, insufficient staffing, facility lighting, and valve cracking.

6.9.1 Lack of Consistent Dike Valve Design

A major contributor to the migration and dispersion of the vapor cloud was the open dike valves that enabled fuel to accumulate in the storm water retention pond in the WWT area. In addition, the use of multiple types of manual valves coupled with poor lighting made it impossible for operators to visually observe whether the dike valves were open or closed on the night of the incident. CAPECO operators failed to determine whether the dike drain valve for Tank 409 was properly shut.

The CSB verified that the dike drain valve for Tank 409 was open at the time of the incident. EPA SPCC regulations require that dike drain valves be closed to prevent discharging oil.

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[75] "Human factors refer to environmental, organizational and job factors, and human and individual characteristics which influence behavior at work in a way which can affect health and safety. A simple way to view human factors is to think about three aspects: the job, the individual and the organization and how they impact people's health and safety-related behavior." U.K. Health and Safety Executive. *Introduction to Human Factors*. http://www.hse.gov.uk/humanfactors/introduction.htm (accessed December 20, 2014).

CAPECO's normal practices required operators to open and close valves during the day shifts. Operators customarily inspected whether the dike drain valves were open or closed from their vehicles as they drove by. The tank farm used both rising stem and fixed stem valves on the dike drains leading to the storm water retention pond in the WWT area. Rising stem valves allowed operators to easily observe the open or closed position while fixed stem valves do not provide a visual indication of the position. The fixed stem valve on the dike drain for Tank 409 made it difficult for tank farm operators to observe its position without physically turning it. (See Figure 15.) In some cases, the valve position could not be determined with a visual inspection because the rising stem valve position was hidden in the sump. (See Figure 15, center photo.) Furthermore, none of the dike valves shown in Figure 15 were consistent with RAGAGEP. Regulatory coverage under the EPA Risk Management Plan (RMP) or OSHA's Process Safety Management (PSM) Standard requires that CAPECO use the best available engineering practices to assess valve open/close status.

Figure 15: Various dike drain valves at CAPECO. Tank 409 fixed stem dike drain valve (left): position of the valve is undeterminable without physically turning the valve. Rising stem valves (center, right). In some cases, the valve position is hidden in the sump (center).

6.9.2 Lack of Facility Lighting

On the night of the incident, operators could not see the tank overflowing or the vapor cloud forming because the lighting was insufficient. Lighting in the tank farm area was limited; therefore, operators used flashlights to monitor tank farm activity and read liquid levels from the tank side gauges. A 1999 EPA inspection found insufficient lighting at the CAPECO tank farm to "detect spills and prevent vandalism." Operators used flashlights, which were insufficient to monitor for unusual activity, such as a tank overflowing or a vapor cloud forming. In a 2010 post-incident inspection report, the EPA again noted inadequate facility lighting for discovering unusual activity, such as vandalism and oil discharges in darkness.[76]

6.9.3 Lack of Sufficient Staffing during Offloading Operations

The management decision to staff each fuel offloading shift with two operators at the tank farm and one operator at the dock provided insufficient staffing resources during filling operations. CAPECO often offloaded inventory into multiple tanks, which required manually switching fuel flow between tanks. This task often required two people due to the increased pressure of the fuel on the valve. Operators addressed this lack of staffing by cracking the valves of the next tank in line to fill. For example, Tank 409 and Tank 411 shared the same line connected to the pipeline. When the operator needed to change the line from the pipeline to fill another tank, he had to call the WWT operator for help, leaving the WWT area unattended.

6.9.4 Valve Cracking

The lack of motor-operated valves compromised the accuracy of tank-filling time estimates. The valves for unloading gasoline were manually operated and as large as 16 to 20 inches. The pressure in the line from the dock was as high as 125 psig, which made opening the valves difficult. To easily change gasoline flow between tanks, operators fully opened the inlet valve to one tank and cracked open the inlet valve on the next tank to be filled. Cracking the inlet valve facilitated opening the valve for the next tank after the previous tank reached the target level. With both valves opened, the flow rate into the individual tanks varied, making it difficult to determine the exact filling time required.

Installing motor-operated valves can eliminate the difficulty of manually opening large valves.

6.10 Using a Risk-based Approach to Design an Overfill Prevention System

Bulk petroleum storage and distribution facilities, like CAPECO's Bayamón facility, are not considered highly hazardous under the U.S. regulatory system, despite often storing flammable liquids near highly populated areas. CAPECO was not required to use a risk-based approach to determine the level of risk posed by facility operations to the nearby community and to mitigate those risks accordingly.

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[76] General requirements for Spill Prevention, Control, and Countermeasure Plans. *Code of Federal Regulations*, Part 112, Section 7, Title 40, 2008.

A Safety Instrumented System (SIS)[77] approach allows tank terminal operators to design an overfill prevention system for controlling the risk of an overfill incident to various safety integrity levels using multiple layers of protection. Following the promulgation of the US Occupational Health and Safety (OSHA) Process Safety Management (PSM) standard (1910.119), the International Society for Automation (ISA) created ISA 84.01-1996, the Safety Instrumented Systems (SIS) standard. Its intent was to augment the PSM standard for implementing instrumentation and controls necessary for safe operation.[78] OSHA recognizes ISA-84 as Recognized and Generally Accepted Good Engineering Practice (RAGAGEP). See Section 8.9 for a discussion of RAGAGEP.

Under this standard, a safety system requires robust design and rigorous management to achieve the required integrity.[79] In applying SIS for process industries, ISA-84 uses two concepts to reduce the risk of facility-based hazards: a safety lifecycle and safety integrity levels (SIL).[80] A safety lifecycle model uses a disciplined systemic approach to design, build, operate, and maintain a facility throughout its lifetime;[81] a safety integrity level (SIL) is a probability-of-failure measurement of safety system performance.[82] There are four SILs,[83] where a higher SIL means that an installed system has a lower potential to fail.

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[77] SIS is an instrumented system used to implement one or more safety-instrumented functions (SIF). This software implements a safety-instrumented function by programming a single instrumented loop or multiple instrumented loops to a single electronic system. SIS removes the human element from a process when the expected human error rate increases because of automated controls with too many repeated and continuous control changes or when the complexity of work activity increases. A Safety Instrumented Function (SIF) is a safety function associated with a specific safety integrity level that is necessary to achieve functional safety. It can be a safety instrumented protection function or a safety instrumented control function. *International Standard IEC 61511-1: Functional safety – Safety instrumented systems.*

[78] A. Summers. *Difference between IEC 8111 and ISA 84.01-1996* (Instrumentation, Systems and Automation Society, 2003).

[79] Buncefield Major Incident Investigation Board. *The Buncefield Incident 11 December 2005 Volume 1*. 2008. http://www.buncefieldinvestigation.gov.uk/reports/volume1.pdf.

[80] International Society for Automation. Technology ISA-84. http://www.isa-95.com/subpages/technology/isa-84.php (accessed December 20, 2014).

[81] S. Gillespie. *Safety Instrumented Systems*. http://www.idc-online.com/technical_references/pdfs/instrumentation/Safety_Instrumented_Systems.pdf (accessed December 20, 2014).
http://www.idc-online.com/technical_references/pdfs/instrumentation/Safety_Instrumented_Systems.pdf

[82] Buncefield Major Incident Investigation Board. *The Buncefield Incident 11 December 2005 Volume 1* (2008). http://www.buncefieldinvestigation.gov.uk/reports/volume1.pdf (accessed December 20, 2014).

[83] SIL 0 = none is the lowest risk; SIL 1 = 95% of the safety instrumented function (ALARP); SIL 2 =5% SIF; SIL 3 = <1% SIF; SIL 4 =highest risk (nuclear industry)
Process Engineering Associates. http://www.processengr.com/ppt_presentations/safety_instrumented_systems.pdf

Facilities such as CAPECO are not covered under OSHA PSM Standard or the EPA RMP Program. They are not required to conduct risk assessments to address flammable hazards on site, or to follow RAGAGEP. Therefore, the CAPECO facility was not required to conduct a hazard assessment that would determine the necessary safeguards needed to prevent a catastrophic incident. This precaution would have alerted management to the need for RAGAGEP, including instrumentation and controls necessary for safe operations. Had CAPECO been covered by these standards, it likely would have installed an independent or redundant level alarm and an automatic overfill protection system with several independent safeguards to prevent a catastrophic overfill incident.

7.0 TANK LOCATIONS, PREVALENCE OF INCIDENTS AND LESSONS LEARNED FROM PREVIOUS CATASTROPHIC INCIDENTS

According to the US Census Bureau, there were 4,810 petroleum bulk stations and terminals in the US in 2007.[84,85] The terminals include commercial facilities, proprietary terminals owned by refineries, chemical manufacturers, and Department of Defense facilities.[86]

Tank terminals are located throughout the US in both rural and urban areas. Figure 16 illustrates the location of bulk petroleum tank terminals in all 50 states in 2012. In 2009, 3,807 bulk liquid storage facilities registered a release with the EPA Toxic Release Inventory (TRI).[87,88] The CSB mapped 3,847 bulk petroleum storage tank terminal locations obtained from the EPA TRI database for 2012 and found 2,959 bulk petroleum storage terminals within one mile of communities with over 300,000 residents (Figure 16).

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[84] *Geographic Distribution*: *Petroleum Bulk Stations* and *Terminals* (Washington, DC: U.S. Census Bureau, 2007). http://www.census.gov/econ/industry/geo/g424710.htm (accessed December 20, 2014).

[85] NAICS code 424710 – bulk petroleum stations and terminals includes industry establishments with bulk liquid storage facilities primarily engaged in the merchant wholesale distribution of crude petroleum and petroleum products, including liquefied petroleum gas.

[86] Advanced Resources International. *Assessment of the Potential Costs and Energy Impacts of Spill Prevention, Control, and Countermeasure Requirements for Petroleum Bulk Storage and Distribution Terminals* (Washington, DC: US Department of Energy Office of Fossil Energy, August 22, 2006).

[87] The EPA Toxic Release Inventory is a database containing self-reported information on the disposal or release of 650 chemicals from facilities in the US.

[88] *Toxic Release Inventory: 2009* (Washington, DC: U.S. Environmental Protection Agency, 2010).

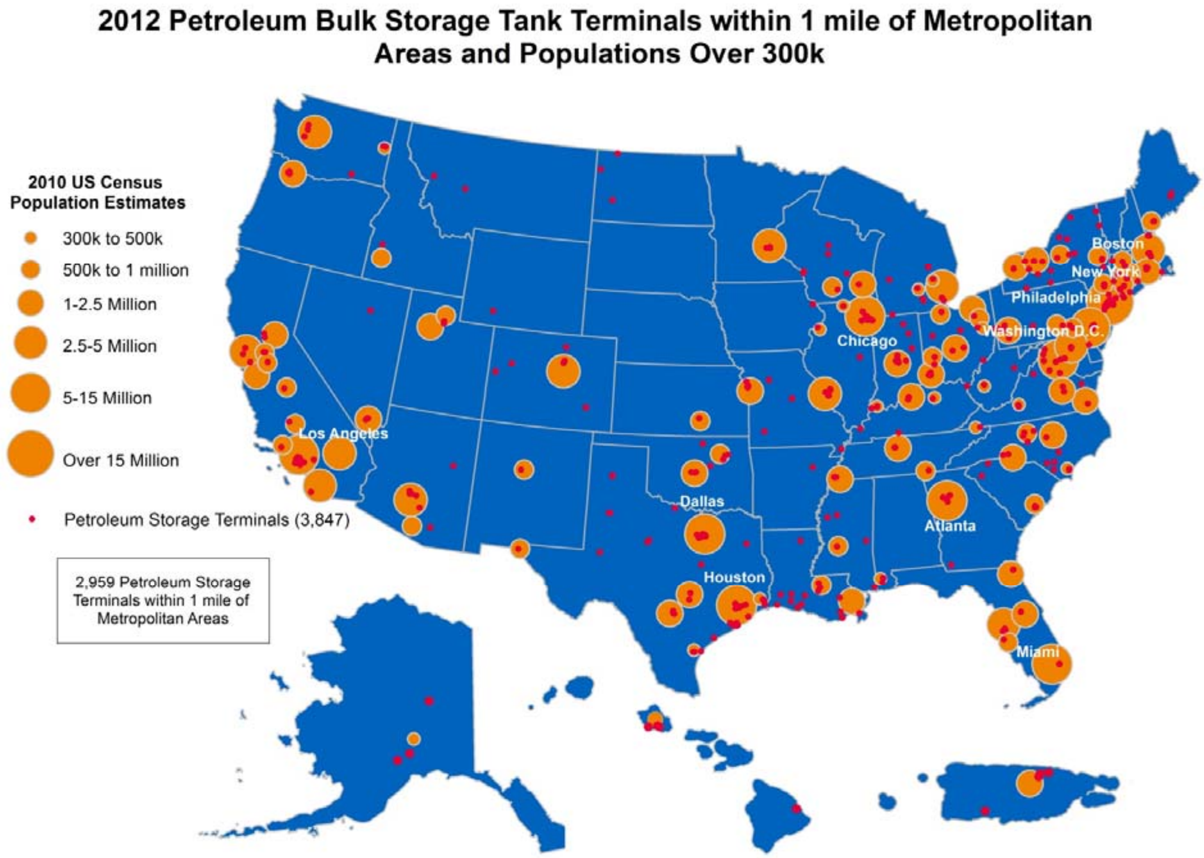

Figure 16: Tank terminals distributed across the US in 2012 in proximity to 2010 population data. (EPA TRI Database, 2012)

7.1 Prevalence of Tank Incidents

The lack of a comprehensive database of publicly available accident data makes it difficult to analyze for trends in overfill incidents. A 2006 study using published reports from various sources analyzed 242 storage tank accidents, finding that fires and explosions accounted for 85% of the accidents on six continents over 40 years (1960-2003).[89] The study also found 105 accidents that occurred in the US. Moreover, terminals and pumping stations accounted for 25%, or 64, of the accidents—the second most frequent sites for accidents after refineries (47.9% or

[89] J. I. Chang, et al. "A Study of Storage Tank Accidents." *Journal of Loss Prevention in the Process Industries*. 2006.19: 56.

116 cases).[90] In addition, overfilling was cited as the most frequent cause of an accident during operation; among the 15 overfill incidents found, 87% led to a fire and explosion. Since 2005, three low-frequency, high-consequence incidents involving a vapor cloud formation from a gasoline storage tank resulted in catastrophic explosions and fires.

The cost of overflow prevention systems is nominal in contrast with the societal and economic costs of incidents such as Buncefield and CAPECO. A 2006 US Department of Energy Office of Fossil Energy assessment found fully automated liquid level sensing alarms and shutoffs range from $12,000 to $18,000 per tank installation, and liquid level sensing devices with alarms cost $4,000 to $5,000.[91]

7.2 Lessons Learned from Previous Incidents

Similar overflow incidents have occurred in the US and internationally. The CSB found 22 incidents of overfills and vapor cloud explosions at bulk petroleum tank terminals, 16 of which occurred in the US. The three incidents discussed below and in Appendix B demonstrate the catastrophic potential and high-hazard nature of storing flammable liquids in aboveground storage tanks. Yet US regulations and industry practices do not adequately reflect the lessons learned from such catastrophic incidents and fail to classify terminals storing flammable materials as high-hazard facilities.

7.3 Buncefield (Hertfordshire, UK)

One of the most notable recent incidents—resulting in a number of technical and regulatory recommendations in the United Kingdom—is an explosion and fire that occurred at the Buncefield Oil Storage Depot in Hemel Hempstead, Hertfordshire, UK, on December 11, 2005. Similar to the CAPECO incident, the vapor cloud explosion and multiple tank fires occurred after a tank was overfilled with gasoline. The overfilling tank was equipped with a gauge that allowed operators to monitor filling operations and an independent high-level switch that allowed for automatic shutdown of filling operations if the tank overfilled. But both were inoperable at the time of the incident.[92] The explosion generated significant blast pressure,

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[90] J. I. Chang, et al. "A Study of Storage Tank Accidents." *Journal of Loss Prevention in the Process Industries*. 2006.19: 56.

[91] Advanced Resources International. *Assessment of the Potential Costs and Energy Impacts of Spill Prevention, Control, and Countermeasure Requirements for Petroleum Bulk Storage and Distribution Terminals* (Washington, DC: U.S. Department of Energy, Office of Fossil Energy, August 22, 2006).

[92] The Competent Authority. Control of Major Accident Hazards. *Buncefield: Why Did It Happen?* (U.K. Health and Safety Executive (HSE) and Environment Agency). http://www.hse.gov.uk/comah/buncefield/buncefield-report.pdf (accessed December 21, 2014).

resulting in additional loss of containment that led to fire and other damage involving 22 tanks. There were no fatalities, but 43 people were injured and the damage to nearby commercial and residential property totaled $1.5 billion.[93] The fire burned for four days.

Following Buncefield, the UK Health and Safety Executive (HSE) established a Major Incident Investigation Board (MIIB),[94] which made recommendations to the industry and regulators concerning the incident. The MIIB recommendations overhauled both the UK legal compliance standards and industry practices governing petroleum storage facilities similar in size to the Buncefield Storage Depot. Differing from the US viewpoint, the United Kingdom considers petroleum storage facilities to be high-hazard facilities, subjecting them to the regulations similar to the US OSHA Process Safety Management (PSM) standard. The UK view allows for additional oversight from the Competent Authority (CA) or the Control of Major Accident Hazards (COMAH). Therefore, covered facilities must demonstrate a major accident prevention policy and a safety management system.[95]

The MIIB report emphasizes that controlling the risks associated with a major incident like Buncefield requires an integration of safety integrity levels at high-hazard sites, specifically addressing containment of dangerous substances and process safety with mitigation planning against offsite impact, preparedness of emergency response, land use planning for controlling societal risk, and regulatory system enforcement at high-hazard facilities.[96]

Many of the MIIB recommendations are pertinent to CAPECO. The most salient MIIB recommendations address preventing primary loss of containment,[97] conducting a risk assessment, maintaining sector leadership, cultivating a safety culture, and conforming petroleum storage facilities to high-reliability organization principles. Table 2 summarizes and

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[93] D. M. Johnson, et al. "The Potential for Vapour Cloud Explosions: Lessons from Buncefield." *Journal of Loss Prevention in the Process Industries*. (2010.23): 921-927.

[94] The Buncefield incident caused the MIIB to conduct a comprehensive review of the design and operation of storage sites, emergency preparedness for and response to incidents, and land use planning. In addition, the MIIB analyzed the regulatory system, including the HSE and UK Environmental Agency requirements governing petroleum storage depots and examined the explosion mechanism of the Buncefield incident. The MIIB produced nine reports published from 2006 to 2009. Follow-up reports resulting from recommendations issued by the MIIB address layer-of-protection analysis while other working groups issued subsequent analysis of the implementation of the HSE recommendations.

[95] Buncefield Standards Task Group. 2007. Safety and *Environmental Standards* for *Fuel Storage Sites*. http://www.hse.gov.uk/comah/buncefield/bstgfinalreport.pdf. (accessed January 2012)

[96] Buncefield Major Incident Investigation Board. 2008. *The Buncefield Incident 11 December 2005 Volume 1*. http://www.buncefieldinvestigation.gov.uk/reports/volume1.pdf. (accessed January 2012).

[97] Primary means of containment are the tanks, pipes, and vessels that hold liquids and the devices fitted to them to allow safe operation. (Buncefield MIIB, 2008).

compares both incidents. Because of the Buncefield incident, the API made changes to the Tank Overfill Prevention Standard (ANSI/API 2350) addressing risk assessment. This report issues additional recommendations to the API to enhance its guidance on conducting a risk assessment. (See Section 8.10.1.)

Table 2: Comparison of CAPECO and Buncefield Incidents

	CAPECO	**Buncefield**
Incident Date	October 23, 2009	December 11, 2005
Number employee injuries	0	0
Number of public injuries	3	40
Number of tanks at facility	47	39
Product being filled	Unleaded Gasoline	Unleaded Gasoline
Time of explosion	12:23 am	6:00 am
Storage capacity of site	283,233 tons (90 million gallons)	194,000 tons (61.6 gallons)
Tank storage capacity	18.9 million liters (5 million gallons)	6 million liters (1.58 million gallons)
Vapor cloud explosion	Yes	Yes
Richter Scale	2.9	2.4
Estimated area of vapor cloud	107.2 acres (4,669,632 ft^2)	32 acres (1,393,920ft^2))
Number of tanks engulfed in fire	17	20
Number of days to contain fire	2.5	5
Tank involved in overfill	Tank # 409	Tank # 912
Estimated overfill volume	757,082 liters (200,000 gallons) of gasoline	250,000 liters (66,043 gallons) of gasoline
Volume of contaminated water released to environment	647,305 liters (171,000 gallons) of collected oil; 83,279,059 liters (22,000,000 gallons) of contact water	800,000 liters (211,338 gallons)
Type of tank gauging system	Manual tank gauging system	Fully automated level control system under remote supervision
Functionality of gauging system at incident	Failed	Failed
Independent high level alarm	Not present	Present but not functioning
Redundant alarms	Not present	Not functioning
Root cause	Deficient Management System	Deficient Management System
	Production Pressure	Production Pressure
	Lack of reliable instruments: Level control failure due to inaccurate available volume calculation; no high-level alarm to notify ship to stop transfer or divert flow; no AOPS with ability to shut down or divert flow into tank	Lack of reliable instruments: Level control failure due to level sensor failure; failure of high level alarm; failure of the independent AOPS
Contributing cause	Failure of Safety Management System	Failure of Safety Management System
Regulatory consideration	Not considered high-hazard facility	Considered high-hazard facility

7.4 Texaco Oil Company (Newark, NJ)

On January 7, 1983, a similar incident occurred at the Texaco Oil Company tank terminal in Newark, New Jersey. A gasoline vapor cloud exploded when a 1.76-million gallon capacity tank overflowed, resulting in one fatality and 24 injuries. Inadequate monitoring of the rising gasoline levels in the storage tank during filling operations contributed to the overflow, explosion, and subsequent fire. An NFPA report on the incident also attributed the root cause to errors in calculating the available space and pumping rates.[98] Equipment damage was observed up to 1,500 feet away from the exploding tank. The overflowing tank had manual level controls. The facility also had no documentation of previous liquid level monitoring in the hours leading up to the explosion. The last "check" on the tank level occurred approximately 24 hours prior to filling operations.[99]

Following the incident, the Newark Fire Department made recommendations to the NFPA to strengthen its guidance on overfill prevention under the *Flammable and Combustible Liquids Code*. (See Section 8.10.9.1 for further discussion on NFPA 30.)

7.5 Indian Oil Company (Jaipur, India)

Another recent incident occurred in Jaipur, India, at the Indian Oil Corporation (IOC) Petroleum Oil Lubricants terminal 16 miles south of Jaipur, India. On October 29, 2009, one week after the CAPECO explosion and fire, four operators were transferring gasoline to a tank when the delivery line developed a large leak, which continued unabated for 75 minutes after fumes overcame two operators. The pooling fuel migrated through an open dike drain valve to a storm drain, producing a large vapor cloud. The cloud was ignited by either non-intrinsically safe electrical equipment or a vehicle startup. The resulting explosion and fireball engulfed the entire site. Fire affected 11 tanks and persisted for 11 days. The incident resulted in 11 fatalities, 6 of them IOC employees, and the others from neighboring organizations. Among the 39 recommendations issued, one was for an independent Hazard Operability study (HAZOP) or risk assessment, and another addressing automated operations and improving instrumentation and alarms.[100] Appendix B contains a list of other similar incidents.

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[98] *Summary Investigation Report: Gasoline Storage Tank Explosion and Fire. Newark, NJ, 7 January 1983* (Quincy, MA: National Fire Protection Agency, 1983).

[99] *Summary Investigation Report: Gasoline Storage Tank Explosion and Fire. Newark, NJ, 7 January 1983* (Quincy, MA: National Fire Protection Agency, 1983).

[100] T. Fishwick. "The Fire and Explosion at Indian Oil Corporation, Jaipur: A Summary of Events and Outcomes." *Loss Prevention Bulletin* (2011. 222): 9.

8.0 REGULATORY ANALYSIS

The CSB analysis of the relevant regulatory, industry, and consensus standards for safety and management of bulk petroleum aboveground storage facilities found that the accident at CAPECO might have been prevented had OSHA and EPA considered the facility to pose a high hazard and required the facility to:

1) Conduct a hazard assessment;
2) Implement more than one layer of protection as an independent level alarm system; and
3) Incorporate changes based on lessons learned from previous similar incidents.

The CSB determined that existing regulatory, industry, and consensus standards do not adequately protect workers and the public from the dangers posed by bulk petroleum storage tank terminals. The following section discusses shortcomings of the regulatory, standard and recommended practice framework governing this industry. (See Figure 17.)

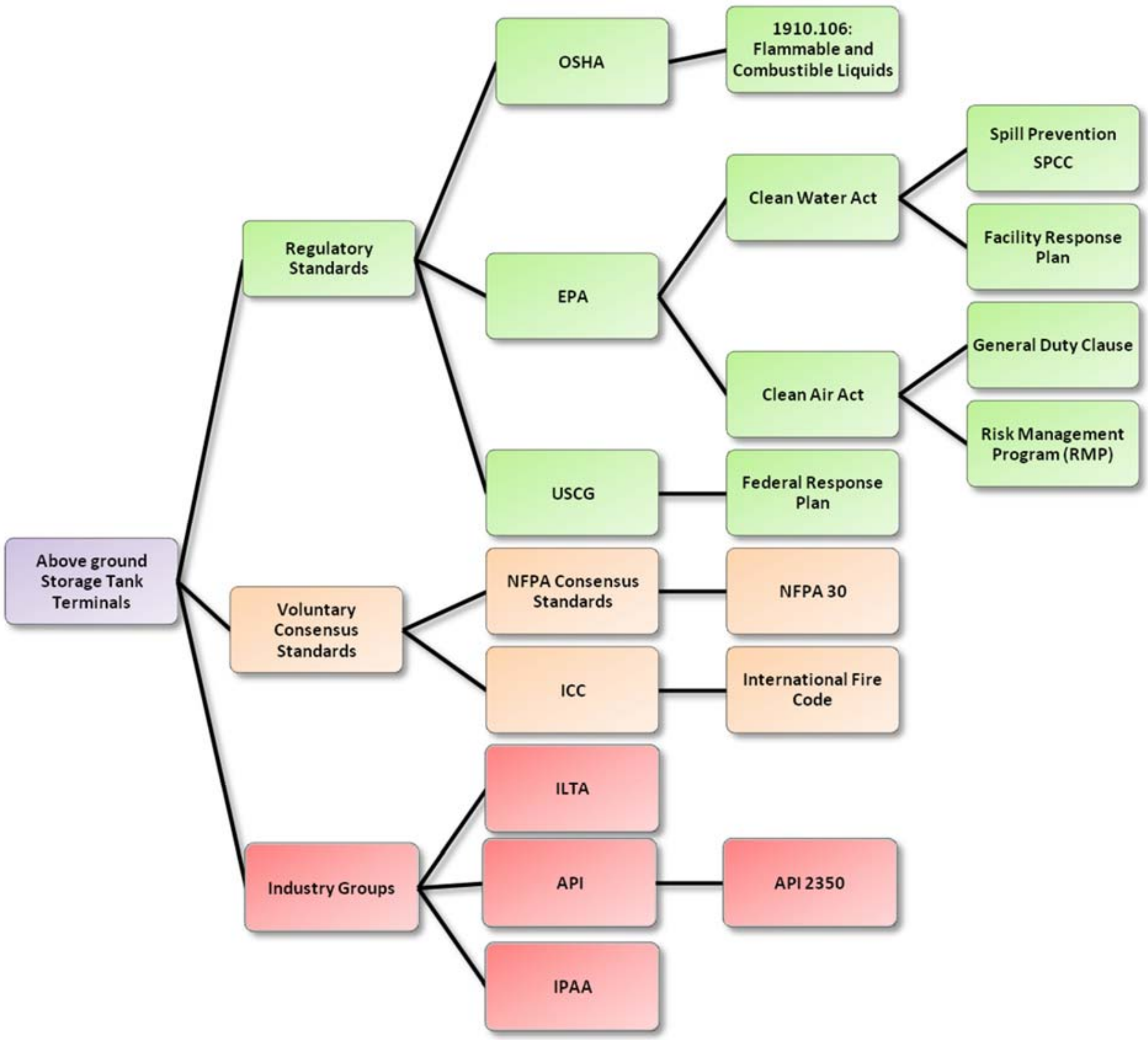

Figure 17: Many regulatory policies, voluntary and consensus standards contain safety requirements or recommendations for bulk petroleum aboveground storage tanks, but not all are required, and storage tank facilities are not generally covered by the RAGAGEP provisions of the OSHA PSM and EPA RMP programs. The voluntary industry and consensus standards could be considered RAGAGEP, if the process or facility were covered under these programs.

8.1 Environmental Protection Agency (EPA)

Although certain environmental statutes and EPA regulations apply to bulk petroleum aboveground storage tank terminals such as CAPECO, the CSB finds these regulations do not adequately protect the public from catastrophic incidents at bulk petroleum storage tank terminals storing NFPA 704, Class 3 flammable liquids:

- The EPA Clean Air Act General Duty Clause (CAA Section 112(r)(1)) lacks specific guidance for preventing accidental releases, while other regulations, such as the Risk Management Program (RMP), the Spill Prevention, Control and Countermeasure (SPCC), and the Facility Response Plan (FRP), do not require an overfill prevention program and a robust hazard assessment.
- The Clean Air Act (CAA) General Duty Clause protects the public living near facilities. Due to a gasoline exemption and the flammable mixture provision[101] under the List Rule (see Section 8.3), bulk petroleum storage tank terminals are not subject to the EPA risk management program regulations because they store NFPA Class 3 flammable liquids not regulated by the standard.
- The Clean Water Act (CWA) SPCC regulations, which protect navigable waterways and shorelines from oil spills, require only one layer of protection for overfill prevention and do not require that bulk petroleum tank terminals implement a second layer of protection, such as an independent high level alarm.

8.2 Clean Air Act: The General Duty Clause

Section 112(r)(1) of the CAA, the General Duty Clause, 42 U.S.C. § 7412(r)(1), requires owners and operators of stationary sources[102] who produce, store and handle extremely hazardous substances to identify hazards, design, and maintain a safe facility to prevent their release and protect the public.[103] The EPA issues chemical safety alerts advising industry on the types of issues covered by the General Duty Clause and publishes alerts on reactive hazards, lightning,

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[101] Flammable mixtures containing more than 1% of a regulated substance and the overall mixture meets the NFPA 4 flammability criteria are covered and must submit a Risk Management Plan to the EPA. *General Duty Clause of the Clean Air Act* (Washington, DC: U.S. Environmental Protection Agency, March 2009). http://www.epa.gov/oem/docs/chem/gdc-fact.pdf (accessed December 21, 2014).

[102] *Stationary source* means any buildings, structures, equipment, installations, or substance-emitting stationary activities that belong to the same industrial group, which are located on one or more contiguous properties and under the control of the same person (or persons under common control), and from which an accidental release may occur (63 FR 645).

[103] *Guidance for Implementation of the General Duty Clause Clean Air Act, Section 112(r)(1)* (Washington, DC: U.S. Environmental Protection Agency, Office of Solid Waste and Emergency Response Office of Enforcement and Compliance Assurance, May 2000). http://www2.epa.gov/sites/production/files/2013-10/documents/gdcregionalguidance.pdf (accessed December 21, 2014).

and other catastrophic hazards. In 2009, the EPA issued a Chemical Safety Alert for Rupture Hazard from Liquid Storage Tanks to address catastrophic hazards posed by fertilizer storage tanks.[104]

However, to date, the EPA has not issued any alerts for overflow hazards from flammable liquids in storage tanks, despite the occurrence of high-consequence incidents such as Texaco Oil Company and Buncefield incidents prior to CAPECO. In addition, the performance-based[105] nature of the general duty clause leaves the responsibility of protecting the public up to each covered facility, without any specific requirements from the EPA. The CSB found that further guidance under the General Duty Clause may be necessary to encourage more than one layer of overfill protection for bulk aboveground petroleum storage tank terminals near communities.

8.3 EPA: The List Rule

After a number of chemical accidents in the US and overseas, Congress enacted the Clean Air Act Amendments (CAAA) of 1990. Sections 301 and 112 of the CAAA require that the EPA issue regulations preventing accidental releases that could harm the public.[106] Section 112(r) of the CAAA, 42 U.S.C. § 7412 (r), requires owners and operators of stationary sources to identify hazards and to prevent and minimize the effect of accidental releases when extremely hazardous substances are present.[107] The EPA promulgated the Risk Management Program rule in 1996 to address accidental releases.[108] The CAAA required EPA to promulgate an initial list of 100 substances "known to cause or may [reasonably] be anticipated to cause death, injury, or serious adverse effects to human health or the environment"[109] in the event of an accidental release.[110]

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[104] *Chemical Safety Alert: Rupture Hazard from Liquid Storage Tanks*. U.S. Environmental Protection Agency: Washington, DC, September 2009. http://www.epa.gov/osweroe1/docs/chem/tanks7.pdf (accessed December 21, 2014).

[105] A performance-based standard, also referred to as a functional approach, allows facilities to define their own methods to achieve the regulatory goal or standard. Examples of performance-based standards are the OSHA PSM standard and a numeric limit on emissions that does not prescribe how it is achieved.

[106] CONSAD Research Corporation. *Analytical Support and Data Gathering for an Economic Analysis of the Addition of Selected Reactive Chemicals within the Scope of the OSHA Process Safety Management Standard* (Washington, DC: U.S. Occupational Safety and Health Administration, 1998).

[107] *Guidance for the Implementation of the General Duty Clause of the Clean Air Act, Section 112(r)(1)*. 550-B00-002 (Washington, DC: U.S. Environmental Protection Agency, May 2000): 2.

[108] *EPA Can Improve Implementation of the Risk Management Program for Airborne Chemical Releases*. 09-P-0092 (Washington, DC: U.S. Environmental Protection Agency, February 10, 2009).

[109] *Guidance for Implementation of the General Duty Clause Clean Air Act, Section 112(r)(1)* (Washington, DC: U.S. Environmental Protection Agency, Office of Solid Waste and Emergency Response Office of Enforcement and Compliance Assurance, May 2000). http://www2.epa.gov/sites/production/files/2013-10/documents/gdcregionalguidance.pdf (accessed December 21, 2014).

[110] The Public Health and Welfare. *U.S. Code,* Section 7412(r)(3), Title 42, 2009.

Known as the List Rule, this requirement obliged covered facilities, in addition to other requirements, to submit a Risk Management Plan (RMP) to the EPA when they exceeded the threshold quantity of a regulated substance on the list. The initial list included 77 acutely toxic substances, 63 flammable gases and volatile flammable liquids, and Division 1.1 high-explosive substances as designated by the Department of Transportation (DOT).

The List Rule has been amended several times since its promulgation. Shortly after enactment,[111] the API and the Institute of Makers of Explosives (IME) filed petitions requesting a judicial review of the List Rule. In settlement of these petitions, the EPA specifically exempted regulated substances in gasoline[112] from determining whether a threshold quantity was present in a process.[113] The EPA stated, "risks associated with the storage and handling of flammable substances are a function of the properties of the materials, not their end use."[114] The agency argued for "exempting gasoline because it does not meet the NFPA 4 flammability criteria,"[115] and "the EPA believes it does not represent a significant threat to the public of vapor cloud explosions."[116]

The EPA also exempted flammable mixtures including blendstocks[117] and natural gasoline that do not meet the NFPA flammability rating of 4.[118] However, flammable mixtures and

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[111] Petitions were filed within the standard 60-day period under CAA 307(b), around March 1994. The settlement of the petitions occurred in early 1996.

[112] Gasoline is exempt from the EPA List Rule because it does not meet the boiling point criterion for listing (NFPA 4 criteria, flammability hazard rating of 4); therefore, this substance is not assigned a threshold level. Approval of Colorado's Petition To Relax the Federal Gasoline Reid Vapor Pressure Volatility Standard for 1996 and 1997. *Federal Register* (1996): 61, 73.

[113] Regulated Substances for Accidental Release Prevention – Threshold Determination. *Code of Federal Regulations,* Part 68.115(b)(2)(ii), Title 40, 1998.

[114] 40 CFR Part 68, List of Regulated Substances and Thresholds for Accidental Release Prevention; Final Rule. Rules and Regulations, January 6, 1998. *Federal Register* (1998): 63 (3),

[115] NFPA 704 defines NFPA 4 flammability criteria to include materials that rapidly or completely vaporize at atmospheric pressure and normal ambient temperature or that are readily dispersed in air and burn readily. This may include flammable gases, flammable cryogenic materials, any liquid or gaseous material that is liquid while under pressure and has a flash point below 22.8°C (73°F) and a boiling point below 37.8°C (100°F) (i.e., Class IA liquids), and materials that ignite spontaneously when exposed to air. Solids containing greater than 0.5 percent by weight of a flammable or combustible solvent are rated by the closed cup flash point of the solvent. NFPA 704. http://www.nfpa.org/codes-and-standards/document-information-pages?mode=code&code=704 (accessed December 21, 2014).

[116] 40 CFR Part 68 List of Regulated Substances and Thresholds for Accidental Release Prevention; Final Rule. Rules and Regulations, January 6, 1998. *Federal Register* (1998): 63 (3).

[117] Blendstocks are motor gasoline blending components intended for blending with oxygenates to produce finished reformulated motor gasoline. (Energy Information Administration, Definitions, Sources and Explanatory Notes http://www.eia.gov/dnav/pet/tbldefs/pet_move_wkly_tbldef2.asp (accessed December 21, 2014).

[118] 40 CFR Part 68, List of Regulated Substances and Thresholds for Accidental Release Prevention. Final Rule. Rules and Regulations, 6 January 1998. *Federal Register* (1998): 63 (3).

blendstocks meeting the NFPA 4 flammability are subject to threshold determinations[119] irrespective of their end use. If a mixture consists of 1% or greater concentration of a regulated flammable substance and the mixture meets the NFPA 4 flammability criteria, the EPA considers the entire weight of a flammable mixture as the regulated flammable substance.[120] The EPA recognizes specific circumstances in which a facility not covered under the List Rule has the potential for a vapor cloud explosion, and it asserts that the General Duty Clause protects against site-specific factors that "make an unlisted chemical extremely hazardous."[121]

The unleaded gasoline involved in the CAPECO incident had an NFPA 704 flammability rating of 3, falling outside the RMP criteria. The flammable mixture also had an API gravity[122] of 63.7, characterizing it as highly flammable. Although the components of unleaded gasoline—benzene, toluene, xylene, cyclohexane, trimethyl benzene, and alcohol additives—are not regulated substances under the List Rule, they contribute to its high flammability. In the CAPECO incident, these components resulted in a vapor cloud formation and explosion.[123] The magnitude of the CAPECO incident warrants that the EPA reassess its criteria for exempting blendstocks and flammable mixtures that do not meet NFPA 4 flammability criteria.

Furthermore, the EPA did not consider the previous incidents when it granted the gasoline and flammable mixture exemption.[124] These incidents and the CAPECO explosion demonstrate that a vapor cloud formation from a flammable mixture such as unleaded gasoline can result in catastrophic impact to local communities and workers. In addition, despite a requirement to protect the public under the General Duty Clause, CAPECO did not implement an adequate safety management system to prevent the catastrophic explosion and fire.

[119] A threshold determination is the method by which a source calculates whether a threshold quantity is present in a process. Exemptions and exclusions of regulated substances from threshold determination allow a source not to include regulated substances in a mixture in specified instances.

[120] 40 CFR Part 68, List of Regulated Substances and Thresholds for Accidental Release Prevention. Final Rule. Rules and Regulations, January 6, 1998. *Federal Register* (1998): 63 (3).

[121] Ibid.

[122] The American Petroleum Institute (API) characterizes flammability of crude oil and condensate by gravity level. The higher the gravity, the lighter and more flammable the compound; materials below an API gravity value of 35 are characterized as crude oil, while those above 45 are considered condensate.

[123] Gasoline with blends that include more than 1% of pentane is subject to coverage under the RMP.

[124] See Section 7.2 and Appendix B for incidents excluded from EPA consideration in its gasoline and flammable mixture exemption.

8.4 Risk Management Program

Under 40 CFR §68, covered facilities fall into three Program Levels (Program 1, 2, or 3) based on a process unit's potential to affect the public and the requirements to prevent accidents.[125] Consistent with OSHA's PSM requirements, facilities that fall under Program 3 must implement a prevention program that includes process safety information, process hazard analysis, standard operating procedures, training, mechanical integrity, compliance audits, incident investigations, management of change (MOC), pre-startup reviews, employee participation, and hot work permits. Tank terminals similar to CAPECO that store gasoline do not fall under Program 1, 2 or 3 requirements. In addition, under the Risk Management Program, covered facilities are subject to the same recognized and generally accepted good engineering practices (RAGAGEP) requirements for mechanical integrity and process hazard analyses (PHAs) as the OSHA PSM standard.

8.5 Chemical Accident Provisions, Risk Management Plan (RMP)

The EPA's Chemical Accident Provisions (40 CFR §68) require facilities that have more than a threshold quantity of a List Rule-regulated substance to submit a Risk Management Plan (RMP) identifying the quantity of flammable or toxic material and to report on their accident prevention program, accident history, and planning.[126] Every five years, covered facilities must conduct a hazard assessment that considers worst-case scenarios, certify to the EPA their compliance with prevention program requirements,[127] and coordinate their emergency response preparedness with local responders. Had CAPECO been required to conduct a hazard assessment that evaluated the quantity of flammable products stored at the terminal and their proximity to the neighboring community, the facility may have had to address the risk of a vapor cloud explosion and resulting multiple tank fires. Under RMP, CAPECO would have had to develop accident prevention programs and coordinate response planning with local emergency responders, actions that might have mitigated the incident.

The EPA requested more information from the public and regulated community on amending the RMP rule to include more specific siting requirements as part of the PHA in a July 31, 2014, Request for Information (RFI).[128] The CSB issued comments under the RFI encouraging the

[125] 40 CFR §68.10. Applicability. http://www.law.cornell.edu/cfr/text/40/68.10 (accessed December 21, 2014).
[126] Regulated Substances for Accidental Release Prevention. *Code of Federal Regulations,* Part 68.115(b)(2), Title 40, 1998.
[127] Ibid.
[128] The RFI was issued under 40 CFR §68, Accidental Release Prevention Requirements: Risk Management Programs Under the Clean Air Act, Section 112(r)(7).

EPA to provide more guidance on facility siting.[129] Examples of siting requirements provided by the EPA include buffer or setback zones for newly covered stationary sources, or establishing safety criteria for siting of structures that house people inside a facility.[130]

8.6 The Clean Water Act (CWA)

The Federal Water Pollution Act of 1972, or Clean Water Act (CWA), as amended, gives the EPA jurisdiction[131] to protect navigable waters from pollution. Section 311 authorizes a program to prevent, prepare for, and respond to discharges of oil and hazardous substances. Section §311(j)(1)(C) provides that the President shall issue regulations establishing procedures, methods, equipment, and other requirements to prevent and contain discharges of oil[132] from facilities and vessels, and to contain such discharges. CAPECO was subject to various EPA regulations promulgated under the CWA.

8.6.1 Spill Prevention, Control and Countermeasure (SPCC) Regulations

The Spill Prevention, Control, and Countermeasure (SPCC) requirements govern oil discharge at aboveground storage tank sites. The EPA promulgated the SPCC regulation (40 CFR §112) on January 10, 1974 (See 38 FR 34164). The SPCC regulation requires a facility to prepare and certify by a Professional Engineer, a plan detailing the equipment, workforce, procedures, and steps to prevent and control an oil discharge to navigable waters and shorelines. The regulation at 40 CFR §112.8(c)(8) requires SPCC-subject facilities to provide for overfill protection for each container in accordance with good engineering practice including applicable industry standards.[133] The regulation allows the owner/operator of a container to select only one suggested method of overfill controls. The options include, high liquid level alarms at a constantly attended location or surveillance station, high liquid level pump cut off devices to stop

[129] Docket No. EPA-HQ-OEM-2014-0328 http://www.csb.gov/assets/1/7/EPA_RFI.pdf. (accessed January 7, 2015)

[130] Environmental Protection Agency. 40 CFR Part 68. Accidental Release Prevention Requirement: Risk Management Programs Under the Clean Air Act, Section 11(r)(7). Proposed Rule. *Federal Register*. (2014): 79 (147), 44604-44633.

[131] CWA jurisdiction includes navigable waters of the United States and adjoining shorelines, the waters of the contiguous zone, and the high seas beyond the contiguous zone in connection with activities under the Outer Continental Shelf Lands Act. It covers activities under the Deepwater Port Act of 1974 or activities that may affect natural resources belonging to, appertaining to, or under the exclusive management authority of the United States, including resources under the Magnuson Fishery Conservation and Management Act of 1976.

[132] Under CWA §311(a)(1), "oil" means "oil of any kind or in any form, including, but not limited to, petroleum, fuel oil, sludge, oil refuse, and oil mixed with wastes other than dredged spoil." Clean Water Act Section 311 – Oil and Hazardous Substances Liability. http://www.epa.gov/region7/public_notices/CWA/section311.htm (accessed December 21, 2014).

[133] Environmental Protection Agency. 40 CFR Part 112.8(c)(8). Spill Prevention, Control, and Countermeasure Plan requirements for onshore facilities (excluding production facilities). Section 112.8(c)(8). (2002).

the liquid flow into a tank at a previously established level, direct audible or code signal communication between the container gauger and the pumping station, and a fast response system such as a digital computer, telepulse or direct vision gauges to determine liquid levels in a tank or container. [134] The regulation also requires regular testing of level sensors for the selected overfill prevention option.[135]

8.6.2 CAPECO's SPCC History

The CAPECO facility had a history of noncompliance with SPCC regulations. In 1993, EPA inspections noted poor housekeeping, including oil in tank berm areas and inadequate control of vegetation in the secondary containment areas. In 1996, the EPA cited CAPECO for deficiencies in their SPCC plan that include not adequately explaining the engineering controls in place to prevent a spill. The facility also experienced an overfill incident in 1999, when fuel spilled from an asphalt tank outside the tank farm area. Oil flowed out of a vent located at the top of the tank into the secondary containment. Although this incident occurred in a separate process from the tank farm, the EPA findings are relevant to the 2009 overfill incident. The EPA cited the facility for not updating the bulk storage tank installations and for not incorporating fail-safe engineering to prevent the overfill incident.[136] After this incident, the EPA recommended that CAPECO consider installing one or more of the following safeguards:

- High-level alarms with an audible or visual signal at a constantly manned operation or surveillance station;
- High-liquid-level pump cutoff devices set to stop flow at a predetermined tank content level;
- Direct audible or code signal communication between the tank gauger and the pumping station; or
- A fast response system for determining the liquid of each bulk storage tank, including digital computers, telepulse, or direct vision gauges or their equivalent.

According to EPA records, CAPECO was compliant with recommendations by 2001. The facility installed two levels of protection, the computer system, equipped with a high-liquid level

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[134] Spill Prevention, Control, and Countermeasure Plan requirements for onshore facilities (excluding production facilities). *Code of Federal Regulations*, Part 112.8, Title 40 (2002). http://www.ecfr.gov/cgi-bin/text-idx?SID=67da1ecbd5068d7f144a92e0e59ef956&mc=true&node=pt40.22.112&rgn=div5#se40.22.112_18 (accessed June 2015).

[135] Ibid.

[136] US Environmental Protection Agency Region 2. *Review of Revised SPCC Plan for the Caribbean Petroleum Refining Facility*, Bayamón, Puerto Rico (Washington, DC: U.S. Environmental Protection Agency, September 20, 1999).

audible/visual alarm, and established direct communication between the gauger and the pump station, but was not required to conduct a hazard assessment to determine if the two safeguards adequately prevented an overfill. See Section 6.5.1 for discussion on the computer system.

After the October 23, 2009, incident, the EPA cited CAPECO again for not having "fail safe engineering"[137] on any of its bulk storage tanks at the time of the incident. CAPECO contended that the facility did employ "fail safe engineering," as evidenced by its gauging system, which included reading the tank side gauge and using the Digital Electric Level Transmitter. The EPA deferred to guidance on fail-safe engineering, referring CAPECO to industry standards. However, the CSB found, both the consensus standards (NFPA 30, Section 8.10.2.1) and industry standard (ANSI/API 2350, Section 8.10.1.1) offer little guidance on fail-safe engineering practices at tank terminals. Furthermore, the 2009 incident breached secondary containment and spilled into navigable waterways. Although the secondary containment captured the gasoline from Tank 409, the open dike valves allowed oil, fire suppression foam, and an oily-water mixture to migrate to the storm water retention pond in the WWT area. The fuel mixture discharged into Las Lajas Creek, which feeds 100 acres of wetlands and nearby Malaria Creek flowing into the Bay of San Juan. (See Section 5.3.1 for a discussion of community impact.) The pooling gasoline in the containment dike also contributed to the formation of the flammable vapor cloud. (See Section 4.3 on flammable vapor cloud development.) The CSB further concludes that a high-level alarm system as part of an automatic overfill prevention system equipped with one additional layer of protection under SPCC could have alerted operators to the high liquid levels, or automatically shut down transfer operations, or diverted the flow operations to another tank.

The CSB learned that tank terminal facilities do not have to register or report overfill incidents unless those discharges are in violation of CWA section 311(b)(3), as per 40 CFR §110.6. A 2008 Government Accountability Office (GAO) report found that the EPA did not have a clear understanding of the universe of facilities regulated under SPCC. This limited knowledge hinders the agency's ability to effectively identify regulated facilities, establish inspection priorities, and evaluate whether the program is achieving its goals."138 These findings were again reiterated in a 2012 report that found the EPA lacked sufficient data on the facilities covered in the Oil Prevention Program, which includes both the SPCC and Facility Response

[137] Fail Safe Engineering refers to the design of a product to fail in a predictable manner, to a "safe state." P. Herena. *The Principle of Fail Safe* (American Institute of Chemical Engineers, February 23, 2011). http://chenected.aiche.org/process-safety/the-principle-of-fail-safe/ (accessed December 21, 2014).

[138] Government Accountability Office. *Aboveground Oil Storage Tanks: More Complete Facility Data Could Improve Implementation of EPA's Spill Prevention Program,* GAO-08-482 (Washington, DC: U.S. Government Accountability Office, April 30, 2008).

Plan (FRP). The 2012 report stated, "the Agency [EPA] remains largely unaware of the identity and compliance status of the vast majority of CWA Section 311 regulated facilities."139 Furthermore, the 2012 report calls attention to the inadequacy of data collection for OPP-covered facilities: "Agency data systems cannot exchange data with each other, and lack consistent and sufficient codes to categorize deficiencies and noncompliance. These data systems limitations prevent EPA from capturing the full details of a violator's history and identifying trends in compliance and enforcement."140 A registry of incidents occurring at tank terminal facilities, such as CAPECO, would allow the EPA to tailor overfill protection requirements more effectively.

8.6.3 Facility Response Plans (FRP)

Section 311(j)(5) of the CWA, amended by the 1990 Oil Pollution Act (OPA), calls for facilities that could cause substantial harm[141] from an oil discharge to submit a Facility Response Plan (FRP). The FRP requires contingency measures for oil discharged from an incident.[142] Designed in accordance with Sections 112.20, 112.21 and Appendices C-F of the CWA FRP regulation, FRPs demonstrate a facility's response to a worst-case discharge of oil. Because CAPECO had vessel loading and unloading capabilities, the terminal was also subject to USCG's FRP regulation at 33 CFR §154. Both the EPA and USCG conducted multiple inspections at the CAPECO facility prior to the incident. The EPA and USCG have separate regulatory jurisdiction for this facility. EPA's jurisdiction begins at the first valve inside secondary containment whereas the USCG's jurisdiction begins at this first valve inside secondary containment for the EPA regulated tank and extends to the vessel. The USCG inspects marine operations at the dock and the pipeline carrying fuel to the first valve inside secondary containment.

The FRP rule at 40 CFR §112.20(f)(1) outlines the substantial harm criteria that allows for owner/operators to self-identify whether their facilities are subject to the FRP regulation. A facility can be classified for the potential to cause substantial harm if they meet the following

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[139] Environmental Protection Agency, Office of Inspector General. *EPA Needs to Further Improve How It Manages Its Oil Pollution Prevention Program*. Report No. 12-P-0253 (Washington, DC: U.S. Environmental Protection Agency, February 6, 2012).

[140] Ibid., p.9.

[141] A facility could reasonably be expected to cause substantial harm to the environment if it has 42,000 gallons or more in oil storage capacity and transfers of oil over water to or from vessels, or if it has 1 million gallons or more in oil storage capacity, and if one of the following is true: 1) it has inadequate secondary containment and freeboard; 2) a discharge could cause injury to fish and wildlife and sensitive environments; 3) a discharge could shut down a public drinking water intake; or 4) it has had a reportable oil discharge of 10,000 gallons or more within the last 5 years.

[142] Subpart D-Response Requirements: Facility Response Plans, *Code of Federal Regulations,* Part 112.20, Title 40 (2000).

criteria: 1) The facility transfers oil over water to or from vessels and has a total oil storage capacity greater than or equal to 42,000 gallons; or 2) The facility's oil storage capacity is greater than or equal to 1 million gallons and one of the following is true:

- The facility does not have adequate sized secondary containment for each aboveground storage area;
- The facility is located at a distance such that a discharge from the facility could cause injury to fish and wildlife and sensitive environments;[143]
- The facility is located at a distance (i.e., planning distance) such that a discharge from the facility would shut down a public drinking water intake; or
- The facility has experienced a reportable oil discharge greater than or equal to 10,000 gallons within the last 5 years.[144]

In accordance with 40 CFR §112.20(f)(3), all FRPs submitted to EPA are reviewed by EPA to determine whether an oil discharge from the facility could cause significant and substantial harm. Facilities with this harm designation require the EPA approval of their FRP. CAPECO met the substantial harm criteria, had submitted an FRP to EPA Region 2, was designated as a "significant and substantial harm" facility, and was inspected multiple times by EPA inspectors for SPCC and FRP compliance.

8.6.4 EPA FRP Inspection History

Similar to its SPCC record, CAPECO had a history of non-compliance related to FRP requirements. CAPECO submitted its first FRP to the EPA in 1997. However, a 1998 EPA field inspection identified violations, which the facility failed to correct when reapplying for approval in 1999 and 2001. The EPA denied approval of CAPECO's FRP in 1999 and March 2001.[145] CAPECO received approval for its FRP in July 2001; however, another EPA FRP inspection in 2005 revealed deficiencies in maintaining discharge prevention meetings or logs.[146]

8.6.5 USCG FRP Inspection History

The USCG conducted annual FRP inspections of the CAPECO facility from 2004 to 2011 to evaluate communications, pollution prevention/response, operations/management, firefighting, documentation, and other emergency response elements. However, the FRP inspection failed to

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[143] This distance is referred to as the "planning distance." Calculation instructions are outlined in Appendix C of 40 CFR §112.
[144] 40 CFR §112.20 Facility response plans. (f)(1)
[145] Caribbean Petroleum Refining LP. *US EPA Region 2 Facility Response Plan (FRP)*; FRP ID 20027. Caribbean Petroleum Refining LP: Bayamon, PR (2001).
[146] Ibid., p.1.

document CAPECO's ability to fight a catastrophic loss of containment that could result in multiple tank fires. CAPECO received a satisfactory inspection from 2004 to March 2008. Seven months prior to the October explosion and fires CAPECO submitted an updated FRP and received a satisfactory inspection.[147]

8.6.6 Lack of Robust FRP Inspections

Despite receiving a satisfactory rating on the various components of emergency response, CAPECO experienced the 2009 overfill incident that spilled into nearby wetlands. The CSB found the FRP inspection process does not require FRP inspectors to conduct a thorough evaluation of an emergency response plan that encompasses catastrophic failure of multiple tanks at once. Under the EPA's jurisdiction, Appendix F of 40 CFR §112.20(h) and Appendix F, Section 1.5.1.2 requires a facility to address chain reactions[148] of a tank failure leading to contaminating navigable waters, while the USCG FRP inspection report assesses oil spill preparedness by evaluating a terminal's pollution prevention and response, firefighting, communications, deck, and cargo, among other factors. However, both FRP inspections lack substantive evaluation of a covered facility's mitigation efforts to prevent a catastrophic incident like an explosion and multiple tank fires that can contaminate navigable waters.

Had the EPA and USCG FRP inspectors been required to fully assess the functioning of the containment dike, dike drain valves, and the full scope of CAPECO's emergency discharge plan, CAPECO might not have received a satisfactory inspection and would have had to evaluate its inadequate dike drainage system, which led to the spread of the gasoline vapor cloud. See Section 6.9.1 for discussion on dike drain valves.

8.6.7 EPA RMP and SPCC Programs Lack Resources to Inspect Tank Facilities

The CSB has identified significant gaps in the RMP and SPCC programs that warrant the EPA to extend coverage to bulk petroleum terminals storing NFPA 704 Class 3 flammable liquids and above. However, both programs lack the resources to sufficiently inspect all covered facilities. The CSB Chevron investigation report discusses how the EPA's Risk Management Program lacks the ability to inspect all covered facilities and made recommendations to the Governor of California to "Ensure that a means of sustained funding is established to support an independent,

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[147]United States Coast Guard. *Activity Summary Report. Annual Exam*, Activity ID 1985003, 2521895, 3093795, 3162359, 3428543 (Washington, DC: U.S. Department of Homeland Security, 2009).

[148] A chain reaction of a failure requires a covered facility to consider the impact of the failure on the environment. Facility response training and drills/exercises. *Code of Federal Regulations*, Part 112.20(h) and Appendix F, Section 1.5.1.2, Title 40 (2000).

well funded, well staffed, technically competent regulator."[149] Federal EPA RMP and SPCC programs lack the capacity to undertake inspection of such tank terminals.

A 2009 report of the EPA Risk Management Program found that EPA inspected only 197 of the 493 high-risk facilities identified by the EPA's Office of Emergency Management. Among the 296 uninspected facilities, 151 had the potential to affect 100,000 people or more in a worst-case accident.[150] The report identified a lack of full-time inspectors as one of the main factors limiting the EPA's ability to conduct on-site audits or inspections of facilities covered under the Risk Management Program. In fiscal year 2009, the EPA had 24 full-time inspectors to cover 11,529 facilities covered in the program.[151] For the EPA to sufficiently inspect tank terminals like CAPECO, the Risk Management Program will require additional resources.

8.6.8 The OPP Program Lacks Resources

EPA lacks sufficient staff to inspect all its SPCC- and FRP-covered facilities and lacks a comprehensive understanding of the facilities it regulates. EPA has an estimated 30 to 40 full-time employees to inspect all SPCC- and FRP-covered facilities. From 2008 to 2012, the EPA inspected only 3,700 of the 640,000 facilities covered under SPCC.[152] In addition, a 2008 report found "Without more comprehensive data on the universe of facilities that are subject to the SPCC rule, EPA cannot employ a risk-based approach to target its SPCC inspections to those facilities that pose the greatest risks of oil spills into or upon U.S. navigable waters and adjoining shorelines."[153] The same report found that the "incomplete information on the universe of SPCC facilities prevents EPA from determining whether and to what extent the SPCC program is achieving its goals."[154]

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[149] U.S. CSB. *Regulatory Report: Chevron Richmond Refinery Pipe Rupture and Fire*, *Chevron Richmond Refinery #4 Crude Unit, Richmond, CA. August 6, 2012*. 2012-03-I-CA (Washington, DC: U.S. Chemical Safety Board, October 2014). http://www.csb.gov/assets/1/19/Chevron_Regulatory_Report_11102014_FINAL_-_post.pdf (accessed December 21, 2014).

[150] Environmental Protection Agency. Office of Inspector General. *EPA Can Improve Implementation of the Risk Management Program for Airborne Chemical Releases*. 09-P-0092 (Washington, DC: U.S. Environmental Protection Agency, February 10, 2009).

[151] Ibid.

[152] Environmental Protection Agency, Office of Inspector General. *EPA Needs to Further Improve How It Manages Its Oil Pollution Prevention Program*. 12-P-0253 (Washington, DC: U.S. Environmental Protection Agency, February 6, 2012).

[153] Government Accountability Office, *Aboveground Oil Storage Tanks: More Complete Facility Data Could Improve Implementation of EPA's Spill Prevention Program,* GAO-08-482, April 30, 2008.

[154] Ibid.

8.7 Occupational Safety and Health Administration (OSHA)

A CSB analysis found deficiencies in various OSHA standards addressing tank terminals in protecting workers from the flammable hazards. In addition, similar to the EPA's policies, OSHA's exemption of atmospheric storage tanks from the Process Safety Management (PSM) standard undermines the development of hazard assessments and management of change (MOC) reviews that would have required CAPECO personnel to analyze the hazards posed by terminal operations. Furthermore, specific requirements for robust overfill prevention and risk management are lacking because OSHA regulations do not consider tank terminals as PSM-covered or high-hazard facilities.[155]

8.7.1 Flammable and Combustible Liquids (1910.106)

OSHA's Flammable and Combustible Liquids standard (1910.106), which covers tank terminals containing flammable materials, does not require overfill protections for aboveground storage tanks.[156] Based on the 1968 version of NFPA 30: Flammable and Combustible Liquids Code, the standard offers no guidance on overfill prevention at terminal facilities during the transfer of flammable or combustible fluids. While recent versions require limited overfill protection, OSHA has not updated 1910.106 to include newer versions of NFPA 30 or other updated good engineering practices. (See Section 8.10.2.1.)

The Puerto Rico Occupational Safety and Health Administration (PR OSHA)[157] cited CAPECO for endangering the lives of tank farm workers following the incident. Although the October 23, 2009, explosion did not result in any worker injuries, tank farm operators escaped the initial vapor cloud ignition by a few minutes. PR OSHA cited CAPECO under 1910.106, stating:

> *"At Caribbean Petroleum Refining in Bayamón employees that worked performing routine tasks such as tank operator, waste treatment operator, loading rack operator, among others were exposed or could be exposed to flammable and combustible release, fire and or explosion during the performance of their duties. At the tank farm area the employer stored gasoline, jet fuel, fuel oil and diesel, in above ground tanks, ranging*

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[155] A PSM-covered facility or high-hazard facility, as defined by OSHA PSM, has the potential for a *catastrophic release* (major uncontrolled emission, fire, or explosion, involving one or more highly hazardous chemicals that present serious danger to employees in the workplace). A *facility* is defined as the buildings, containers, or equipment which contain a process. *Highly hazardous chemical* is defined as a substance possessing toxic, reactive, flammable, or explosive properties. Process safety management of highly hazardous chemicals. *Code of Federal Regulations*, Part 1910.119, Title 29, 2012.

[156] 1910.106 contains some overfill provisions for tank trucks and tank cars.

[157] Puerto Rico OSHA operates as a state plan. Established by the 1975 Occupational Safety and Health Act of Puerto Rico, the Puerto Rico Occupational Safety and Health Administration (PR OSHA) oversees 29 CFR 1910.106 – Flammable and Combustible Liquids, 29 CFR 1910.119 – Process Safety Management of Highly Hazardous Chemicals, 29 CFR 1910.120 – Hazardous Waste Operations and Emergency Response.

> *from 500 to 500,000 barrels. The employer did not review the Operational hazard of a large Hydrocarbon release from on-site piping entering the process sewer and storm water sewer systems. Equipment hazards like the additional hazards created by the use of expansion joints on the gasoline transfer lines at the Cummins pump station area. Human factors analysis related to what could occur if operators did not follow instructions for conducting rounds or gauging tanks. Level reading erroneous at the tank gauge and at the operators console. Additional hazards created when operators had to read tank sight gauge levels during the night in low light conditions. Lack of formal written operating procedures for determining the level of storage tanks during filling operations."*

The CSB found OSHA's Flammable and Combustible Liquids standard to be outdated, concluding that requiring terminal facilities to implement more than one safeguard and good engineering practice would have spared endangering the lives of CAPECO tank farm operators, and they would have likely been notified of the overfill before the vapor cloud developed.

8.7.2 Incorporating Elements of Process Safety Management (PSM) into 1910.106

OSHA's PSM Standard (29 CFR §1910.119) is a performance-based standard that requires covered entities, such as refineries and chemical plants, to implement a safety management system to prevent accidental releases from highly hazardous processes. PSM requires periodic audits, process hazard analysis (PHA),[158] and a management of change (MOC) process. Although the standard needs strengthening,[159] these tools indoctrinate additional safety measures into a covered entity's procedures. OSHA requires employers to use appropriate methods, such as hazard and operability studies (HAZOP), failure mode and effects analyses (FMEA), or fault tree analyses, among other safeguards, to identify and control hazards when conducting a PHA.

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[158] "The process hazard analysis is a thorough, orderly, systematic approach for identifying, evaluating, and controlling the hazards of processes involving highly hazardous chemicals. The employer must perform an initial process hazard analysis (hazard evaluation) on all processes covered by the [PSM] standard. The process hazard analysis methodology selected must be appropriate to the complexity of the process and must identify, evaluate, and control the hazards involved in the process." U.S. Department of Labor OSHA. *Process Safety Management*. OSHA 3132 (Washington, DC: U.S. Department of Labor Occupational Safety and Health Administration, 2000).

[159] The CSB made recommendations to amend the PSM regulations in the following investigations: BP Texas City, Motiva, Universal Form Clamp, Chevron and Tesoro. OSHA is undertaking measures to strengthen the standard. The CSB submitted comments to OSHA's request for information addressing PSM in January 2014. These comments are located on the CSB website: http://www.csb.gov/assets/1/16/CSB_RFIcomments.pdf (accessed December 21, 2014).

This performance-based standard requires the PHA methodology to address factors[160] such as engineering and administrative controls and appropriate detection methods, including process monitoring and control instrumentation with alarms.[161] Additionally, the standard requires covered facilities to update or revalidate their PHA every five years. PR OSHA adopted the Federal PSM standard as written.

The CSB found that the CAPECO incident was attributable to a lack of controls, enforcement, and adherence to these best engineering practices:

(1) A PHA, which might have identified additional engineering controls to prevent the vapor cloud formation.

(2) Engineering controls, such as automatic tank overflow protection system with a separate independent high-level alarm, which could have prevented the overflow.

(3) Facility design and tank spacing in a hazard analysis under aspects of PSM, likely increasing the number of safeguards to prevent an overfill.

Following the shutdown of the CAPECO refinery in 2000, the tank farm facility was no longer covered under PSM due to standard Section (a)(ii)(B) of the PSM standard, which expressly exempts flammable liquid stored in atmospheric storage tanks not connected to a covered process that are below normal boiling point. Under PSM, the facility was required to conduct periodic PHAs and MOCs of its process equipment. Facing fewer regulatory requirements for the tank farm, CAPECO management was not required to maintain the safety management system an MOC, and a periodic hazard assessment mandated under the PSM standard. Any of these requirements might have identified the lack of independent or redundant level alarm, overfill prevention safeguards and poor preventive maintenance. Including elements of PSM like the process hazard methodology into 1910.106 would compel tank terminals storing flammable liquids to reduce the risk posed to the workers and the public.

[160] Other PHA factors include the hazards of the process, previous incidents, consequences of failure of engineering and administrative controls, facility siting, human factors, and a qualitative evaluation of possible safety and health effects on employees in the workplace.

[161] U.S. Department of Labor OSHA. *Process Safety Management*. OSHA 3132 (Washington, DC: U.S. Department of Labor Occupational Safety and Health Administration, 2000).

8.8 Puerto Rico Occupational Safety and Health Administration (PR OSHA)

The Puerto Rico Occupational Safety and Health Administration (PR OSHA) visited the CAPECO facility nine times between 1988 and 2000. None of the visits occurred after the refinery shutdown in 2000 when the facility operated solely as a tank farm.

In 1988, PR OSHA fined CAPECO for serious violations under the General Duty Clause and the Flammable, Combustible Liquids standard (1910.106) after an employee was fatally injured, and another hospitalized while removing a blind from the pipeline when gasoline spilled and ignited. PR OSHA inspected CAPECO after the October 23, 2009 incident, issuing general duty citations for inadequate overfill prevention consistent with the recommended practice of ANSI/ANSI/API 2350, *Recommended Practice, Overfill Protection for Storage Tanks in Petroleum Facilities*, and NFPA 30, *Flammable and Combustible Liquids C*ode. Unable to issue citations under the PSM standard due to the atmospheric storage tank exemption, PR OSHA issued multiple serious violations and fines for lacking written procedures and not providing a safe workplace, and it referred to consensus and industry standards to address the flammable hazards onsite. The PHA, MOC, and procedural components of the PSM standard address most of the deficiencies cited by PR OSHA, but CAPECO was not compelled to follow them. If the OSHA PSM standard covered tank terminals, not only would terminals like CAPECO have to conduct a periodic analysis of their hazards, but also PR OSHA would be empowered to issue appropriate citations aimed at preventing similar incidents. The CSB issued a similar recommendation to remove the storage tank exemption in its Motiva investigation.[162]

8.9 Recognized and Generally Accepted Good Engineering Practices (RAGAGEP)

CFR §1910.119(d)(3)(ii) of the PSM and RMP standards require covered facilities and high-hazard facilities to ensure their equipment complies with recognized and generally accepted good engineering practices (RAGAGEP). These may include the Center for Chemical Process Safety (CCPS) research and publications; ASTM standards; piping, mechanical, and electrical codes; professional society standards; fire codes; and lessons learned from previous incidents.[163] OSHA and the EPA can cite facilities covered under PSM and RMP for noncompliance with

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[162] The CSB Motiva Enterprises LLC investigation called for OSHA to extend PSM coverage to atmospheric storage tanks that could be involved in a catastrophic release interconnected to a covered process with 10,000 pounds of a flammable substance. This recommendation came after one worker was fatally injured and eight were injured when hot work on an aboveground storage tank holding sulfuric acid ignited the flammable vapors inside the tank, releasing contents into the Delaware River on July 17, 2001.

[163] A. S. Blair. "RAGAGEP Beyond Regulation: Good Engineering Practices for the Design and Operation of Plants." *Process Safety Progress* 26.4: 330–332.

RAGAGEP. Covering tank terminal facilities like CAPECO under PSM and RMP would ensure that they use the best available engineering practices**.**

8.10 Industry and Consensus Standards

Industry and consensus standards serve as industry best practices and fire codes for tank terminal facilities. In some cases, specific versions of industry standards and fire codes are incorporated by reference into different regulations. The API and the National Fire Protection Association (NFPA) have a number of standards and codes that apply to overfilling a petroleum storage tank.

8.10.1 American Petroleum Institute

The American Petroleum Institute (API), a national trade association representing the oil and natural gas industry, develops voluntary industry standards and recommended practices widely used in industry. Updated periodically, API standards and recommended practices use the term "shall" to communicate requirements and "should" to indicate a recommendations. The American National Standards Institute, ANSI/API Standard 2350 and API Manual of Petroleum Measurement Standards (MPMS) Ch. 3.1A are the most relevant to overfilling of tanks at storage terminals.

8.10.2 ANSI/API Standard 2350 and the Overfill Prevention Process

ANSI/ANSI/API 2350, *Overfill Protection for Storage Tanks in Petroleum Facilities*, offers guidance on preventing overfills in petroleum storage tanks. The current, fourth edition, released in 2012, recommends that heavier oils including gasoline be included in the scope of a facility-specific overfill prevention program. The standard recognizes that prevention provides the most basic level of protection; thus, while using both the terms "protection" and "prevention," the document emphasizes prevention. The standard covers minimum overfill (and damage) prevention practices for aboveground storage tanks in petroleum facilities, including refineries, marketing terminals, bulk plants, and pipeline terminals that receive flammable and combustible liquids.

8.10.3 Overfill Prevention Process

To prevent tank overfills, ANSI/API Standard 2350 (2012) calls for implementing an overfill prevention process (OPP) and an automatic overfill prevention system (AOPS) supported by a risk assessment or risk analysis. The standard recommends that an OPP contain a management system, a risk assessment system, defined operational parameters, and other procedures, including those for receipt termination.[164] Incorporating a management system into the overfill prevention process is a significant revision to the standard from previous editions. The standard recommends that facilities implement a safety management system that includes, among other safeguards:

- Formal documented operating procedures;
- Competent operating personnel;
- Scheduled inspections;
- A management of change process for personnel and equipment changes; and
- Systems for investigating and communicating overfill near misses and lessons learned.

The standard asserts overfill prevention is best achieved through awareness of available tank capacity and inventory, careful monitoring, product movement control, reliable instrumentation and sensors and systems, and automatic overfill prevention systems when recommended by a risk assessment or risk analysis.[165] Although this standard did not exist in its current form at the time of the incident, CAPECO lacked formal procedures, sufficient operations personnel, and an effective safety management system.

8.10.4 Inadequate Guidance on Conducting a Risk Assessment

The CAPECO facility was not required to conduct a risk assessment. However, if the facility looked to API for guidance, neither the 2008 nor the current 2012 edition of the ANSI/ANSI/API 2350 standard offers guidance on how to conduct a thorough risk assessment. The risk assessment component of ANSI/ANSI/API 2350 asks the owner and operator of facilities to "categorize risks associated with potential tank overfills as either meeting or not meeting the criteria of the stakeholders."[166] It offers a conceptual framework for conducting an overall risk assessment, without significant details on what is necessary.

While this standard provides a level of autonomy to tank terminal owners and operators, it should offer clear guidance on minimum criteria. The standard says tank terminals "shall consider" incorporating regulatory requirements when conducting a risk analysis, but facilities are not limited to using regulatory requirements to define the parameters of their risk analysis. Since the basis for the AOPS is contingent on results from a risk assessment, API should provide more guidance on the risk assessment process or provide authoritative resources for this purpose.

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[164] Receipt termination refers to stopping or completing tank-filling operations.
[165] *ANSI/API Standard 2350-2012. Overfill Protection for Storage Tanks in Petroleum Facilities.* Fourth edition. (Washington, DC: American Petroleum Institute, May 2012).
[166] *Ibid*.

8.10.5 Insufficient Requirement for Alarm Levels

Another deficiency of the ANSI/ANSI/API 2350 standard is the levels of concern (LOC) required for necessary level alarms. The standard recommends terminal owners and operators consider a number of parameters[167] when establishing LOC for all tanks and at minimum establish three levels: critical-high (CH) levels, high-high level (HH), and maximum-working level (MW).[168] ANSI/ANSI/API 2350 recommends using the LOC to set level alarms. The standard also recommends a minimum of three inches separating the CH and HH tank levels to account for potential errors in data and measurement.[169] Each level should be set sufficiently below the other to allow appropriate response time to terminate the process if necessary. ANSI/ANSI/API 2350 also stipulates that an AOPS level for emergency action be set below the critical-high level to allow for automatic termination of a receipt before the critical level is reached.

The aboveground storage tank industry should implement either a high-level alarm, an automatic overfill prevention system, or both, but the current edition of ANSI/API 2350ANSI/ANSI/API 2350 recommends only a high-level alarm. ANSI/API 2350 neither specifies using a highly reliable alarm nor provides guidance on when a high-level alarm is sufficient to reduce the overfill risk. In the case of CAPECO, the level alarms were prone to failure because the transmitter signal did not transmit the level signal to the computer, forcing operators to work with no automatic fill rate or time to fill estimate. The lack of guidance on when to use high-level alarms may encourage owners and operators of tank terminals to use only one level of alarm when two may be necessary. The UK Government and industry response to Buncefield included comprehensive new guidance on Safety and Environmental Standards for Fuel Storage Sites. *Process Safety Leadership Group, Final*, (PSLG) report sets minimum standards of overfill protection for gasoline storage tanks.[170] The UK Regulator (COMAH Competent

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[167] ANSI/API 2350 recommends tank terminals consider the product stored, operating practices in the field and for each tank, operating limits for valves and manifolds, tank capacities and physical conditions, the amount of product transferred, delivered or received and the rate of flow into each tank.

[168] The critical-high level of concern delineates the highest level that product in the tank can reach without detrimental impacts. The high-high level alarm is set below the critical-high level to enable termination of product receipt before reaching the critical-high level. Maximum-working level is an operational level and the highest product level to fill the tank during normal operations. No alarm is required at this level, but alerts are recommended.

[169] *ANSI/API Standard 2350-2012: Overfill Protection for Storage Tanks in Petroleum Facilities*. Fourth edition (Washington, DC: American Petroleum Institute, May 2012).

[170] *The Process Safety Leadership Group Report*: *Safety and Environmental Standards for Fuel Storage Sites*, *Final Report* (Kew, Richmond, UK: U.K. Health and Safety Executive, The Office of Public Sector Information, Information Policy Team, 2009): 25-37. www.hse.gov.uk/comah/buncefield/fuel-storage-sites.pdf (accessed December 21, 2014).

Authority) treats these as the minimum standard to meet UK legal requirements for major hazard sites.

8.10.6 Categories

ANSI/API 2350 also establishes the level of overfill protection based on three categories of onsite or remote monitoring:

- Category 1 includes fully attended and continuously monitored storage facilities, which have the option to install level instrumentation. Operations staff may terminate receipt of product if emergencies arise.
- Category 2 includes semi-attended facilities and requires personnel to be present during the start of receipt and transfer operations and to attend the operations for 30 minutes. This category requires a storage facility to have an automatic tank gauging system with an independent high-level alarm transmitted to a local or remote control center.
- Category 3 is for unattended facilities. It requires both an automatic tank gauging system and an independent high-level alarm.

Overall, these categories are arbitrary—API does not explain its rationale—despite increasing layers of protection with each category. CAPECO, for example, was a fully attended facility that would have fallen under Category 1. Because the level instrument did not function appropriately, operators were unable to terminate receipt because they were unable to recognize they had an overfill developing. Had CAPECO been required to use a functioning independent high-level alarm and automatic overfill prevention system, surpassing the Category 3 requirements, notification of the overflow would have sounded, and automatic termination of the transfer would have occurred prior to the tank overfill.

Additionally, ANSI/API 2350 does not discuss the risk reduction achieved in each of these categories compared to an automatic overfill prevention system. It also does not consider that increased flow rates or flammability of various products may require more layers of protection. At CAPECO, the tank farm stored unleaded gasoline (NFPA flammability 3), jet fuel (NFPA Flammability 2), diesel fuel (NFPA flammability 2), and fuel oil (NFPA flammability 2), all with different NFPA ratings requiring varying layers of protection.

The current ANSI/API 2350 does not go far enough to require implementing an automatic overflow prevention system for all tank terminals but acknowledges it may be necessary based on risk level. It leaves the decision to the owner/operator of the facility. Finally, the standard does not provide sufficient guidance to facilities on how to fully assess their hazards and make decisions based on the best overfill prevention plan.

To further streamline the hazard assessment process and facilitate safety audits on new or existing tank farms, ANSI/API 2350 should provide guidance on creating a risk-based system to assign all tanks a risk level.

8.10.7 Lack of One Industry Standard for Operations at Tank Farms

The CSB found that while multiple standard practices govern tank farm operations, a single industry standard for tank terminal operations does not exist, including for filling operations. For example, to avert hydrocarbon ignition in the petroleum industry, API 2003, "Protection against Ignitions Arising out of Static, Lightning, and Stay Currents" (2008), provides best practices for preventing static and stray electrical currents.[171] While the standard provides charts that compare pipe diameter, flow velocities, and flow rates that minimize static and stray currents, it is not specific to tank filling operations.

Similarly, API MPMS, Chapter 3.1A, *Standard Practice for the Manual Gauging of Petroleum and Petroleum Products*, 3rd edition (August 2013), discussed in Section 6.5, offers useful information on manual gauging and floating roof displacement, but it is unlikely that the standard practice is accessible to the aboveground tank industry. Furthermore, in addition to ANSI/ANSI/API 2350, these standard practices are not mandatory but considered RAGAGEP under PSM and RMP. Creating one standard practice, or publicizing the existence of all standard and recommended practices governing aboveground storage tank operations including references to international standards[172] and best practices at tank terminals, would enable facilities to readily access these good engineering practices.

8.10.8 International Fire Code (IFC)

The International Code Council (ICC) is a consensus organization that develops the International Fire Code (IFC) in addition to other I-Codes. I-Codes are "minimum safeguards for people at

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[171] ANSI/API Standard API 2003-2008. *Protection against Ignitions Arising out of Static, Lightning, and Stay Currents.* Seventh edition (Washington, DC: American Petroleum Institute, January 2008),

[172] The UK Government response to Buncefield published guidance on 'Identification of Instrumental level detection systems used with Buncefield in-scope substances.

Health and Safety Laboratory. *Identification of Instrumented Level Detection and Measurement Systems Used with Buncefield In-scope Substances* (Buxton, Derbyshire, UK: U.K. Health and Safety Executive, 2011). www.hse.gov.uk/research/rrpdf/rr872.pdf (accessed December 21, 2014).

home, at school and in the workplace."[173] The I-Codes are building safety and fire prevention codes. Puerto Rico adopted the International Fire Code (IFC); therefore, all municipalities on the island are required to follow the IFC guidance to prevent fires.

At the time of the incident, the 2009 edition of IFC was in place. The 2009 IFC Section 3404.2.7.5.8, "Overfill Prevention," requires the use of an overfill prevention system for each tank over 1,320 gallons of flammable liquids falling within Class I, II and IIIA.[174] Same as the NFPA, the IFC defines gasoline as a class 1B liquid. Similar to the NFPA recommendations and the SPCC requirements for filling operations, the IFC requires that in no case should the tank fill in excess of 95% of its capacity. IFC provides two options to achieve this requirement:

1. Install an audible or visual alarm system that signals the tank has reached 90% of the capacity, and automatically shut off flow after a tank reaches 95% of its capacity.
2. Reduce the flow rate to not more than 15 gallons per minute (0.95 L/sec) in the system so that at the reduced flow rate, the tank will not overfill for 30 minutes and automatically shut off flow into the tank so that none of the fittings on the top of the tank are exposed to product because of overfilling.[175]

Although CAPECO had audible alarms that were not functioning, they were not required to have an independent audible or visual alarm to indicate rising liquid levels in Tank 409.

The ICC modified the overfill prevention text above in the 2015 edition IFC by requiring terminal owners and operators to provide an independent means of notifying the person filling the tank that the fluid level has reached 90% of tank capacity. The code then provides options that include an audible or visual alarm signal, a level gauge marked at 90% of tank capacity or other approved means. The CSB recognizes the ICC for requiring the independent level notification in addition to automatic shutdown as one viable option to prevent an overfill incident. However, the ICC did not go far enough to require:

1) A visual or audible alarm physically separate and independent from the level control and monitoring system;
2) A hazard assessment to determine the necessary safeguards and operations, as well as the reliability of the gauging system and operator monitoring, to prevent an overfill, especially for terminals near a community or sensitive environment, or

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[173] International Code Council. http://www.iccsafe.org/AboutICC/Pages/default.aspx (accessed December 21, 2014).

[174] ICC defines flammable liquids as a liquid having a closed cup flash point below 100ºF (38ºC). Class 1 liquids include Class 1A liquids having a flash point below 73ºF (23ºC) and a boiling point below 100ºF (38ºC); Class IB liquids having a flash point below 73ºF (23ºC) and a boiling point at or above 100ºF (38ºC); and Class IC liquids having a flash point at or above 73F (23ºC) and below 100F (38ºC).

[175] International Fire Code 2009. http://publicecodes.cyberregs.com/icod/ifc/2009/ (accessed December 21, 2014).

3) Proof testing to ensure the overfill prevention system is tested regularly.

Including these safety parameters into the IFC and extending it to both existing and new tank terminals will further ensure an incident like CAPECO does not occur.

8.10.9 National Fire Protection Association (NFPA)

The NFPA, a nonprofit organization, develops consensus codes and standards for fire protection and prevention. The standards are voluntary but can be adopted by reference into law. Various groups, including insurance companies, engineers, and safety professionals, use the codes and standards. Approximately 250 panels and committees within the NFPA develop and revise NFPA codes and standards. Although Puerto Rico adopted the International Fire Code (IFC) issued by the International Code Council (ICC), many states have adopted NFPA codes. NFPA 30, *Flammable and Combustible Liquids Code* (2003), had overfill provisions that applied to tank terminals like CAPECO at the time of the 2009 incident.

8.10.9.1 NFPA 30: Code for Storage of Flammable and Combustible Liquids

NFPA 30 provides guidance on storing and transporting flammable and combustible liquids from mainline pipelines and marine vessels. The NFPA defines flammable liquids having an NFPA 704 flammability rating of 3 as class 1B liquids.[176] Section 21.7.1 of the NFPA 30 code, “Prevention of Overfilling of Storage Tanks,” addresses overfill hazards for tanks containing flammable liquids, such as those at CAPECO, but lists an automatic overfill prevention system as only one of three options. The code also references ANSI/API 2350, *Overfill Protection for Storage Tanks in Petroleum Facilities*, for additional guidance. The 2008, 2012, and 2015 editions of NFPA 30 require terminal facilities storing gasoline to follow formal written procedures or to provide equipment or both to prevent overfilling of tanks by choosing one of the following options:

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[176] NFPA 30 defines flammable liquids as any liquid that has a closed-cup flash point below 100ºF (37.8ºC). Flammable liquids are further classified into Class I, II, and III liquids. Class I liquids include Class IA, which is any liquid with a flash point below 73ºF (22.8ºC) and a boiling point below 100ºF (37.8ºC); Class IB, which is any liquid with a flash point below 73ºF (22.8ºC) and a boiling point of or above 100ºF (37.8Cº); and Class IC, which is any liquid with a flash point at or above 73ºF (22.8ºC), but below 100ºF (37.8ºC). Class II and Class III liquids are considered combustible liquids because they have a flash point at or above 100ºF (37.8ºC) and at or above 140ºF (93ºC). *NFPA 30: Flammable and Combustible Liquids Code* (Quincy, MA: National Fire Protection Association, 2014). http://www.nfpa.org/codes-and-standards/document-information-pages?mode=code&code=30 (accessed December 21, 2014).

1) Gauge tanks at intervals in accordance with established procedures by deploying personnel continuously on the premises during product receipt. Maintain communication with the supplier so flow can be shut down or diverted in accordance with established procedures.
2) Equip tanks with a high-level detection device that is either independent of any gauging equipment or incorporates a gauging and alarm system with electronic self-checking to indicate when the gauging and alarm system has failed. Locate alarms where on-duty personnel throughout product transfer can arrange for flow stoppage or diversion in accordance with established procedures.
3) Equip tanks with an independent high-level detection system that will automatically shut down or divert flow in accordance with established procedures.

CAPECO was fully compliant with the NFPA 30 since the facility implemented option 1, but it had neither a high-level alarm nor an automatic overfill prevention system that allowed for automatic shutdown. The only overfill protection was the hourly gauging performed as part of the level control and monitoring system. This was insufficient given the fill rate of Tank 409.

The NFPA first amended the overfill prevention guidance in 1981 to require overfill prevention for tanks located near a residence or community.[177] Then after the Texaco Tank Farm incident in Newark, New Jersey, occurred during the 1984 revision cycle (see Section 7.4 and Appendix B), the Newark Fire Department issued a comment, asking the NFPA 30 committee to require:

1) Gauging tanks at frequent intervals during transfer of product;
2) Increasing communication with pipeline or marine personnel;
3) Equipping terminals with the ability to rapidly shut down or divert flow; and
4) Installing independent high-level alarms that automatically shut down or divert flow during filling operations.

The NFPA 30 committee amended the standard to require one of the four recommendations,[178] stating, "It would be inappropriate and unjustifiably burdensome to require cumulative provisions." The technical committee of NFPA 30 stated that any one of the methods would

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[177] R. Benedetti. *Flammable and Combustible Liquids Code Handbook.* Third edition (Quincy, MA: National Fire Protection Association, 1987).

[178] In 1984, the NFPA 30 committee required overfill protection whenever Class 1 liquids were transferred from mainline pipelines or marine vessels, formal written procedures, a continuous presence of personnel during the transfer operation at manned facilities, and two-way communication with the supply source. The committee also required a high-level detection device independent of any gauging equipment and allowed alternatives to the three options if approved by the local authority with jurisdiction.

provide an acceptable degree of safety.[179] It asserted that one of the four options would also protect unmanned, fully automated receiving terminals that have a good safety record. These remote terminals would have been required to implement all four level control recommendations, had the Newark Fire Department recommendations been adopted by the NFPA 30 committee.[180]

The four options taken together improve the reliability of the level control and monitoring system and ensure that an automatic overfill prevention system is used to detect and prevent an overflow incident. Recent findings from Buncefield and now CAPECO further enhance the need for more robust overfill prevention guidance beyond one of the four options presented by the NFPA 30 committee in 1984.

The CSB finds it necessary to further strengthen the overfill protection language in NFPA 30 to require all four options within an automatic overfill prevention system. In addition, a hazard assessment should be completed considering a facility's proximity to neighboring communities and sensitive environments, the complexity of terminal operations, the reliability of tank gauging system and operator monitoring, and periodic proof testing.[181] This assessment should ensure 1) the overfill system continues to function appropriately and 2) a facility implements and maintains an overfill prevention system that addresses the site-specific hazards. These requirements should extend to both old and new tanks.

The OSHA Flammable and Combustible Liquids standard (1910.106), incorporates by reference the 1968 version of NFPA 30. (See Section 8.7.1.) However, the current 2015 version of NFPA 30 does not require an automatic overfill prevention system and an independent high-level alarm or automatic shutdown to prevent a similar incident like CAPECO from occurring—despite prior recommendations to do so following the Texaco Oil Company tank overfill incident in 1983 discussed in Section 7.4.

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[179] R. Benedetti. *Flammable and Combustible Liquids Code Handbook*. Third edition. (Quincy, MA: National Fire Protection Association, 1987).

[180] Ibid.

[181] ANSI/ANSI/API 2350 defines proof testing as a complete overfill prevention system instrumentation loop test through the primary sensing element verifying appropriate response all the way from sensors to the final control element including alarms. The standard identifies proof testing as an essential element in maintaining the reliability of overfill prevention systems. Section 4.5.5.4 of the ANSI/ANSI/API 2350 standard recommends the testing procedures be in sequential format to ensure safe, consistent practices and the testing procedures be accessible to personnel responsible for testing, inspection, and maintenance of the overfill prevention system. American Petroleum Institute. *ANSI/API Standard 2350-2012. Overfill Protection for Storage Tanks in Petroleum Facilities*. Fourth edition (Washington, DC: American Petroleum Institute, May 2012).

To prevent another overfill incident like CAPECO's, OSHA should incorporate the most updated version of NFPA 30 with the CSB recommendation to incorporate more than one safeguard.

8.11 Trade Associations

Both the International Liquid Terminals Association (ILTA) and the Independent Petroleum Association of America (IPAA) represent small independent producers and storage terminals in the US. They can advocate for safer operations at their member facilities by endorsing and publicizing best industry practices.

9.0 ROOT AND SYSTEMIC CAUSES

The CSB's investigation identified the following key findings:

Physical Cause

1) During an operation to transfer gasoline from the vessel *Cape Bruny* tanker ship, gasoline overflowed from CAPECO Tank 409, resulting in a vapor cloud formation encompassing approximately 107 acres of the CAPECO tank farm.
2) The gasoline vapor cloud migrated to low-lying areas of the tank farm and to the storm water retention pond in the wastewater treatment (WWT) area through open dike valves.
3) The vapor cloud ignited in the WWT area, which was not electrically classified for use in a flammable atmosphere.
4) Multiple proximate causes likely contributed to Tank 409 overfill:
   - Malfunctioning tank side gauge during filling operations that led to inaccurate tank levels being recorded;
   - Normal variations in the gasoline flow rate and pressure from the *Cape Bruny* without the facility's ability to identify and incorporate the flow rate change in real time into tank fill time calculations may have contributed to the overfill;
   - Potential failure of the tank's internal floating roof due to turbulence and other factors may have contributed to the overfill.

Control Failures

1) An unreliable level control and monitoring system did not provide accurate and timely information for the operator to prevent overfilling Tank 409.
2) The failure-prone float and tape gauges and the unreliable level transmitters proved ineffectual. The level transmitters were frequently out of service due to lightning damage.
3) Insufficient independent and separate safeguards to prevent overfill, such as a high-level alarm and an automatic overfill prevention system (AOPS) compromised facility safety.

Safety Management Systems

1) Inadequate formal tank filling procedures were restricted to a list of equipment to be manipulated. In addition, the outdated procedures were often applicable to the tank farm when the refinery was in operation.

2) The automatic tank gauging system, the only level control and monitoring system to support the operator in preventing overfill, was often out of service.
3) The defective level transmitter was not sending data for Tank 409 or 107 to the computer in the operator shack or to the supervisor's office on the day of the incident.
4) A nonexistent automatic overfill prevention system and the inability to rapidly stop transfer operations or divert flow before an overfill weakened CAPECO's safety program.
5) Ill-equipped CAPECO tanks were left with an unreliable level monitoring and control system or a high-level alarm system.

Safety Management Systems

1) Tanks were not equipped with an independent high-level alarm system.
2) Tanks were not equipped with an independent Automatic Overfill Prevention System (AOPS) for terminating transfer operations.

Human Factors

1) The design of the dike valve system made it difficult to distinguish between open and closed valve positions
2) Insufficient lighting in the tank farm areas hindered operators from observing the overfilling of Tank 409 and the subsequent vapor cloud formation.

Lack of Reporting Requirements

1) The CSB analysis of the EPA's Toxic Release Inventory data for 2012 found that 2,959 bulk petroleum tank terminals are within one mile of communities with over 300,000 residents.
2) An incomplete national incident database for assessing the frequency of specific types of incidents at bulk petroleum storage tank terminals inhibits the development and implementation of more tailored regulatory requirements, industry consensus standards, and best practices in this sector.

Emergency Response Findings

1) CAPECO and the local fire department lacked sufficient firefighting equipment to effectively fight and control a fire involving multiple tanks because they are not required to conduct a risk analysis where they have to consider and plan for the potential of a vapor cloud explosion involving multiple tanks.
2) CAPECO did not preplan with local emergency responders or adequately train facility personnel to deal with a fire involving multiple tanks.
3) Local fire departments lacked sufficient training and resources to respond to industrial fires and explosion.
4) There was a lack of coordination among the 43 federal, commonwealth and nongovernmental organizations that responded to the CAPECO incident.

Regulatory Findings

1) The US regulatory system does not consider bulk aboveground storage tank terminals storing flammable liquid to be highly hazardous, even those near communities. Although the EPA characterizes facilities like CAPECO as substantial harm facilities, under the Facility Response Plan requirements, the risk assessment required for these facilities do not consider the potential of multiple tank releases as a worst case scenario.
2) Due to a lack of regulatory coverage under the Occupational Safety and Health Administration's (OSHA) Process Safety Management (PSM) standard and the Environmental Protection Agency's (EPA) Risk Management Plan (RMP), tank terminal facilities are not required to conduct risk assessments to address flammable hazards on site or to follow Recognized and Generally Accepted Good Engineering Practices (RAGAGEP).
3) A high-level alarm system or high-integrity overfill prevention system are not required by OSHA's Flammable and Combustible Liquids standard, the EPA's Spill Prevention Control and Countermeasure (SPCC) requirements. While facilities covered under SPCC must certify an SPCC plan by a Professional Engineer, only the EPA FRP plans meeting the substantial harm criteria are approved by the EPA. Furthermore, under SPCC facilities similar to CAPECO do not have to report overfill incidents unless oil is discharged to navigable waters.

Industry Standards

1) Despite past incidents in the US and internationally, the response of US industry, trade associations, professional associations, and standard-setting organizations has been inadequate to prevent similar incidents in the US.
2) NFPA 30 only requires one layer of protection on storage tanks, at minimum consistent gauging without requirement for an independent or redundant level alarm or an automatic overfill prevention system.
3) ANSI/API 2350 only requires an automatic overfill prevention system for remotely operated facilities and does not offer substantial guidance on conducting a risk assessment that considers the complexity of site operations, the type of flammable and combustible liquids stored at the facility or proximity to nearby communities when considering the necessary safeguards to protect the public. In addition, there is a lack of one comprehensive industry standard to address tank terminal operations, including tank-filling operations and overfill prevention.
4) ICC does not require an independent audible or visual alarm to indicate rising liquid levels.

10.0 RECOMMENDATIONS

Environmental Protection Agency (EPA)

2010-02-PR R1

Revise where necessary the Spill Prevention, Control and Countermeasure (SPCC); Facility Response Plan (FRP); and/or Accidental Release Prevention Program (40 CFR Part 68) rules to prevent impacts to the environment and/or public from spills, releases, fires, and explosions that can occur at bulk aboveground storage facilities storing gasoline, jet fuels, blendstocks, and other flammable liquids having an NFPA 704 flammability rating of 3 or higher.

At a minimum, these revisions shall incorporate the following provisions:

a) Ensure bulk above ground storage facilities conduct and document a risk assessment that takes into account the following factors:
   1. The existence of nearby populations and sensitive environments;
   2. The nature and intensity of facility operations;
   3. Realistic reliability of the tank gauging system; and
   4. The extent/rigor of operator monitoring
b) Equip bulk aboveground storage containers/tanks with automatic overfill prevention systems that are physically separate and independent from the tank level control systems.
c) Ensure these automatic overfill prevention systems follow good engineering practices.
d) Engineer, operate, and maintain automatic overfill prevention systems to achieve appropriate safety integrity levels in accordance with good engineering practices, such as Part 1 of International Electro-technical Commission (IEC) 61511-SER ed1.0B-2004, *Functional Safety – Safety Instrumented Systems for the Process Industry Sector*.
e) Regularly inspect and test automatic overfill prevention systems to ensure their proper operation in accordance with good engineering practice.

2010-02-PR R2

Conduct a survey of randomly selected bulk aboveground storage containers storing gasoline or other NFPA 704 flammability rating of 3 or higher at terminals in high risk locations (such as near population centers or sensitive environments) that are already subject to the Spill Prevention, Control and Countermeasure (SPCC) and/or Facility Response Plan (FRP) rules to determine:

a) The nature of the safety management systems in place to prevent overfilling a storage tank during loading operations. Analysis of the safety management systems should include equipment, training, staffing, operating procedures and preventative maintenance programs.
b) The extent to which terminals use independent high level alarms, automated shutoff/diversion systems, redundant level alarms or other technical means to prevent overfilling a tank

c) The history of overfilling incidents at the facilities, with or without consequence
d) Whether additional reporting requirements are needed to understand the types of incidents leading to overfilling spills that breach secondary containment and have the potential to impact the environment and/or the public, as well as the number of safeguards needed to prevent them.

2010-02-PR R3

As an interim measure, until the rule changes in CSB Recommendation No. 2010-02-I-PR-R1are adopted and go into effect: issue appropriate guidance or an alert, similar to EPA's previously issued Chemical Safety Alert addressing *Rupture Hazard from Liquid Storage Tanks*, to illustrate the hazards posed by spills, releases, fires and explosions due to overfilling bulk aboveground storage containers storing gasoline, jet fuel, blendstocks, and other flammable liquids having an NFPA 704 flammability rating of 3 or higher.

Occupational Safety and Health Administration (OSHA)

2010-02-PR R4

a) Revise the Flammable and Combustible Liquids standard (29 CFR§ 1910.106) to require installing, using, and maintaining a high-integrity automatic overfill prevention system with a means of level detection, logic/control equipment, and independent means of flow control for bulk aboveground storage tanks containing gasoline, jet fuel, other fuel mixtures or blendstocks, and other flammable liquids having an NFPA 704 flammability rating of 3 or higher, to protect against loss of containment. At a minimum, this system shall meet the following requirements:
   1. Separated physically and electronically and independent from the tank gauging system.
   2. Engineered, operated, and maintained to achieve an appropriate level of safety integrity in accordance with the requirements of Part 1 of International Electrotechnical Commission (IEC) 61511-SER ed1.0B-2004, *Functional Safety – Safety Instrumented Systems for the Process Industry Sector.* Such a system would employ a safety integrity level (SIL) documented in accordance with the principles in Part 3 of IEC 61511-SER ed1.0B-2004, accounting for the following factors:
      i. The existence of nearby populations and sensitive environments;
      ii. The nature and intensity of facility operations;
      iii. Realistic reliability for the tank gauging system; and
      iv. The extent/rigor of operator monitoring.
   3. Proof tested in accordance with the validated arrangements and procedures with sufficient frequency to ensure the specified safety integrity level is maintained.

b) Establish hazard analysis, management of change and mechanical integrity management system elements for bulk above ground storage tanks in the revised 1910.106 standard that are similar to those in the Process Safety Management of Highly Hazardous Chemicals standard (29 CFR §1910.119) and ensure these facilities are subject to Recognized and Generally Accepted Good Engineering Practices (RAGAGEP).

International Code Council (ICC)

2010-02-PR R5

Revise the Section 5704.2.7.5.8 (2015), Overfill Prevention of the International Fire Code (IFC) to require an automatic overfill prevention system (AOPS) for bulk aboveground storage tank terminals storing gasoline, jet fuel, other fuel mixtures or blendstocks, and other flammable liquids having an NFPA 704 flammability rating of 3 or higher, or equivalent designation. These safeguards shall meet the following requirements:

a) Engineered, operated, and maintained to achieve an appropriate safety integrity level in accordance with the requirements of Part 1 of International Electrotechnical Commission (IEC) 61511-SER ed1-2004, *Functional Safety – Safety Instrumented Systems for the Process Industry Sector*.
b) Specified to achieve the necessary risk reduction as determined by a documented risk assessment methodology in accordance with Center for Chemical Process Safety *Guidelines for Hazard Evaluation Procedures*, 3rd Edition, accounting for the following factors:
    i. The existence of nearby populations and sensitive environments;
    ii. The nature and intensity of facility operations;
    iii. Realistic reliability for the tank gauging system; and
    iv. The extent/rigor of operator monitoring.
c) Proof tested in accordance with the validated arrangements and procedures with sufficient frequency to maintain the specified safety integrity level.
d) Ensure that the above changes are not subject to grandfathering provisions in the codes.

National Fire Protection Association (NFPA)

2010-02-PR R6

Revise NFPA 30, Flammable and Combustible Liquids Code, Section 21.7.1.1 (2015) for bulk aboveground storage tank terminals storing gasoline, jet fuel, other fuel mixtures or blendstocks, and other flammable liquids having an NFPA 704 flammability rating of 3 or greater. This modification shall meet the following requirements:

a) More than one safeguard to prevent a tank overfill, all within an automatic overfill prevention system as described in ANSI/API Standard 2350 (2015) *Overfill Protection for Storage Tanks in Petroleum Facilities* with an independent level alarm as one of the safeguards. The safeguards should meet the following standards:
    1. Separated physically and electronically and independent from the tank gauging system;

2. Engineered, operated, and maintained for an appropriate level of safety based on the predetermined risk level after considering part b of this recommendation; and
3. Proof tested with sufficient frequency in accordance with the validated arrangements and procedures.

b) Specified to achieve the necessary risk reduction as determined by a documented risk assessment methodology conducted in accordance with Center for Chemical Process Safety *Guidelines for Hazard Evaluation Procedures, 3rd Edition*, accounting for the following factors:
1. The existence of nearby populations and contamination of nearby environmental resources;
2. The nature and intensity of facility operations;
3. Realistic reliability for the tank gauging system; and
4. The extent/rigor of operator monitoring.

c) Ensure that the above changes not subject to grandfathering provisions in the code.

American Petroleum Institute (API)

2010-02-PR R7

Revise ANSI/API 2350, Overfill Protection for Storage Tanks in Petroleum Facilities (2015), to require the installation of an automatic overfill prevention systems for existing and new facilities at bulk aboveground storage tanks storing gasoline, jet fuel, other fuel mixtures or blendstocks, and other flammable liquids having an NFPA 704 flammability rating of 3 or higher. At a minimum, this system shall meet the following requirements:

a) Separated physically and independent from the level control and monitoring system.

b) Engineered, operated, and maintained to achieve an appropriate safety integrity level in accordance with the requirements of Part 1 of International Electrotechnical Commission (IEC) 61511-SER ed1-2004, *Functional Safety – Safety Instrumented Systems for the Process Industry Sector*.

c) Specified to achieve the necessary risk reduction as determined by a documented risk assessment methodology set in accordance with Center for Chemical Process Safety *Guidelines for Hazard Evaluation Procedures, 3rd Edition*, accounting for the following factors:
1. The existence of nearby populations and contamination of nearby environmental resources;
2. The nature and intensity of facility operations;
3. Realistic reliability for the tank gauging system; and
4. The extent/rigor of operator monitoring.

d) Proof tested with sufficient frequency in accordance with the validated arrangements and procedures to maintain the required safety integrity level.

e) Ensure that the above changes are not subject to grandfathering provisions in the standard.

2010-02-PR R8

Develop detailed guidance on conducting a risk assessment for onsite and offsite impacts of a potential tank overfill during transfer operations involving one and multiple tanks and for determining the Safety Integrity Level of the required overfill prevention safeguard to replace Annex E of ANSI/API 2350, *Overfill Protection for Storage Tanks in Petroleum Facilities (2015)*.

2010-02-PR R9

Develop a single publication or resource describing all API standards and other relevant codes, standards, guidance, and information for filling operations of aboveground storage tanks in petroleum facilities that describes:

a) The required design and management practices for control of filling operations;
b) The minimum set of independent overfill prevention safeguards if the control fails; and
c) Operational challenges (e.g., monitoring/calculating flow rates, ability to maintain constant line pressures, and influences of valve cracking) related to loading multiple tanks concurrently from a single product source.

Appendix A INCIDENT TIMELINE

Timeline of events leading to explosion and fire

Date	Time	Events
10/21/09	**8:47 p.m.**	Pumping starts. Verification pumping is sent to Tank 405.
10/21/09	**9:43 p.m.**	Pumping verification ends. Valves lined to fill tank 504.
10/22/09	**12:20 a.m.**	Product movement begins into Tank 504.
10/22/09	**1:18 a.m.**	Line displacement into Tank 504 ends.
10/22/09	**1:40 a.m.**	Bulk pumping begins into 504, 409 and 411.
10/22/09	**4:00 a.m.**	Tank levels, posted in the daily log, read as follows: 504 @ 14'6.5" (from 5' 24 hours prior) *Increase* 409 @ 8'4" (from 3'2.8" 24 hours prior) *Increase* 411 @ 4'7" (from 8'8.8" 24 hours prior) *Decrease*
10/22/09	**~11:00 a.m.**	The tank farm operator notes the level of Tank 504 before going to lunch (level unknown) and calculates that the tank would be full around 1 p.m.
10/22/09	**11:20 a.m.**	411 @ 2'5.7" *Decrease (contractor gauge)*
10/22/09	**~12:15 p.m.**	The operator returns to see that the same numbers on Tank 504 that he noted before lunch are still on display. The level instrument is physically stuck inside of the tank. He climbs to the top of Tank 504 to visually inspect the level and finds that it is well below the fill level – 42.75' (out of ~54').
10/22/09	**~12:15 p.m.**	The operator and supervisor decide to close Tank 504 early. Tank 409 is fully opened, and Tank 411 is cracked open.
10/22/09	**~1:00 p.m.**	Tank 409 is fully opened, and Tank 411 is cracked open. 2 p.m. is shift change (8-hour shifts: 2 p.m.-10 p.m., 10 pm-6 a.m., 6 a.m.-2 p.m.).
10/22/09	**1:25 p.m.**	Tank 504 is gauged by the contractors and CAPECO personnel: Level 42' $2^3/_4$".
10/22/09	**~6:00-6:30 p.m.**	The tank farm operator calculates that Tank 409 will be full at shift change (9-10 p.m.). Since Tank 409 does not display properly on the computers and to avoid complications at shift change, the operator fully opens the valve to Tank 411 and cracks down the valve to 409 (cracked open). 409 @ ~44' 411 @ ~20'-27'
10/22/09	**~9:00-9:30 p.m.**	Shift Change. Relief for the wastewater and tank farm operators arrive. The tank farm operator rotates to the dock (working a double shift).
10/22/09	**10:10 p.m.**	The tank farm operator determines that Tank 411 is full; with help from the other operator, he closes 411 and fully opens 409. He asks the assistant to briefly close Tank 409, while he observes the full flow rate into Tank 411; then they perform the switch. The tank operator estimates that 409 will be full around 1 a.m.
10/22/09	**11:20 p.m.**	Tank 411 is gauged by the outside inspectors and CAPECO personnel: Level 46' $7^3/_4$". Nothing abnormal is observed.
10/22/09	**~11:25 p.m.- 12:00 a.m.**	Tank 409 begins to overflow. The CSB calculates that the overflow lasted approximately 26 minutes. See Appendix E.
10/23/09	**~12:00 a.m.**	The tank farm operator notices a fog on the ground and on the road along Tanks 504, 411, and 409. He notifies the supervisor, who then instructs the ship to stop pumping and for the WWT operator to assist the guards at the gate. The supervisor and the tank farm operator attempt to drive around to the other side of the fog to determine its origin.
10/23/09	**12:23 a.m.**	Explosion occurs.

Appendix B TANK INCIDENTS IN THE PAST 50 YEARS

	Facility Name / Location	Incident Date	Injured	Fatality	Cost	Product	Incident Type	Description
1	Houston, TX, USA [4]	4/1962	0	0		Gasoline	Leak, Vapor Cloud Explosion	A 12,700 M gasoline tank leaked and vapors accumulated. A car driving on a nearby highway ignited the vapor cloud.
2	Collegedale, TN, USA [8]	9/25/1972	0	0		Gasoline	Overfill	An overfill of a 55 ft diameter gasoline tank ignite while emergency responders were preparing to foam the spill surface. Multiple tank explosion involving five tanks followed. A dike fire burned for over 24 hours due to leaking flanges and manways and lack of firefighting foam.
3	Gulf Oil Co., Philadelphia, PA, USA [1]	8/17/1975	8	14		Gasoline	Overfill, Vapor Cloud Explosion	Flammable vapors were released from an overfilled. Crude oil tank, which exploded. A second explosion occurred in the crude tank during the incident response, killing 8 firefighters and injuring 14.
4	Baytown, TX, USA [5]	1/27/1977	0	0		Gasoline	Ship Hold Overfill, Vapor Cloud Explosion	In a ship overfilling incident, a tugboat ignited as it was tied up alongside a dock on the opposite side of the ship. The explosion overturned the tug, which sank. Little other explosion damage occurred.

5	Rialto, CA, USA [8]	2/21/1978	0	0		Gasoline	Overfill, Vapor Cloud Explosion	Gasoline vapors ignited after an overfill of a 50 ft gasoline tank. A valve was mistakenly opened causing fuel to spill out of the tank vents into the secondary containment dike at approximately 30,300 L/min(8000 gpm).
6	Chevron Tank Terminal, HI, USA [8]	1980	4	2		Gasoline	Overfill, vapor cloud ignition	At 10:30 am, an overfilling gasoline tank created a vapor cloud that ignited after reaching a switch-room at an adjacent Shell facility.
7	Texaco Oil Company, Newark, NJ, USA [1]	1/7/1983	1	24		Gasoline	Overfill, Vapor Cloud Explosion	A gasoline vapor cloud exploded when a 1.76-million gallon capacity tank overflowed, resulting in one fatality and 24 injuries. Lack of monitoring of the rising gasoline levels in the storage tank during filling operations contributed to the overflow, explosion, and subsequent fire.
8	Naples Harbour, Italy [4]	12/21/1985	0	4	$50.9M	Gasoline	Overfill, Vapor Cloud Explosion	A gasoline storage tank overflowed and spilled nearly 800 tons into a diked area. A vapor cloud formed and ignited. The explosion killed 2 employees and 2 members of the public, destroyed 24 of the 32 tanks onsite, caused serious structural damage within 100 meters, and broke glass out to 1 kilometer. Fire covered 3.7 acres, caused severe damage to nearby industrial and residential areas, and took 3.5 days to extinguish. The estimated loss was $50.9 million.
9	Saint Herblain, France [3]	1991	0	0		Gasoline	Pipe leak, Vapor Cloud Explosion	A release of gasoline from a section of pipe inside a bund produced a vapor cloud. Ignition of the vapor cloud produced extensive damage.

10	Brenham, TX, USA	4/7/1992	0	0		Gasoline	Vapor Cloud Explosion	The ignition of a vapor cloud comprising a mixture of hydrocarbons in a rural area resulted in significant damage to nearby buildings. No pipework congestion was present but the cloud engulfed wooded areas.
11	Steuart Petroleum, Jacksonville, FL USA[8]	1/2/1993	0	1		Gasoline	Overfill, Vapor Cloud Explosion	Gasoline vapors ignited after an overfill of a 2.3 million gallon gasoline tank fatally injuring one terminal operator who was driving into the spill. A large ground fire persisted impinging two additional tanks located approximately 50 feet away. Gasoline flowed from the tank's eyebrow vents, complicating firefighting activities. The fire covered about one acre and exposed unprotected aboveground pipelines, manifolds and a number of flange connections.
12	Nanjing, China	10/21/1993	0	2		Gasoline	Overfill, Vapor Cloud Explosion	A gasoline storage tank (10,000 m^3 tank) overflowed resulting in a gasoline spill and vapor cloud. The vapor cloud ignited by passing tractor and killed 2 employees. Fire involved at least 100 tons of gasoline. The fire took 17 hours to control.
13	IOCL Baroda, Gujarat, India	8/4/1995	N/A	N/A	N/A	Gasoline	Overfill, Vapor Cloud Ignition	An overfill of a tank created a vapor cloud which ignited. The fire encompassed two tanks in the same secondary containment area. Nearby tanks were cooled to prevent further fire impact.

14	Thai Oil Company, Laem Chabang, Thailand [2]	12/2/1999	0	7	$22.3M	Gasoline	Overfill, Vapor Cloud Explosion	A gasoline storage tank overflowed forming a vapor cloud. It exploded and killed seven onsite personnel. Thai Oil Company was blending product onsite when an operator manually opened a valve to fill a tank, which was already filled with product. It began to overfill. The rising liquid level set off two safety alarms at an offsite control room, but the control room operators did not hear the alarms. Five gasoline storage tanks and 250,000 barrels of gasoline were destroyed. The fire burned for 35 hours and total damages cost $22.3 million.
15	Conoco, Helana, MT, USA [1]	12/13/2000	0	0	0	Gasoline	Tank Overfill	Approximately 60,000 gallons of gasoline spilled from a storage tank causing the evacuation of 100 residents and restricting traffic to the area.
16	Amerada Hess Corp., Wilmington, DE, USA [1]	3/13/2000	0	0	0	Gasoline	Tank Overfill	A million gallon capacity storage tank overfilled while being filled by a barge unloading gasoline creating a vapor cloud that caused local residents to evacuate their homes.
17	Buncefield Oil Storage Depot Hemel Hempstead, Hertfordshire UK	12/11/2005	43	0	$1.5B	Gasoline	Overfill, Vapor Cloud Explosion	An overfill of an atmospheric storage tank of gasoline resulted in the development of a vapor cloud which ignited damaging 22 tanks.
18	BP Milne Point, AK, USA [1]	1/15/2009	0	0	0	Crude Oil	Tank Overfill	Approximately 24,400 gallons of crude oil spilled from an overfilled tank at BP's Milne Point oil field. Reportedly, a malfunction in the automated flow control system caused the overfill. Workers were able to manually cut off flow to the tank.

19	CAPECO, Bayamón, Puerto Rico, USA [1]	10/23/2009	3	0		Gasoline	Tank Overfill, Vapor Cloud Explosion	An overfill of a 5 million gallon capacity atmospheric storage tank with gasoline caused a vapor cloud which ignited causing multiple tank explosions and tank fires. 17 of 48 tanks were burned. The fire took three days to control.
20	Gladieux Trading and Marketing Huntington, IN, USA [1]	3/10/2010	0	0	N/A	Diesel fuel	Tank Overfill	A gasoline storage tank overflowed at Gladieux Trading and Marketing in Huntington, IN, when a pump that was transferring product was left on at the end of a shift. A high- and high-high level safety alarm activated, but it was hidden from view on the alarm monitoring screen. An offsite contracted employee spotted the product overflowing from the tank 157 minutes after the overfill occurred and alerted the control operator to the incident.
21	Aloha Petroleum Bulk Storage Facility, HI, USA [1]	11/1/2011	0	0	0	Diesel fuel	Tank Overfill	Approximately 14,700 gallons of diesel fuel spilled during transfer operations when diesel fuel was being pumped from a barge to storage tanks at the Aloha Petroleum Bulk Storage facility. Workers reportedly miscalculated the amount of fuel that could be pumped into the storage tank.
22	International-Matex Tank Terminlas, NJ, USA [1]	6/2/2014	0	0	0	Gasoline	Tank Overfill	A fuel tank overfilled during transfer operations spilling approximately 6,000 gallons of gasoline into the soil.
[1] CSB data.								
[2] The 100 Largest Losses 1972-2001, Large Property Damage Losses in the Hydrocarbon-Chemical Industries, 20th Edition: February 2003, a publication of Marsh's Risk consulting practice.								
[3] J.F. Lechaudet and Y. Mouilleau. "Assessment of an accidental vapour cloud explosion. A case study: Saint Herblain, October the 7th 1991, FRANCE," Loss Prevention and Safety Promotion in the Process Industries, 1995, 1, pp. 377-388.								

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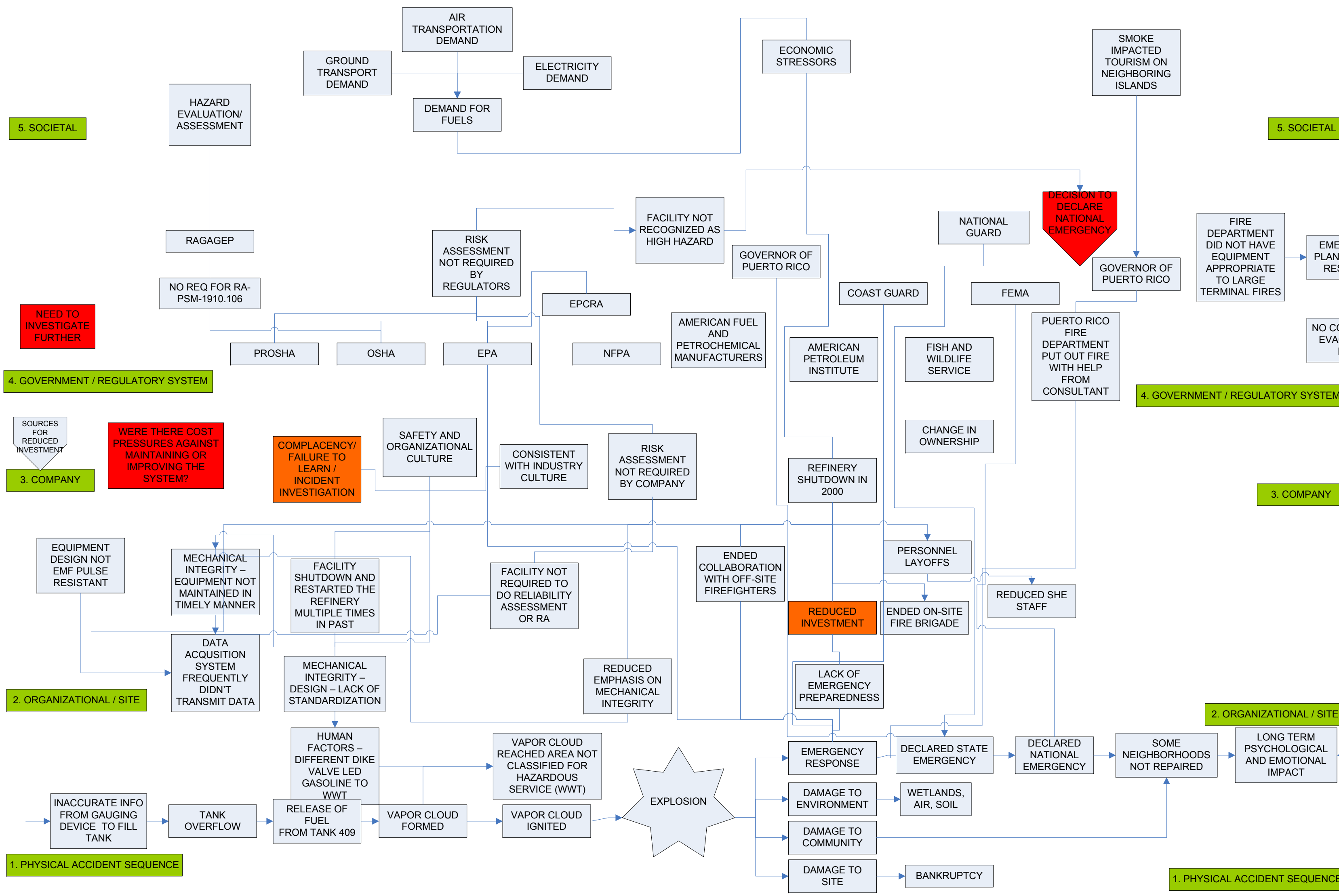
[8] Persson, H. 3M Case History 7; Fire Engineering, August 1978.

Appendix C CARIBBEAN PETROLEUM ACCI MAP



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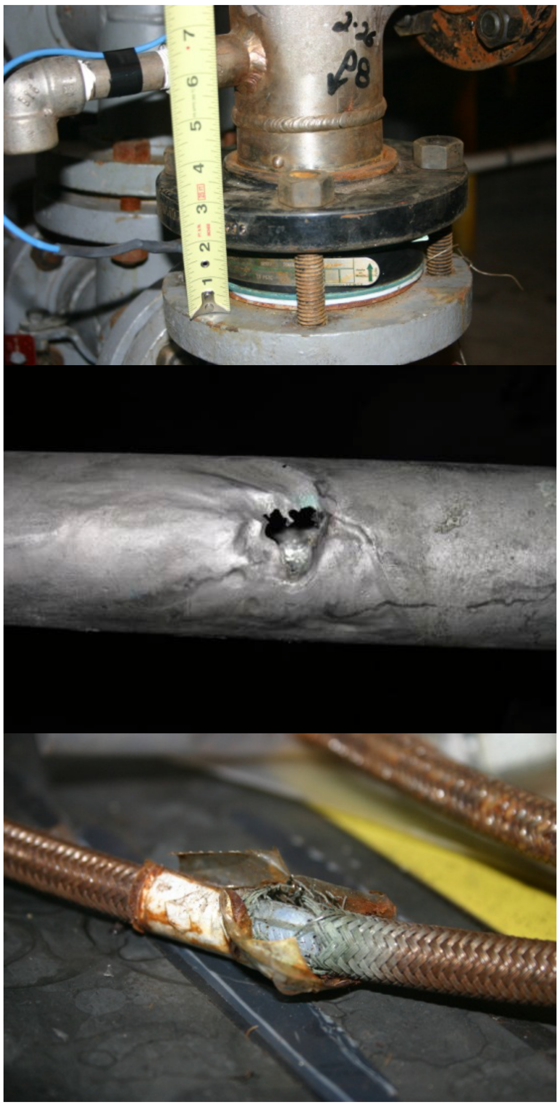
U.S. CHEMICAL SAFETY AND HAZARD INVESTIGATION BOARD

INVESTIGATION REPORT

Final Report

E.I. DUPONT DE NEMOURS & CO., INC.

BELLE, WEST VIRGINIA



METHYL CHLORIDE RELEASE
JANUARY 22, 2010

OLEUM RELEASE
JANUARY 23, 2010

PHOSGENE RELEASE
JANUARY 23, 2010

One Fatality

One Confirmed Exposure

One Possible Exposure

KEY ISSUES:

- MECHANICAL INTEGRITY
- ALARM MANAGEMENT
- OPERATING PROCEDURES
- COMPANY EMERGENCY RESPONSE & NOTIFICATION

REPORT NO. 2010-6-I-WV

SEPTEMBER 2011

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List of Acronyms and Abbreviations

ACC	American Chemistry Council
ACGIH	American Conference of Governmental Industrial Hygienists
AIHA	American Industrial Hygiene Association
ALOHA	Area Locations of Hazardous Atmospheres
CERCLA	Comprehensive Environmental Response, Compensation, and Liability Act
CFR	Code of Federal Regulations
Cl_2	chlorine
CMMS	Computerized Maintenance Management System
CO	carbon monoxide
CSB	U.S. Chemical Safety and Hazard Investigation Board
DCS	distributed control system
DMA	dimethylamine
DMS	dimethylsulfate
ECF	ethyl chloroformate
EMS	emergency medical services
FRC	flame-resistant clothing
EPA	U.S. Environmental Protection Agency
GIS	Graphical Information System
HCl	hydrochloric acid
HTM	Highly Toxic Materials
IDLH	immediately dangerous to life and health
KCEAA	Kanawha County Emergency Ambulance Authority
KPEPC	Kanawha-Putnam County Emergency Planning Committee
LDAR	Leak Detection and Repair
MIC	methyl isocyanate
MM	million (old notation style)
MOC	Management of Change
NDE	non-destructive examination
NIMS	National Incident Management System
NIOSH	National Institute for Occupational Safety and Health
NOAA	National Oceanic and Atmospheric Administration
NPS	nominal pipe size

OSHA	U.S. Department of Labor, Occupational Safety and Health Administration
OTPT	Oleum Tower Pump Tank
PEL	Permissible Exposure Limit
PHA	Process Hazard Analysis
PM	Preventive Maintenance
ppm	parts per million
psig	pound-force per square inch gauge
PSSR	pre-startup safety review
PSM	OSHA Process Safety Management Standard (29 CFR 1910.119)
PTFE	polytetrafluoroethylene
RCRA	Resource Conservation and Recovery Act
RMP	Risk Management Plan
RQ	reportable quantity
SAP	System Application & Products
SAR	Spent Acid Recovery Unit
SCBA	self-contained breathing apparatus
SLM	Small Lots Manufacturing Unit
SOPs	Standard Operating Procedures
TQ	threshold quantity
TWA	time-weighted average
VOC	volatile organic compounds

Executive Summary

On January 22 and 23, 2010, three separate incidents at the DuPont plant in Belle, WV, involving releases of methyl chloride, oleum, and phosgene, triggered notification of outside emergency response agencies. The incident involving the release of phosgene gas led to the fatal exposure of a worker performing routine duties in an area where phosgene cylinders were stored and used.

Operators discovered the first incident, the release of methyl chloride, the morning of January 22, 2010, when an alarm sounded on the plant's distributed control system monitor. They confirmed that a release had occurred and that methyl chloride was venting to the atmosphere. Managers assessing the release estimated that more than 2,000 pounds of methyl chloride may have been released over the preceding 5 days.

The oleum release, the second incident, occurred the morning of January 23, 2010. Workers discovered a leak in an overhead oleum sample pipe that was allowing a fuming cloud of oleum to escape to the atmosphere. The plant fire brigade, after donning the appropriate personal protective equipment, closed a valve that stopped the leak about an hour after it was discovered. No injuries occurred, but the plant called the Belle Volunteer Fire Department to assist.

The third incident, a phosgene release, occurred later that same day when a hose used to transfer phosgene from a 1-ton cylinder to a process catastrophically failed and sprayed a worker in the face while he was checking the weight of the cylinder. The employee, who was alone when exposed, was assisted by co-workers who immediately responded to his call for help. Initial assessments by the plant's occupational health nurse indicated that the worker showed no symptoms of exposure prior to transport to the hospital for observation and treatment. A delayed onset of symptoms, consistent with information in phosgene exposure literature, occurred after he arrived at the hospital. His condition deteriorated over the next day and he died from his exposure the next night.

At the request of the Board, the U.S. Chemical Safety and Hazard Investigation Board (CSB) investigation team examined all three incidents at Belle due to the severity and potential for even greater consequences and to understand how and why they could occur at a DuPont facility. DuPont is regarded as an industry leader in the advancement of health and safety practices and develops sound, respected, and widely used safe practice guidance. With such a reputation, the CSB was interested in examining the conditions at the Belle facility that led to a decline in adherence to the higher standard of performance that the corporation historically held.

The CSB incident investigation determined root and contributing causes for each of the three incidents. An overall analysis revealed common deficiencies in the following management systems:

- Maintenance and inspections
- Alarm recognition and management
- Incident investigation
- Emergency response and communications
- Hazard recognition

The CSB found that each incident was preceded by an event or multiple events that triggered internal incident investigations by DuPont, which investigated all of these precursor events and issued recommendations and corrective actions. Despite investigating these preceding events, the recommendations and corrective actions did not prevent the occurrence of similar events.

Because of recent changes to the Kanawha County Metro 9-1-1 response policies and procedures that could lead to delays in treatment for future incidents, the CSB investigators also examined concerns raised by the emergency response organizations. These concerns included the timeliness and quality of information provided to dispatchers and EMS personnel who responded to two of the incidents and which mirrors issues identified in the CSB Bayer CropScience August 2008 incident investigation. [1]

The CSB identified the following root causes:

Methyl Chloride Incident (January 22, 2010, 5:02 a.m.)

- DuPont management, following their Management of Change process, approved a design for the rupture disc alarm system that lacked sufficient reliability to advise operators of a flammable methyl chloride release.

Oleum Release Incident (January 23, 2010, 7:40 a.m.)

- Corrosion under the insulation caused a small leak in the oleum pipe.

Phosgene Incident (January 23, 2010, 1:45 p.m.)

- DuPont's phosgene hazard awareness program was deficient in ensuring that operating personnel were aware of the hazards associated with trapped liquid phosgene in transfer hoses.
- DuPont relied on a maintenance software program that was subject to changes without authorization or review, did not automatically initiate a change-out of phosgene hoses at the prescribed interval, and did not provide a back-up process to ensure timely change-out of hoses.
- DuPont Belle's near-miss reporting process was not rigorous enough to ensure that the near failure of a similar phosgene transfer hose, just hours prior to the exposure incident, would be immediately brought to the attention of plant supervisors and managers.
- DuPont lacked a dedicated radio/telephone system and emergency notification process to convey the nature of an emergency at the Belle plant, thereby restricting the ability of personnel to provide timely and quality information to emergency responders.

[1] CSB-2008-I-WV (Bayer CropScience).

The CSB makes recommendations to

- Occupational Safety and Health Administration (OSHA)
- DuPont Belle, WV, plant
- E.I. DuPont de Nemours & Co., Inc.
- Compressed Gas Association of America (CGA)
- American Chemistry Council (ACC) Phosgene Panel

1.0 Introduction

1.1 Background

At 5:02 a.m. on Friday, January 22, 2010, a release of methyl chloride activated an alarm in the F3455 unit control room, signaling the first of three incidents that would occur over the next 33 hours at the DuPont Belle, WV, facility. No injuries were associated with this incident, but the release went undetected for as long as 5 days. DuPont estimates that more than 2,000 pounds of methyl chloride released to the atmosphere.

At 7:40 a.m. on Saturday, January 23, 2010, a contractor reported seeing a fuming plume on a 1-inch diameter sample pipe in the Spent Acid Recovery (SAR) unit. Operations personnel confirmed that oleum was leaking; thus, a fume alert was activated for the entire Belle plant. Plant fire brigade members responded to the release and closed valves that stopped the leak at about 8:09 a.m., after which the "all clear" was sounded.

The third incident occurred just 6 hours later. At approximately 1:45 p.m., an operator walked into the phosgene cylinder storage area in the Small Lots Manufacturing (SLM) unit and was sprayed in the face and upper torso with phosgene when a flexible hose suddenly ruptured. The worker called for assistance and coworkers immediately went to his aid. His personal dosimeter indicated that he had been exposed to a significant dose of phosgene; however, he did not exhibit immediate signs of breathing problems. About 3 hours after arriving at the hospital his condition deteriorated, and he died the following night.

No injuries occurred as a result of the first two releases, but communication to Metro 9-1-1 dispatchers regarding the nature of each release on Saturday became an issue post-incident. The CSB investigators examined how information related to the incidents was conveyed to Metro 9-1-1 dispatchers. The CSB also interviewed Kanawha County Ambulance Authority (KCEAA), Kanawha-Putnam Emergency Planning Committee (KPEPC), and Metro 9-1-1 representatives to assess each incident and determine if actions could be taken to improve communication methods to prevent recurrence of the issues brought to the attention of county officials. During the Saturday afternoon call for assistance from DuPont, Metro 9-1-1 dispatchers were not provided with sufficient information regarding the nature of the emergency and the chemicals involved to adequately inform responding EMS personnel. Many of those interviewed were familiar with the role of the CSB, having participated in conferences and interviews as part of the CSB investigation of the August 2008 Bayer CropScience incident.

Due to recurring communication problems associated with emergency responses to chemical plants in the Kanawha Valley, responding medical units established a practice of waiting before going onto a property that called for assistance. EMS personnel respond to a staging area as far as a mile away where they remain until they receive more detailed information about the material involved and whether the victim has been, or will need to be, decontaminated prior to transport to a hospital. Emergency response organizations developed this practice as EMS personnel were receiving information that was sometimes so imprecise that they could not ensure that they or their equipment would not be contaminated by a hazardous chemical as a result of transporting an exposed victim.

In examining the activities of employees involved in the response, the CSB learned that two other DuPont employees were also possibly exposed to phosgene. One worker, after he transported the victim part of the way to the plant medical center in a company truck, noticed that his dosimeter was discolored, indicating exposure. The second exposure occurred when a worker, unaware of the phosgene release, went into the area of the phosgene shed and noticed an odor that he had never smelled before. Unsure of what the odor was, he left the area and joined his co-workers in the control room.

1.2 Investigative Process

Via the media and the National Response Center (NRC), the CSB monitored and tracked information related to the chemical release incidents at the DuPont Belle, WV, facility throughout the weekend of January 22 and 23, 2010. On January 25, 2010, the CSB Board deployed an investigation team. Because of the number and potential for more severe consequences at the DuPont Belle plant over this 2-day period, the CSB launched an investigation to determine the root and contributing causes, which it would use to issue recommendations to help prevent similar occurrences. Although the consequences of the first two incidents were not as severe as the third, the CSB decided that since the three incidents occurred in less than 2 days, including one that led to a fatality, all three would be investigated to determine any common causes.

The investigative team arrived at the Belle Plant on January 26, 2010, and met with Occupational Safety and Health Administration (OSHA) inspectors; U.S. Environmental Protection Agency (EPA) officials; and DuPont representatives to explain the CSB's authority and purpose for conducting the investigation.

The CSB investigation team remained onsite for 2 weeks and subsequently visited Belle to conduct independent investigations of each of the three DuPont Belle, WV, facility incidents. During its investigations, CSB investigators

- interviewed plant personnel, emergency responders, plant supervisors and managers, and corporate personnel;
- coordinated the examination, removal, and storage of physical evidence;
- requested and reviewed relevant documentation;
- reviewed technical and industry guidance, standards, and regulations;
- discussed emergency response issues with the KPEPC, KCEAA, and Metro 9-1-1 dispatch center officials;
- entered into joint testing protocol agreements with DuPont, OSHA, and the EPA;
- observed metallurgical testing of the oleum sample line and the phosgene stainless steel overbraid hose; and
- observed analytical testing and analysis of the polytetrafluoroethylene (PTFE) transfer hoses involved in the phosgene release.

1.3 E.I. DuPont de Nemours & Co., Inc.

1.3.1 Company History

E.I. DuPont de Nemours and Co, named after its French founder, Eleuthère Irénée du Pont, was established in 1802 as a gunpowder manufacturing company on the Brandywine River in Wilmington, DE. DuPont grew as a manufacturer of gunpowder and explosives in the United States and in 1902 transitioned into a science-based chemical company. DuPont established Experimental Station, the first industrial laboratory where researchers and scientists began work on nitrocellulose chemistry and smokeless powders to improve military rifles for the World War I effort. By the 1920s, DuPont purchased several chemical companies and focused on polymers, which led to the discovery of neoprene (synthetic rubbers), polyester, and nylon by 1935. Many of these products were in demand during the Second World War. Further work with plastics and fibers led to the development of Teflon™, Lucite™, Nomex™, and Mylar™ in the 1950s. DuPont also introduced a number of inorganic insecticides and fungicides such as Lannate® (methomyl) and Telvar®, which eventually led to the establishment of its agricultural products business. By the mid-1980s, DuPont had grown to almost 100 major businesses selling a wide range of materials such as textiles, agricultural chemicals, petroleum, and biomedical products.

1.3.2 DuPont Business Areas and Corporate Management

DuPont, headquartered in Wilmington, DE, has 58,000 employees in more than 80 countries. The company offers a broad range of products for industry and consumer use, including pesticides, electronics, apparel, and biomedical supplies. Five business platforms comprise the DuPont organization: Agriculture and Nutrition, Coatings and Color Technologies, Performance Materials, Electronics and

Communications, and Safety and Protection. Within each business platform are strategic business areas[2] focusing on the production, sale, and distribution of products and services related to each marketing area.

The Crop Protection business area, a segment of the Agriculture and Nutrition platform, is responsible for the development, manufacture, and sale of fungicides, herbicides, insecticides, and seed treatments globally. The agriculture industry uses DuPont Crop Protection products on a variety of crops worldwide including cotton, soybeans, fruits, and vegetables. The F3455 and SLM units at the Belle Plant manufacture intermediate chemicals for their Crop Protection products. In 2009, the Agriculture and Nutrition platform had the most sales of any business area at $8.3 billion.

A 13-member Board of Directors, including the chairperson and CEO, manage DuPont. Executive committees made up of board members and representatives from DuPont businesses oversee areas such as environmental policy, corporate governance, strategic direction, and auditing. In 2010, DuPont had global sales of $31.5 billion and ranked as the third-largest chemical company in profits and second in revenues in the world.

1.3.3 Safety at DuPont

Concern for safety and health at DuPont became a part of the company's structure in 1805 due to the hazards of producing gunpowder and explosives. The early corporate safety program was rooted in process safety concepts more than a century before governing safety regulations existed. Practices such as safe siting of buildings, explosion venting concepts, incident investigation processes, and emergency response were implemented in the DuPont gunpowder mills throughout the 19th century.

[2] Pioneer Hy-bred, Crop Protection, Nutrition and Health, Electronics and Communications, Performance Coatings, Performance Polymers, Protection Technologies, Building Innovations, Sustainable Solutions, Chemicals and Fluoroproducts, Titanium Technologies, and Applied Biosciences.

The company continued to focus on health and safety to improve safety performance and in 1915 created its first corporate safety division, which was responsible for technical training, safety inspections, project design reviews, and the purchase of safety equipment. According to DuPont incident records, the safety division participation in facility operations decreased incident rates throughout the company. As a result, individual sites established site-specific safety groups in the mid-1930s. Hazard elimination was recognized as a priority above education and personal protection (Klein, 2009).

1.3.3.1 Early Process Safety Program

The release of highly toxic methyl isocyanate (MIC) at the Union Carbide Corp. in Bhopal, India, resulted in nearly 3,800 immediate deaths, and 16,000 are estimated to have since died as a result of exposure, while more than 100,000 still report associated illnesses. In response to the Union Carbide incident, chemical companies, industry associations, and government agencies directed efforts to decrease process safety risks, which eventually led to the establishment of the OSHA Process Safety Management (PSM) Standard (29 CFR 1910.119), EPA Chemical Accident Prevention Program, and the creation of the CSB as part of the Clean Air Act amendment of 1990.

Prior to establishing the OSHA PSM Standard, DuPont was practicing many process safety concepts at its facilities as part of the DuPont Process Hazards Management (PHM) Program. After a 1965 incident in Louisville, KY, killed 12, the company directed all sites to perform hazard reviews to evaluate the safety of site processes, which eventually became a corporate Process Hazards Review (PHR) program. The PHR was intended to prevent serious process-related incidents, and each site handling hazardous substances had to have a PHM program.

The Bhopal incident contributed to an increase in DuPont's focus on PHM, particularly in the manufacture of MIC. DuPont developed an inherently safer method of manufacturing and handling MIC that eliminated MIC bulk storage, as it relied on producing and directly consuming MIC. The company also created the Highly Toxic Materials (HTM) Subcommittee to review the global management of toxic chemicals. In 1985, HTM became a corporate guideline, and a separate subcommittee was established to focus on each of the 15 highly hazardous materials identified within the company. DuPont continued to refine its PHM program, eventually developing professional guidance for process safety and OSHA PSM rulemaking (Mottle et al., 1995).

1.3.3.2 "Zero Incidents" Goal

DuPont introduced the "zero incidents" goal in the early 1900s as a management directive to drive injury rates down to zero through continuous improvement of safety practices. The "zero" concept became a core strategy as the company grew and embraced the philosophy that all injuries, occupational illnesses, and environmental incidents are preventable and that the goal for all is zero.

DuPont became recognized throughout industry as a safety innovator and leader. The company offers services as a safety resource for other corporations to evaluate and improve workplace safety, which include methodologies and technical training to manage and improve employee and contractor health and safety performance as well as process safety improvements.

1.4 DuPont Belle Plant

Figure 1. DuPont Belle, WV, facility on the Kanawha River (EPA, 1973)

The DuPont Belle plant is located in Belle, WV, about 8 miles east of Charleston, the state capital . The plant occupies about 723 acres along the Kanawha River and sits in an industrial, commercial, and residential use area. The plant was established in the West Virginia coal country as part of a post-World War I effort to produce ammonia. In the early 1920s DuPont spent $27 million[3] on a highly complex production facility with atmospheric compressors capable of producing 25 tons of ammonia per day. Belle's high-pressure ammonia technology yielded a host of collateral benefits. Methanol was initially manufactured on a small scale and then rapidly expanded to 1 million gallons a year. By 1935, Belle had

[3] Equivalent to $332 million in 2010, according to the Bureau of Labor Statistics Inflation Calculator.

become DuPont's largest facility with more than 80 different chemical products, which included the first synthetic urea used in fertilizers and plastics. In 1939, DuPont began producing nylon chemical intermediates at Belle, and by 1944 the plant was producing 30 million pounds of synthetic polymers per year. Expansion of nitrogen and nylon intermediate production at Belle continued after the war, and product lines were introduced regularly. In 1969 Belle began producing the fungicide Benlate®. Currently, the DuPont Belle plant produces a variety of organic chemicals and agricultural intermediates and products. According to company documents, the plant had the best safety record of any DuPont production facility prior to the incidents of January 22 and 23.[4]

In January 2010, the DuPont Belle plant employed approximately 440 and had seven primary operating divisions occupying a 105-acre manufacturing area nearly 1 mile long. The DuPont-operated SAR unit was owned by Lucite International and operated by DuPont employees. The Belle facility is also the site of the newly constructed Kureha unit, owned by the Kureha Corp. of Japan, which is operated by Kureha employees on DuPont's Belle site. The Kureha production unit uses glycolic acid produced by DuPont as a feedstock for polyglycolic acid, a specialty plastic.

The DuPont Belle plant holds a Resource Conservation and Recovery Act (RCRA) Part B Treatment and Storage Permit for onsite handling of waste materials, in addition to a RCRA-permitted drum storage facility onsite. The Belle plant participates in a Community Action Council (CAC), comprised of citizens from neighboring communities and representatives from the industrial facilities in the region,[5] that aims to address citizen concerns regarding site safety, health, and environmental performance.

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[4] www.2.dupont.com/heritage.

[5] DuPont Belle Plant Information Sheet.

2.0 Methyl Chloride Release (January 22, 2010)

2.1 Background

The Belle plant's F3455 unit manufactures the intermediate F3455, a chemical that is shipped to another DuPont facility to make the herbicide Velpar®. Due to the exothermic reaction in the first reactor, dissolved methyl chloride vaporizes and normally exits through the reactor vent line along with carbon dioxide, nitrogen, and trace amounts of dimethylamine (DMA) vapor through a process scrubber and then to a thermal oxidizer for emission control. To avoid damage to the scrubber[6] if excessive pressures occur, a piping connection upstream of the vent line is routed to a rupture disc that will burst and allow venting outside on the roof of the building which contains two reactors (Figure 2). However, due to a lack of safety considerations during installation, a 0.5-inch weep hole[7] was placed on the vent line inside the building; consequently, dangerous chemicals vent inside the building if the rupture disk bursts.

Unaware that the rupture disc had blown during a nitrogen purge activity before the reactor startup, plant personnel proceeded with the normal production run. For nearly 5 days, methyl chloride vapor passed through the blown rupture disc and escaped into the operation building and outside atmosphere. On the fifth day, the methyl chloride vapors interfered with the chemical sensor configured to detect ethyl chloroformate (ECF), which alerted the workers.

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[6] A thermal oxidizer is a process unit for air pollution control in many chemical plants that decomposes hazardous gases at a high temperature and releases them into the atmosphere.

[7] In process vent lines that lead to the atmosphere, protection must be installed to prevent ambient moisture -- from rain or other elements -- from collecting within the vent line. One such protection is a "weep hole," a small hole drilled into a vent line that allows drainage.

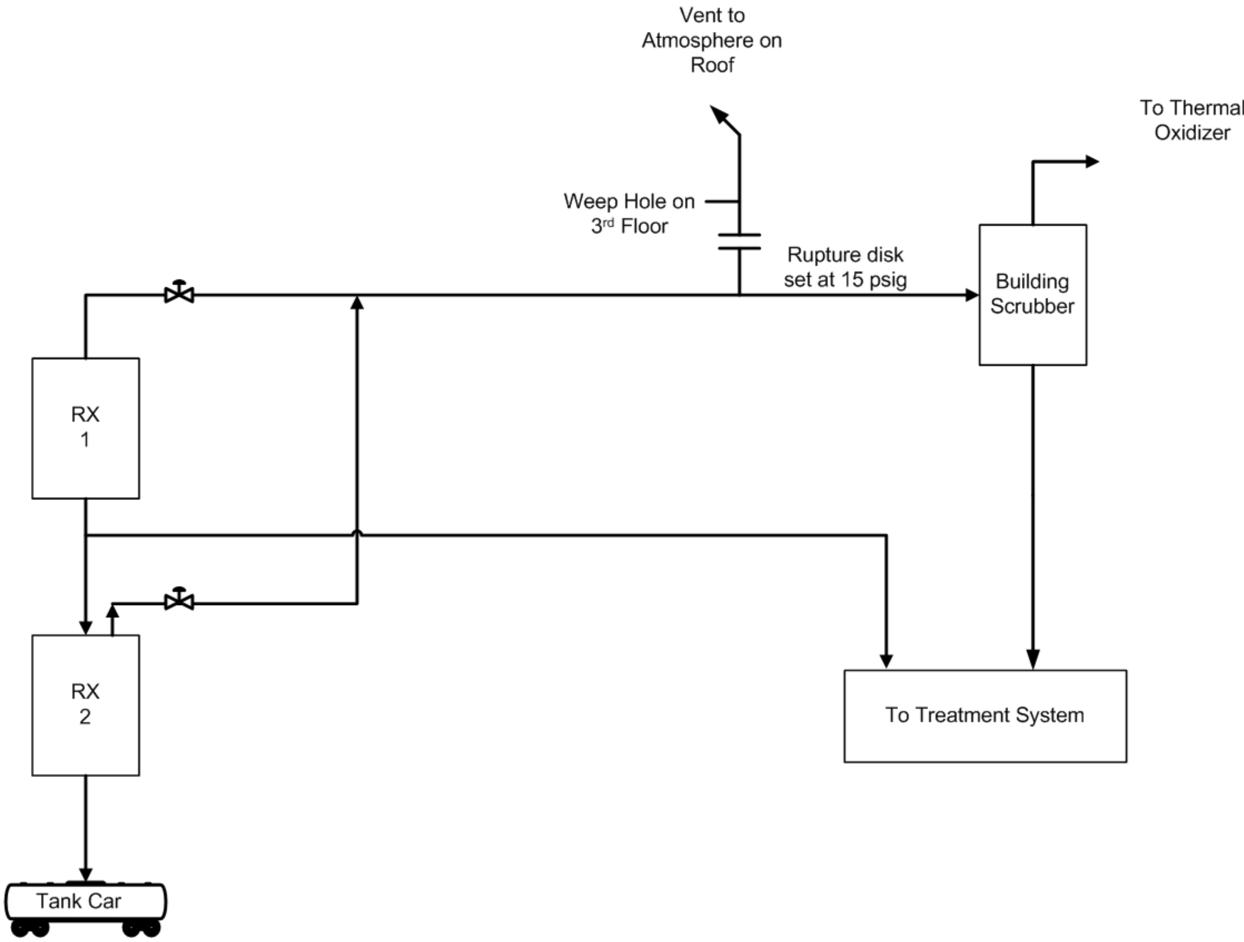

Figure 2. Simplified thermal oxidizer and rupture disc block flow diagram

2.1.1 Methyl Chloride

Methyl chloride, also called chloromethane or monochloromethane, is a colorless gas with a faint sweet odor at low concentrations.[8] The odor may not be noticeable and cannot be relied upon as warning of concentrations that are dangerous to health.[9] Methyl chloride is extremely flammable; has a potent

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[8] The odor threshold, or concentration, of methyl chloride detectible by most humans varies between 10 and 250 ppm.

[9] http://www.oxy.com/Our_Businesses/chemicals/Documents/methyl_chloride/Methyl%20Chloride%20Handbook.pdf.(11/2009)

narcotic effect similar to trichloromethane, also known as chloroform; and is listed as a Group 3 carcinogen[10] by the International Agency for Research on Cancer (IARC). The OSHA 8-hour time-weighted average (TWA) concentration is 100 ppm and the National Institute of Occupational Safety and Health (NIOSH)-designated Immediately Dangerous to Life and Health (IDLH) concentration is 2,000 ppm.

Symptoms of methyl chloride exposure include dizziness, confusion, and nausea, and at higher concentrations, extreme nervousness, trembling, and possible loss of consciousness. High concentrations or long exposure can be fatal. The gas is also heavier than air and therefore settles close to the ground.

2.2 Incident Description

The F3455 process was in the first series of batch runs following an extended maintenance outage from September 12, 2009, through January 17, 2010. The release is thought to have initiated on January 17 during the first batch run in the unit and continued until discovered on January 22; the release rate may have been sporadic throughout this period.

On January 22, 2010, an air monitor alarm on the process control monitor alerted plant operating personnel of a chemical release while they were adding DMA[11] to the reactor. The sensor for this alarm, located on the third floor of the F3455 building, is calibrated to activate when it detects ECF at 0.5 ppm. The methyl chloride vapors interfered with the ECF sensors on the third floor and activated the alarm. The distributed control system (DCS) recorded the alarm at 5:02 a.m., and responding operators saw a diffused fog and a liquid puddle near a 0.5-inch nominal pipe size (NPS) vent/drain pipe referred to as a

[10] Substances the IARC lists as Group 3 carcinogens are mixtures or agents for which evidence of carcinogenicity in humans is inadequate and limited in experimental animals.

[11] DMA is a toxic and extremely flammable, colorless product with a fishy or ammonia-like odor. DMA attacks the respiratory system and irritates eyes and skin and at higher concentrations can cause pulmonary edema. The OSHA 8-hour TWA is 10 ppm and the NIOSH IDLH is 500 ppm. Humans can detect DMA odors at 0.34 ppm (Sittig, 2008). DMA is a heavier than air vapor and settles close the ground

weep hole (Figure 3). This connection was associated with a thermal oxidizer "vent stack," that vents to the atmosphere on the roof of the building during a process upset. Operators notified the board operator at 5:19 a.m. when they found the source of the release.

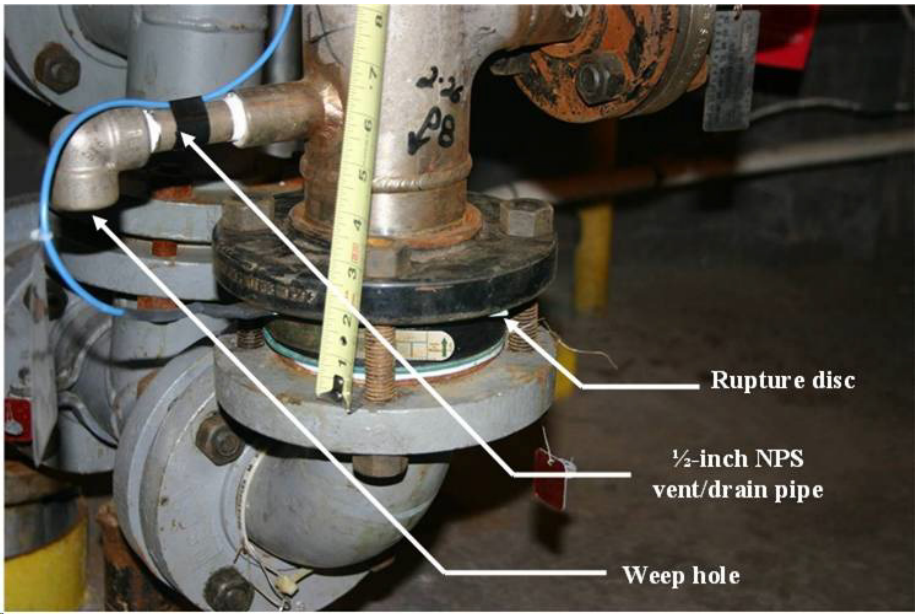

Figure 3. 0.5-inch NPS vent/drain pipe and rupture disc

2.2.1 ECF Sensor Alarm

The ECF sensor was detecting chlorine, not ECF. The ECF sensor is responsive to chemicals composed of chlorine (i.e. ethyl-*chloro*formate [ECF] and methyl-*chloride*); consequently, on the fifth day, the chlorides in the release were of sufficient concentration near the ECF sensor to activate the alarm.

2.2.2 Odor Detection Considerations

The methyl chloride, DMA, and hydrochloric acid (HCl) mixture is extremely odorous; however, due to the nature of the F3455 process, operating personnel would have had to be in the area of the 0.5-inch weep hole at the time of the release to see or smell the leak.

Methyl chloride liberated during this phase of the reaction would have likely taken the normal route to the thermal oxidizer piping, where it would have been consumed and vented to the atmosphere unnoticed.

The vent releases products of the reaction into the room if a rupture disc is blown and if the pressure inside the pipe is greater than the pressure in the room.

The rupture disc piping was routed to the atmosphere above the roof of the building, which would have provided an outlet path for the methyl chloride vapor where it would have dissipated and dispersed without notice.

The day before the leak was discovered, a crew performed a leak detection and repair (LDAR)[12] inspection on the third floor of the building near the location of the release. The volatile organic compounds (VOC) electronic monitor was calibrated to detect methyl chloride, ECF, DMA, and methanol. Although an area within 12 inches of the weep hole was checked for leaks with the monitor, it did not detect any VOCs.

2.2.3 Incident Response

In response to the ECF alarm, operators using a VOC analyzer to search for the source of the vapor immediately smelled an offensive odor on the third floor. They saw steam-like fumes near the vent pipe and dripping liquid puddling on the floor, both clear indications that the rupture disc had burst (Figure 4). They left the process area, closed all valves leading to the vent line, and cooled the reactors to stop the process. At about 9:30 a.m., maintenance mechanics replaced the rupture disc and burst sensor.

After receiving confirmation of the release, the board operator notified the process supervisor who then calculated the estimated duration and magnitude of the release. After performing these calculations, the supervisor notified the plant manager, the Safety Health and Environmental (SHE) manager, the area manager, and the unit technology leader and told them that the release may have been ongoing for the

[12] The Clean Air Act requires refineries and chemical plants to develop and implement an LDAR program to control fugitive emissions, which occur from leaks in valves, pumps, compressors, pressure relief valves, flanges, connectors, and other piping components.

entire run of nine batches, which occurred over 5 days. DuPont estimated that approximately 2,000[13] pounds of methyl chloride were likely released to the atmosphere.

During the initial phases of the DuPont incident investigation, employees discovered that the burst sensor on the rupture disc had started alarming 5 days prior to the incident. Due to its history of unreliability, operators likely became desensitized to this alarm. The burst sensor was the first in this sequence of incidents that led to a safety pause[14] at the plant.

[13] DuPont, in its final investigation report, determined that 2,045 pounds of methyl chloride and 25 pounds of HCl released to the atmosphere as a result of this incident.

[14] A safety pause is a structured work stoppage that the plant manager initiates to engage the entire workforce with the objectives of increasing awareness of hazards, providing safety education, and addressing past incidents. A safety pause was initiated at the Belle facility on Saturday, January 23, 2010, because of the incidents at the F3455 and SAR units.

Figure 4. Rupture disc piping and vent pipeline to atmosphere on roof

Once DuPont determined that the release quantity exceeded the Comprehensive Environmental Response, Compensation and Liability Act (CERCLA) reportable quantity (RQ) of 100 pounds,[15] in compliance with CERCLA of 1980 it reported the release of methyl chloride to the NRC and to the West Virginia State Department of Homeland Security Emergency Operations Center, which notified the U.S. Coast Guard. Kanawha County Metro 9-1-1 was not informed of the release until 2:00 p.m. on January 22, 2010, 9 hours after discovery.

2.2.4 Community Impact

DuPont estimated that between January 17 and 22, 2010, 2,045 pounds of methyl chloride; 25 pounds of hydrogen chloride; and trace amounts of DMA released to the atmosphere through a vent line on the roof of the F3455 building. No monitoring information was available to determine the concentrations of chemicals released to the atmosphere through the vent line. If monitoring information had been recorded, a more accurate estimate of chemical concentration would have provided data about when the release started and the potential for offsite impact. No workers at the facility reported symptoms from methyl chloride or any of the other toxic chemicals either during or after the release. DuPont did not receive any odor complaints from the community.

2.3 Incident Analysis

2.3.1 Mechanical Integrity

Rupture discs are overpressure protection devices used in processes operating above ambient pressure and are intended to prevent equipment damage, including catastrophic failure. Without them, a process upset can cause unsafe pressure levels and an overpressure incident. Since these devices activate only when a system has had an overpressure event, it is imperative that their activation be discovered. In this

[15] Under CERCLA, operators of facilities and vessels are required to immediately report releases to the NRC above the EPA RQ.

application, the rupture disc releases hazardous chemicals to the atmosphere. One approach to help with early detection is to evaluate the alarm management process and, where appropriate, adjust process parameters so that an alarm will activate prior to the disc actually bursting. Another is to evaluate the process and eliminate the conditions that increase the pressure that cause the disc to burst. Regardless, once systems have been selected, the configuration should be reviewed by a team, including process engineers, control engineers, and operations managers (Lees, 2005).

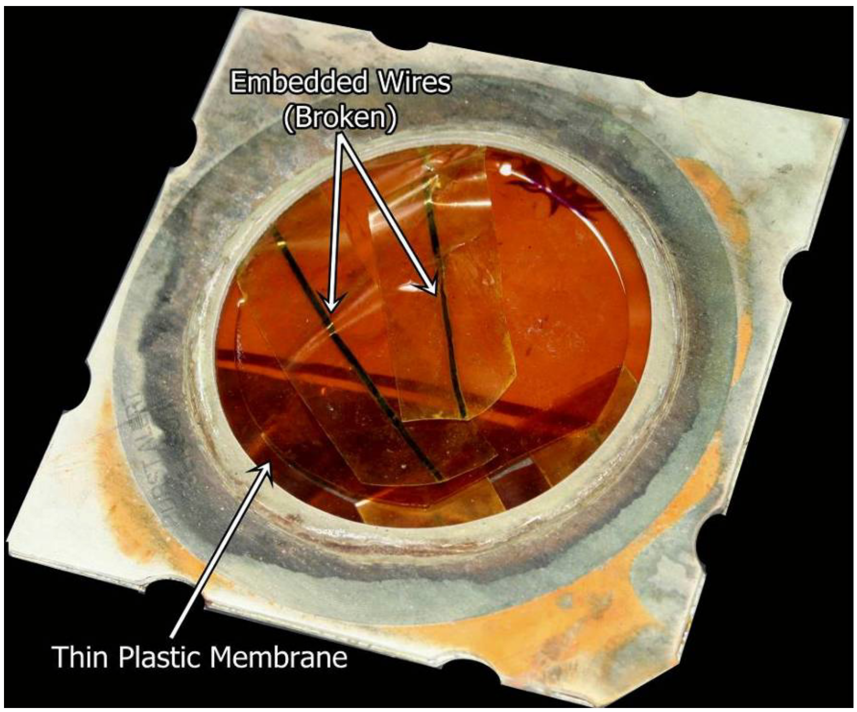

Figure 5. Rupture disc burst sensor post-incident

DuPont Belle used a "burst sensor" intended to notify the board operator that the rupture disk (Figure 5) activated. A burst sensor is a thin plastic membrane with embedded wires installed on top of the rupture disc. Small electrical current passes through the wires. When the rupture disc activates, the membrane and embedded wires break, triggering the alarm.

The CSB learned that the rupture discs and sensors associated with this system were historically problematic. The burst sensor involved in the January 22, 2010, incident had been replaced many times because it was unreliable. Initially the sensor was battery-operated, sending signals to a remote receiver in the control room rather than to the process control monitor. However, the battery life was short; consequently, operators received frequent false, or "nuisance," alarms. According to Management of Change (MOC) documentation, "the burst sensor [was] in and out of alarm every 3 minutes" and required replacements almost monthly. When its batteries failed, the transmitter sent an alarm to the remote receiver to notify the operators. The receiver displayed the same alarm text as when the sensor detected a burst rupture disc. Because the batteries needed frequent replacing and because the operators had to wait for an electrician to change the batteries, the false alarms became a nuisance.

Battery life, however, was not the only reported shortcoming of burst sensors. Operators told the CSB investigators that burst sensors were so delicate that they could sometimes tear during installation and that liquid condensation on top of the sensors sometimes caused them to fail and trigger a false alarm.

An improved burst sensor was installed on the DCS while the unit was down for maintenance just before the incident. Operators indicated they were not retrained to respond to the more reliable burst sensor alarm and still considered it a nuisance.

2.3.2 Design and Maintenance of Rupture Discs

The rupture disc involved in the incident was a 4-inch diameter graphite rupture disc, designed to rupture at 15 psig, and mounted in neoprene casing (Figure 6). While the rupture disc is on a preventive maintenance (PM) schedule, the annual inspection was so infrequent that the disc is replaced only when it has activated or is removed for certain processes. Operators told the CSB investigators that once removed, the rupture discs, intact or compromised, are discarded and replaced with new ones. Even without a burst sensor, all overpressure protection devices, including rupture discs, should be routinely checked on an effective PM schedule as a layer of protection.[16]

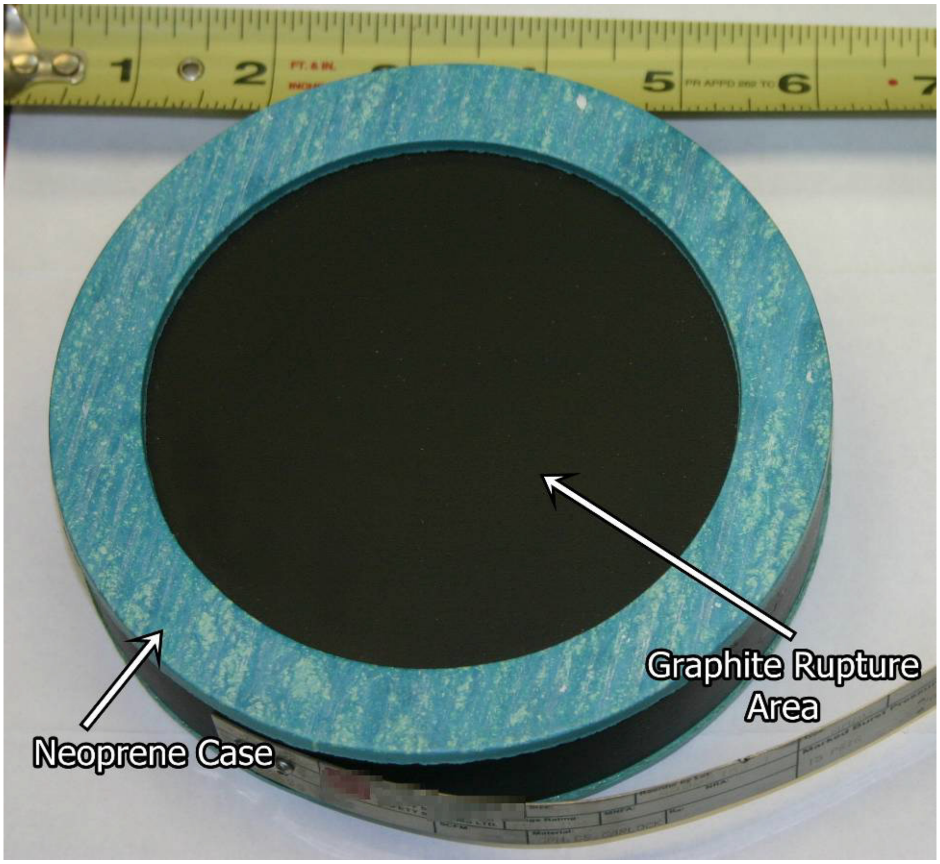

Figure 6. New rupture disc

2.3.3 Previous Incidents of Rupture Discs Bursting

From 2005 to 2010, the rupture disc on the F3455 unit vent line experienced nine recorded activations (Table 1). On April 11, 2006, the rupture disc activated three times. DuPont determined that the disc was most likely experiencing thermal or hydraulic shock. Thermal shock would occur from boiling reactor

[16] BS&B Safety Systems, Inc, *Special Applications and Preventive Maintenance*, Catalog 77-1007, Section B.

vapor mixing with cool liquid on the disc due to its close proximity to the reactor; hydraulic shock would occur from any “sloshing” in the line upstream of the disc. This recurring problem was remedied by moving the rupture disc farther away from these units and eventually to the third floor toward the extreme end of the vent line.

On May 6, 2006, a rupture disc activation at the same facility went unnoticed for 48 hours, which illustrates how the January 22, 2010, release could have gone undetected for 5 days. In the May incident, although operators complained about strong odors in the F3455 building, the rupture disc was never considered as the source; indeed, operators and supervisory staff identified multiple locations where fugitive emissions could have produced the offensive smell. Eventually, when a new batch of F3455 was started, an operator near the vent line saw the rupture disc fuming, indicating that it was the odor source.

At the Belle facility, pipe blockage at the unit was the most commonly reported cause of premature rupture disc activation (Table 1). The F3455 process creates various solids in the vent and process lines, which eventually block flow, increasing the pressure in the system. Once the blockage is melted by the process temperature or forced through the line due to the increased pressure, the resulting pressure spike activates the rupture disc.

Previous Rupture Disc Incidents	
Date	Cause
05/20/05	Unknown
05/31/05	Pressure Control Issues
04/11/06	Hydraulic/Thermal Shock[17]
05/06/06	Blockage[18]
06/16/06	Unknown
05/30/07	Ruptured during Water Cleaning
06/12/07	Blockage
04/15/08	Blockage
02/24/09	Blockage

Table 1. Previous rupture disc events in the F3455 unit

2.3.4 Management of Change--Technology and Subtle Change

Within DuPont, MOC procedures are defined at a corporate level and adopted according to each site's procedures. At the corporate level, the PSM Standard defines two types of MOC: technology (MOC-T) and subtle changes. MOC-T is defined as "a change in hazards of materials (including the introduction of chemicals), a change in equipment design basis, or a change to the process design basis." Subtle changes are defined as "any change within the documented [process technology] that is not a replacement in kind."[19] Regarding high-hazard processes, such as the F3455 and SLM units at Belle, the corporate PSM Standard states, "[S]ubtle changes in the field can (and have) led to catastrophic events." However, even with this knowledge the MOC team at Belle incorrectly categorized the burst sensor installation as a subtle change.

[17] This incident was actually three incidents over a short period. The rupture disc was discovered ruptured and replaced three times before the unit was shut down for further investigation.

[18] This incident went undiscovered for 48 hours.

[19] The corporate DuPont PSM Standard defines "replacement in kind" as the "replacement of an instrument or electrical, piping, or other process equipment component with an identical part or an approved equivalent part that is specified by the applicable DuPont Engineering standard."

At the Belle site the standard operating procedures (SOPs) do not distinguish between MOC subtle changes and MOC-T. The MOC package documentation, however, shows that subtle, often referred to as "minor," changes are not subjected to the same in-depth review as a MOC-T. When the MOC is marked as "subtle," the level of safety review is at the discretion of the MOC team leader.

The MOC package that first installed the rupture disc burst sensor was marked as a subtle change and included a "What If" review that stated, "What if you get a false positive indication (indicating failed disc, but not actually failed)? Not a safety issue. Shut down and investigate."

This type of review did not go deep enough to confirm that false-positives could lead to nuisance alarms, which can create risk by desensitizing operators to a hazard and be more detrimental than the absence of the alarm. In the MOC section marked "Reason for this Type of Safety Review," the response by the MOC team leader was "Minor Change."

The MOC package that converted the burst sensor from battery-powered to a supplied power device was also marked as a subtle change. Again, the MOC team leader recorded in the documentation that "a 'What If' review [was] appropriate for the afore-mentioned [sic] change." The MOC did not address the operators' non-battery related concerns for the burst sensor or how to re-train the board operator to no longer treat the burst sensor alarm as a false-positive.

Because MOC packages deemed "subtle" are not given the same level of review as MOC-T packages, the subtle change MOC packages did not identify or prevent the potential causes of this incident.

2.3.5 F3455 Unit Turnaround

On June 6, 2009, nearly 2 years after installing the battery-operated transmitter, DuPont attempted to eliminate the false alarms caused by low batteries by wiring the transmitter to a standard electrical circuit.

During a unit shutdown that lasted from September 12, 2009, through January 17, 2010, there was significant maintenance activity, including work that, by its nature triggered alarms; however, these alarms did not require response from the operators because there were no “live” process streams that would initiate an actual alarm.

DCS data recorded during the shutdown indicated that the pressure in the reactor system increased slowly from December 18, 2009, to December 20, 2009, when it exceeded the rupture disc rating (Figure 7). The source of the pressure was a nitrogen valve on a level indicator that slowly leaked nitrogen into the system.[20] The rupture disc burst, triggering an alarm, as it should have. Under normal, live operating conditions, the operators would have investigated to understand, acknowledge, and correct the alarm condition. However, extensive maintenance work was still underway in the unit; thus, the operators did not address the alarm as they would have under normal operation.

[20] The level instrument measures the difference between the pressure in the vapor space inside the top of the reactor and the pressure under the liquid at the bottom of the reactor. Based on the pressure difference, the control computer calculates the amount of liquid in the reactor. The nitrogen provides a chemical barrier between the reactor liquid and the level instrument.

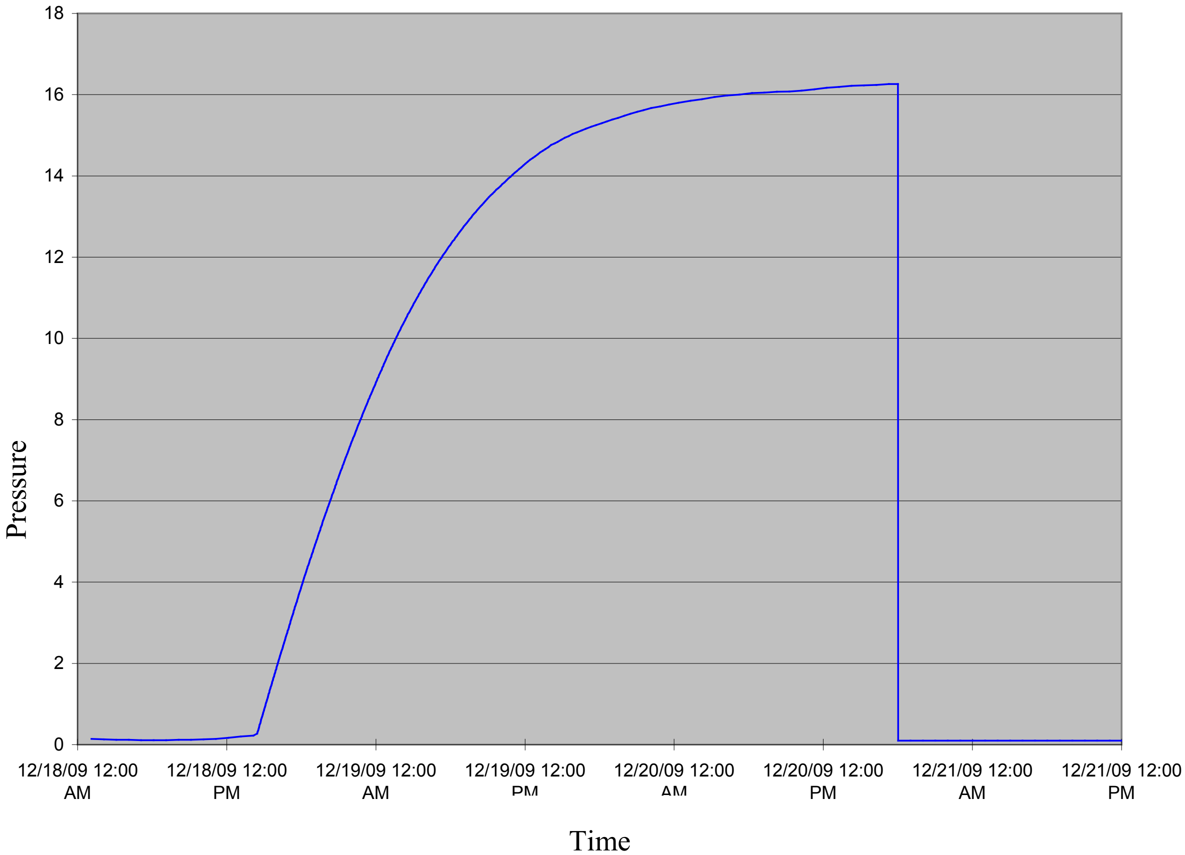

Figure 7. Process data showing sudden pressure decrease when rupture disc burst

The operators did not address the alarm when it triggered in December because they knew that work in the area was causing nuisance alarms; however, when the ECF alarm activated on January 22, 2010, operators responded. The board operator in the F3455 control room investigated and observed that the original alarm from December 21, 2009, was still displayed; the first item on the alarm screen had not been acknowledged because they had become accustomed to nuisance alarm conditions. [21]

[21] Under normal operating conditions, when an alarm point activates it will remain in an activated state until the alarm condition is cleared and acknowledged.

2.3.6 Second-Party Process Safety Management Audit

In 2007, an audit team of engineers and safety and health experts from other DuPont facilities conducted a 4-day second-party audit[22] of the Crop Protection business at Belle, which included the F3455 and SLM units. The four-member team audited the units against PSM focus areas such as MOC-subtle change, pre-startup safety reviews (PSSRs), training, PHA, mechanical integrity, and process technology. While auditing the F3455 unit and during a review of site and area management practices, the team noted the many active alarms in the unit control room: "[The] control system is not engineered to eliminate alarms from idled and secure process equipment [and as a result] the contribution to 'nuisance' alarms is unknown." The audit team recommended that Belle evaluate the control system and develop an engineered solution to reduce the number of active alarms and establish a policy reflective of improvements to safely manage operations with active alarms.

During another review of SOPs and worksite practices, the team noted that the Crop Protection procedure for operating with active alarms did not effectively address alarm activations from idle equipment: "The current situation can lead to human factors errors such as failing to recognize an alarm and misidentifying an alarm." The team recommended that Belle conduct an engineering evaluation to determine changes that could separate alarms on active processes from those associated with shutdown equipment so that operators could readily identify abnormal process conditions.

Both recommendations, added to a corrective action tracking plan, were completed in fourth quarter 2008, months beyond the original target completion dates. Despite these recommendations, F3455 unit personnel continued to restart the unit while the alarm was activated, failing to recognize the impact of the burst sensor alarm.

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[22] A second-party audit is an independent assessment of PSM systems performed against the requirements of the DuPont corporate PSM standard.

2.4 Key Findings

1. The rupture disc alarm system being monitored by a battery-powered transmitter, with batteries requiring almost monthly replacement, was designated as PSM-critical[23] equipment by DuPont.
2. DuPont ran the equipment with an unreliable battery-powered transmitter for 18 months before executing a MOC package to convert to a wired power supply.
3. Operators expected maintenance work to trigger alarms, but planning and communication were insufficient to distinguish which alarms needed immediate attention during the turnaround and after work was completed.
4. Despite repeated incidents of rupture discs bursting, DuPont did not adequately address the cause to prevent recurrence.
5. The alarm from the transmitter did not distinguish between a condition that required immediate attention (ruptured disc burst) and a lower priority condition such as failed batteries.
6. Operators became desensitized to the rupture disc burst alarm.

2.5 Root Causes

1. DuPont's MOC process approved a design for the rupture disc alarm system that lacked sufficient reliability for minimizing the release of methyl chloride.
2. DuPont did not resolve the "nuisance alarm" condition in a timely manner despite various safety reviews.

[23] PSM-critical is defined in DuPont SHE Standards S21A and S24 A as components, equipment, or systems whose failure could cause, allow, or contribute to process incidents that result in death or serious injuries, significant property damage, or significant environmental impact.

3.0 Oleum Release (January 23, 2010)

3.1 Background

Lucite International owned the sulfuric acid recovery (SAR) unit on DuPont's Belle plant property and DuPont employees operated the equipment. The SAR unit produced oleum, which is a solution of sulfur trioxide dissolved in sulfuric acid. As the sulfuric acid is consumed, the sulfur trioxide converts to sulfuric acid.

The process unit adjacent to the SAR unit used the oleum to produce methacrylic acid, an ingredient for acrylic polymers, and then returned the spent oleum to the SAR unit. The SAR unit burned off the impurities from the spent oleum and used the remaining sulfur compounds to produce clean oleum.

As a result of an unrelated, earlier inspection, the EPA ordered the Belle facility to upgrade emissions monitoring equipment or improve abatement capacity in the SAR unit. As part of a consent decree with the EPA issued on April 24, 2009, Lucite International chose to permanently shut down the plant. The complete and final shutdown of the SAR was concluded in March 2010.

3.2 Incident Description

On January 23, 2010, at about 7:40 a.m., contract personnel working near the SAR unit saw an unusual cloud near the oleum tower and reported a fume release to the board operator. The contractors estimated the release to be about midway along the length of a1-inch diameter insulated pipe between the Oleum Tower Pump Tank (OTPT) and a sample station (Figure 8). The board operator asked the plant operator to go to the area of the reported leak to determine the nature of the release. The plant operator confirmed that a leak had developed on the sample piping between the OTPT and the sample station and alerted other workers in the vicinity to move to a safe area. Based on the information the plant operator provided, at about 7:45 a.m. the board operator notified the main gate guard, who then activated a "fume alert" [24] to notify the facility of the release.

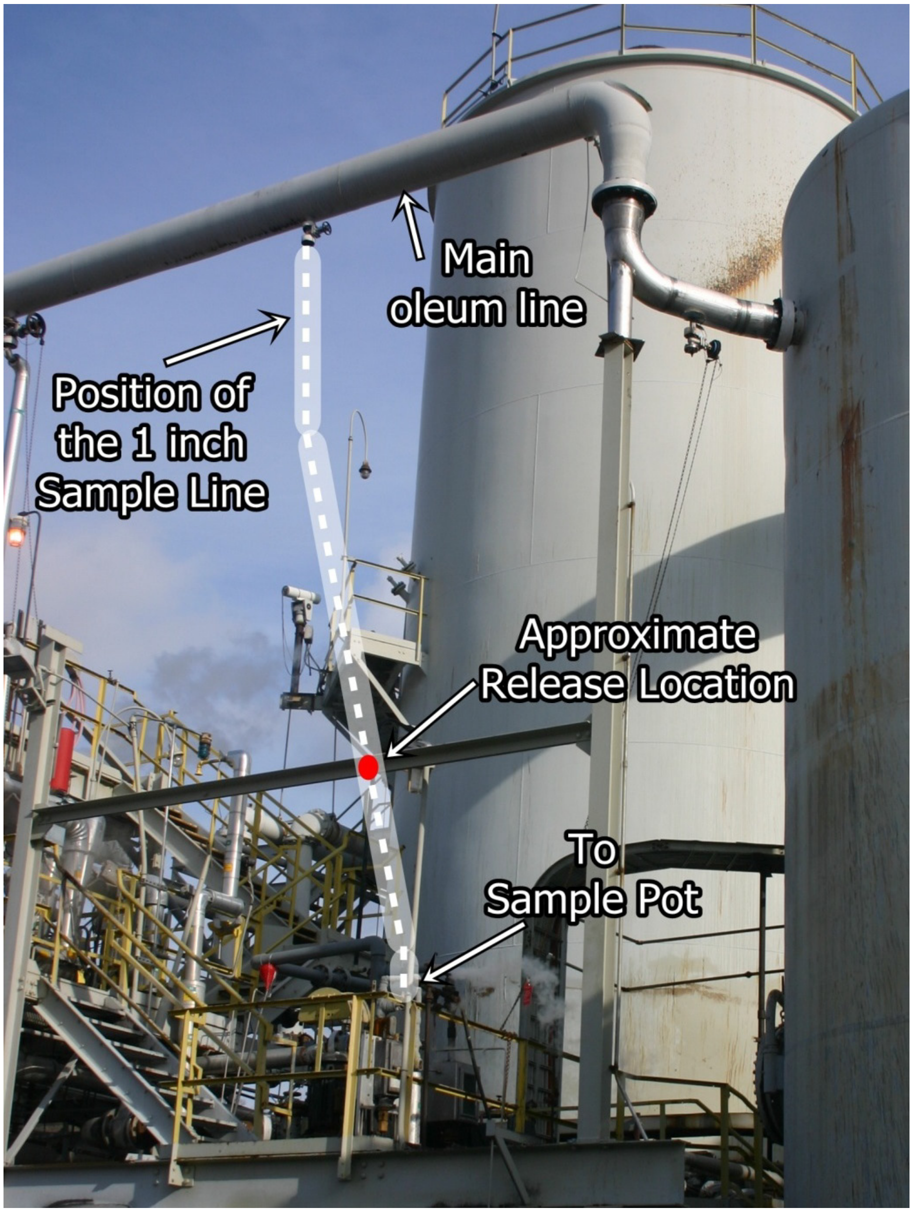

Figure 8. Photo of the position of the 1-inch sample line, which had not yet been replaced

[24] Each plant in the facility has a pre-determined unique number of rings that identify it in case of a release or emergency.

A cloud of steam and sulfuric acid mist from this release is reported to have traveled west and dissipated in an adjacent operating unit. A concrete dike surrounding the OTPT contained liquid from the leak. There were no reports of exposure to any DuPont or contract employees or the public.

3.2.1 Incident Response

When the plant activates a fume alert, a klaxon bell notifies plant personnel of the location of the incident. This action also initiates a response by plant fire brigade personnel who go to the facility's fire station to obtain the plant fire engine and personal protective equipment (PPE) necessary to respond to the incident.

At about the same time the fume alert was sounded, the gate guard called Metro 9-1-1. The shift supervisor radioed the gate guard to notify the Belle Volunteer Fire Department, which then dispatched three engines to the plant. Two of the engines staged outside the plant's gate while the third went into the plant to stand by.

DuPont fire brigade members arrived at the site of the release and set up a water fog spray from the DuPont fire engine and an oscillating water spray from a nearby hydrant for about an hour. After donning an acid suit and self-contained breathing apparatus (SCBA), one responder entered the area and closed a valve, which stopped the release at about 8:09 a.m. The gate guard sounded the "all clear" at about 8:27 a.m. Calculations estimate that 22 pounds of 20 percent oleum was released during the incident.[25]

3.3 Incident Analysis

3.3.1 Reconstructive Analysis

The CSB investigators documented the analysis of the oleum sample line, which was conducted by an independent metallurgical lab, to determine the incident cause.

[25] 20 percent oleum has an acid content that is 20 percent greater than pure sulfuric acid.

Caused by an unknown defect, oleum corroded through a small section of the pipe involved in the release on January 23, 2010. Starting as a pitting phenomena and finishing slightly larger than a pin hole, the corrosion penetrated the insulated stainless steel sample pipe (Figure 9).

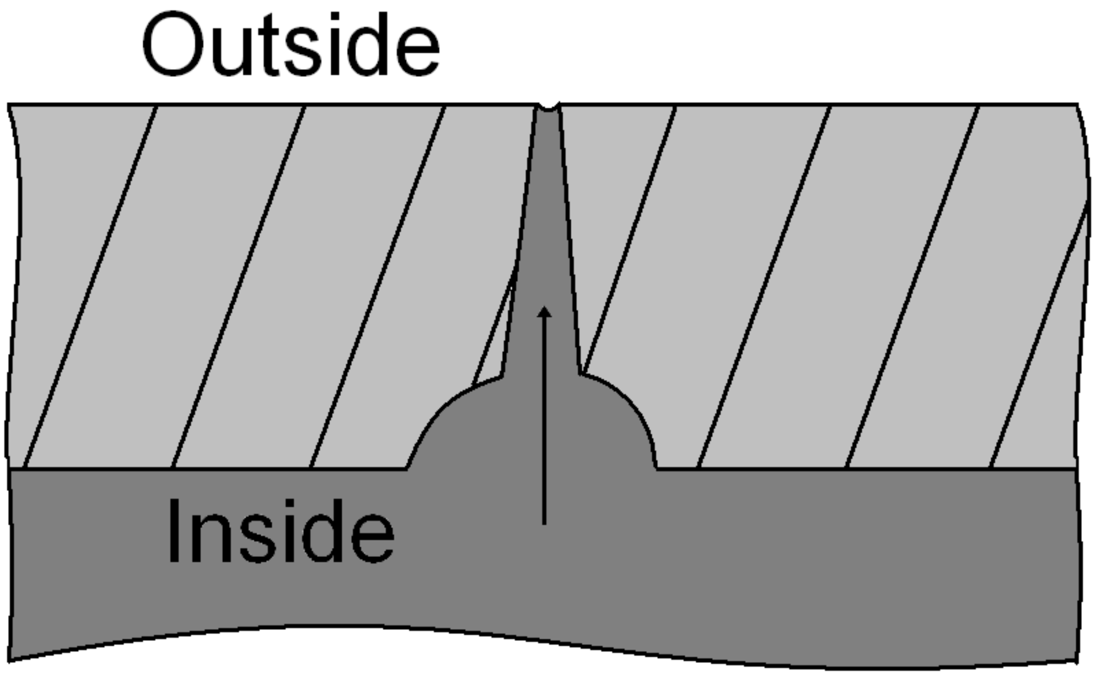

Figure 9. The pitting phenomena in the small initial hole of the oleum sample line wall

Once oleum was present on the exterior of the oleum pipe, it readily corroded the insulation and steam tracing line and then created a leak in the steam tracing, causing the steam and oleum to mix. This reaction created a strong solution of sulfuric acid that rapidly and effectively corroded the stainless steel sample line exterior, until a second larger hole developed at a location near the original small leak. The second hole clearly shows corrosion occurring from the outside-in (Figure 10).

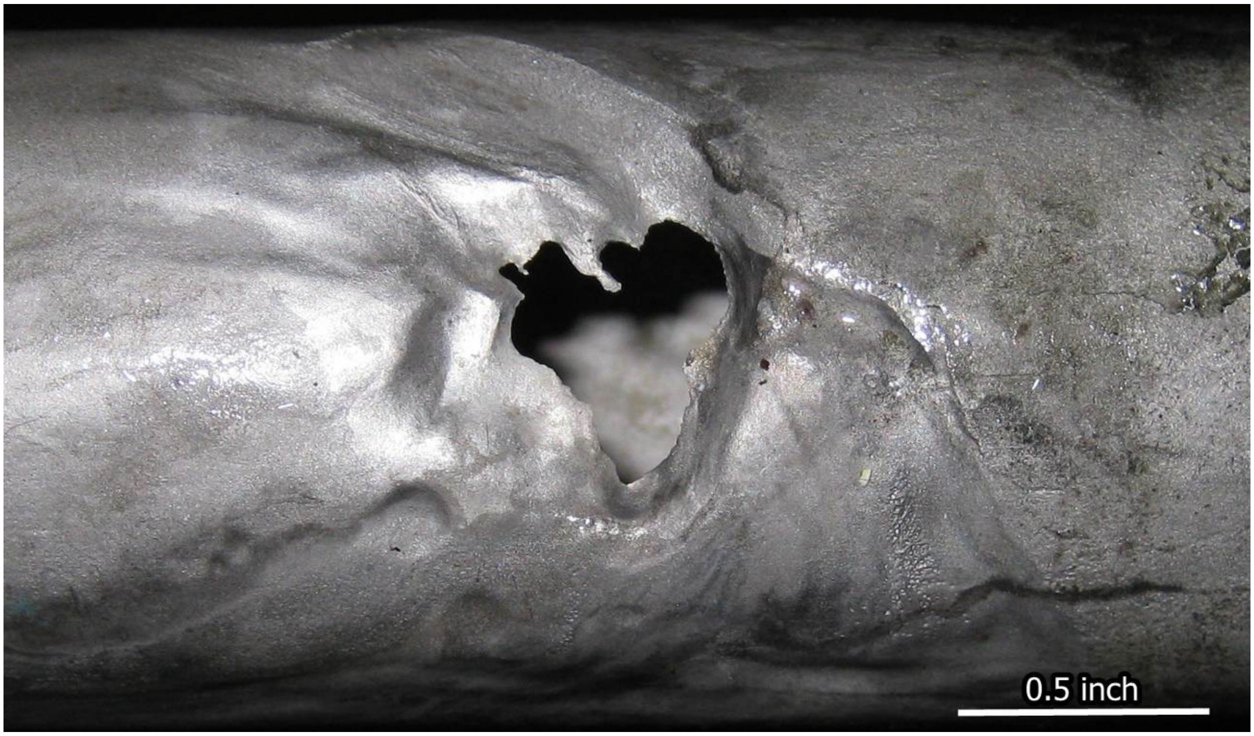

Figure 10. The larger hole eroded from the outside-in on the oleum sample line[26]

When DuPont removed the oleum-soaked insulation and cover, a larger hole was visible; the acid had also corroded a large amount of the steam tracing. When the sample line was properly cleaned, inspection revealed that the smaller hole was only a few inches away from the larger hole, and after thorough examination, metallurgists concluded that the small hole in the sample line initiated the oleum release (Figure 11).

[26] Because the oleum pipe was held as evidence, its decontamination was delayed; the size of the holes may have marginally increased from continued corrosion prior to examination.

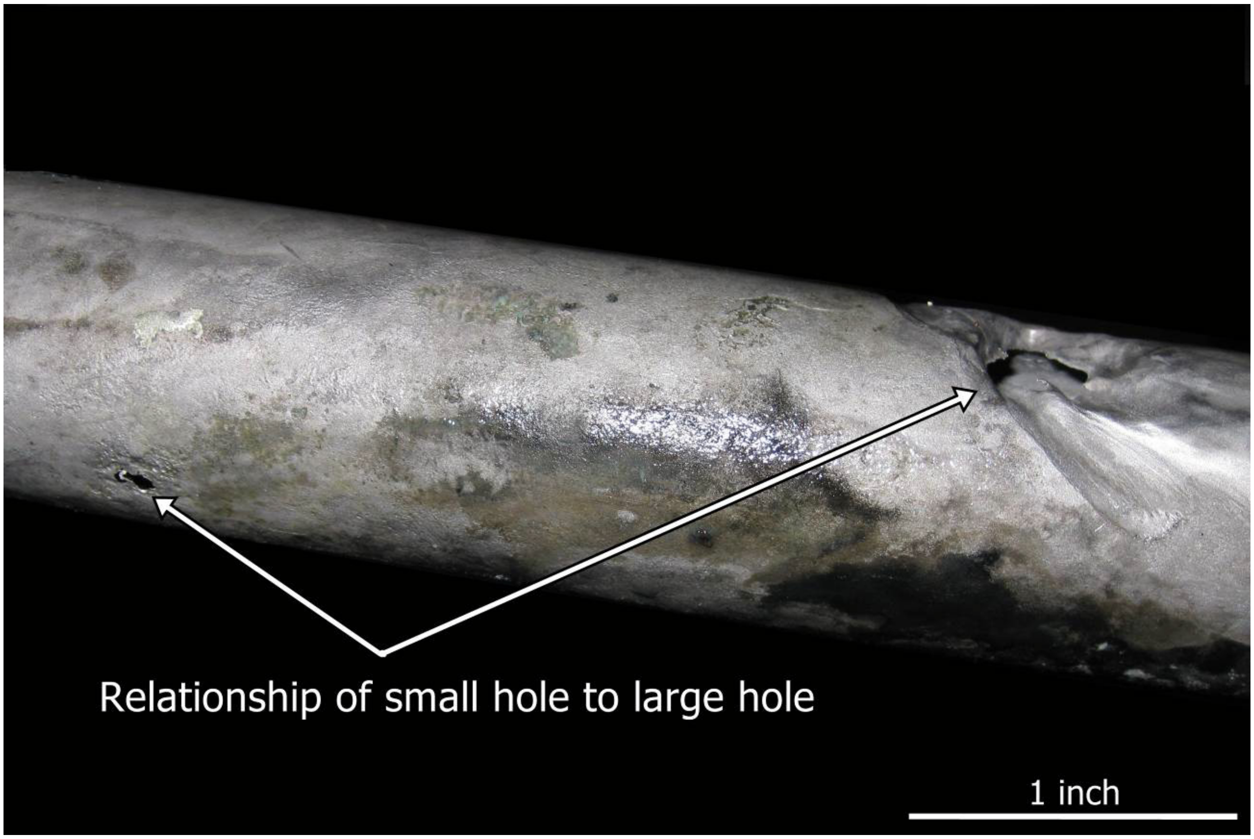

Figure 11. Photo showing the orientation of the small hole to the main hole

3.3.2 Pipe Testing and Analysis

The oleum sample line was tested using gamma ray radiography, ultrasonic thickness (UT), and metallographic analysis. The metallographic analysis confirmed that the sample line was fabricated from 304L stainless steel, one of the few metals approved by the DuPont Piping Standard for this oleum service.

The radiographic and UT testing showed that the pipe wall had suffered general thinning from corrosion, which is expected in most piping applications involving corrosive materials. The thinning rate can predict the service life of the pipe, and in the case of pipes routing corrosive materials, the expectation is that roughly 1 to 2 mils[27] will corrode per year. UT testing and radiography revealed that general wall thinning of the sample line was much less than the predicted 1 to 2 mils per year and showed much less thinning than expected for its lifetime. This sample line had been in place for 19 years, which is not unusual for this type of service.

Only one anomaly, later deemed the initiator of this incident, was found during the testing. During visual inspection a small hole was discovered 90^{o} off and a few inches from the larger hole. Under microscopic examination, the small hole corrosion phenomenon could clearly be seen; however, its exact cause is unknown. One theory is that this small hole may have originated from some sort of manufacturing defect, but the size and shape of the pitting phenomenon suggest that if this were a manufacturing defect, the pitting would have occurred around the circumference of the pipe or along the longitudinal axis. This particular phenomenon does not fall into any easily defined defects. Due to the small size of this pitting, it is unlikely that routine non-destruction examination (NDE) techniques would have identified this defect.

3.3.3 Previous Incident Investigation

On January 27, 2009, almost a year to the day prior to the incident, a leak developed in the Oleum Tower circulation piping. Although the amount estimated to have been released was greater than the January 23, 2010, release (40 pounds vs. 22 pounds), supervisors deemed the situation unnecessary for an emergency shutdown and activation of a fume alert.

The emergency response for the 2009 incident was inconsistent with that taken in 2010. Unlike in 2010, in 2009 a “hot line”[28] announcement informed plant personnel of the incident. In the incident

[27] A mil is a unit of measure equal to one-thousandth of an inch (i.e., 1/1000 in).

[28] A “hot line” announcement involves notification to a pre-determined list of operating and supervisory personnel who are all informed of an incident at the facility with one call.

investigation report for the 2010 incident, no criteria is discussed that would provide guidance for the appropriate response or what distinguished the two events.

3.3.4 PM Program Recommendation from 2009 Incident

The internal DuPont investigation identified the following key factor in the 2009 incident: "Pipe in acid service tends to have very localized areas of erosion/corrosion that can be easily missed while performing thickness checks. These areas are often the result of welds, the heat affected area of welds, and, disruptions or turbulence in the acid flow."

Although DuPont realized that certain wall thinning in acid service could go undetected, one recommendation from this investigation was to incorporate all piping in oleum service into a PM schedule; however, this recommendation was not completed prior to the January 2010 incident. Moreover, the sample line involved in the January 2010 incident was not included in the PM schedule. An interview with one of the engineers responsible for arranging for this equipment to be included in the PM schedule revealed that the oversight occurred due to poor communication between DuPont and the contractors hired to perform the PM inspections.

3.3.5 Mechanical Integrity

The piping material, 304L stainless steel, is acceptable to carry this concentration of oleum. The expected rate of wall thinning would project the lifetime of the pipe to be approximately 40 years, and this pipe had been in service for only 19. While the oleum sample line was within the design specifications, DuPont did not address the corrosion issues associated with acid service.

3.3.6 Heat Tracing Design

The oleum sample line was heat-traced[29] with a steam tracing line comprised of ¼-inch copper tubing strapped to the outside of the sample line. The steam in the copper tracing line heats the sample line to prevent the oleum inside from freezing. Steam tracing, however, can create hot spots and often does not distribute heat evenly throughout its length. A preferred method is electric tracing, which can be easily controlled and prevents hot spots through even heat distribution (Dillon, 1997).

As described in the Analysis Section, steam tracing played a significant role in the failure of the sample piping. Once the oleum escaped containment, the copper tracing corroded away. The oleum and steam then mixed, and the resulting extremely corrosive sulfuric acid created the larger hole. If an electric tracing line had been used, as DuPont suggests for these conditions, the larger hole would not have formed, reducing the magnitude of this incident.

3.4 Key Findings

1. An internal DuPont investigation report from a prior oleum leak recommended including all piping in a PM thickness monitoring program. The CSB found no evidence that the piping in the January 23, 2010, incident was included in the program.
2. The general wall thinning rate estimate for the oleum service was conservative. However, highly localized corrosion attack cannot be predicted by this method.
3. Corrosion caused a small leak in the oleum pipe under the insulation.

[29] The protection of a liquid-filled pipe against freezing by installing heat tubing or heating cable around or along the pipe

3.5 Root Causes

1. DuPont did not adhere to industry recommended practices to use electrical tracing instead of steam tracing.
2. A defect in the piping, undetectable by routine NDE techniques, allowed for a loss of containment.

4.0 Phosgene Release (January 23, 2010)

4.1 Background

4.1.1 Phosgene

Phosgene, in liquid and gaseous forms, is colorless and highly toxic and has a characteristic odor of freshly cut hay or grass, with a boiling point of 8° C (47° F), and is liquid in cold weather, gas in warmer weather. At room temperature phosgene is a dense gas that is heavier than air. Phosgene is manufactured through the reaction of carbon monoxide and chlorine and is used widely in industry as a chemical intermediate for isocyanate-based insecticides, polymers, and pharmaceuticals.

Inhalation is the primary route of exposure to phosgene. The OSHA 8-hour TWA PEL for phosgene is 0.1 ppm[30]; the NIOSH IDLH concentration is 2 ppm. The odor threshold[31] ranges between 0.4 and 1.0 ppm, which is higher than the OSHA PEL; therefore, odor is not a reliable detection method for phosgene, as injury may occur before the odor becomes prominent. Phosgene gas may irritate skin and eyes upon contact at lower concentrations. Liquid phosgene contact with skin can also cause severe chemical burns at higher doses.

[30] The NIOSH- and ACGIH-recommended TWA concentrations are also 0.1 ppm for phosgene.

[31] An odor threshold is the lowest airborne concentration that can be detected by a population of individuals. The range of detection varies among individuals.

Phosgene inhalation can result in two mechanisms of injury to the respiratory tract, both of which can result in pulmonary edema[32] at high concentrations. Inhaled phosgene slowly undergoes hydrolysis and forms HCl, which results in upper respiratory irritation and burning sensations, cough, and chest oppressions. Symptoms may not appear until several hours after exposure. Phosgene also reacts with proteins in the pulmonary bronchioles and alveoli, disrupting the blood-air barrier in the lungs and resulting in increased lung fluid. Pulmonary edema can be present in victims as long as 40 hours after exposure and may last days depending on the concentration and duration of the exposure.

4.1.2 Phosgene Stainless Steel Hose Transfer Operation

The SLM unit runs on a campaign[33] basis and is divided into two processes: the “front end” and “back end.” The front end process makes five isocyanate intermediate products. Phosgene used to produce the five intermediate products is fed to a process from 1-ton cylinders stored in the phosgene shed at the SLM unit. The phosgene cylinder storage shed is a covered, partially walled structure where the phosgene transfer and storage operations occur (Figure 12). All equipment used for these purposes is in or around the shed. The shed contains no mechanical ventilation or exhaust systems to control phosgene leaks, only natural ventilation flowing through the shed wall opening from the atmosphere.

[32] Pulmonary edema, which occurs when fluid accumulates in the lungs, leads to impaired gas exchange and may cause respiratory failure. It is due to either failure of the heart to remove fluid from the lung circulation ("cardiogenic pulmonary edema") or direct injury to the lung parenchyma ("noncardiogenic pulmonary edema").

[33] The front end of the SLM unit manufactures several types of isocyanate intermediates on a demand-based schedule.

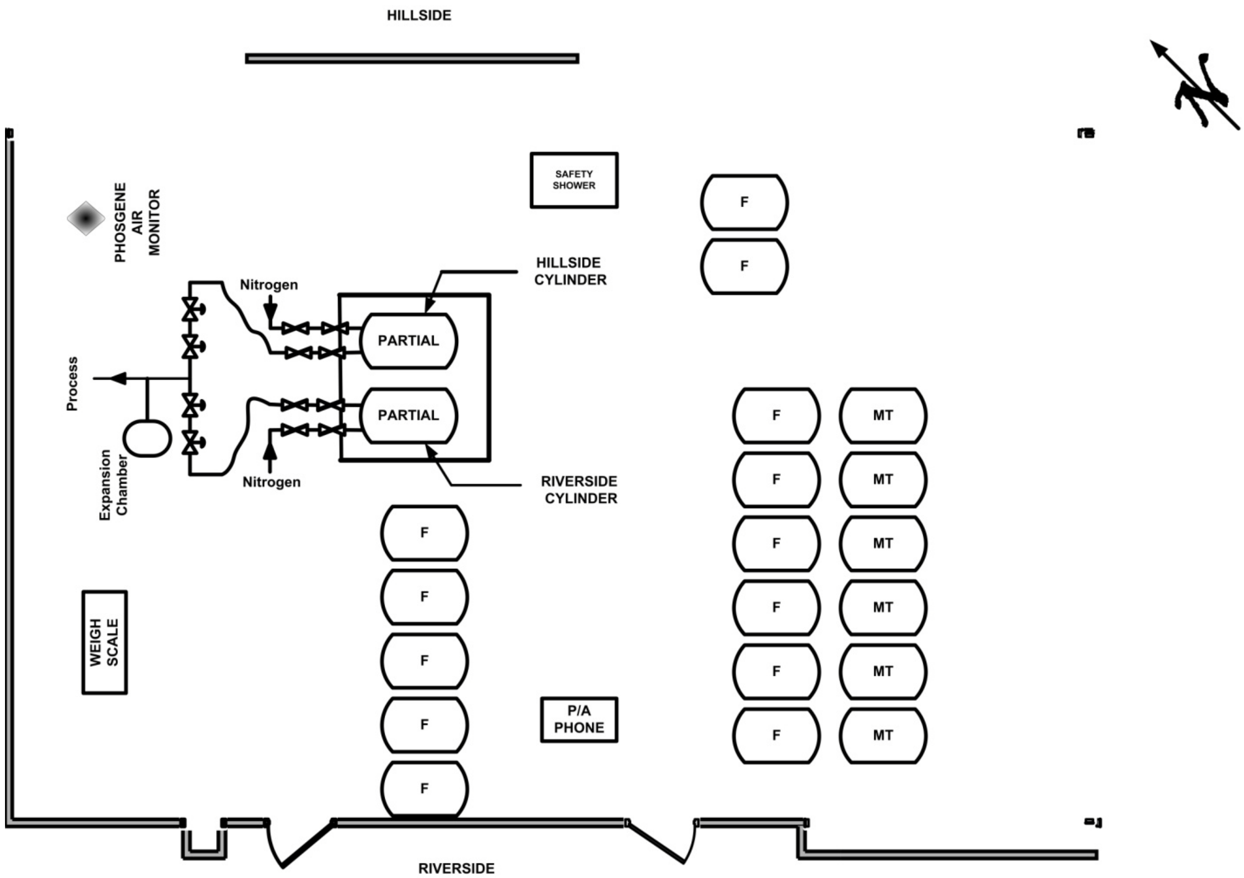

Figure 12. Phosgene shed and full (F) and empty (MT) cylinder locations on day of incident (not to scale)

During normal operation, two cylinders are staged on weigh scales and each is connected to the process with two 0.25-inch diameter by 48-inch long PTFE-lined, 304 stainless steel overbraid hoses. One hose transfers liquid phosgene to a steam vaporizer and one provides 70-psig nitrogen to the cylinder. The scales record the weight of the in-service cylinder and when the container is nearly empty, an alarm notifies the board operator, who then directs operators to switch to a full cylinder. This switch is completed by opening valves to the full cylinder and closing valves to the empty cylinder. The hoses remain coupled in this operation, and plant SOPs do not require enhanced PPE such as a fully encapsulated suit and breathing air. Under normal operating conditions, the process consumes two to three cylinders of phosgene per day.

The SOPs do require operators to don a fully-encapsulated suit with supplied breathing air when they replace an empty cylinder with a full cylinder. After clearing all phosgene from the stainless steel hose with a nitrogen purge under vacuum to a scrubber, the hose is isolated from the vent piping and disconnected from the empty cylinder. Operators then replace the empty cylinder on the scale with a full cylinder and connect the stainless steel hose to the new cylinder.

Maintenance mechanics replace stainless steel hoses in phosgene service when a work order is generated to change-out the hoses. The DuPont SOPs for the change-out frequency of the nitrogen and phosgene hoses directs replacement every 30 days.[34]

A number of manufacturers fabricate hose assemblies to DuPont's specifications for phosgene and nitrogen hoses, which arrive pre-assembled and are stored in plastic bags in the maintenance shop. Prior to connecting the hoses to the phosgene cylinders, the maintenance mechanics install valves on either end of the hose. Hoses removed from service are decontaminated in a water bath and then disposed.

4.1.2.1 VanDeMark Chemical, Inc.

VanDeMark Chemical supplies phosgene to the Belle plant in 1-ton cylinders. VanDeMark, located in Lockport, NY, is the only North American company that both produces and distributes phosgene. It distributes phosgene and phosgene derivatives in 1-ton cylinders. Each VanDeMark cylinder is 87 percent full and contains 2,000 pounds of phosgene. Each U.S. Department of Transportation-regulated cylinder has two valves with a seal plug screwed in the outlet covered by a flanged and gasketed bonnet to protect the valves and prevent leaks during transport. The Belle plant receives phosgene cylinders via truck that are unloaded at the phosgene shed; empty cylinders are loaded onto the truck and returned to VanDeMark.

[34] DuPont's former maintenance management process directed that hoses be changed every 2 months.

4.1.2.2 Use of Personal Protective Equipment (PPE)

DuPont safety procedures include two levels of PPE required for work in the phosgene cylinder shed on the SLM unit, based on the connection status of the phosgene cylinders. When the phosgene cylinders are connected to the process and no breaks in the phosgene lines are occurring, the standard required PPE for the SLM unit is a hard hat, steel-toed safety shoes, safety glasses, flame resistant clothing (FRC), and a phosgene indicator badge. Work with this level of protection includes

- entering the phosgene shed to check cylinder scale weights,
- opening and closing valves to switch from one cylinder to another, and
- operating the crane when loading and unloading full or empty cylinders in the phosgene shed

The Belle Plant SOPs for disconnecting a phosgene cylinder require operators to wear a chemical suit (gloves, boots, and hood) with supplied breathing air in addition to the PPE listed above while performing the work. During all phosgene cylinder line break operations, another operator, wearing standard PPE, stands outside the shed to monitor the breathing air supply of the operator performing the work.

At the time of the incident, the employee fatally exposed to phosgene was wearing the standard PPE. This met DuPont operating standards for the task he was performing, because he was likely checking cylinder weights in preparation for switching to the partially filled riverside cylinder. The Belle Plant PPE requirements and SLM unit procedures did not require him to don a chemical suit, with supplied air, during this activity.

4.1.2.3 Phosgene Indicator Badge

Belle Plant safety procedures require all personnel (operators, contractors, managers) and visitors in the SLM unit to sign a log sheet and obtain a phosgene indicator badge from the SLM control room prior to entry and to wear a phosgene indicator badge in their breathing zone (Figure 13). Phosgene indicator badges change color when exposed to phosgene, and the color indicates the concentration 1 minute after exposure. After 2 consecutive days of use, personnel using badges must discard and replace their indicator badge to ensure accurate sensitivity.[35]

Two types of phosgene indicator badges are available for use in the SLM unit. For work tasks not involving supplied air, personnel clip SafeAir® System phosgene badges (Morphix Technologies) to the collar or pocket of FRC near the breathing zone. The badges change from white to pink or red to indicate dose, concentration, or duration of exposure. In addition to badges, the SafeAir system uses a color comparator wheel to detect exposure dose and the presence of phosgene between 0.9 and 100 ppm-min.[36]

[35] The manufacturing specifications state that the maximum recommended sampling time for each badge is 3 days. The Belle plant requires phosgene badges to be replaced after 2 days to ensure accurate detection and avoid discoloration or interference with other chemicals.

[36] Parts per million-minute (ppm-min) is the concentration of a contaminant in air related to the exposure time through inhalation; 48 ppm-min = 480 minutes of exposure at 0.1 ppm concentration.

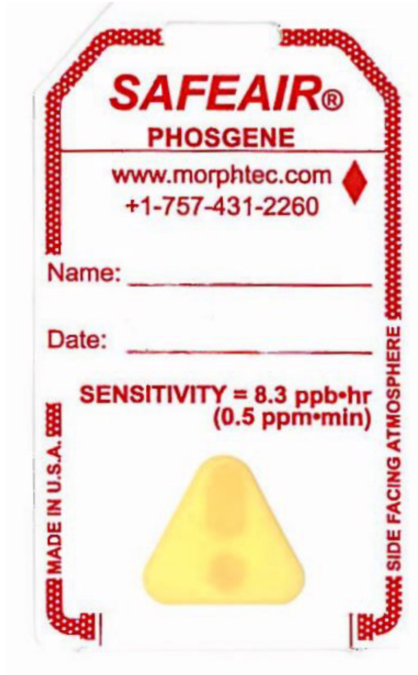

Figure 13. SafeAir Phosgene Dosimeter Badge[37]

For work tasks in the SLM unit requiring supplied air, all personnel must wear a CheckAir® phosgene badge inside the mask of their supplied air respirator. The CheckAir detector (Morphix Technologies) detects exposure dose concentrations between 0.9 and 100 ppm-min. The color comparator wheel for detecting exposure concentrations of the CheckAir detectors differs from that of the SafeAir badges.

4.1.2.4 Alarms

The SLM unit has 12 phosgene sensors placed in and around it to continuously sample and record phosgene concentrations every 30 seconds; concentrations of phosgene are detected via an electrochemical diffusion sensor within a range of 0.05 to 1 ppm. One phosgene sensor is located in the phosgene shed, six are in the SLM building, and two are located outside the building. Three sensors are

[37] The badge in Figure12 has a range of 0.5 to 450 ppm-min. The SafeAir badge worn by the exposed employee had a range of 0.9 to 100 ppm-min.

on the fence line of the facility along the Kanawha River, approximately 120 feet from the phosgene storage shed.

The analyzer readings are monitored by the DCS in the SLM control room, and concentrations in excess of 0.05 set off audible and visual alarms at the board operator's work stations. Concentrations equal to or greater than 0.05 ppm set off a medium-high alarm and concentrations at or above 0.1 ppm set off a high-high alarm. The CSB could find no evidence that audible or visual alarms were in service in the phosgene shed when the release occurred.

On the day of the incident, the phosgene release activated alarms in the control room for four of the 12 analyzers in and around the SLM unit. The phosgene analyzer in the shed recorded concentrations ranging from 0.04 to 1.0 ppm for approximately 50 minutes following the initial release. Two of the three fence line monitors triggered alarms, with the maximum recorded concentration of 0.27 ppm on a monitor located approximately 120 feet from the phosgene shed along the river. Another monitor, located on a spill tank outside the SLM unit building, also recorded a concentration of 0.04 around the time of the release.

All 12 phosgene analyzers have a maximum detectable concentration of 1 ppm. The analyzers do not record actual values for concentrations in excess of 1 ppm; therefore, if phosgene concentrations exceed the detection range at the analyzer sample point, the values are recorded only as 1 ppm.

4.1.3 Phosgene Highly Toxic Material Guardian Committee

DuPont's Phosgene Highly Toxic Material Guardian Committee focuses on the safe management of phosgene at applicable DuPont facilities. DuPont has several guardian committees for highly toxic materials (HTMs) used within the company. The committee is comprised of representatives, known as phosgene guardians, from all DuPont sites that produce or consume phosgene. Managers from affected processes, corporate health and safety representatives, engineers, and industrial hygiene specialists also participate. The Phosgene Guardian Committee holds meetings twice a year to share learnings and discuss phosgene handling issues.

DuPont has an HTM manual for phosgene, a company protocol that includes requirements and guidelines for the safe design and operation of processes that generate or use phosgene. The primary purpose of the manual is to reduce the likelihood of phosgene harming employees or the public. The requirements of the manual are mandatory for all DuPont facilities with enough phosgene to impose a significant offsite hazard as determined by a chemical consequence analysis of offsite exposure. The Phosgene Committee conducts a second-party audit of all facilities using phosgene against the requirements and guidelines set forth in the phosgene HTM manual approximately every 3 years. The Phosgene HTM Committee audited the SLM unit at the Belle Plant in September 2006; the next audit was scheduled for January 25, 2010, just two days after the phosgene release incident.

4.2 Incident Description

The third incident occurred on January 23, 2010, between 1:45 and 2:00 p.m. A stainless steel braided transfer hose connected to a partially filled, but not in service 1-ton phosgene cylinder failed catastrophically in the SLM unit phosgene shed. This incident occurred in the phosgene shed. When the release occurred, an operator was in the phosgene shed inspecting the status of the riverside[38] phosgene cylinder as he anticipated that the active cylinder was nearly empty and would need to be switched. He was sprayed across the chest and face with liquid phosgene remaining in the riverside hose from a previous transfer operation.

[38] The cylinders are commonly referred to as "hillside" or "riverside" based on their orientation in the phosgene shed relative to the hills north of the building and the Kanawha River to the south.

DuPont estimates that about 2 pounds of phosgene were released to the atmosphere when the hose failed. The CSB concurs with this estimate and further calculated that the operator would have received a lethal dose of phosgene in less than one-tenth of a second (Appendix D).

Immediately after the operator was sprayed, he called for assistance on the SLM unit public address phone in the phosgene shed. A coworker who responded to the call noticed that the victim's phosgene dosimeter badge (Figure 13) was discolored, indicating an exposure. The coworker directed the exposed worker to a plant truck to transport him to the plant's medical center for assessment and treatment. As they drove to the medical center, the two workers were met by the Shift Supervisor and the exposed worker was transferred to the shift supervisor's vehicle to complete the trip. While en route to the plant's medical center, the front gate guard was radioed and advised to call Metro 9-1-1 and request that an ambulance respond for a medical emergency. The exposed worker, while at the medical center waiting for the ambulance, chose to wash his face and hands, but there is no evidence or record that he was placed in a safety shower to wash off, as instructed by the emergency procedures, or that any decontamination activity took place beyond the hand and face washing. He was given a change of coveralls to put on in exchange for the work clothes he was wearing. The gate guard called Metro 9-1-1 at 1:59 p.m., requesting transport for a medical emergency patient to the hospital. The 9-1-1 dispatcher asked if there was a chemical release; however, the gate guard, who was unaware of the situation, responded that there was no release and that the response was for a medical emergency. As part of the Metro 9-1-1 emergency response protocol, the dispatcher asks for specific information to ensure that responders are as informed as possible prior to arrival at the scene. At 2:03 p.m., an ambulance was dispatched from the KCEAA.

At 2:08 p.m., responding EMTs asked Metro dispatchers if more information was available about the victim. When Metro called DuPont to get more information, the line was busy. EMTs also wanted to know if there was a chemical exposure, but Metro 9-1-1 could not get that information from DuPont. Six minutes later, the EMTs arrived at the DuPont gates.

EMTs were directed to the DuPont medical center to meet the exposed worker. As the EMTs gathered the worker for transport, they were given a written phosgene treatment protocol intended to be used at the hospital to provide treatment. While the worker was being transferred to their care, DuPont employees told the EMTs that the victim had been exposed to liquid phosgene.

The EMTs left the facility with the victim at 2:26 p.m., or 27 minutes after the first call to Metro 9-1-1. During transit and after arrival at the hospital at 2:34 p.m., the victim was lucid, conscious, and talking clearly to the emergency responders and attending physician. Until the attending ER physician consulted the company-provided phosgene treatment protocol, which advised 48-hour monitoring for suspected phosgene exposures, he considered sending the victim home based on his condition shortly after arriving at the hospital. A baseline X-ray revealed no congestion in the victim's lungs. At about 5:30 p.m., or almost 4 hours after exposure, the operator's condition began to rapidly deteriorate. Over the next 29 hours, the victim received treatment from a variety of physicians, but his condition failed to improve and he died at 9:27 p.m. on Sunday, January 24, 2010.

Post-incident, KCEAA staff voiced concerns regarding the quality and timeliness of information DuPont provided to Metro 9-1-1 dispatchers and responding EMTs. The concerns raised address the need to ensure that emergency responders and their equipment are not exposed to contaminants and that the victims they are assisting receive optimum care in transit for medical treatment. A review of comparable responses by KCEAA EMTs in the region reveal that the response time to DuPont and from there to the hospital was not unduly delayed by the lack of information. A sampling of similar emergency responses reveal an average response time from the initial call to Metro 9-1-1 until arrival at the hospital to be about 36 minutes. Total elapsed time for the response time on the day of the exposure was 35 minutes.

Although the emergency response and transport of the victim was not delayed during this incident or the oleum release, because of a lack of clear, accurate information regarding the material involved, response procedures have since been modified by Metro 9-1-1 administrators. These modifications mandate that

EMS units not report directly to the site of an incident until clear information has been provided such that EMS personnel will not be at risk of unknown contaminants/threats. This change in response protocol was incorporated after several incidents in the Kanawha Valley. The CSB considers the change in response protocol significant enough to define the cause and effect of the communication gap as a "near-miss." Several key factors that contributed to poor communication, including the absence of a process knowledgeable person assigned to convey information to the dispatchers and the lack of a direct line to the Metro 9-1-1 emergency operations center, must be recognized and addressed.

One confirmed and one possible phosgene exposure to workers occurred after the initial release. The first was when a coworker responded to the call for assistance immediately after the phosgene hose ruptured. As he drove the victim to the facility's medical building, the coworker's dosimeter badge became slightly discolored, indicating phosgene exposure.

A possible source of this exposure was phosgene vapor in the atmosphere as recorded on one of three fence line monitors about 120 feet from the shed along the river. Another possible source was the victim's clothing, which may have been saturated with phosgene immediately after the release. When interviewed, this employee said that pulmonary function tests performed afterward showed no signs of adverse effects.

A second possible exposure occurred when an employee working in the SLM unit went toward the phosgene shed shortly after the release. He reported in an interview that as he got closer, he noticed a smell that he had not encountered before or since. He recalled that the odor was not strong or offensive as would be expected with ammonia or chlorine, but noticeably different from any odors he had smelled in the past. Being unfamiliar with the characteristic fresh mown hay odor associated with phosgene, he left the area.

Although the phosgene shed area has flashing lights to alert against entry into the area during cylinder changes, there is no evidence that a fume, medical, or plant radio alert sounded at any time during this release episode to warn operators and maintenance personnel to avoid coming near the phosgene shed.

4.2.1 Community Impact

Two of the three fence line analyzers recorded a maximum concentration of 0.15 and 0.27 ppm[39] phosgene, indicating that phosgene concentrations had traveled offsite toward the Kanawha River. However, no member of the public reported phosgene exposure symptoms the day of the incident nor did the U.S. Coast Guard restrict river traffic or conduct air monitoring as it had a day prior as a result of the methyl chloride release.

4.3 Incident Analysis

4.3.1 Hose Failure Analysis

Post-incident inspections of the stainless steel hoses used for the two phosgene cylinders connected to the process identified comparable degradation patterns. Their failure was associated with corrosion that developed in approximately the same location on hoses used to transfer phosgene from the riverside and hillside cylinders.

Investigators found that while the majority of tags attached to the hoses to indicate the intended service were secured in place with plastic ties and metal clamps—as was normal—one manufacturer's tag was secured with white plastic adhesive tape (this tag applied by the manufacturer also provided identification information). The corrosion identified on the two hoses associated with the hillside and riverside cylinders was localized under the area covered by the white plastic adhesive tape securing the tag.[40] The characteristics of the transfer hose, consisting of a core constructed of permeable PTFE and braided 304-

[39] ERPG-2 value for phosgene is 0.20 ppm and at this concentration "all could be exposed for up to one hour without experiencing or developing irreversible or other serious health effects or symptoms that could impair their abilities to take protective action" (AIHA, 2008).

[40] Witnesses could not provide an exact date that the hoses came into the facility with the tags affixed with adhesive tape.

stainless steel, provided a suitable environment under the adhesive tape for stress corrosion cracking (SCC[41]) to occur.

To provide comparative data, hoses from the hillside, riverside, and exemplars of similar age and new assembly were sent to an analytical lab for testing and analysis. The tests established that all of the hoses were constructed with 304-stainless steel and the construction material for the inner core of the hoses was PTFE, as expected.

4.3.2 Effect of Plastic Adhesive Tape

The PTFE, 304 stainless steel, and white plastic adhesive tape contributed to the incident. The PTFE inner core was permeable and susceptible to phosgene vapor diffusing through the hose. The adhesive tape used to secure the tag contributed to the retention of phosgene gas on the exterior of the stainless steel overbraid. The phosgene gas converted to HCl, and 304-stainless steel overbraid is subject to corrosive attack by HCl. Since the white plastic adhesive tag trapped the phosgene permeating through the PTFE inner core, the resulting concentration of HCl was much higher under the tag than elsewhere on the hose (Figure 14).

[41] Stress corrosion cracking is the formation of brittle cracks in a normally sound material through the simultaneous action of a tensile stress and a corrosive environment.

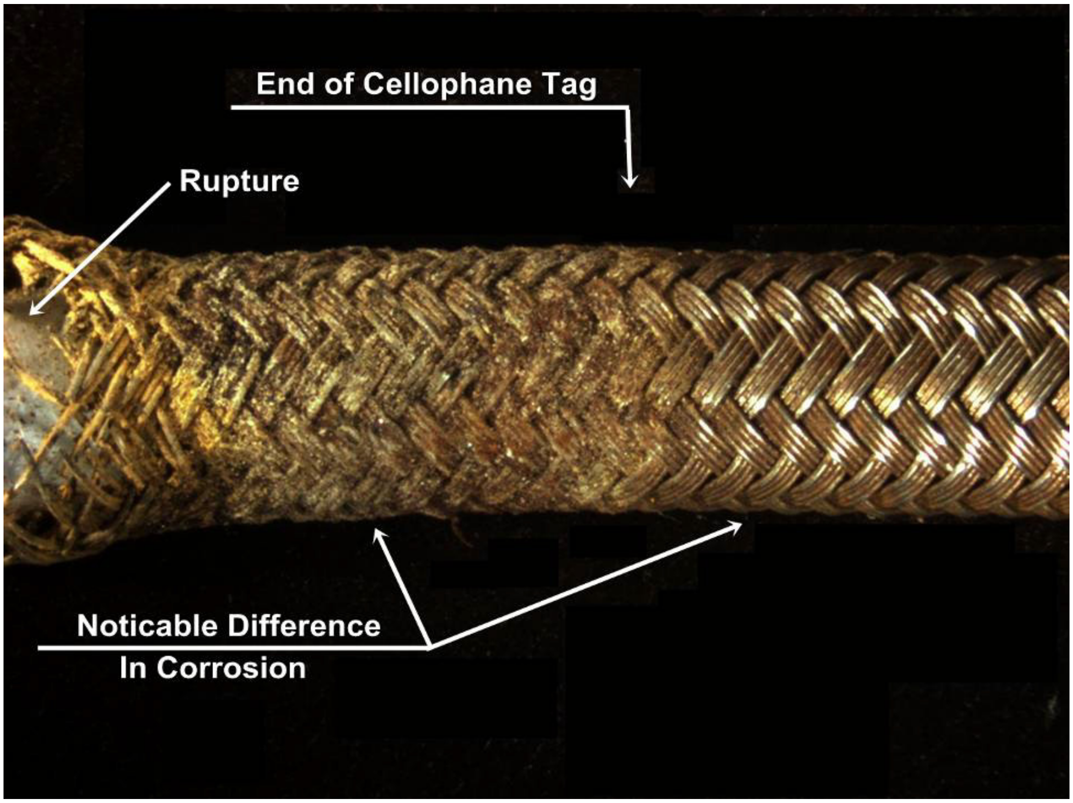

Figure 14. The distinct effect of the white plastic adhesive tag on the corrosion of the stainless steel overbraid

Additionally, at the time of the incident, the isolation valves on the phosgene hose on the riverside cylinder were closed, which retained liquid phosgene in the hose and pipe between the valves that isolated the cylinder from the process. The heavy corrosion of the stainless steel overbraid, coupled with the time the hose had been in service and thermal expansion[42] of the isolated liquid phosgene, caused the hose to fail catastrophically. When this failure occurred, the worker was exposed as he walked nearby to check on the status of the adjacent in-service cylinder.

[42] Tendency for solids, liquids and gases to change in volume in response to a change in temperature.

4.3.3 Hose Degradation Issues

Although the maintenance plan for the hillside and riverside hoses prescribed a regular change-out schedule of 30 days, work orders show that change-out frequency was neither systematic nor predictable. At least three times from 2006 to 2010, phosgene hoses were left in service from 4 to 7 months.

4.3.4 Hose Change-out Frequency

Several times each year, the phosgene process is halted so the plant can produce a material requiring the physical removal of phosgene, including all full or empty 1-ton cylinders, from the phosgene shed.

Table 2 shows the change-out frequency of the phosgene hoses in the SLM unit and the periods when SLM did not run processes using phosgene. The most recent recorded instance where phosgene was not used in the process was between September and November 2009, 2 months prior to the incident. Work orders for changing-out the phosgene hoses indicate that the stainless steel transfer hoses connected at the time of the incident had been in service for more than 6 months. This included a removal of the phosgene system change-out in September 2009 when the hoses could have been changed-out.

Hose Change-out Frequency		
Month/Year	Phosgene Hoses	Phosgene Used
Jul-05	Changed	Phosgene Used
Aug-05	Changed	
Sep-05	Changed	
Oct-05	Changed	
Nov-05	Changed	
Dec-05		
Jan-06		Phosgene Used
Feb-06		Phosgene Used
Mar-06	Changed	Phosgene Used
Apr-06		Phosgene Used
May-06		Phosgene Used
Jun-06	Changed	Phosgene Used
Jul-06	Changed	Phosgene Used
Aug-06		
Sep-06		
Oct-06	Changed	
Nov-06	Changed	
Dec-06		
Jan-07		Phosgene Used
Feb-07		Phosgene Used
Mar-07	Changed	Phosgene Used
Apr-07		Phosgene Used
May-07	Changed	Phosgene Used
Jun-07		Phosgene Used
Jul-07		Phosgene Used
Aug-07		
Sep-07	Changed	
Oct-07		
Nov-07		
Dec-07		
Jan-08		Phosgene Used
Feb-08		Phosgene Used
Mar-08		Phosgene Used
Apr-08	Changed	Phosgene Used
May-08	Changed	Phosgene Used
Jun-08		Phosgene Used
Jul-08	Changed	Phosgene Used
Aug-08	Changed	
Sep-08		
Oct-08		
Nov-08		
Dec-08		
Jan-09	Changed	Phosgene Used
Feb-09		Phosgene Used
Mar-09		Phosgene Used
Apr-09		Phosgene Used
May-09		Phosgene Used
Jun-09	Changed	Phosgene Used
Jul-09		Phosgene Used
Aug-09		
Sep-09		
Oct-09		
Nov-09		
Dec-09		
Jan-10		Phosgene Used

Table 2. Phosgene hose change-out frequency

The CSB found that change-out frequency was intended to be governed automatically by the Belle facility's SAP maintenance program. Some supervisors also relied on the maintenance coordinator remembering to initiate the change-out.

4.3.5 SAP Work Process

DuPont uses the plant maintenance module of SAP enterprise resource planning software[43] to schedule the change-out of phosgene hoses at pre-determined 30 day intervals. The SAP system is programmed to issue the work orders for hose replacement to prevent the release of phosgene; thus, maintaining accurate data in the SAP database is crucial to protect against phosgene exposure (Appendix C).

In late 2006, SAP data managing the change-out frequency of the phosgene hoses at the Belle facility were changed; consequently, SAP stopped automatically issuing work orders to change the hoses, but plant personnel were unaware that SAP no longer automatically issued the work orders. The CSB requested additional information regarding the change; however, DuPont could not determine who changed the SAP data, why it was changed, or when the change was executed. No back-up layer of protection, such as a weekly critical equipment maintenance check sheet or an inspection tag, ensured that the hoses were changed at the pre-determined frequency. With SAP no longer automatically issuing work orders to change the hoses, the system did not trigger maintenance notifications to change-out the hoses at assigned intervals.

[43] Enterprise resource planning software is a type of database that allows data related to flows of money and other resources in areas such as accounting, supply chain management, sales and marketing, manufacturing, maintenance, and project management to be recorded and accessed.

4.3.6 Near-Miss Phosgene Incident

On the morning of the phosgene incident, operators asked maintenance personnel to replace the phosgene hose on the hillside cylinder because of a suspected flow restriction. Although the cylinder was still about half full, it was removed from service and replaced with the full riverside cylinder.

The hillside phosgene supply hose and valve assembly were removed and decontaminated in a water bath. When the hose was removed from the water, the white adhesive ID tag had fallen off, revealing a broken stainless steel braid and collapsed PTFE liner, a possible cause of the flow restriction (Figure 15).

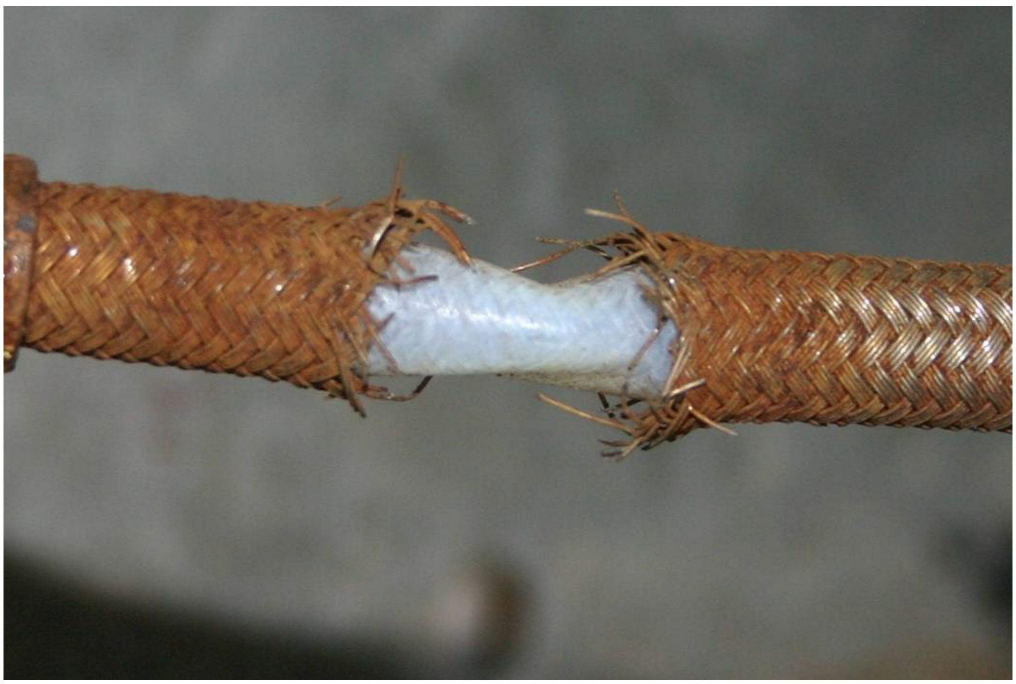

Figure 15. Damaged hillside phosgene hose removed from phosgene cylinder. The plastic adhesive tag that covered the damaged section fell off during the hose decontamination procedure.

An operator stated during an interview that when he saw the physically defective section of the frayed hose, he told his coworkers, stressing that the hose was close to rupturing and that they were lucky to have found it and changed-out the hose in time. Unfortunately, this discovery was not captured as a near-miss, since supervisors were not made aware of the issue.

Operators told the CSB investigators that they had never seen a phosgene stainless steel hose braid corroded to the point of separation. Although they were surprised and concerned about their finding, and since supervisory staff does not work on weekends, they planned to tell the supervisors about the discovery on Monday morning, about 48 hours later. Operators said that they expected that the supervisors would conduct a full investigation; however, since the incident occurred on a Saturday, it was not investigated. Had there been a system in place for operators to report near-miss incidents on weekends, the near-miss investigation may have been properly initiated prior to the fatal release.

4.3.7 Mechanical Integrity

The DuPont P3H Standard lists acceptable construction materials for flexible hoses used in HTM service and recommends three different hoses acceptable for use with phosgene: H2, H7, and H9 (Table 3).

DuPont P3H Standard Hoses for Phosgene Service		
Name	**Specifications**	
H2	Inner core material:	Monel® 400, corrugated
	Reinforcement material:	Monel® 400 overbraid
	End fitting material:	Monel® 400 SCH. 80
	Core/fitting connection method:	Welded, full penetration
H7	Inner core material:	Hastelloy® C276, corrugated
	Reinforcement material:	Monel® 400 or Hastelloy® C276 overbraid
	End fitting material:	Hastelloy® C276 stub ends
	Core/fitting connection method:	Welded, full penetration
H9	Inner core material:	Teflon®[44] PTFE, helical, corrugated, taped or extruded construction, unpigmented or conductive
	Reinforcement material:	PVDF (Kynar®) double overbraid
	End fitting material:	Monel® 400, Hastelloy® C276, or Teflon® encapsulated SS
	Core/fitting connection method:	Crimped (or swaged)

Table 3. Flexible hoses for phosgene service as listed in the DuPont P3H Standard: Flexible Chemical Hose for Highly Toxic Services

The Belle facility did not use any of the P3H specified hoses and configurations; instead, it used a flexible hose made of a Teflon® PTFE inner core and a braided stainless steel reinforcement material, even though stainless steel is not recommended for phosgene service, as it is susceptible to SCC from chlorides. Phosgene, which can readily react with air to produce chlorides, can permeate PTFE, directly exposing the stainless steel braid to chloride attack.

[44] Teflon is the DuPont-registered trademark for PTFE.

4.3.8 Flex Hose Materials of Construction

The Belle facility referred to corporate experts and the La Porte[45] facility, where flexible hoses were being used for phosgene service.

The discussions between the two plants and corporate experts about flexible hoses began in 1987, when corporate experts suggested the use of Monel metal for both the hose core and hose overbraid, since it resists chloride SCC. However, the La Porte plant asserted that its history with Monel metal was less than desirable; one correspondent noted, "The La Porte plant was considering testing Kynar overbraid-[46]covered Teflon hose because of discoloration and gradual deterioration of the Monel."

An expert from DuPont corporate told Belle that the discoloration was not a problem:

> Reports from La Porte that Monel braided hoses were corroding in phosgene service are not exactly true. The hoses at that time were Teflon lined, with a Monel outer overbraid. Due to permeation of phosgene through Teflon, the Monel was slightly attacked, forming a green surface film known as a 'patina'[47] which is common to all copper-based alloys.

A Belle representative sent a questionnaire to La Porte in August 1987 to evaluate its hose program. The questionnaire revealed that La Porte had been using PTFE-lined stainless steel hoses for the previous 3 to 4 years and that they were replaced every 3 months. It reported that the majority of the hose failures were due to fatigue, and that the facility was using stainless steel because it is not as susceptible to failure from

[45] DuPont uses phosgene at four of its facilities. DuPont no longer uses phosgene in La Porte, TX.

[46] The Kynar hose was also not pursued due to pre-conceived flexibility limitations.

[47] Patina, most easily observed on old pennies, is a green film formed naturally on the surface of copper and copper-based metals.

fatigue and bending stresses as are Monel and Kynar hoses. After reading the questionnaire, the corporate DuPont expert wrote,

> I still believe that Monel is the best choice for material of construction for phosgene unloading hoses (and definitely for the fittings). I am surprised that La Porte is using Teflon-lined hose with stainless overbraid since Teflon is known to be permeable and the phosgene is known to attack the stainless.

The DuPont expert further stated,

> Admittedly, the Monel hose will cost more than its stainless counterpart. However, with proper construction, and design so that stresses are minimized…useful life should be much greater than 3 months. Costs will be less in the long run and safety will also be improved.

Correspondence or other records that would explain why the expert's recommendation went unheeded at La Porte and why the Belle staff decided to follow the La Porte approach was not discovered during the CSB investigation. However, Belle decided to follow La Porte's example, and adopted a hose design not recommended by its P3H Standard or by a DuPont corporate expert.

The phosgene hose replacement frequency at Belle is defined in DuPont's Phosgene Hose Assembly Procedure: "Due to the extremely hazardous nature of phosgene the hose assemblies are replaced every 2 months."

However, the PM schedule in SAP is actually set to a replacement frequency of 30 days. This procedure does not effectively communicate why the hoses must be replaced so frequently: if left on too long, the accepted corrosion condition poses a serious risk to the facility and the community.

Figure 16. Flex hose comparison photographs: (top to bottom) ruptured riverside hose, flow restricted hillside hose, a new hose with attached ID tag

4.3.8 Non-routine Job Planning

Operators told the CSB investigators about the difficulty maintaining the required flow of phosgene from one of the two cylinders on the weigh scales the day prior to the exposure incident. The phosgene flow from the cylinder to the process was inadequate; thus, they performed a non-routine operation to establish a steady flow of phosgene because they suspected a plugged hose or a malfunctioning automatic feed control valve. Non-routine operations are characterized by infrequent practice, can be both planned and scheduled, or can occur without scheduling

To minimize disruption of the phosgene flow to the process, operators switched to the riverside cylinder, which operated as expected and supplied the normal flow rate. Continuing throughout the day and into the next, operators repeated switching to the riverside cylinder as the flow from the hillside cylinder became low enough to begin to affect the process. When valves for each of the respective transfer hoses were closed, liquid phosgene was not evacuated as required by the SOP for switching from one cylinder to another. Since the operators were not fully aware of the hazards of thermal expansion, liquid phosgene remained in the hoses as the cylinders were switched.

The CSB investigators reviewed DCS flow and weight data and saw a distinct difference in the ability of the riverside cylinder to provide the needed flow rate of phosgene compared to the hillside cylinder in this operation. All DCS information the operators received as a result of the non-routine cylinder switching indicated that their actions were successfully maintaining the smooth operation of the unit.

The operators, however, were involved in non-routine operations by attempting to maintain steady-state operations, as the SOPs did not address handling flow restriction. In addition, they were unaware of the threat of liquid thermal expansion developing as a result of switching the cylinders and not evacuating the hoses after each switch-out operation.

4.4 Process Hazard Analysis

PHAs were conducted on the phosgene cylinder feed system and vaporizer as part of the Front End SLM Unit assessment in 1994, 1999, 2004, and 2009. The 2009 PHA team, all DuPont employees, included a senior process engineer, two technical resources, a mechanic, and a front end operator; reviewed subtle changes to the process and associated MOC documentation since the last PHA in 2004 and previous phosgene release incidents, and recommended corrective actions. The PHA for the phosgene system included the 1-ton cylinders, nitrogen pressuring system, the vaporizer, and all associated piping and controls. The team used a Hazard and Operability[48] (HAZOP) and "What If[49]" methodologies to review process hazards and deviations.

[48] A systematic method in which process hazards and potential operating problems are identified using a series of guidewords to investigate process deviations (CCPS, 2008).

The team recognized and assessed the potential for a phosgene release from the cylinder transfer hoses but only if the hoses were incorrectly connected or inadvertently disconnected while the cylinder feed valve remained open. They did not assess the potential for the hose to rupture due to thermal expansion of liquid phosgene even though the potential for liquid phosgene thermal expansion was evaluated in other process equipment during the 2009 PHA.

None of the consequence scenarios the PHA team assessed involved failure of the phosgene transfer hose or the nitrogen flex hose. When the team evaluated the phosgene vaporizer, it considered corrosion potential when stainless steel is exposed to phosgene and water, but did not apply those factors to the cylinder transfer hoses. For the vaporizer, the probability value assigned to the phosgene leak scenario was decreased by reliance on the PM program to detect corrosion. The PHA team also noted that the slowly developing corrosion would decrease the probability of a leak because the corrosion would be noticeable during visual inspections. If the PHA team had assessed the thermal expansion and corrosion issues for the phosgene transfer hoses and had applied the same conditions to decrease the probability as used for the vaporizer corrosion scenario, the incident may still have occurred due to the team's reliance on the PM program to reduce the hazard. Unfortunately, the slowly developing corrosion on the hose was not visible due to the location of the white plastic adhesive tape, and the PM program was not configured to ensure that the hoses were changed at the appropriate frequency.

Phosgene permeation through PTFE had resulted in leaks at Belle in the past; however, the PHA team did not consider this hazard for the phosgene cylinder hoses. The CSB received documentation of all SLM PHA audits dating back to 1994. The 1999 PHA included two incidents in which phosgene likely permeated through PTFE-lined conveyance equipment in other parts of the phosgene process. Even with

[49] A technique in which a team with process knowledge and experience examines possible process deviations or combinations of deviations than can result in an undesired consequence (CCPS, 2008).

these previous incidents considered, the PHA team still did not account for the potential of the phosgene cylinder hoses to result in a release under similar conditions.

4.5 Audits

4.5.1 Unit Second-Party PSM Audit

In August 2007, a second-party audit team of engineers and health and safety experts from other DuPont facilities audited the SLM unit against regulatory and company PSM requirements. As in the F3455 unit audit, the team focused on MOC-subtle change, pre-startup safety reviews (PSSRs), training, PHAs, mechanical integrity, and process technology. The audit contained 64 findings—27 observations, 35 policy, and two regulatory issues—within the F3455 and SLM units at Belle.

One regulatory issue noted for the SLM and F3455 units was timely initiation of accident investigations. Auditors noted several instances where incident investigations were not started and communicated within the Belle plant 24- or the 48-hour OSHA requirements. The audit team recommended revising the Belle Plant Incident Investigation procedure and area practices to ensure that plant personnel initiate investigations within 24, and no later than 48, hours following an incident. According to the audit tracking plan the CSB investigators reviewed, an assigned DuPont employee completed and closed the recommendation as of June 2009.

However, in the case of the hillside hose near-miss prior to the phosgene exposure (Section 4.3.3), operators told the CSB investigators that they planned to communicate the near-miss to supervisors for investigation the following Monday; however, this would not have been within the Belle Plant required 24-hour period. The OSHA PSM Standard requires the employer to “investigate each incident which resulted in, or could reasonably have resulted in, a catastrophic release of highly hazardous chemical in the workplace” (1910.119(m)(1)) and that an incident investigation “shall be initiated as promptly as possible” (1910.119(m)(2)). The EPA Risk Management Program also requires an investigation of an incident involving a regulated substance, such as phosgene, be initiated within 48 hours (40 CFR part

68.81(b)). Though supervisors are not typically at the facility on weekends, management and safety and health experts, including the SLM Area Manager, were at the Belle Plant the morning of Saturday, January 23, 2010, attending the safety pause meeting. Had the incident been reported in a timely manner, management onsite could have immediately initiated an investigation.

4.5.2 Onsite Phosgene Generation

In 1988, DuPont engineers considered two options for using phosgene at the Belle facility: in cylinders from an offsite provider or constructing a phosgene generation plant to make phosgene onsite. To better understand the hazards involved in each design, DuPont engineers conducted a risk assessment in which four cases were considered (Table 4):

Case 1. Operating with a liquid phosgene feed from cylinders
Case 2. Vaporizing the feed from the cylinders
Case 3. Installing a plant to make phosgene from CO and Cl_2
Case 4. Enclosing the phosgene plant (in a fully contained building with an air scrubber)

After evaluating each case, they estimated the risk of fatality as follows:

	Onsite Fatalities per 10,000 years	Offsite Fatalities per 10,000 years
Case 1	244	10.5
Case 2	154	0.22
Case 3	16.7	0.007
Case 4	2.3	0.006

Table 4. Preliminary risk assessment by DuPont Engineering, 1988 (Appendix E)

While Case 4 was estimated to have the least amount of risk, the assessment concluded,

> Spending \$2 MM for an enclosure to get from Case 3 to Case 4 saves 14.4 lives per 10,000 years. (Almost all the improvement is in on-site risk. Off-site risk improvement is not significant.) This sets a value of life plus public outrage at \$143 MM. It may be that in the present circumstances the business can afford \$2 MM for an enclosure; however, in the long run can we afford to take such action

> which has such a small impact on safety and yet sets a precedent for all highly toxic material activities [?].

After the analysis, construction on Case 3, the open-to-atmosphere phosgene generation plant, began. However, the phosgene generation plant was abandoned mid-construction, and Case 2 is the current configuration at the Belle facility.

Documentation to support why the phosgene generation plant was abandoned was not provided, although the CSB obtained a proposal by a third-party contractor to build the plant. The proposal for a plant, as presented in Case 3, estimated a cost of $830,000 and stressed the contractor's history of building successful phosgene generation units. DuPont did not act on this proposal; anecdotal evidence from interviews suggests that corporate engineers decided to use DuPont resources to construct the plant. However, once the project was partially complete, the effort was abandoned as it was determined that the DuPont-designed system would not work.

DuPont cancelled plans for the enclosed phosgene generation unit, but the potential for offsite impact still remained a concern and was identified in SLM unit PHAs years later. In 2004, a PHA on the SLM unit by Belle Plant personnel identified the need for a shed enclosure with a scrubber to mitigate or prevent the release of phosgene offsite. The recommendation resulted from a "What if" analysis during the PHA. The PHA team listed two separate scenarios that could result in a plant-wide or offsite consequence, both recommending a shed enclosure. The original due date for the shed enclosure was scheduled for December 2005 but extended to December 2006; three subsequent extensions on the enclosure recommendation remained incomplete the day of the fatal phosgene release (Table 5).

PHA Enclosure Recommendation Delays	
2004	
Original Recommendation created in SLM 2004 PHA "Provide appropriate mitigation to prevent multiple fatalities from the release of a 2000 lb phosgene cylinder." **Due Date: Dec-05**	Dec-04
2005	
First Extension "A COC12 generation system is currently being evaluated, and if this was installed the shed enclosure may be designed differently to handle the appropriate chemicals." **New Due Date: Dec-06**	May-05
2006	
Second Extension "Work to define the scope on this item is progressing but not yet complete. We are evaluating potential lower cost alternatives to total shed enclosure." **New Due Date: Dec-08**	Dec-06
2008	
Third Extension "...the schedule indicates completion by August 2009." "The holds on the capital project were due to uncertainty of the future of the facility and due to the cost of the project." **New Due Date: Nov-09**	Dec-08
2009	
Fourth Extension "… project to install a phosgene scrubber to address these recommendations, an error in basic data was discovered. This invalidated the original design basis for the scrubbing system, and required a halt to the project activity." **New Due Date: Nov-10**	Nov-09
SLM 2009 PHA Completed 32 Recommendations are made, none of which capture the outstanding recommendation from the SLM 2004 PHA	Dec-09
2010	
Fatal Phosgene Incident Occurs	Jan-10

Table 5.Delay for Completing the PHA Recommendation for Enclosing the Shed

Following the phosgene release incident, DuPont announced that it would idle the storage and use of phosgene at the Belle site for 2011 and later told the CSB that the site has permenantly discontinued all onsite phosgene operations. The CSB requested documentation from DuPont that defines the status of the PHA recommendation for the shed enclosure as of the date of this report. DuPont extended the PHA recommendation for the shed enclosure until November 2010; however, the work was not completed and was extended again until the end of 2011.

4.5.3 2006 Phosgene Committee Audit

In 2006, the Phosgene Guardian Committee audited against the *DuPont Phosgene Highly Toxic Materials (HTM) Manual*, which included a review of the phosgene cylinder storage shed, the SLM production area, and other areas of the Belle plant. Three audit team members from other DuPont sites visited the Belle facility to conduct field walkthroughs and hold discussions with process unit personnel. The audit team divided the findings and recommendations from the audit into two categories: policies and observations. The policies were related to the requirements of the HTM manual and the observations were suggestions or preferred, but not mandatory, practices.

The team found no regulatory compliance deficiencies in the audit, but did issue five policy recommendations and eight observations. The policy recommendations applied to equipment downstream of the phosgene cylinder feed system, including a recommendation to add inspection plans for corrosion detection of the Teflon-lined reactor piping. The team found, and noted as an observation, that the hoses used on the phosgene feed system were not one of the three types recommended for phosgene service by the DuPont P3H Standard, but did not require the Belle facility to use the appropriate hoses.

The team also observed that liquid phosgene lines in the shed had moderate external corrosion and that significant moisture in the shed should be addressed to eliminate future corrosion potential. Because these items were observations, the HTM manual did not require that DuPont develop an action plan to resolve them. Consequently, the Belle plant continued to use a hose for phosgene service that the company standard did not recommend.

SLM unit equipment selection practices did not align with the requirements and recommendations in the phosgene HTM manual. The manual states, “Materials of construction must be selected properly to handle phosgene safely” but only recommends against the use of nonmetals for piping, valves, and process equipment containing phosgene. It further states, “Where small amounts of phosgene are present, stainless steel lined with Teflon is commonly used” without specifically quantifying an amount of phosgene where Teflon is acceptable. In the SLM phosgene transfer system, phosgene was continuously present in the PTFE-lined hoses while the connected cylinder was feeding the process.

The HTM manual’s design information section requires that special attention be given to the “prevention of over pressuring those lines and vessels where liquid phosgene can be trapped between two isolation valves.” In the course of switching between cylinders on the morning of the phosgene incident, SLM operators “blocked in” (i.e., closed the valve on each end of the hose), which trapped liquid phosgene between the partially filled riverside cylinder and the valve to the process. The liquid phosgene trapped in the hose underwent thermal expansion, rupturing the hose due to the overpressure of the line that was facilitated by the weakened and corroded stainless steel overbraid. None of the SOPs for the SLM unit warned against blocking in liquid phosgene to prevent hose ruptures, making operators less aware of the thermal expansion hazards of phosgene.

4.6 Standards and Guidelines

4.6.1 DuPont Highly Toxic Materials Phosgene Manual

The DuPont HTM manual includes mandatory criteria for the storage, handling, maintenance, and management of phosgene in quantities with the potential to cause offsite impact if released. The 86-page manual also includes non-mandatory practices for new and existing units or facilities handling phosgene, and company requirements and procedures related to first aid and medical treatment, MOC, design information for new and existing phosgene equipment, and PSM principles. The Phosgene Guardian Committee reviews and revises the manual and the committee chairperson and SHE leader authorize the revisions. The Responsible Care Core Team reviews and approves all changes to mandatory requirements before issuing the revised manual. The Plant or Unit Manager must authorize any deviation from the manual requirements before using an alternative practice. The HTM Committee conducts a safety analysis to ensure that the alternate practice is acceptable before implementation.

4.6.2 American Chemistry Council (ACC) Phosgene Safe Practice Guidelines

Manufacturers and users of phosgene formed the Phosgene Panel in 1972 to share information about practices to safely produce, handle, and use phosgene throughout industry. The Phosgene Panel is part of the Chemical Products and Technology Division of the ACC, an industry trade association for chemical companies; its Chemical Products and Technology Division supports companies through continuous evaluation and communication improvements related to the safe use of hazardous chemicals. Engineers, health and safety experts, and occupational health physicians from member companies participate on the panel,[50] which meets twice a year to share information and experiences related to handling phosgene. The panel sponsors engineering studies and research to prevent phosgene-related incidents and has prepared manuals for phosgene safe practices and medical treatment information as a resource for ACC member companies.

The ACC Phosgene Panel compiles information from member companies into the *Phosgene Safe Practice Guidelines Manual* to provide general information to those that manufacture or handle phosgene. The manual contains nine sections of phosgene safety information such as phosgene properties, design

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[50] In 2010, all U.S. phosgene manufacturers participated in the panel: BASF Corp.; Bayer Corp.; Chemtura; Dow Chemical; DuPont; Huntsman; SABIC Innovative Plastics; and VanDeMark Chemicals, Inc.

information for phosgene process facilities, transportation, emergency planning, first aid and medical treatment, and training.

Phosgene panel members draft summaries of industry practices that they submit for review and approval by all members of the ACC Phosgene Panel prior to inclusion in the manual. The panel periodically updates the manual and adds new and relevant practices identified by industry. The ACC does not intend for the manual to be a training tool or be adopted as procedure; it is to be referenced for general information regarding safe practices for phosgene storage and use.

The "Design of Facilities" section of the manual has several subsections pertaining to construction materials and layout of phosgene process equipment and facilities. This section includes leak prevention information such as equipment inspections, monitoring, and alarms, and describes the use of engineering controls and multiple layers of protection or barriers between phosgene exposure hazards and personnel.

This section includes precautions with regards to piping and valves in phosgene service. The manual states that users should pay particular attention to

- protecting piping from over-pressurization due to liquid phosgene trapped between closed valves;
- protecting dry[51] phosgene systems from the intrusion of moisture, which can react with phosgene and cause severe corrosion and failure; and,
- inspecting and testing where stainless steel materials are used to detect the presence of stress corrosion cracking caused by exposure to chlorides.

The section also states that the use of metallic and non-metallic hoses for permanent or temporary piping systems may increase the opportunity for phosgene leakage and advises users to give due consideration to

[51] Phosgene in the absence of water or moisture, sometimes referred to as "anhydrous."

the design, fabrication, and testing of all components. The manual also notes the potential permeability issue with PTFE liners, stating that these liners are typically used for phosgene service in well-ventilated areas; however, it does not specifically describe acceptable methods of ventilation.

4.6.3 National Fire Protection Association (NFPA)

NFPA 55: Compressed Gases and Cryogenic Fluids Code provides fundamental safeguards to users, producers, distributors, and others who handle compressed gas cylinders and includes general requirements for storage, occupancy, and emergency response and provisions for specific chemicals or hazard classes as defined by the NFPA. The current version of the CGA P-1 Standard references NFPA 55 in the "Ventilation, Storage, and Site Criteria" section for toxic and corrosive gases.

DuPont Belle's programs and practices related to the storage and handling of phosgene cylinders does not align with the provisions set forth in NFPA 55. NFPA 55 defines phosgene as a highly toxic gas because it contains a lethal concentration (LC_{50}) equal to or less than 200 ppm in air when administered via inhalation for 1 hour.[52] The LC_{50} for phosgene is 5 ppm for 1 hour of exposure (CGA P-20, 1995). NFPA 55 includes guidelines for controls in buildings that store compressed gas cylinders, and classifies the phosgene shed structure as an indoor storage area because the walls comprise more than 25 percent of the shed perimeter (Figure 12). Indoor storage for highly toxic gases must include a gas cabinet, exhausted enclosure, or a gas room, according to NFPA 55. Exhausted enclosures, gas cabinets, or gas rooms fully enclose cylinders and associated process equipment and are equipped with ventilation systems to capture and treat hazardous vapors. The phosgene shed at Belle, though considered indoor storage by NFPA, does not contain a ventilation system; instead, DuPont relies on natural ventilation from the outside to decrease concentrations of phosgene, which allows phosgene vapors to travel downwind, potentially exposing

[52] LC_{50} is the lethal concentration for 50 percent of the exposed population.

other employees working outside. Without exhausted enclosures, no barriers were present to prevent phosgene from exposing operators or traveling offsite.

The standard also includes guidance for alarms to warn personnel of potential releases from compressed gas cylinders and associated equipment. The SLM unit at the Belle plant had alarms for phosgene releases that were activated manually by the control board operator upon notification from outside personnel or if a phosgene analyzer activated an alarm at the control board. NFPA 55 guidance states that manual emergency alarms should be provided in the buildings that enclose cylinders and, when activated, sound local alarms to alert occupants in the surrounding area. The phosgene shed at Belle contains no alarms that can be activated locally. Operators suspecting a release are expected to communicate verbally with the control operator who then sounds an alarm. In the absence of automatic alarm notifications, personnel in the surrounding area risk exposure, as was the case on the day of the incident.

For gas detection systems, the NFPA states that alarms should activate a local alarm that is both audible and visual. In the phosgene shed, the SLM building area, and on the Belle Plant fence line, the gas detection systems activate alarms only in the SLM control room if concentrations exceed the alarm set points. The gas detectors do not locally sound or visually indicate the detection of a hazardous concentration to alert surrounding personnel.

4.6.4 Compressed Gas Association (CGA) Standards for the Safe Handling of Cylinders

The industry association CGA represents manufacturers, distributors, suppliers, and transporters of gases and cryogenic liquids. It develops and promotes standards and practices for the industrial and medical gas industry, with input from over 125 member companies. Standards include technical specifications, health and safety practices, and training and educational materials.

The VanDeMark phosgene bulletin references the current CGA Standard, Safe Handling of Compressed Gases in Containers (P-1), for the training and proper handling of phosgene cylinders. The 2008 P-1 Standard includes safe practices related to the transportation, identification, and storage of compressed gases and specific safe handling and storage rules for chemicals defined by hazard classes. Each chemical has an assigned hazard class based on its physical properties: flammable, asphyxiant, oxidizer, toxic, corrosive, or extreme cold. The CGA lists phosgene as a primary toxic and secondary corrosive. The toxic and corrosive gas section includes requirements for cylinder storage and ventilation, emergency response, and training. OSHA adopted the 1965 version of the CGA P-1 Standard under the requirements of the Compressed Gas Standard (29 CFR 1910.101). Under the OSHA Standard, the in-plant handling and storage of compressed gas cylinders will be in accordance with CGA P-1 (1965).

The current version of the CGA P-1 Standard includes a specific reference to Chapter 7 of NFPA 55 for the storage and handling of compressed gas cylinders with flammables, but contains only basic requirements for the storage and handling of corrosives and toxics. In CGA P-1 Section 6.2.6 of Flammable Gases, the standard includes NFPA 55 requirements such as separation distances, flammable storage quantities, and fire barriers. However for toxics, the P-1 Standard states, "Storage of corrosive and toxic gases shall be in accordance with local and/or provincial/territorial building and fire prevention codes." The standard also states that toxics "shall be filled and used only in adequately ventilated areas or preferably outdoors or in exhausted enclosures," but does not contain any specific provisions to achieve adequately ventilated areas such as the requirements set forth in NFPA Section 7.9.

4.6.5 CGA Standards for PTFE-lined Hoses

On January 29, 2010, CGA published the fourth edition of Standard E-9, Standard for Flexible, PTFE-lined Pigtails[53] for Compressed Gas Service. Section 1 of E-9 states that the standard applies to hoses with a diameter of 0.25 inches or smaller and with a maximum allowable working pressure (MAWP) of at least 3,000 psi, such as those used at DuPont. Section 2 of E-9 states, "PTFE-lined pigtails are not suitable for use with… poisonous, toxic, or pyrophoric gases because permeation of gas through the

[53] "Pigtails" are hoses or flexible tubing used to transfer material from a compressed gas cylinder.

PTFE wall creates a potential hazard." Since phosgene is toxic, this standard rules out using PTFE-lined hoses for phosgene.

Additionally, Section 5 of Standard E-9 defines how to label hoses: rather than allow tags with adhesive or heat-shrink wrap, as was the case with the DuPont hoses, it states, "The markings shall be made on the end fitting, collar, separate band, or other permanent location." The hose supplier's practice of affixing adhesive tape on the hose itself did not align with the requirements in CGA E-9 and enhanced the corrosion of the metal braid on the PTFE-lined hoses at Belle.

The CGA 2008 P-1 Standard does not specifically reference prior revisions of the E-9 standard. Section 5.9 of P-1 includes general requirements for container connections and states that "[p]iping, regulators, and other apparatus should be kept air tight to prevent leakage..." The P-1 Standard does not address materials of construction or permeability for cylinder discharge hoses in its general or safe handling requirements by corrosive and toxic hazard class.

4.7 Key Findings

1. An out-of-service phosgene transfer hose failed, exposing a worker to a lethal dose of phosgene.
2. DuPont did not follow its own standards for the change-out of phosgene transfer hoses.
3. DuPont engineers voiced concern regarding the materials of construction for phosgene hoses that were not addressed.
4. Liquid phosgene was not evacuated from the riverside hose, as the SOPs indicate, between transfers to the process from the 1-ton cylinders.
5. A similar hose failure almost occurred a few hours before the exposure of the worker; however, this near-miss did not prompt an investigation when operators observed the near failure of the hose on the morning of the fatal release.

6. The SAP maintenance program was altered so that a work order to change-out the phosgene transfer hoses was no longer generated automatically (Appendix C).
7. One worker was confirmed to have been exposed to phosgene after the initial exposure while a second is thought to have been possibly exposed.
8. Emergency responders did not receive timely and detailed information on how to adequately prepare to respond to the incident.
9. No audible or visual phosgene alarm indication in or around the phosgene shed.
10. The 2009 PHA did not address thermal expansion and corrosion potential for phosgene transfer hoses.
11. Operators were unaware of the hazards of liquid phosgene thermal expansion (training and procedures).
12. No plant-wide notification occurred in response to the exposure.

4.8 Root Causes

1. DuPont relied on a maintenance software program to initiate the automatic change-out of phosgene hoses at the prescribed interval.
2. DuPont did not provide a back-up method to ensure timely change-out of the hoses.
3. A maintenance software program change was not documented or reviewed in accordance with the MOC process.
4. No person with process knowledge was in place and assigned to convey timely and useful information to Metro 9-1-1. This responsibility was consigned to the gate guard.

5. The Belle Plant did not use the construction materials recommended by a corporate expert, the P3H standard, CGA, or the HTM manual for phosgene hoses, even though the 2006 second-party HTM audit recorded it as an observation.

5.0 Three Incidents in 33 Hours

Because two incidents occurred in a relatively short period, on Saturday, January 23, 2010, after the oleum release had been secured, the Plant Manager convened a meeting of supervisors and roughly 10 managers and supervisors assigned to the Belle Plant Crisis Committee to discuss and initiate a safety pause, the intent of which was to evaluate what the managers had seen and "take appropriate steps to ensure safe operation." Approximately 10 managers are part of the Crisis Committee and, after a debriefing, other supervisors and managers were advised that a safety pause would be conducted. Where possible, processes would be shut down to allow the discussion, and in those plants that could not be shut down, employees were expected to participate as best they could.

The Plant Manager assigned the Area Manager for the SLM and F3455 units (who was part of the Belle Plant Crisis Committee) to contact supervisors and managers and ask that they come to the plant to participate in planning a plant-wide safety pause. These calls went out at about 11:00 a.m., and supervisors and managers started arriving at the plant at about noon. At about 2:00 p.m., shortly after the planning for the safety pause began, the group heard a radio call advising the plant of a medical emergency. In response to the Plant Manager's inquiry, it was learned a worker had been exposed to phosgene in the SLM unit, making it the third incident in about 33 hours at the facility.

In a striking similarity of events and activities, after two release incidents at the Honeywell Baton Rouge facility in July 2003, upper management ordered the entire plant to shut down and review all facility operations prior to re-start. During this safety stand-down, a third incident occurred where an employee was exposed to hydrofluoric acid during cleanup of an area in the plant.[54]

The objective of both shutdowns was to get the attention of the workforce, acknowledge that the occurrence of incidents was unacceptable, and recommit to the two companies' core values of adhering to health and safety guidance. One common element was that both companies initiated safety stand-down activities after the string of incidents started in their respective plants. Another common theme was the precursor or near-miss events preceding actual incidents. Despite these efforts to address the cause of the string of incidents at the Belle plant, a fatal incident occurred. At the Belle plant, although investigations were conducted, near-miss investigations were not immediately responded to on weekends, including the near catastrophic failure of a separate phosgene transfer hose only hours earlier. Management at all levels is responsible for fostering an atmosphere of trust and openness and for encouraging the reporting of near-misses and incidents, as failure to do so could result in non-reporting of near-miss events (CCPS, 1992). Despite these efforts to address the cause of the string of incidents at the Belle plants, a fatal incident occurred.

As part of another investigation of the BP Texas City incident in 2005,[55] the CSB examined corporate oversight of safety management systems and corporate safety culture. As a result of an urgent recommendation from that same investigation, *The Report of the BP U.S. Refineries Independent Safety Review Panel,* The examination of corporate oversight of safety management systems and corporate safety culture has been conducted as part of another CSB investigation of the BP Texas City incident in 2005[56], and a blue ribbon panel of experts chaired by former Secretary of State James A. Baker was

[54] CSB-2003-13-I-LA (Honeywell).
[55] CSB 2005-04-I-TX, 2007.
[56] CSB 2005-04-I-TX, 2007

convened. as the result of an urgent recommendation from that same investigation, *The Report of the BP U.S. Refineries Independent Safety Review Panel*. While not indicating that the work/safety culture was irretrievably broken at the Belle facility—and perhaps within the DuPont Corp.—the events before and after the string of incidents in late January 2010 suggest that the safety culture has "shifted"; is not operating as it has historically; and could benefit from an extensive examination of all facets of the safety culture, both within the facility and throughout the corporation.

5.0.1 Additional DuPont Incidents

About 8 months after the series of incidents at the Belle plant triggered this investigation, another significant release occurred. At about 4:00 p.m. on September 21, 2010, DuPont Belle plant personnel discovered a methanol leak in a heat exchanger in the methylamines production unit while conducting regular sampling of the plant's water effluent stream. More than 160,000 pounds of methanol were estimated to have been released into the Kanawha River over a 24-hour period. This incident occurred when pressure on the process side of a heat exchanger was increased to a pressure greater than the steam condensate side of the process. After troubleshooting, operators suspected a leak on the process side of the heat exchanger and increased steam pressure until samples of the effluent stream confirmed that the leak had stopped. No employee or community injuries were recorded as a result of this release.

Almost 3 months after the methanol release, on December 3, 2010, at about 2:23 a.m., a fume alert was sounded in the amines unit at the DuPont Belle, WV, facility announcing a release of monomethylamine (MMA). The release occurred while two operators—one senior operator with 34 years of experience at DuPont and a junior operator with a little over a year—were sampling MMA from a rail car. One operator received first- and second-degree chemical burns to his face, while the other inhaled some of the escaping MMA and received first-degree chemical burns to his face. Both were transported to Charleston Area Medical Center for 24-hour treatment and observation and released the following day.

The CSB investigators returned to the Belle facility to assess the MMA release incident. In examining the equipment, one area of concern was the design of the valves used to isolate the sampling apparatus. As configured during the sampling operation, only a single block valve isolated the process from the sample container. This contrasts with industry standards, which suggest the use of double block valves and bleed vents to assure that the sample piping is clear of hazardous material prior to disconnecting. About 10 pounds of MMA are estimated to have been released during this incident; no employee or community injuries were recorded as a result of this release.

At DuPont's Yerkes facility in Tonawanda, NY, the CSB assessed a hot work incident that killed a welder and injured his supervisor on November 9, 2010. This incident was under investigation as this report went to publication, but preliminary assessments indicate that pre-hot work inspections were less than adequate, including a failure to check the atmosphere in a tank that normally processes non-flammable material, but that had inter-connecting piping that could route flammable vinyl fluoride into the tank. The workers were assigned to repair the tank; however, prior to beginning work, there is no record of DuPont using a portable gas detector to ensure that the tank being worked on was free of flammable material.

5.1 Management Systems

5.1.1 Knowledge Management

DuPont employees told the CSB investigators that many "very knowledgeable" Belle plant operations and maintenance workers had recently retired or are approaching retirement age. From 2005 to the end of 2009, 82 Belle Plant employees retired and 14 resigned. The total number of employees at the Belle plant has dropped 13 percent (55 people) over the last 5 years. A loss of plant-specific knowledge, or "corporate memory fade," has contributed several incidents in industry (CCPS, 1995), as new hires cannot replace years of experience; thus, companies must train and supervise new staff until they acquire job competencies to work safely.

Experienced maintenance mechanics and technicians have valuable hands-on experience and knowledge of equipment essential to the safe operation of plant processes. A worker in the Belle maintenance department told the CSB investigators that the maintenance staff reported to four different maintenance site leaders over the last 5 years prior to the January 2010 incidents. Other employees expressed concern that new hires spent too little time learning from veteran employees.

The CSB investigators reviewed and compiled workforce data from DuPont Belle organization announcements between January 2005 and June 2010, which listed all new hires, transfers, resignations, and retirements that affected the Belle workforce. Over the 4 years, there were 85 retirements totaling 2,572 years of experience with an average 30 years of service per employee. Among the 85, 20 were from the maintenance department, contributing to a loss of 713 total years of knowledge and experience (Table 6).

DuPont Belle Workforce 2005 to 2009		
Retirements		Years Experience at Belle
Maintenance	20	713
Total	85	2,572
New hires		Years Experience at Belle
Maintenance	10	0
Total	101	0

Table 6. Sum of Belle plant retirements and new hires from 2005 to 2009[57]

In addition to the 85 retirements, there were 14 resignations and 14 transfers to other sites. The Belle plant hired 101 employees over the 4 years and 8 DuPont employees transferred to Belle from other sites. Though the overall proportion of new to departing employees has remained consistent, a significant

57 This does not include interns, co-ops, special assignments, or leaves of absence.

reduction of employees with an average of 30 years of experience working on the Belle site contributes to a loss of institutional and plant-specific knowledge.

In the case of Belle, a significant population of employees is retiring, with a great deal of process knowledge that is lost if not properly maintained. This is an issue for industry in general as an entire generation of baby boomers approaches retirement. In January, 2011, DuPont announced plans to hire 150 employees at Belle over the next few years to compensate for the number of retiring workers.

5.1.2 Hierarchy of Controls

The Hierarchy of Controls is a method generally recognized and used by health and safety professionals to control workplace hazards. The National Safety Council (NSC) developed the Hierarchy of Controls in the 1950s and Congress later adopted and enacted it into the Occupational Safety and Health Act of 1970. The Hierarchy of Controls (Figure 17) demands the use of higher-level engineering and administrative controls to eliminate hazards. When those operations are not feasible, a PPE program must be implemented.

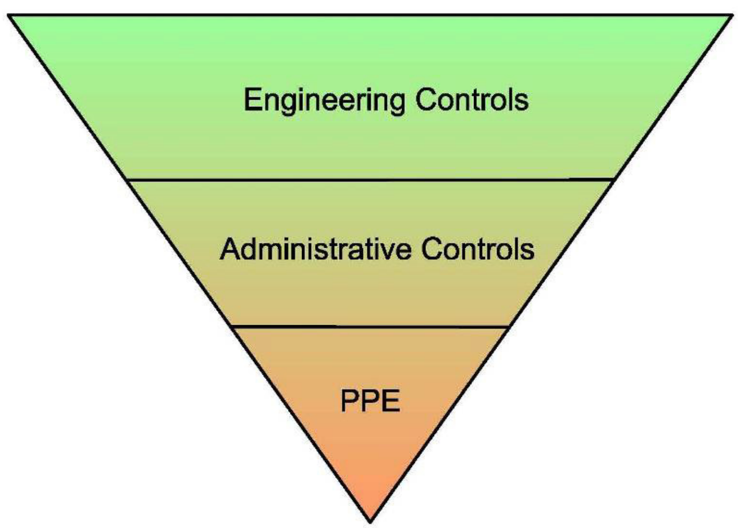

Figure 17. Hierarchy of Controls

In the early 1900s, DuPont recognized that eliminating hazards is preferred beyond education and protection. However, SOPs for the SLM phosgene cylinder feed system relied primarily on work practices and PPE to protect operators from the exposure hazards. Other facilities within DuPont and in the chemical industry have engineering controls in place for similar phosgene cylinder operations.

5.1.2.1 Design and Engineering Controls for Phosgene Cylinders

In 1984, Ciba-Geigy Corp. employees published a technical paper about the safe handling of phosgene in chemical processing specific to the operation of 1-ton phosgene cylinders (Alspach et al., 1984). Ciba-Geigy, now part of BASF, had a facility in Toms River, NJ, where two 1-ton cylinders of phosgene fed a chemical process. Similar to DuPont, the cylinders connected to the process through PTFE-lined hoses with a stainless steel overbraid induced with nitrogen to drive liquid from the cylinders. At the Ciba-Geigy plant, a transparent isolation chamber enclosed the cylinder valve connections, and operators opened and closed valves while standing outside the enclosure, extending their arms though rubber arms and gloves that were part of enclosure. The enclosure continuously vented to a caustic scrubber and acted as a barrier between the operator and any potential phosgene vapors near the cylinders.

The phosgene area had phosgene analyzers to continuously monitor and alarm if concentrations exceeded a defined set point. At high concentrations, flashing lights and audible warnings automatically alerted the production building, plant guards, and adjacent roadways and buildings. At the Belle facility, phosgene readings on the analyzers activate alarms in the control room, but DuPont relies on the board operator to notify personnel in the unit and the rest of the plant. By automating the phosgene analyzer alarm system to activate notifications plant-wide, Ciba-Geigy eliminated reliance on administrative controls to notify and protect personnel.

5.1.2.2 Phosgene Handling at the DuPont Mobile, AL Plant

The DuPont Mobile plant in Mobile, AL, uses the same 1-ton phosgene cylinders as Belle for its agricultural chemicals' process. The Mobile process has three cylinders on weigh scales, transferred to the process through similar PTFE-lined flexible hoses with a stainless steel overbraid made by a different manufacturer. The Mobile hoses are 18 inches shorter and have a greater maximum operating temperature and pressure than those used at Belle. A hose distributor supplies both hoses from the manufacturer to each site.

The phosgene cylinders and weigh scales at the Mobile plant are housed in the cylinder room, an enclosed room that vents to an emergency scrubber that pulls a slight negative pressure on the room and scrubs air before venting to the atmosphere. The scrubber is designed to capture vapors from a release of an entire cylinder. Operators at the Mobile plant enter the phosgene cylinder area under the same PPE requirements as Belle for isolating and changing cylinders (hard hat, steel-toed shoes, safety glasses, and phosgene dosimeter). However, at Mobile, to capture and scrub phosgene vapors in the event of a release, the operator turns on the emergency scrubber and pump before entering the enclosure.

Like Belle, Mobile has phosgene analyzers located in and around the unit to continuously monitor concentrations. At Mobile, alarms in the cylinder enclosure activate local audible alarms inside the enclosure and a flashing light outside to alert employees. If no operators are present in the enclosure when the alarm activates, the emergency vent scrubber automatically starts. The Belle plant analyzer in the phosgene shed has no audible alarm to alert personnel in the area; instead, Belle plant procedures require the board operator to notify personnel of the release and only operators at the phosgene shed can activate the switch for the warning light.

The emergency scrub system and automated alarms at Mobile are examples of higher-level controls that protect workers. Mobile has automated alarms where Belle relies on operator action to initiate alarms to warn personnel of a suspected or actual release. Mobile implemented the scrubber system, an example of an engineering control, to manage the concentrations of phosgene in the cylinder enclosure in the event of a release. The Belle plant phosgene shed design allows only for natural ventilation to carry unwashed phosgene gases that can potentially harm personnel in or around the shed and possibly enter the community.

5.1.2.3 Safety in Design Issues

Safety considerations in the equipment design stage eliminate the need for companies to retrofit existing process equipment or implement administrative or PPE programs to protect workers and the environment. In addition to the SLM unit, the CSB also identified a lack of safety and health considerations during the design and construction phases of the F3455 and SAR units. In the F3455 unit, engineers did not design the control system alarms so that operators could distinguish between a failed battery and activation of a rupture disc burst sensor, which resulted in nuisance alarms for the rupture disc on the methyl chloride vent line. Instead of addressing the reliability issues associated with the frequently failing sensor, management wired the burst sensor to electric power so that low batteries were no longer causing frequent and false alarms. However, since operators were not retrained to respond to the alarm, they ignored the alarm during the F3455 unit maintenance activity; consequently, the unit restarted with a failed rupture disc.

The CSB investigators also noted safety in design issues with the presence of the weep hole on the methyl chloride vent line upstream of the rupture disc assembly. DuPont engineering standards require that drainage holes be placed downstream of the relief devices on vent lines to allow for drainage and prevent liquid from lodging in the discharge side of the rupture disc. However, the location of the weep hole allowed toxic vapors from the methyl chloride vent line to enter the F3455 building where concentrations could accumulate to dangerous levels. DuPont could have designed the vent line so that the weep hole would drain to the exterior of the facility where vapors would dissipate into the atmosphere if a rupture disc burst.

In the SAR unit, DuPont chose copper steam tracing to prevent the oleum sample line and other process lines from freezing, even though steam tracing is not the preferred method for oleum service (Dillon, 1997). Steam tracing can create hot spots that result in an uneven heat distribution in the oleum sample line, which can accelerate corrosion. Steam tracing in the SAR unit exacerbated the corrosion incident in the oleum sample line, resulting in a significant release of oleum. Had the SAR unit design engineers called for electric tracing or replaced the steam tracing, the larger hole in the sample line might not have formed.

6.0 Regulatory Analysis

6.1 Occupational Safety and Health Administration (OSHA)

6.1.1 Process Safety Management Program

The OSHA PSM Standard (29 CFR 1910.119) requires employers to minimize or prevent the consequence of catastrophic incidents involving highly hazardous chemicals by applying elements of the PSM regulation to covered processes. PSM applies to processes using or producing any of the 137 listed toxic chemicals at or above threshold quantities and processes with flammable liquids or gases onsite in quantities of 10,000 pounds or more in one location. The PSM Standard applies to the SLM and F3455 units because they contain listed toxic chemicals in excess of the threshold quantities (TQ) specified in the regulation.

A PHA is one of the 14 elements in the PSM Standard requiring the employer to assess all PSM-covered processes to identify, evaluate, and control hazards by using one or a combination of several methodologies listed in the regulation. Furthermore, the standard requires the PHA to address[58]

- the hazards of the process

[58] 29 CFR 1910.119(e)(3).

- engineering and administrative controls applicable to the hazards and their interrelationships such as appropriate application of detection methodologies to provide early warning of releases
- consequences of failure of engineering and administrative controls

In the 2009 PHA for the SLM unit, the team did not assess the potential for a phosgene release from a failed transfer hose due to corrosion or thermal expansion but did consider these issues in process equipment downstream of the hoses. The team identified that engineering and administrative controls, such as the PM system and adherence to SOPs, would reduce the likelihood of a phosgene release from this equipment. However, the team did not assess the consequences caused by the PM system failing to initiate hose replacements at the proper frequency. In its 2009 PHA for the SLM unit, an audit team did not address phosgene thermal expansion in the liquid transfer hose; subsequently, in July 2010, OSHA issued a serious violation to DuPont.

The PSM Standard also requires employers to conduct an MOC for all modifications to process chemicals, technology, equipment, and procedures; and changes to facilities that affect a PSM-covered process. The procedures are meant to address the following prior to the change[59]:

- The technical basis for the proposed change
- Impact of change on safety and health
- Modifications to operating procedures
- Necessary time for the change
- Authorization requirements for the proposed change

The MOC also requires that the employees in operations and maintenance affected by the change be informed of the change and trained prior to the start-up of that process.

[59] 29 CFR 1910.119(l).

Investigators found MOC program deficiencies for modifications made to critical equipment on both the F3455 and SLM units. On the F3455 unit, DuPont's MOC process approved a design for the rupture disc alarm system that lacked sufficient reliability to minimize the release of flammable methyl chloride. The unit changed the rupture disc burst sensor on the methyl chloride vent line from battery power to electric to eliminate battery failure, but failed to assess the reliability of the burst sensors individually. The MOC process did not evaluate the basis of the modification to verify that it met the intended purpose of eliminating nuisance alarms caused by battery failure.

DuPont did not perform an MOC review for the changes to the maintenance system that handled the phosgene hose replacements on the SLM unit. The modification made to the phosgene hose replacement work orders kept the system from generating a new work order, thus extending phosgene hose use beyond its planned service life. DuPont stated that knowledge of the change was limited to only a few key SAP users, but these users lacked training necessary to recognize its impact on hose replacement frequency.

6.1.2 Compressed Gases

The OSHA Standard for Compressed Gases (29 CFR 1910.101) applies to employers that handle, store, and use compressed gases in cylinders, portable tanks, or tank cars. The standard includes requirements for cylinder inspections, safety relief devices, and storage and handling of compressed gas cylinders, and requires employers to handle and store cylinders in accordance with CGA pamphlet P-1 1965, "Safe Handling of Compressed Gases in Containers."

In the 41 years since OSHA adopted the reference standard as part of the Compressed Gas Regulation, CGA P-1 has been revised 10 times. The current 2008 version is more comprehensive than the OSHA-adopted 1965 version, which does not list chemicals by hazard class and contains specific safety information only for flammable and poisonous gases. The current version lists 82 chemicals that fall into the primary toxics category, while the 1965 version lists only 13 poisonous gases as defined by the Interstate Commerce Commission (ICC).[60] The 1965 standard contains the same general information as the current version, but lacks detailed guidance for facility siting, emergency response, and safety information specific to various types of chemicals stored in compressed gas cylinders. The 1965 version includes obsolete and outdated references and lacks references to applicable OSHA regulations, as it was published prior to the establishment of OSHA. With respect to the issues identified in the phosgene release investigation, had OSHA adopted the 2008 version of the CGA P-1 Standard, DuPont would have been accountable for more phosgene storage engineering controls via the incorporation of NFPA 55 and other consensus standards referenced in the standard.

6.1.3 Inspection History

OSHA is authorized under the Occupational Safety and Health Act of 1970 to inspect workplaces to ensure that employers are providing a safe and healthy work environment by complying with OSHA standards. A range of inspection categories establish a system of priorities:

- Imminent danger
- Catastrophes and fatal accidents
- Complaints and referrals
- Programmed inspections
- Follow-up inspections

[60] A regulatory body abolished in 1995, some of whose responsibilities were transferred to the Surface Transportation Board, an agency within the U.S. Department of Transportation.

A review of OSHA's inspection history reveals that three planned inspections were conducted at the Belle facility in 1982, 1984, and 1993, in addition to one unprogrammed-related[61] inspection in 1981. Although no planned inspections occurred from 1993 through 2010, two inspections, one in 1995 and one in 2004, were the result of complaints; both were closed.

In a series of post-incident inspections, OSHA cited DuPont for a serious violation of Section 5(a)(1) of the Occupational Safety and Health Act, alleging that inspections were not conducted for all sections of oleum piping based on prior leak incidents at the SAR unit. Citations for numerous violations of the PSM[62] Standard were also issued. OSHA cited DuPont for serious violations, including the company's failure to properly inspect piping used to transfer phosgene, perform a thorough PHA for its phosgene operation, and train workers on hazards associated with phosgene. Proposed penalties for all violations totaled $43,000.The OSHA PSM Standard (29 CFR 1910.119) requires employers to prevent or minimize the consequences of a catastrophic release of highly hazardous chemicals and of flammable liquids and gases. Phosgene and methyl chloride are listed chemicals, and the SLM and F3455 units processed more than the TQ, thus the PSM Standard applied.

6.2 Environmental Protection Agency

The EPA Risk Management Program (RMP) regulation (40 CFR 68), mandated by Section 112(r) of the Clean Air Act Amendments of 1990, regulates the use of highly hazardous chemicals at fixed facilities. Its purpose is to prevent accidental offsite releases of listed substances and ensure that a company and the

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[61] An unprogrammed-related inspection can occur at a multi-employer worksite when an employer is being inspected because of a complaint, accident, or referral. Any other employer with staff on the worksite is subject to inspection.

[62] PSM is a regulation promulgated by OSHA. A process is any activity or combination of activities including any use, storage, manufacturing, handling, or the onsite movement of HHCs as defined by OSHA and the EPA.

community are able to respond effectively in the event of a release. The regulation applies to facilities using or storing regulated substances exceeding the TQ specified in the EPA regulations.

Each covered process is required to be designated as one of three "prevention program" levels based on offsite consequence analyses, incident history, and PSM program applicability. Program 1 is the lowest, simplest management program; Program 2 is an intermediate management-level program with added program elements and basic documentation requirements (PSM-covered processes cannot be designated Program 2); Program 3 is the highest-level management program. Most PSM-covered processes are Program 3, which requires a rigorous management program with detailed record retention criteria and all PSM program elements. All PSM program activities and records are directly applicable to Program 3 regulatory activities, and all RMP covered chemicals at the DuPont Belle plant fall into Program 3 requirements (Table 7).

Toxics	**RMP TQ (lbs)**
Anhydrous Ammonia	10,000
Phosgene	500
Sulfur Trioxide	10,000
Formaldehyde	15,000
Oleum	10,000
Methyl Chloroformate	5,000
Flammables	
Dimethylamine	10,000
Methylamine	10,000
Methyl Ether	10,000
Ethylamine (70% aqueous)	10,000

Table 7. DuPont Belle RMP-covered chemicals and threshold quantities

Each covered process must undergo a hazard assessment (40 CFR 68, Subpart B) in which the owner is required to prepare a "worst case release scenario" and an "alternative release scenario" for each covered process. Different analysis criteria apply based on whether the covered chemical is toxic or flammable. The hazard assessment also requires inclusion of the "five year accident history." The results of the hazard assessment, along with other pertinent information for each covered process, must be submitted to the EPA. The RMP (40 CFR 68, Subpart G) is submitted electronically and must be periodically updated. The DuPont RMP submission for 2010 had no accident history to report.

In November 2003, the EPA Region III Chemical Accident Prevention Program audited the Belle facility to ensure compliance with the EPA RMP, and covered all RMP elements and emergency response and site security. The EPA audited the 2-million gallon ammonia storage tank against the RMP requirements for Program 3 management programs and the RMP documentation DuPont submitted. The EPA audit report submitted to DuPont in December 2003 contained no deficiencies or recommendations for improvement. The November 2003 RMP audit is the only one conducted at the Belle Plant prior to the January 2010 incidents.

6.3 State Hazardous Chemical Release Prevention Program

On January 20, 2011, the CSB Bayer CropScience investigation resulted in a recommendation being issued to the Kanawha-Charleston Health Department to establish a Hazardous Chemical Release Prevention Program, whose objective is to enhance the prevention of accidental releases of highly hazardous chemicals and optimize responses if they occur. In light of its proximity in the Kanawha Valley, the series of incidents at the DuPont Belle, WV, facility support the plant's inclusion in such a program.

The implementation of the new program would incorporate several key guidelines applicable to chemical plants operating in the Kanawha County. The Belle facility is one of 13 in the county that report EPA RMP-covered chemicals assigned as Program level 3 that could fall under the auspices of the new program. The recommendation to the Kanawha-Charleston Health Department stated:

> Specifically, the Bayer report recommends that the Director of the Kanawha-Charleston Health Department establish a Hazardous Chemical Release Prevention Program to enhance the prevention of accidental releases of highly hazardous chemicals, and optimize responses in the event of their occurrence. In establishing the program, study

and evaluate the possible applicability of the experience of similar programs in the country, such as those summarized in Section 5.3 of this report. At a minimum:

a. Ensure that the new program:

1. Implements an effective system of independent oversight and other services to enhance the prevention of accidental releases of highly hazardous chemicals
2. Facilitates the collaboration of multiple stakeholders in achieving common goals of chemical safety; and,
3. Increases the confidence of the community, the workforce, and the local authorities in the ability of the facility owners to prevent and respond to accidental releases of highly hazardous chemicals

b. Define the characteristics of chemical facilities that would be covered by the new Program, such as the hazards and potential risks of their chemicals and processes, their quantities, and similar relevant factors;

c. Ensure that covered facilities develop, implement, and submit for review and approval:

1. Applicable hazard and process information and evaluations.
2. Written safety plans with appropriate descriptions of hazard controls, safety culture and human factors programs with employee participation, and consideration of the adoption of inherently safer systems to reduce risks
3. Emergency response plans; and,
4. Performance indicators addressing the prevention of chemical incidents.

d. Ensure that the program has the right to evaluate the documents submitted by the covered facilities, and to require modifications, as necessary

e. Ensure that the program has right-of-entry to covered facilities, and access to requisite information to conduct periodic audits of safety systems and investigations of chemical releases;

f. Establish a system of fees assessed on covered facilities sufficient to cover the oversight and related services to be provided to the facilities including necessary technical and administrative personnel; and,

g. Consistent with applicable law, ensure that the program provides reasonable public participation with the program staff in review of facility programs and access to:

1. The materials submitted by covered facilities (e.g., hazard evaluations, safety plans, emergency response plans);
2. The reviews conducted by program staff and the modifications triggered by those reviews;
3. Records of audits and incident investigations conducted by the program;
4. Performance indicator reports and data submitted by the facilities, and;
5. Other relevant information concerning the hazards and the control methods overseen by the program.

Ensure that the program will require a periodic review of the designated agency activities and issue a periodic public report of its activities and recommended action items.[63]

[63] CSB-2008-I-WV (Bayer CropScience).

7.0 Recommendations

The CSB makes recommendations based on the findings and conclusions of its investigations. Recommendations are made to parties that can effect change to prevent future incidents, which may include the companies involved; industry organizations responsible for developing good practice guidelines; regulatory bodies; and/or organizations that have the ability to broadly communicate lessons learned from the incident, such as trade associations and labor unions.

Phosgene Exposure

The Occupational Safety and Health Administration (OSHA)

2010-06-I-WV-R1

Revise OSHA 29 CFR 1910.101, *General Industry Standard for Compressed Gases*, to require facilities that handle toxic and highly toxic materials in compressed gas cylinders to incorporate provisions that are at least as effective as the 2010 edition of Section 7.9, *Toxic and Highly Toxic Gases,* in National Fire Protection Association (NFPA) 55, *Compressed Gases and Cryogenic Fluids Code*, including enclosures, ventilation and treatment systems, interlocked fail-safe shutdown valves, gas detection and alarm systems, piping system components, and similarly relevant layers of protection.

2010-06-I-WV-R2

Take sustained measures to minimize the exposure of hazards to workers handling highly toxic gases from cylinders and associated regulators, gages, hoses, and appliances. Ensure that OSHA managers, compliance officers, equivalent state OSHA plan personnel, and regulated parties conform, under the Process Safety Management Standard (29 CFR 1910.119) Recognized and Generally Accepted Good Engineering Practices (RAGAGEP) provisions, to industry practices at least as effective as the following:

1. NFPA 55 - *Compressed Gases and Cryogenic Fluids Code (*2010*)*
2. CGA P-1 *Safe Handling of Compressed Gases in Containers* (2008)
3. CGA E-9 *Standard for Flexible, PTFE-lined Pigtails for Compressed Gas Service* (2010)
4. ASME B31.3 *Process Piping* (2008)

DuPont Belle Plant

2010-06-I-WV-R3

Improve the existing maintenance management by

- Supplementing the computerized system with sufficient redundancy to ensure tracking and timely scheduling of preventive maintenance for all PSM-critical equipment.
- Conducting Management-of-Change (MOC) reviews for all changes to preventive maintenance orders for all PSM-critical equipment in the computerized maintenance management system.

2010-06-I-WV-R4

Revise the facility emergency response protocol to require that a responsible and accountable DuPont employee always be available (all shifts, all days) to provide timely and accurate information to the Kanawha County Emergency Ambulance Authority (KCEAA) and Metro 9-1-1 dispatchers.

2010-06-I-WV-R5

Revise the near-miss reporting and investigation policy and implement a program that includes the following at a minimum:

- Ensures employee participation in reporting, investigating, analyzing, and recommending corrective actions as appropriate for all near-misses and disruptions of normal operations.

- Develops and encourages use of an anonymous electronic and/or hard copy near-miss reporting process for all DuPont Belle site employees.
- Establishes roles and responsibilities for ownership, management, execution, and resolution of recommendations from incident or near-miss investigations at the DuPont Belle facility.
- Ensures that the near-miss investigation program requires prompt investigations, as appropriate, and that results are promptly circulated to well-suited recipients throughout the DuPont Corp.
- Ensures that this program is operational at all times (e.g. nights, weekends, and holiday shifts).

E.I. DuPont de Nemours and Co., Inc.

2010-06-I-WV-R6

Revise safeguards for phosgene handling at all DuPont facilities by

- Requiring that all indoor phosgene production and storage areas, as defined in NFPA 55, have secondary enclosures, mechanical ventilation systems, emergency phosgene scrubbers, and automated audible alarms, which are, at a minimum, consistent with the standards of NFPA 55 for highly toxic gases.
- Prohibiting the use of hoses with permeable cores and materials susceptible to chlorides corrosion for phosgene transfer.
- Conducting annual phosgene hazard awareness training for all employees who handle phosgene, including the hazards associated with thermal expansion of entrapped liquid phosgene in piping and equipment.

2010-06-I-WV-R7

Review all DuPont units that produce and handle phosgene that, at a minimum, observe and document site-specific practices for engineering controls, construction materials, PPE, procedures, maintenance, emergency response, and release detection and alarms, and use information from external sources to develop and implement consistent company-wide policies for the safe production and handling of phosgene.

2010-06-I-WV-R8

For each DuPont facility that uses, but does not manufacture, phosgene onsite

- Conduct a risk assessment of manufacturing phosgene onsite against the current configuration.
- Communicate the findings of each assessment to compile recommendations applicable to all DuPont phosgene delivery systems.
- Implement these recommendations.

Compressed Gas Association, Inc.

2010-06-I-WV-R9

Revise CGA P-1, *Safe Handling of Compressed Gases in Containers*, to include specific requirements for storing and handling highly toxic compressed gas, including enclosure ventilation and alarm requirements at least as protective as Section 7.9, Toxic and Highly Toxic Gases and NFPA 55*, Compressed Gases and Cryogenics Fluids Code.*

2010-06-I-WV-R10

Revise CGA P-1, *Safe Handling of Compressed Gases in Containers*, to incorporate by reference CGA E-9, *Standard for Flexible, PTFE-lined Pigtails for Compressed Gas Service*.

American Chemistry Council Phosgene Panel

2010-06-I-WV-R11

Revise the *Phosgene Safe Practice Guidelines Manual* to

- Advise against the use of hoses for phosgene transfer that are constructed of permeable cores and materials subject to chlorides corrosion.
- Include guidance for the immediate reporting and prompt investigation of all potential (near-miss) phosgene releases.

Methyl Chloride Release

E.I. DuPont de Nemours and Co., Inc.

2010-06-I-WV-R12

Commission an audit in consultation with operations personnel to establish and identify the conditions that cause nuisance alarms at all DuPont facilities. Establish and implement a corporate alarm management program as part of the DuPont PSM Program, including measures to prevent nuisance alarms and other malfunctions in those systems. Include initial and refresher training as an integral part of this effort.

2010-06-I-WV-R13

Revise the DuPont PSM standard to require confirmation that all safety alarms/interlocks are in proper working order (e.g., not in an *active* alarm state) prior to the start-up of all Higher-Hazard Process facilities.

2010-06-I-WV-R14

Reevaluate and clarify the DuPont corporate MOC policies to ensure that staff can properly identify and use the distinctions between subtle and full changes and train appropriate personnel how to properly apply the distinctions on any changes in the policy.

By the

U.S. Chemical Safety and Hazard Investigation Board

Dr. Rafael Moure-Eraso

Chair

John Bresland

Member

Mark Griffon

Member

William Wark

Member

William Wright

Member

Date of Board Approval

September 20, 2011

References

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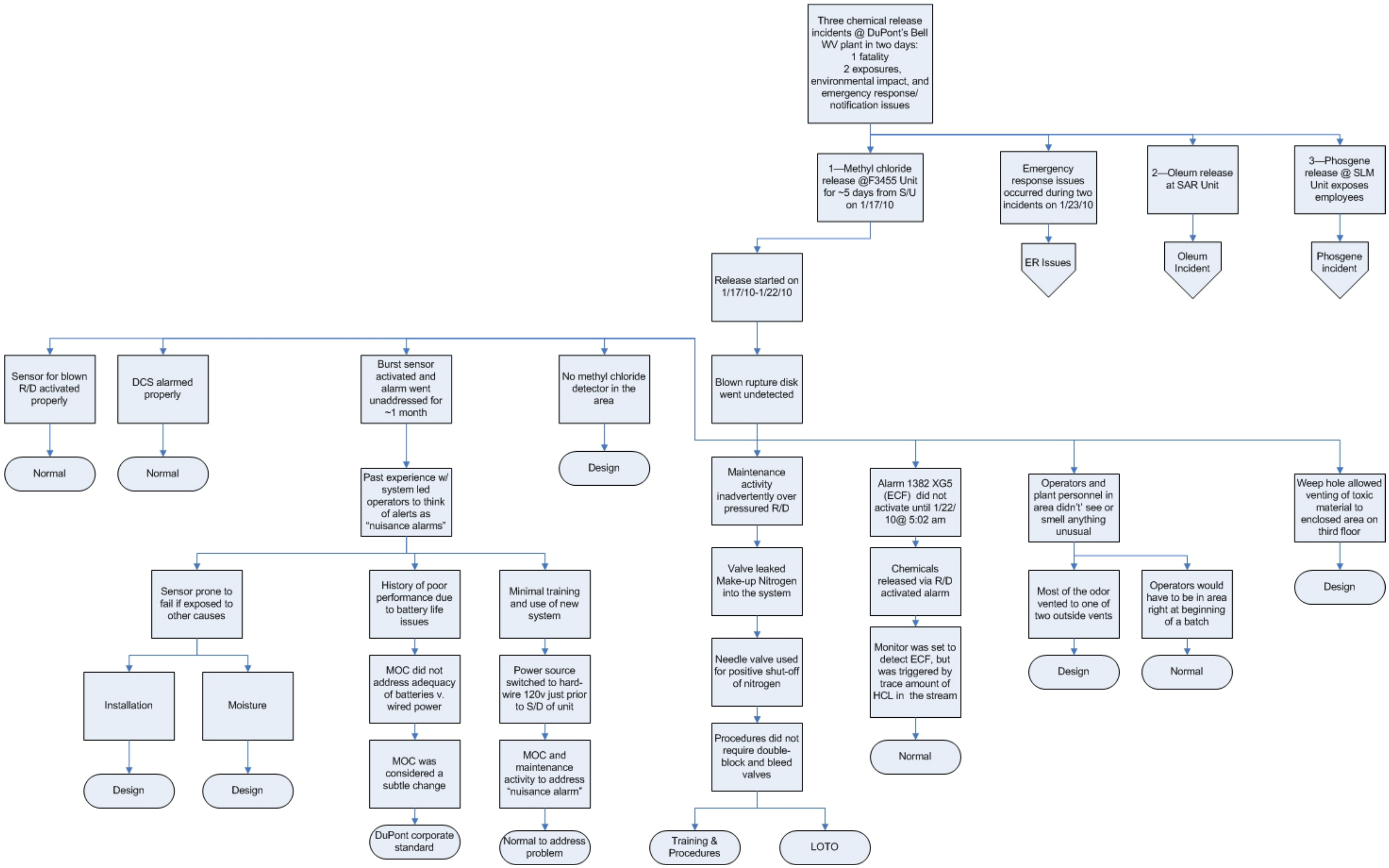
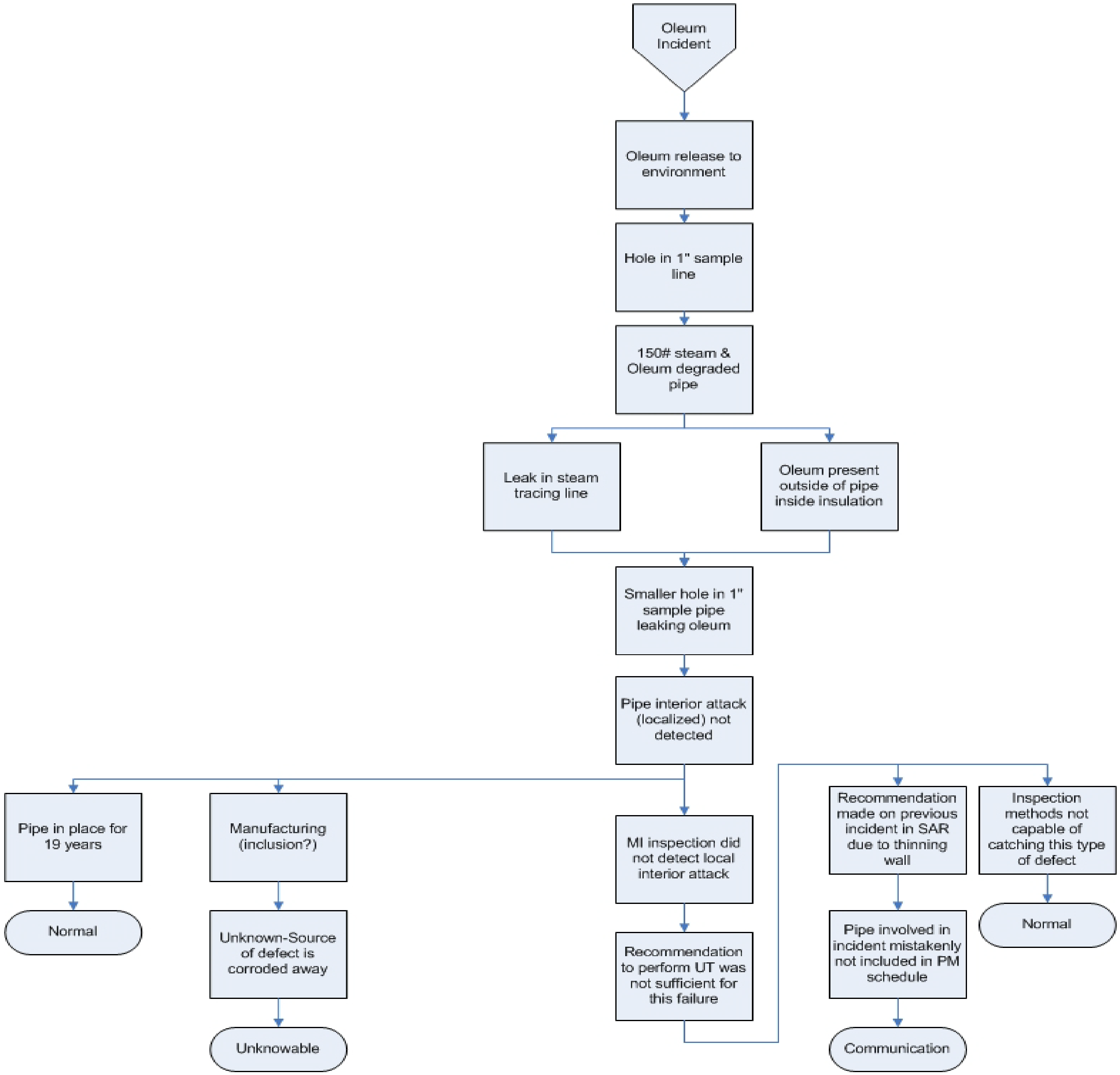
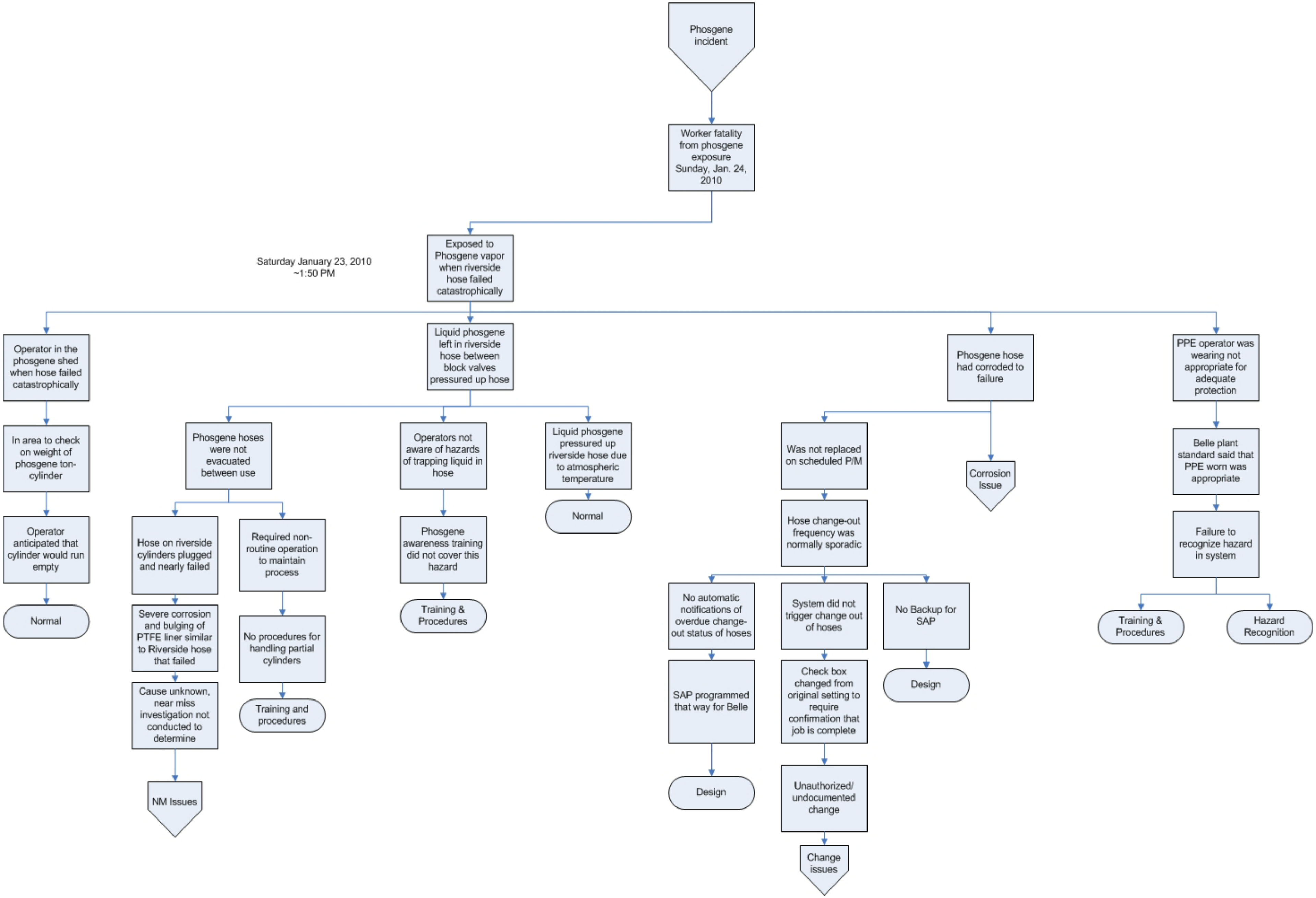
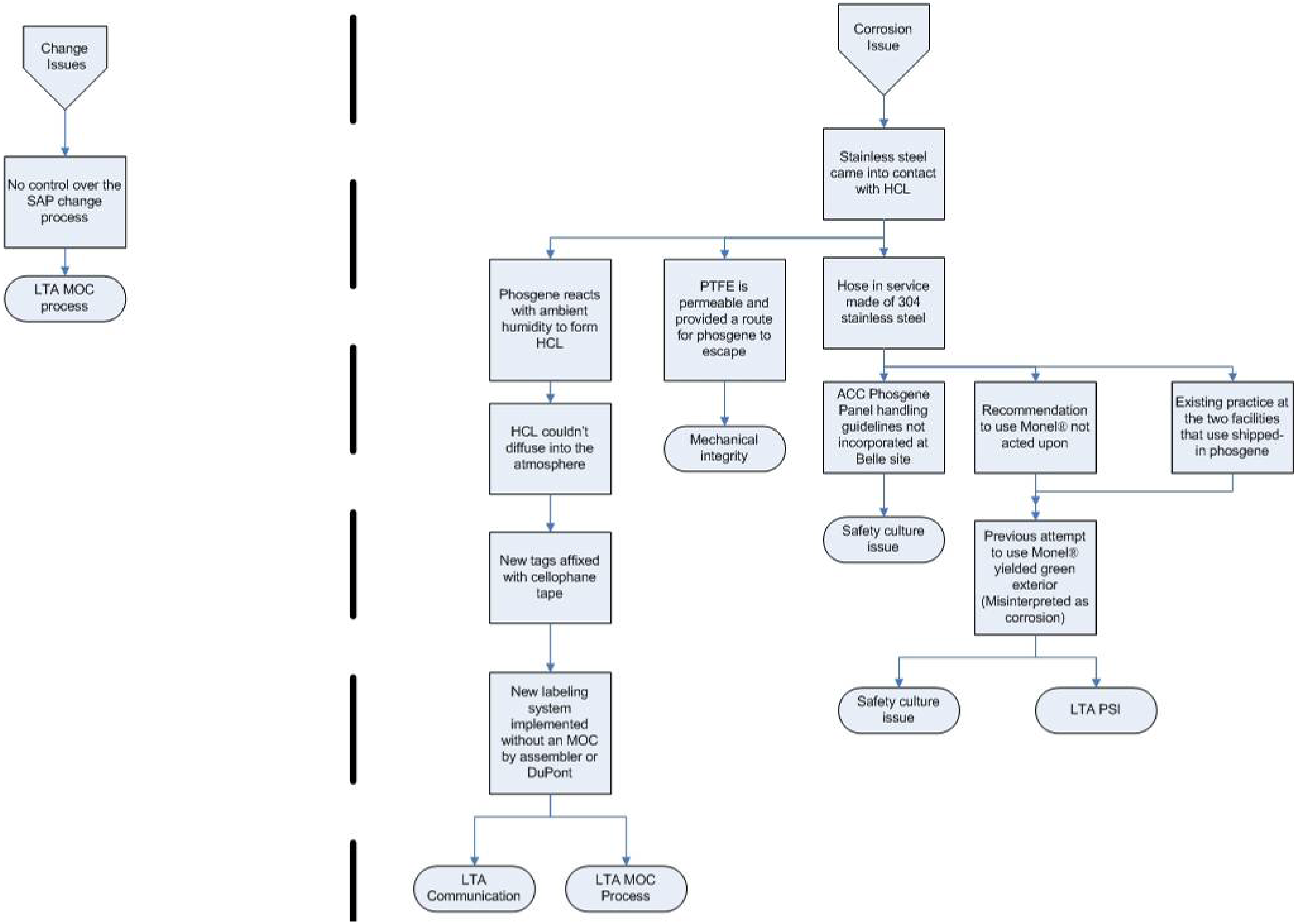
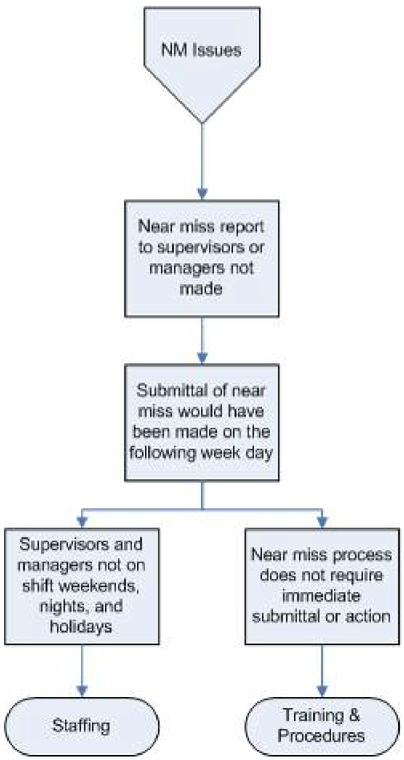
Appendix A: Three Event Logic Tree

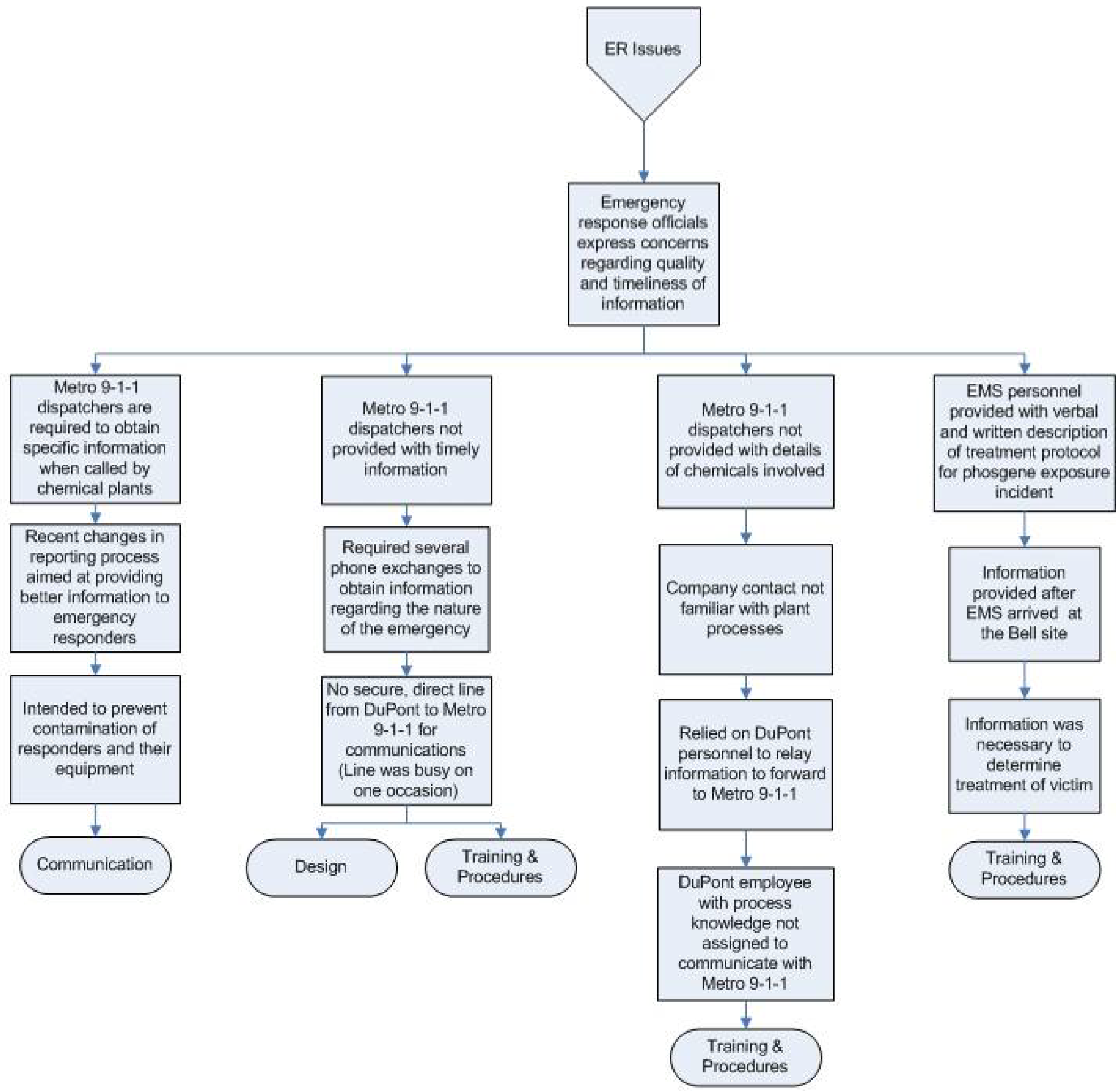



Oleum Incident
Oleum release to environment
Hole in 1" sample line
150# steam & Oleum degraded pipe
Leak in steam tracing line
Oleum present outside of pipe inside insulation
Smaller hole in 1" sample pipe leaking oleum
Pipe interior attack (localized) not detected
Pipe in place for 19 years
Normal
Manufacturing (inclusion?)
Unknown-Source of defect is corroded away
Unknowable
MI inspection did not detect local interior attack
Recommendation to perform UT was not sufficient for this failure
Recommendation made on previous incident in SAR due to thinning wall
Pipe involved in incident mistakenly not included in PM schedule
Communication
Inspection methods not capable of catching this type of defect
Normal

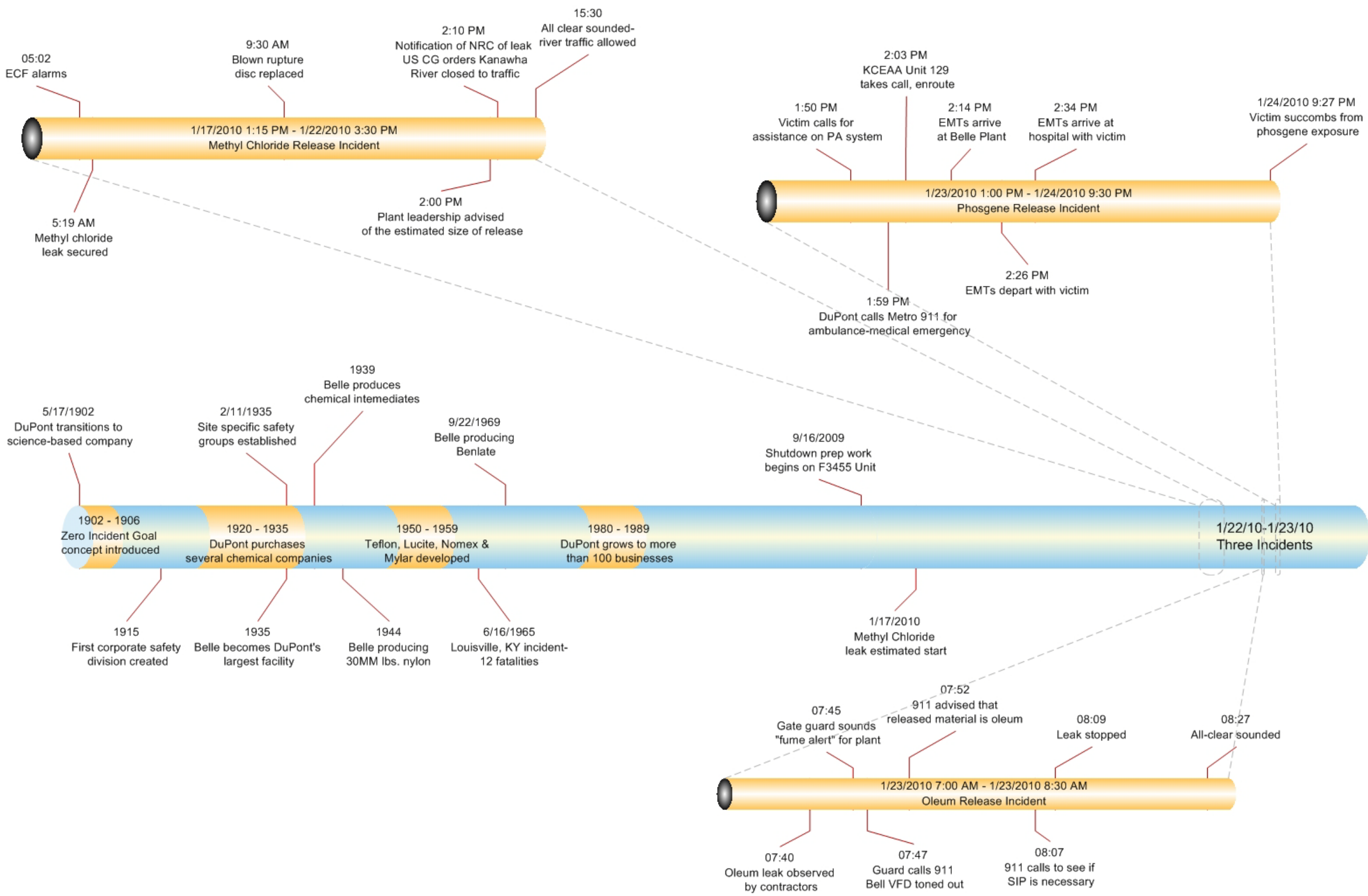

Phosgene incident
Worker fatality from phosgene exposure Sunday, Jan. 24, 2010
Saturday January 23, 2010 ~1:50 PM
Exposed to Phosgene vapor when riverside hose failed catastrophically
Operator in the phosgene shed when hose failed catastrophically
In area to check on weight of phosgene ton-cylinder
Operator anticipated that cylinder would run empty
Normal
Liquid phosgene left in riverside hose between block valves pressured up hose
Phosgene hoses were not evacuated between use
Hose on riverside cylinders plugged and nearly failed
Severe corrosion and bulging of PTFE liner similar to Riverside hose that failed
Cause unknown, near miss investigation not conducted to determine
NM Issues
Required non-routine operation to maintain process
No procedures for handling partial cylinders
Training and procedures
Operators not aware of hazards of trapping liquid in hose
Phosgene awareness training did not cover this hazard
Training & Procedures
Liquid phosgene pressured up riverside hose due to atmospheric temperature
Normal
Phosgene hose had corroded to failure
Was not replaced on scheduled P/M
Hose change-out frequency was normally sporadic
No automatic notifications of overdue change-out status of hoses
SAP programmed that way for Belle
Design
System did not trigger change out of hoses
Check box changed from original setting to require confirmation that job is complete
Unauthorized/ undocumented change
Change issues
No Backup for SAP
Design
Corrosion Issue
PPE operator was wearing not appropriate for adequate protection
Belle plant standard said that PPE worn was appropriate
Failure to recognize hazard in system
Training & Procedures
Hazard Recognition


Change Issues
No control over the SAP change process
LTA MOC process
Corrosion Issue
Stainless steel came into contact with HCL
Phosgene reacts with ambient humidity to form HCL
PTFE is permeable and provided a route for phosgene to escape
Hose in service made of 304 stainless steel
HCL couldn't diffuse into the atmosphere
Mechanical integrity
ACC Phosgene Panel handling guidelines not incorporated at Belle site
Recommendation to use Monel® not acted upon
Existing practice at the two facilities that use shipped-in phosgene
New tags affixed with cellophane tape
Safety culture issue
Previous attempt to use Monel® yielded green exterior (Misinterpreted as corrosion)
New labeling system implemented without an MOC by assembler or DuPont
Safety culture issue
LTA PSI
LTA Communication
LTA MOC Process


NM Issues
Near miss report to supervisors or managers not made
Submittal of near miss would have been made on the following week day
Supervisors and managers not on shift weekends, nights, and holidays
Near miss process does not require immediate submittal or action
Staffing
Training & Procedures


ER Issues
Emergency response officials express concerns regarding quality and timeliness of information
Metro 9-1-1 dispatchers are required to obtain specific information when called by chemical plants
Recent changes in reporting process aimed at providing better information to emergency responders
Intended to prevent contamination of responders and their equipment
Communication
Metro 9-1-1 dispatchers not provided with timely information
Required several phone exchanges to obtain information regarding the nature of the emergency
No secure, direct line from DuPont to Metro 9-1-1 for communications (Line was busy on one occasion)
Design
Training & Procedures
Metro 9-1-1 dispatchers not provided with details of chemicals involved
Company contact not familiar with plant processes
Relied on DuPont personnel to relay information to forward to Metro 9-1-1
DuPont employee with process knowledge not assigned to communicate with Metro 9-1-1
Training & Procedures
EMS personnel provided with verbal and written description of treatment protocol for phosgene exposure incident
Information provided after EMS arrived at the Bell site
Information was necessary to determine treatment of victim
Training & Procedures

Appendix B: Historical and Event Timeline



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Appendix C: SAP Program

The DuPont Belle plant uses the SAP R/3 Plant Maintenance module to schedule PM and repair work and track maintenance costs. Many companies use a Computerized Maintenance Management System (CMMS) such as SAP Plant Maintenance for this purpose. In particular, companies use the CMMS to schedule PM to ensure that PSM-critical equipment functions properly. This appendix gives additional detail on scheduling and completing PM jobs in SAP, and why SAP failed to issue work orders to change the hoses.

PM keeps plant equipment functioning properly, and to minimize the likelihood of a phosgene hose corroding and rupturing, DuPont created a PM job in SAP to replace the hoses regularly. The SAP Plant Maintenance module automatically schedules the job at the frequency DuPont designates.

In the SAP Plant Maintenance module, DuPont created a number for the physical equipment and an electronic document, or “maintenance plan,” to store all information about the job. The maintenance plan is a complex form with many fields. One field, “confirmation required,” can be clicked “on” or “off.” If this button is “off,” SAP schedules the first hose change job; waits the specified time indicated in the interval field, such as “30 days”; and then automatically schedules another hose change job. Thus, when the button is “off,” by default SAP schedules hose change-outs “every 30 days,” which, for critical equipment subject to intermittent operation, is usually the desired option (CCPS, 1995). If this button is “on,” SAP requires confirmation that the hoses have been changed. Thus, if the confirmation-required button is “on,” SAP schedules hose changes “30 days after the previous change,” but opens the possibility that no one will confirm the completion date in the system, creating a scenario where SAP will not schedule the hose change at the pre-determined interval.

Despite the computer-based and administrative controls that SAP and DuPont provided, in late 2006 someone changed the confirmation-required field for the phosgene hoses from "off" to "on"—or requiring confirmation. These administrative controls highlight gaps that contributed to the fatality.

When an SAP user account is created, access is provided according to the “work role” profile that DuPont establishes. Only certain users would have had access to change the data in the maintenance plan for the phosgene hoses.

Programmers are “super users” who have higher level access than normal users and can write batch programs to change data, forms, and other SAP computer code that affects multiple pieces of equipment and multiple plant sites simultaneously. As an administrative control at DuPont, programmers write computer code in a “development box” to prevent creating problems in the SAP “production box” that normal users see. When the programmer completes the code or downloads it to the “sandbox,” the process owners test the change to see that it performs as requested or if it creates a problem. After the process owners approve the change, the programmer runs the code or downloads it to the “production box” and makes the actual change for regular users. These computer controls help ensure the integrity of the “production box” for regular users, but were not enough to prevent the Belle Plant fatality.

The CSB discovered evidence relevant to the SAP change:

- The SAP work role controls allow programmers, process owners, and specific Belle Plant employees to access the phosgene hose maintenance plan.
- In 2005, the Belle Plant upgraded from SAP R/2 to the newer SAP R/3 partly because SAP R/3 included the new PM module. Converting from the previous CMMS to the SAP PM module was a large project that involved site personnel who verified the data in spreadsheets before contract SAP programmers uploaded the data into SAP.

Based on this evidence, the most likely scenario is that a programmer accidentally changed the confirmation-required field for the phosgene hoses. The change may have been an unintended effect of a valid change that DuPont requested or may have been an accidental change that went undetected.

Appendix D: Phosgene Release Calculations

DuPont initially estimated that 0.7 pounds of phosgene released from the riverside cylinder hose and associated valving at the time of the rupture. After more detailed calculations, DuPont revised the estimated release quantity to 2.0 pounds of phosgene. The CSB performed calculations and modeled the release to verify the phosgene release quantity.

Process Equipment

Figure 18 shows the hose and piping dimensions and the maximum amount of phosgene present in the piping system associated with the hose failure.

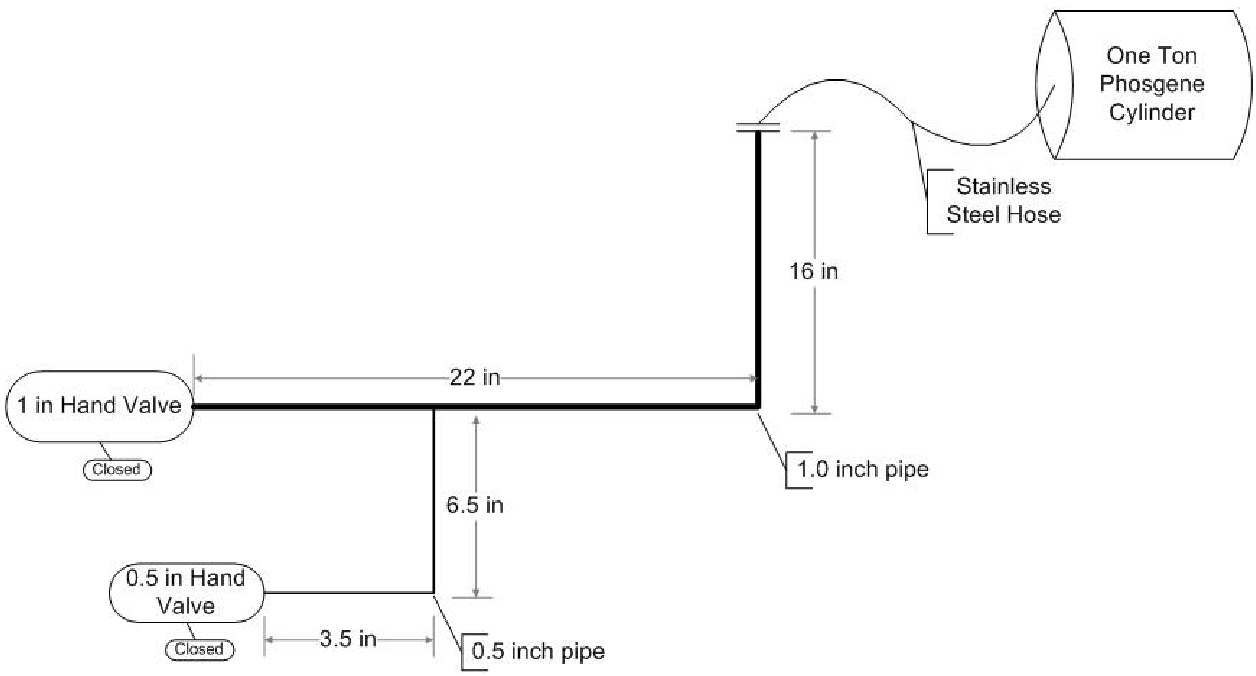

Figure 18. The hose and piping system that supplied phosgene for the release

1) Area of a circle:

$$\pi(r)^2 \quad \text{or } \pi\left(\frac{D}{2}\right)^2 = (ft)^2 = ft^2$$

2) Volume of a cylinder is equal to the area of the circle, multiplied by the length (L):

$$\pi\left(\frac{D}{2}\right)^2 * L = ft^2 * ft = ft^3$$

3) To determine weight, multiply by the density (ρ):

$$\pi\left(\frac{D}{2}\right)^2 * L * \rho = \cancel{ft^3} * \frac{lbs}{\cancel{ft^3}} = lbs$$

The density of phosgene, given that the ambient temperature was 8 °C:

$$\rho = 87.5\frac{lb}{ft^3}$$

Phosgene contained in the 1-inch pipe:

$$D = 1.05\ in = 0.0875\ ft$$

$$L = 16\ in + 22\ in = 38\ in = 3.17\ ft$$

Thus,

$$\pi\left(\frac{D}{2}\right)^2 * L * \rho = \pi\left(\frac{0.0875}{2}\right)^2 * 3.17 * 87.5 = \mathbf{1.67\ lbs}$$

Phosgene contained in the 0.5-inch pipe:

$$D = 0.622\ in = 0.052\ ft$$

$$L = 6.5\ in + 3.5\ in = 10\ in = 0.83\ ft$$

Thus,

$$\pi\left(\frac{D}{2}\right)^2 * L * \rho = \pi\left(\frac{0.052}{2}\right)^2 * .83 * 87.5 = \mathbf{0.154\ lbs}$$

Phosgene contained in the 0.5-inch valve:

$$D = 0.622\ in = 0.052\ ft$$

$L = 5.5/3 = 1.83\ in$ (1/3 the full length of the valve, since it was closed)

$$1.83\ in = 0.153\ ft$$

Thus,

$$\pi\left(\frac{D}{2}\right)^2 * L * \rho = \pi\left(\frac{0.052}{2}\right)^2 * .153 * 87.5 = \mathbf{0.028\ lbs}$$

Phosgene contained in the 1-inch valve:

$$D = 1.05\ in = 0.0875\ ft$$

$L = 6.5/3 = 2.17\ in$ (1/3 the full length of the valve, since it was closed)

$$2.17\ in = 0.181\ ft$$

Thus,

$$\pi\left(\frac{D}{2}\right)^2 * L * \rho = \pi\left(\frac{0.0875}{2}\right)^2 * .181 * 87.5 = \mathbf{0.095\ lbs}$$

Phosgene contained in the quarter inch, four foot long hose:

$$D = 0.25\ in = 0.021\ ft$$

$$L = 48\ in = 4\ ft$$

Thus,

$$\pi\left(\frac{D}{2}\right)^2 * L * \rho = \pi\left(\frac{0.021}{2}\right)^2 * 4 * 87.5 = \mathbf{0.12\ lbs}$$

The sum of phosgene in the system:

$$1.67 + 0.154 + 0.028 + 0.095 + 0.12 = \mathbf{2.067\ lbs\ of\ phosgene\ released}$$

Phosgene Dose Calculation

Using this phosgene release quantity (2.067 pounds), the CSB calculated the approximate concentration of phosgene the fatally injured operator was exposed to. Assuming the operator was 3 feet from the release and the phosgene instantly vaporized in a spherical fashion from the point of release, the operator would have received a lethal dose of phosgene in less than one-tenth of a second. This calculation assumes homogeneous concentration/mixing within the spherical phosgene gas cloud:

$$Air\ molecular\ weight = \mathbf{28.97\frac{g}{mol}}$$

$$\mathit{Phosgene\ molecular\ weight} = \mathbf{98.9161\frac{g}{mol}}$$

$$\mathit{Volume\ of\ a\ sphere\ with\ a\ 3\ ft\ radius} = \frac{4}{3} * \pi * (3)^3 = \mathbf{113.1\ ft^3}$$

$$2.067\ lbs\ phosgene * \frac{453.593\ g\ phosgene}{1\ lb\ phosgene} * \frac{1\ mol\ phosgene\ gas}{98.9161\ g\ phosgene} * \frac{22.414\ L\ phosgene\ gas}{1\ mol\ phosgene\ gas}$$

$$* \frac{1\ ft^3\ phosgene\ gas}{28.3168\ L\ phosgene\ gas} = \mathbf{7.5\ ft^3\ phosgene\ gas}$$

$$\mathit{Phosgene\ concentration\ in\ the\ sphere\ (uniform\ dispersion)} = \frac{7.5\ ft^3}{113.0973\ ft^3}$$

$$= .0661\ or\ 6.61\ volume\%\ phosgene;\ effectively = \mathbf{6.63\ mol\%\ phosgene}$$

$$\mathit{Average\ total\ molecular\ weight\ of\ gas\ (phosgene - air\ mix)}$$

$$= \left(\left(98.9161\frac{g}{mol} phosgene * 6.63\%\right) + \left(28.97\frac{g}{mol} air * (100\% - 6.63\%)\right)\right)$$

$$= \mathbf{33.6\frac{g}{mol} gas\ in\ the\ sphere}$$

$$\mathit{Weight\ percent\ of\ phosgene} = 6.63\ mol\%\ phosgene * \frac{98.9161\ g\ phosgene}{1\ mol\ phosgene} * \frac{1\ mol\ gas}{33.6\ g\ gas}$$

$$= 0.195\ or\ \mathbf{19.5\ wt\%\ phosgene\ in\ the\ sphere\ or\ 195{,}000\ ppm}$$

$$\mathit{Where\ a\ lethal\ dose\ is\ estimated\ to\ be}\ 300\ ppm * \min\ (\text{Collins et al, 2011}) = \frac{300\ (ppm * min)}{195{,}000\ ppm}$$

$$* \frac{60\ seconds}{1\ minute} = \mathbf{0.09\ seconds\ to\ recieve\ a\ lethal\ dose\ of\ phosgene}$$

Vapor Cloud Dispersion Modeling

The CSB used the ALOHA® (Area Locations of Hazardous Atmospheres) 5.4.1 program to model the phosgene release based on the characteristics of the release and atmospheric conditions on the afternoon of January 23, 2010. The National Oceanic and Atmospheric Administration (NOAA) and the EPA developed ALOHA to estimate the threat zones associated with hazardous chemical releases from toxic plumes, fires, and explosions. The user inputs chemical property and weather information and the program generates a user-defined release scenario that shows the concentration of toxic gases within a radius of the release source.

The following assumptions were used to model the phosgene release in ALOHA:

Atmospheric and Environmental Conditions:

Atmospheric temperature: 50 °F
Wind speed: calm, 1.5 m/s
Wind direction: from the north
Humidity: 66%
Cloud cover: scattered
Surrounding terrain: urban

<u>Release conditions</u>

Chemical: Phosgene
Amount released: 2 pounds
Release type: instantaneous
Height of release: 4 feet

The ALOHA program generated a display of concentration "threat zones" over a distance downwind from the source of the release. Using the EPA MARPLOT program, threat zones are displayed over a satellite map of the area using a GIS interface (Figure 19).

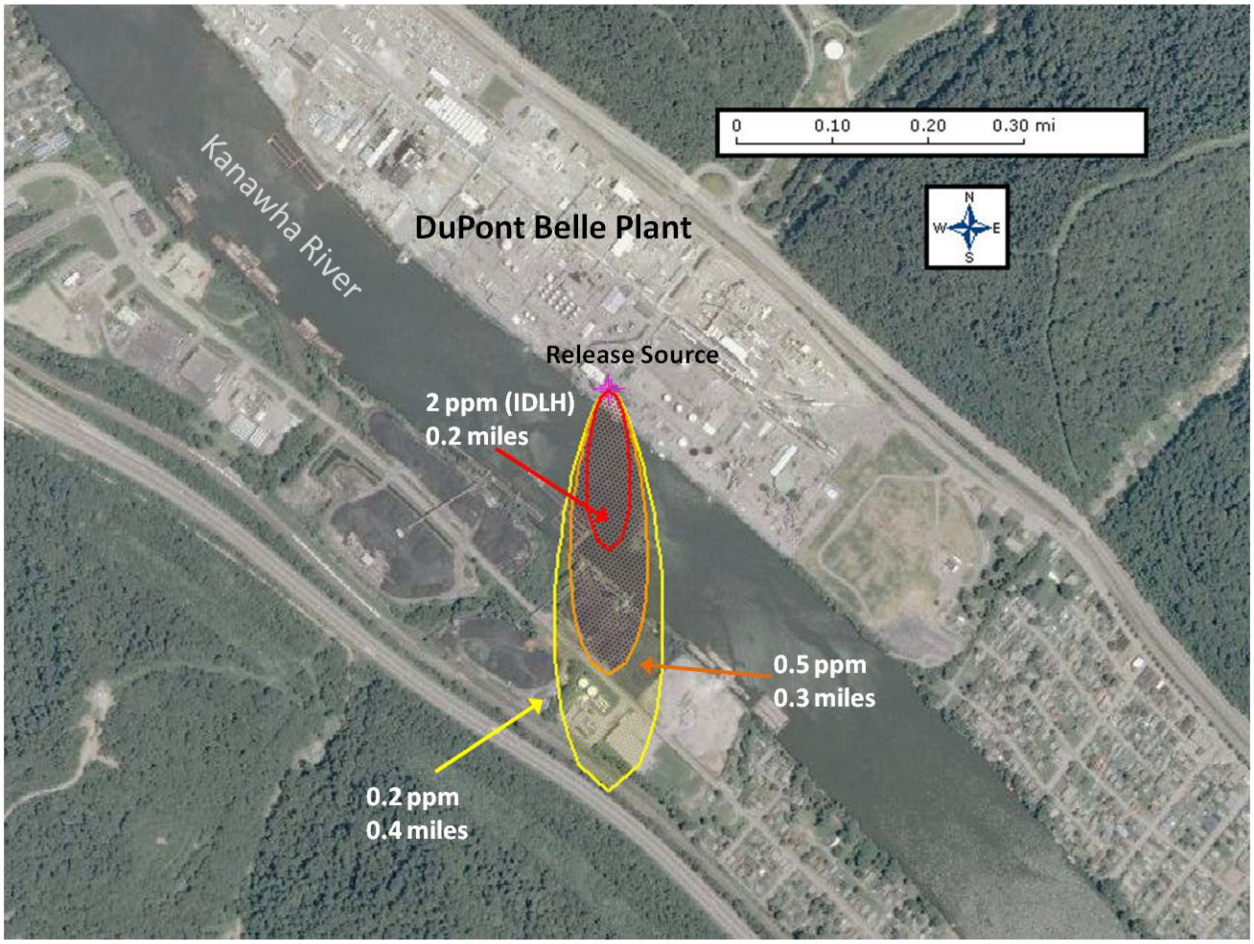

Figure 19. ALOHA estimate of phosgene concentrations with MARPLOT GIS overlay

The ALOHA program estimated threat zones for three user selected phosgene concentrations:

- 2 ppm (IDLH) 0.2 miles from release source
- 0.5 ppm (odor threshold) 0.3 miles from release source
- 0.2 ppm (ERPG-2[64]) 0.4 miles from release source

[64] ERPG-2 is the concentration to which all could be exposed for up to 1 hour without experiencing or developing irreversible or other serious health effects or symptoms that could impair their ability to take protective action (AIHA, 2008).

The release estimates from the ALOHA program are based on the weather conditions recorded at the Charleston Yeager Airport around the time of the January 23, 2010, phosgene release, but may not accurately represent atmospheric conditions at the plant. The ALOHA program also does not consider the topography or terrain surrounding the plant. The fence line monitors south and southwest of the phosgene shed recorded phosgene concentrations between 0 and 0.27 ppm, suggesting phosgene vapor may have traveled south of the DuPont Belle plant fence line toward the river. The ALOHA threat zone overlay in Figure 19 displays a model of the worst case release conditions indicating that IDLH concentrations of phosgene could have been present on the Kanawha River shortly after the release and lower concentrations could have traveled across the river. The community reported no odors or exposure symptoms the afternoon of the phosgene release incident.

Appendix E: Hazard Analysis for Phosgene Use at Belle

(Documents in this appendix are redacted for confidentiality)

List of Acronyms, Abbreviations, and Terminology

dia	diameter
flashing	instantly vaporizing liquid
IHI	Individual Hazard Index
LD50	50% lethal dose
MM	million (old notation style)
PHI	Process Hazard Index
ppm	parts per million

AG-6 REV. 4/86

DU PONT
ESTABLISHED 1802

E. I. DU PONT DE NEMOURS & COMPANY
INCORPORATED
BELLE, WEST VIRGINIA 25015

AGRICULTURAL PRODUCTS DEPARTMENT
BELLE PLANT, 901 W. DU PONT AVENUE

CC: [redacted]

June 2, 1988

CONFIDENTIAL

[redacted]
AGRICULTURAL PRODUCTS DEPARTMENT
[redacted]
WILMINGTON

BELLE PHOSGENE PLANT
PRELIMINARY RISK ASSESSMENT

References: (1) Attached Memo, [redacted] to [redacted], "BELLE PHOSGENE PLANT PRELIMINARY RISK ASSESSMENT REVISED CALCULATIONS", Dated May 19, 1988

(2) Attached Memo, [redacted] to [redacted], "IS THE PHI A GOOD RISK PARAMETER?", Dated April 29, 1988

(3) Attached Memo, [redacted] to [redacted], "DU PONT RISK CRITERIA", Dated May 6, 1988

Reference 1 describes risk assessment studies pertaining to the existing and proposed phosgene supply operations at the Belle Plant. References 2 and 3 question the value of PHI as a means of directing resources towards cost effective improvements in safety.

We plan to continue to work with [redacted] towards reducing the uncertainties in the Belle phosgene risk assessment studies preparatory to arriving at a decision concerning a ventilated enclosure for the Belle phosgene plant. We anticipate a decision on this matter when the current appraisal cost estimates are available three months after authorization of the Engineering Department P&E.

Please advise the writer if you have comments or suggestions.

[redacted]

EN-1028 REV 11-86

E. I. DU PONT DE NEMOURS & COMPANY
INCORPORATED
P. O. Box 6090
NEWARK, DE 19714-6090

ENGINEERING DEPARTMENT
LOUVIERS BUILDING

CC: [redacted]

May 19, 1988

[redacted]
AGRICULTURAL DEPT
BELLE PLANT

BELLE PHOSGENE PLANT PRELIMINARY RISK ASSESSMENT
REVISED CALCULATIONS

INTRODUCTION

A previous assessment transmitted as E-mail dated March 22, 1988, was discussed at Belle Plant on March 29 and revisions suggested. This note documents the results of those revisions.

The four cases considered are:

1. Operating with a liquid phosgene feed from cylinder to No. 2 reactor.

2. Vaporizing the feed from the cylinders.

3. Installing a plant to make phosgene from CO and Cl_2.

4. Enclosing the phosgene plant.

EXPLANATION OF TABLES

One change to all the assessments was the use of 720 ppm minutes as an LD50 instead of the 2700 ppm minutes used previously.

Table 1

Item 1

400 ft of 2 in. pipe, containing 800 lbs phosgene. Large leak interval is 1,200 years for 300 ft pipe (see letter [redacted] to [redacted] 5/13/87).

The line is pressurized to 60 psig to feed the reactor for 30% of the time and the remainder of the time it is assumed to be at phosgene vapor pressure of 8.7 psig.

Assuming flashing flow gives 70 & 22.4 lbs/min for pressurized and non-pressurized flow respectively from a 0.4" equivalent diameter hole.

Item 2

UK data, no failures in 200,000 cylinder years is equivalent to a failure interval of 600 K years. Arbitrary failure 0.5" diameter, flashing flow from pressurized cylinder.

Item 3

Assumed stored cylinders on rollers so that first 20 minutes leak assumed in liquid (flashing) then cylinder rolled to leak vapor for 15 minutes then capped.

Item 4

Pigtails made and broken 500 times per year. One in 10,000 not done correctly, one in 10 not capable of being corrected by man on the spot. Assume someone will close cylinder valve within 10 minutes. Fashing flow from full bore pigtail 0.194" hole.

Item 5

The American Trucking Association reports that the 1985 average for reportable accidents involving carrier trucks is 1.3 accidents per mm miles. Statistics from DE, MA, NJ, NY, and PA indicate that the overall accident rate for all vehicles is 3.05 accidents per MM miles. US Highway Statistics Division, Office of Highway Planning, 1984 gives the fatality rate as 2.58 fatalities per 100 MM miles. Assuming the number of fatalities per accident is the same for trucks as for all vehicles one might deduce there would be

1.1 (= 2.58 x 1.3 ÷ 3.05) fatalities per 10 MM truck miles

Table 2

Item 1

As Table 1, Item 1, except vapor flow.

Also assumed vaporizer level would fall quickly until the maximum flow is controlled by the liquid flow control valve (usually set at 7 lbs/min.

3
May 19, 1988
[redacted]

Item 2,3,4,5

As Table 1, Item 2, 3, 4, and 5.

Item 6

The vaporizer is assumed to hold 25 lbs when operating (30% of time) and about 12 lbs the remainder of the time. Again a leak would deinventory the vaporizer and then the flow would be limited to 7 lbs/min by the flow control valve.

The failure data transmitted from [redacted] to [redacted] by E-mail, July 31, 1987-August 5, 1987, suggests a failure interval for vaporizer of 180 years. The works suggest only one serious failure is relevant in phosgene service giving a 540 year failure interval equivalent to 1,800 years in operation and 770 in standby. Flow rates (flashing) through a 0.5" hole would be 109 lbs per min for 1/4 min followed by 7 lbs/min for 3/4 minutes until phosgene detectors isolated feed, and in standby 109 lbs for 0.1 minutes.

Table 3

Item 1

Assume catastrophic release from storage tank. Small leaks will have little impact.

Item 2

The works consider hose rupture due to tank truck driving off as incredible because of carefully enforced administrative procedures. Since this type of incident does happen, the works would have to convince the outside world that with their procedures this failure is incredible.

Item 3

Using same failure rates as Table 1, Item 1, assumed 100 psig, 0.4" diameter hole, 30 minutes to detect and isolate.

Item 4

1.1 fatalitites per 100 MM miles.

Item 5

Similar to Table 1, Item 2, but assumed all chlorine is at 100 psig since chlorine vapor pressure at 20°C is 85 psig.

4
May 19, 1988
[redacted]

Item 6

Similar to Table 2, Item 6, except two failures per 540 years are relevant for chlorine.

Item 7

Similar to Table 1, Item 4.

Item 8

1.1 fatalities per 100 MM miles.

Item 9

Used same failure rate for phosgene process as for phosgene vaporizer (Table 2, Item 6). However, the leak rate is determined by the production rate which is at 5 MM lbs/yr is about 10 lbs/min. We have arbitrarily assumed it would take 10 minutes to isolate the leak and therefore the volume in the process is irrelevant.

In standby mode we assume, probably pessimistically, that 10 lbs phosgene could be released.

Item 10

A more direct route would use 200 ft pipe. Production rate would again limit leak rate assumed operating only 30% of time.

Table 4

As Case 3 except items 5, 6, 7 and 9 would be enclosed. I have assumed the ventilation and scrubbing system would have a one in 1,000 chance of failing.

CONCLUSIONS

- The uncertainties in data are enormous.
- The gas dispersion model is not valid for under about 100 meters which covers most of the on-site analysis.
- Case 3 meets Du Pont guidelines for on-site and off-site IHIs.
- There is no Du Pont guideline for off-site PHI.
- See notes sent to [redacted] (5/17/88) re on-site PHI criteria

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May 19, 1988
[redacted]

(the PHI of 10,000 is a guideline target, not a mandatory specification).

o Case 4 does not meet the PHI target of 10,000.

o Spending $2 MM for an enclosure to get from Case 3 to Case 4 saves 14.4 lives per 10,000 years. (Almost all the improvement is in on-site risk. Off-site risk improvment is not significant.) This sets a value of life plus public outrage at $143 MM.

o It may be that in the present circumstances the businees can afford $2 MM for an enclosure; however, in the long run can we afford to take such action which has such a small impact on safety and yet sets a precedent for all highly toxic material activites.

ENGINEERING SERVICE DIVISION
Air Quality and Hazards Evaluation

[redacted]

[redacted]

TABLE 1
Liquid Phosgene Feed to No. 2 Reactor

Item	Leak	Failure Interval	Failures Per 10,000 Years	Leak Rate Lb/Min	Dur Mins	Onsite Fats Per Inc	Onsite Fats Per 10,000 Yr	Offsite Fats Per Inc	Offsite Fats Per 10,000	Max Probable Risk Onsite	Max Probable Risk Offsite	IHI Onsite	IHI Offsite
1 400'x2" pipe contains 800 lbs phosgene	0.4"dia hole at 60psig for 30% time	3000 (1200x3x100) / 4 30%	3.3	70	12	23.7	78.2	2.4	7.9	.56	.075	2.1	0.29
	As above except at 8.7psig for 70% time	1286	7.8	22.4	36	5.6	43.7	.31	2.4	.41	.0053	3.6	0.047
2 1x1 ton cylinder	Say 0.5" hole	600M	0.017	109	10	34.9	0.59	4.3	0.073	.59	.11	0.011	0.0021
3 9x1 ton cylinder	Say 0.5" hole	67000	0.15	35 8.3	20 15	9.2 .83	1.4 0.12	0.6 0	0.09 0	.48 .16	.022 0	0.082 0.027	0.0038 0
4 Pigtails	Break 0.194"	200	50	16	10	2.0	100	.0009	0.045	.33	.00003	18.8	0.0017
5 Road transport 53,000 miles/yr									(5.8)				
				Totals			224		10.5			24.6	0.34

(PHI = 45)

TABLE 2
Vaporized Phosgene Feed

Item	Leak	Failure Interval	Failures Per 10,000 Years	Leak Rate Lb/Min	Dur Mins	Onsite Fats Per Inc	Onsite Fats Per 10,000 Yr	Offsite Fats Per Inc	Offsite Fats Per 10,000	Max Probable Risk Onsite	Max Probable Risk Offsite	IHI Onsite	IHI Offsite
1 400' x 2" pipe vapor filled 30% time 13 lbs	Blown gasket 0.4" dia at 60psig	3000	3.3	18.4	2	.75	2.5	0	0	.15	0	0.57	0
				7	8	.57	1.9	0	0	.11	0	0.42	0
2 1x1 ton cylinder	Say 0.5" hole	600M	0.017	109	10	34.9	0.59	4.3	0.073	.59	.11	0.011	0.0021
3 9 x 1 ton cylinder	Say 0.5" hole	67000	0.15	35	20	9.2	1.38	0.6	0.09	.48	.022	0.082	0.0038
				8.3	15	.83	0.12	0	0	.16	0	0.027	0
4 Pigtails	Break 0.194	200	50	16	10	2.0	100.0	0.0009	0.045	.33	.00003	18.8	0.0017
5 Road 53000 mile per year									(5.8)				
6 (a) vaporizer 25 lbs online	Unknown Say 0.5"	1800	6	109	1/4	2.5	15	.00045	0.0027	.45	.000017	3.1	0.00012
				7	3/4	.0087	0.052	0	0	.0017	0	0.12	0
(b) offline Say 12 lbs	Unknown Say 0.5"	770	13	109	0.1	2.5	32.5	.00045	0.0059	.45	.000017	6.7	0.00025
						-	-						
				Total			154		0.22			29.8	0.008

(PHI = 65)

TABLE 3
New Phosgene Plant

Item	Leak	Failure Interval	Failures Per 10,000 Years	Leak Rate Lb/Min	Dur Mins	Onsite Fats Per Inc	Onsite Fats Per 10,000 Yr	Offsite Fats Per Inc	Offsite Fats Per 10,000	Max Probable Risk Onsite	Max Probable Risk Offsite	IHI Onsite	IHI Offsite
CO													
1 CO storage tank	Catastrophic	100M	0.1	40000	puff	2.9	0.29	0.04	0.004	.47	.0017	0.054	0.00019
2 6 truck shipments per year	Unloading hose rupture due tank truck driving off whilst connected considered by plant to be not a credible event. The administrative controls must convince others of this.												
3 2000 ft 2" vapor line	0.4" hole	180	56	15	30	$8x10^{-6}$	0.0004	0	0	$.16x10^{-5}$	0	0.0001	0
4 10000 truck miles per year									(1.1)				
Cl_2													
5 (a) 1x1 ton cylinder	0 .5" dia hole	600M	0.016	150	8	1.6	0.026	0.0088	0.00014	.27	.00031	0.0049	5.7^{-7}
(b) 7x1 ton cylinder	0.5" dia hole	86M	0.12	150	10	1.8	0.22	0.025	0.003	.27	.00086	0.037	0.00012
				37	15	0.085	0.01	0	0	.016	0	0.0022	0
6 (a) Vaporized	0.5" dia	900	11	150	1/4	0.18	1.98	0	0	.035	0	0.44	0
Online	hole			10	3/4	$3.4x10^{-9}$	0	0	0	neg	0	0	0
(b) Offline	0.5" dia hole	390	26	150	0.1	0.18	4.68	0	0	.035	0	1.04	0
7 Pigtails	.194" dia	200	50	23	10	0.016	0.8	0	0	.003	0	0.17	0

Item	Leak	Failure Interval	Failures Per 10,000 Years	Leak Rate Lb/Min	Dur Mins	Onsite Fats Per Inc	Onsite Fats Per 10,000 Yr	Offsite Fats Per Inc	Offsite Fats Per 10,000	Max Probable Risk Onsite	Max Probable Risk Offsite	IHI Onsite	IHI Offsite
8 11250 truck miles per year									(1.2)				
$\underline{CO\ Cl_2}$													
9 (a) Process Online	0.5" dia	1800	6	10	10	1.1	6.6	0	0	.21	0	1.44	0
(b) Standby	0.5" dia	770	13	10	1	.038	0.49	0	0	.0073	0	0.11	0
10 200' x 2"	0.4" dia	6000	1.7	10	10	1.1	1.9	0	0	.21	0	0.37	0
				Totals			16.7		0.007			3.6	.00031

(PHI = 600)

TABLE 4
Enclosed Phosgene Plant

Item	Leak	Failure Interval	Failures Per 10,000 Years	Leak Rate Lb/Min	Dur Mins	Onsite Fats Per Inc	Onsite Fats Per 10,000 Yr	Offsite Fats Per Inc	Offsite Fats Per 10,000	Max Probable Risk Onsite	Max Probable Risk Offsite	IHI Onsite	IHI Offsite
CO													
1 CO storage tank not enclosed	catastrophic	100M	0.1	40000	puff	2.9	0.29	.04	0.004	0.47	.0017	.054	.00019
2 6 truck shipments not enclosed	Not a credible incident - see Table 3, Item 2												
3 2000' x 2" pipe vapor not enclosed	.4" dia	180	56	15	30	$8x10^{-6}$	0.0004	0	0	$0.16x10^{-5}$	0	.0001	0
4 10000 truck miles per year									(1.1)				
CL2													
5 (a) 1 x 1 ton cylinder enclosed	.5" dia hole	600MM	0.000016	150	8	1.6	.000026	0.0088	10^{-7}	0.27	.00031	4.9^{-6}	5.7^{-9}
(b) 2 x 1 ton cylinder	.5" dia hole	300MM	0.000032	150	10	1.8	.000058	0.025	$8x10^{-7}$	0.27	.00086	9.9^{-6}	3.1^{-8}
				37	15	.085	.000003	0	0	.016	0	5.8^{-7}	0
(c) 5 x 1 ton cylinder not enclosed	.5" dia hole	120M	0.083	150	10	1.8	.15	0.025	0.002	0.27	.00086	0.026	0.00008
				37	15	.085	.007	0	0	.016	0	0.0015	0
6 (a) Vaporized Online enclosed	.5" dia hole	900M	0.011	150	1/4	0.18	.002	0	0	.035	0	0.00044	0
				10	3/4	3.4x10-9	0	0	0	neg	0	0	0
(b) Offline	.5" dia	390M	0.026	150	0.1	0.18	0.005	0	0	0.35	0	0.0010	0

TABLE 4
(CONTINUED)

Item	Leak	Failure Interval	Failures Per 10,000 Years	Leak Rate Lb/Min	Dur Mins	Onsite Fats Per Inc	Onsite Fats Per 10,000 Yr	Offsite Fats Per Inc	Offsite Fats Per 10,000	Max Probable Risk Onsite	Max Probable Risk Offsite	IHI Onsite	IHI Offsite
7 Pigtails enclosed	.194"	200M	0.05	23	10	0.016	0.0008	0	0	.003	0	0.00017	0
8 11250 truck miles per year									(1.2)				
9 (a) Process Online	0.5" dia	1800M	0.006	10	10	1.1	.00066	0	0	.21	0	0.0014	0
(b) Standby	0.5" dia	770M	0.013	10	1	.038	.00049	0	0	.0073	0	0.00011	0
10 200' x 2"	.4"	6000	1.7	10	10	1.1	1.9	0	0	.21	0	0.37	0
					Total		2.3						
									.006			.40	0.00027

(PHI = 4350)

TABLE 5

SUMMARY

	On Site			Off Site		
					Transport	
Totals	Fats per 10,000 yrs	PHI	IHI	Fats per 10,000 yrs	Fats per 10,000 yrs	IHI
Case 1	244	45	24.6	10.5	5.8	0.34
Case 2	154	65	29.8	0.22	5.8	0.008
Case 3	16.7	600	3.6	0.007	2.3	0.00031
Case 4	2.3	4350	0.4	0.006	2.3	0.00027

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Engineering Department
Louviers Building

April 29, 1988

[redacted]

IS THE PHI A GOOD RISK PARAMETER?

The attached note challenges the use of PHI as a good parameter for risk criteria.

It is a note I have been intending to write for years because we and other companies have been spending inefficiently on reducing process hazards.

However, after a visit to a General Electric phosgene plant near Mount Vernon early in April, I recognized that this inefficiency had reached a peak with precedent setting action GE had taken to enclose, purge, and scrub the plant.

If we accept the premise that we spend money on process hazards to save lives, prevent damage and avoid public outrage, and if we use the number of lives saved as a measure of these three contributions, then the $40MM GE spent to enclose their plant to achieve an arbitrarily established FN curve criterion (a sort of sophisticated PHI) represents a spending rate of about $4 billion per life saved.

Such a precedent is neither in the interests of GE, Du Pont, the chemical industry, nor the public as a whole. But using criteria like FN curves, PHIs, and IHIs without also considering the cost/risk/benefit tradeoff explicitly will inevitably lead to increasingly inefficient use of resources.

ENGINEERING SERVICE DIVISION
Air Quality and Hazards Evaluation

[redacted]

DU PONT RISK CRITERIA

There is no such thing as an acceptable risk per se. A risk is only acceptable "in the circumstances".

In many cases, a risk is acceptable to a person because of the benefit he derives from taking the risk, whether that benefit is financial, health or pleasure.

Whenever the benefits accrue to the person taking a risk, a fair tradeoff can be negotiated in the circumstances and an "acceptable risk" level can be determined. Such tradeoffs are common between companies and employees where the risks are explained, training and protection are provided and the employee benefits with a good job.

However, each case will be different; the circumstances will include a variety of factors, but one of the most important and variable will be the cost of reducing the risk.

The idea of establishing uniform criteria for in-plant risk levels in Du Pont was to provide consistency across the company, but consistent risk levels do not lead to the most efficient use of resources. There are situations where rigid adherence to such criteria leads to wasteful use of resources, and as we try to improve our standards, these situations will occur more frequently.

We are not spending money and resources to reduce risk to some arbitrarily chosen level; we are spending that money to save lives, damage to one's reputation, property, the environment and to avoid public outage.

So, if we use lives as a measure of all the adverse damage, it should be incontrovertible that we ought to save the maximum number of lives for any money we spend.

Let us consider an example; to illustrate the point.

Let us assume that in this example, all the other damages etc. are proportional to the loss of life, so we shall just be considering the lives lost.

Consider five processes as follows:

Process	Existing PHI	Existing Fats/ 10,000 Yrs	Cost to Improve PHI to 10,000	No. of Fats Per 10,000 Yrs If PHI=10,000	Cost to Improve PHI to 100,000
1	5,000	2	$ 10,000	1	$50,000
2	5,000	2	$100,000	1	$1MM
3	5,000	2	$ 10,000	1	$50,000
4	Not Known	?	?		?
5	Not Known	?	?		?

Plant Manager A rigidly adheres to the guideline and spends $120M getting processes 1, 2, and 3 to the PHI guideline of 10,000. In so doing, he saves three lives per 10,000 years. Assuming a 10-year plant life, he is saving 0.025 lives per $1MM spent.

Plant manager B decides to spend his $120M improving plants 1 and 3 to 100,000 and leaving plant 2 alone. He saves 3.8 lives per 10,000 years -- equivalent to saving 0.032 lives per $1MM spent.

Plant Manager C decides to spend $20,000 on improving Plants 1 and 3 to 10,000 PHI and does a risk assessment on Plants 4 and 5, yielding the following information:

Process	Existing PHI	Existing Fats/ 10,000 Yrs	Cost to Improve PHI to 6,000	Improved Fats per 10,000 Yrs	Cost to Improve PHI to 10,000
4	3,000	3.33	$50,000	1.67	$200,000
5	3,000	3.33	$50,000	1.67	$200,000

Plant Manager C now decided to spend an additional $100M improving 4 and 5 to 6,000 PHI, saving 3.33 lives.

Plant Manager C has, in Step 1, saved 0.1 lives per $1MM; in Step 2 saved 0.0333 lives per $1MM; and in Steps 1 and 2 combined, saved 0.044 lives per $1MM.

Summarizing, we have:

Plant Manager	Spent	Saving Lives Per 10,000 Yrs	At Lives/$M	No. of Plants Achieving Target PHI of 10,000
A	$120M	3	0.025	3
B	$120M	3.8	0.032	2
C	$120M	5.3	0.044	2

Who is working in the best interests of Du Pont; it's employees, it's reputation, etc?

The numbers used are not from examples nor are they intended to indicate appropriate levels of spending. However, no matter what numbers are used, they will always illustrate that evaluating the benefits (lives saved, in this case) per $ spent will always define the most cost-effective use of resources.

Conclusion

Seeking to achieve an arbitrary PHI regardless of cost is not the way to use numerical risk assessment nor the most cost-effective way to spend

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Du Pont Risk Criteria
April 26, 1988

money to improve risk. If we insist on using the PHI as our major criterion then we should be content if we can match the PHI target for reasonable cost, but if there are circumstances where the cost of achieving the target appears to be too high we should use the lives saved per $1MM to decide whether such expenditure is a wise use of resources.

Fortunately, we usually have little difficulty in achieving our PHI target of 10,000, even if we do spend our resources inconsistently in so doing. However, if there is ever a need to improve or add to our Company Guidelines, the use of PHI as a primary criterion should be rigorously challenged since the above illustrates only one of the problems associated with its use.

Risks to the Public

It is not the intention of this note to consider off-site risks. The problems associated with risk criteria for the public are compounded for a variety of reasons.

o We never deal with the pubic (they stay at home, don't attend meetings, etc). The only ones we ever deal with are the special interest groups.

o They see no benefit accruing from the risks of living near a chemical plant so the risk benefit tradeoff does not exist in their minds.

o They do not understand FN curves, probabilities or even the simplest presentation of the numbers.

o Their perception of the risk is what dominates their thinking (and their perception often is totally different from the actual risk).

The numerical criteria quoted in S&OH Guideline 6.7 therefore needs treating with ultimate caution.

[redacted]

MORE COMMENTS ON PHI CRITERIA

Whilst we all recognize that there is a need to revise our risk criteria, there is an even bigger need to explain how to use the existing ones.

The ignorance which abounds concerning PHI and IHI indicates that any revision should be towards simplification.

Whatever new criteria are chosen must be explained and publicized so that their meaning and application are clear and unambiguous. (What chance does the public stand of understanding the subject when the majority of Du Pont technical staff can't.)

The PHI was introduced solely to deal with the multiple fatality cases; if we could guarantee that all our incidents involved no more than one or two persons (and our history shows this is pretty close to the truth) the IHI criterion would have been sufficient and we would never have needed the PHI criterion.

The PHI criterion of 10,000 years was introduced for one risk, say $1- or- $2MM, and not for the whole plant site.

Extrapolating to large plants and smaller PHIs is not only unnecessary if all the incidents are involving one one or two casualties, but can also be quite inconsistent. To illustrate my point, consider three plants (A, B, and C) each with 10 processes as follows:

> Plant A has 10 risks each with an IBI = 10,000. Each risk therefore has a PHI of 10,000 and with one operator at risk each operator would have an IHI = 1.1.
>
> Plant B has one risk with an IBI = 1,000 giving a PHI of 1,000, one operator at risk with an IHI = 11 and the remaining nine plants having no risk.
>
> Plant C has one risk with an IBI = 10,000 but with 10 operators affected by each incident gives a PHI of 1,000. Each operator's risk is an IHI of 1.1. The remaining nine plants have no risk.

All three plants have a total PHI of 1,000 which might be said to meet the extrapolated PHI target for a large area of risk. All three plants kill 10 people over 10,000 years.

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The following comments are suggested by the example:

Summing risks over a large site does not help to improve safety nor give any clearer impression of the risks. In fact, it clouds the issue (all three plants appear, in total, to be acceptable).

Summing PHIs confuses the issue the PHI was introduced to deal with, namely the large incident, the risk in Plant C, putting 10 operators at risk, isn't highlighted by the PHIs in the example.

The use of the PHI doesn't do anything to ensure each operator has his fair share of risk (one Plant B operator has an IHI = 11).

The use of the total PHI would suggest no effort (or equal effort) is required on each plant.

The use of individual PHIs would suggest no effort on Plant A, probably weight more effort towards Plant C because of the larger incident.

The use of the IHI would suggest no effort on Plant A and probably weight more effort towards Plant B because of the higher IHI.

The use of a cost per life criterion would put all the effort where it would do most good.

Maybe these comments, committed to paper to help me organize my thoughts will have some influence on producing better guideline risk criteria.

[redacted]

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ENGINEERING DEPARTMENT
LOUVIERS BUILDING

May 6, 1988

[redacted]

DU PONT RISK CRITERIA

At the risk of becoming a bore, I have attached yet another note on risk criteria.

I have not thought so much about criteria since I was responsible for developing the FAR target for [redacted] early in the 1970s. At that time I, like many others who have been involved in quantitative risk assessment for only a year or two, was very naive, not recognizing many of the problems.

We were fortunate that the FAR target worked because reducing individual's risks to the target never cost us money that we couldn't afford. Nevertheless, I was asked to write notes for VPs on more than one occasion to prove this.

However, when we tried to extend our criteria to transportation, major accidents and risks to the public, we were never able to find a suitable number or set of numbers which satisfied our needs. We tried using numbers, bands, grey areas, FN curves, ranges, but none could stand all the tests.

The fact of the matter is that every safety improvement is done to save lives, reduce injuries, prevent damage both to plant and environment, and prevent outrage. We make whatever improvements someone judges to be appropriate and no more.

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May 6, 1988
[redacted]

That judgment may well be influenced by the person making the decision, the state of the business, and by some arbitrary criterion as well as the knowledge of the consequences but nevertheless that precise sum of money and no more, is spent at that time.

I would suggest that, no matter how difficult or emotional, we should recognize the fact that by so doing we are implicitly putting values on life, environment, outrage, etc. And there is nothing to be ashamed of in doing it explicitly, although there may be a need to convince people of this fact.

We shall then be making a better contribution to safety than by retaining or extending our current arbitrary parameters.

We would also eliminate much of the confusion over how to use and interpret our current targets.

I have directed these notes of the past few days to the people I consider most relevant and if I have your general support, I should be pleased to help initiate any appropriate action. [redacted] suggested that he and I might redraft S&OH Guideline 6.6 in an attempt to introduce some of these ideas whilst preserving the best of the past.

ENGINEERING SERVICE DIVISION
Air Quality and Hazards Evaluation

[redacted]

[redacted]

3
May 6, 1988
[redacted]

EVEN MORE ABOUT PHI

Regardless of whether we consider the PHI of a small system or a total integrated plant site, improving the PHI:

from 100 to 10,000 saves 0.0099 lives per year
from 1,000 to 10,000 saves 0.0009 lives per year
from 5,000 to 10,000 saves 0.0001 lives per year

So, improving the PHI from x to y will always provide the same benefit (namely save the same number of lives) regardless of the system being analyzed and improved. At first sight that would indicate the same expenditure on improvement would always be justified. However, although lives lost is one measure of risk, it is accepted that public outrage is an added (and possibly dominant) loss and so preventing that outrage is an additional benefit that can be used to justify expenditure.

So, let us take say $10MM for the minimum cost of a single life in a small accident.

Now consider say 100 lives in a large accident and assume we put the Du Pont Company (say $30MMM) at risk with this. Now our cost per life at the other extreme of the scale is ($30MMM + 100 x $10MM) + 100 = $330MM.

We now have a range of values for life depending upon the circumstances namely $10-330MM.

Assuming we require a 10% return on investment and reverting to our PHI table, improving the PHI from -

100 to 10,000 saves 0.0099 lives/yr and justifies spending from $1MM-33MM

1,000 to 10,000 saves 0.0009 lives/yr and justifies spending from $90M-3MM

5,000 to 10,000 saves 0.0001 lives/yr and justifies spending from $10M-330M

You will note that the PHI value tells you nothing about the size of the incident or the public outrage factor. So whereabouts in the spending range is a justified expenditure depends on the specific incident and not on the PHI.

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May 6, 1988
[redacted]

Conclusion

The arbitrary PHI target serves little purpose in directing resources towards cost effective improvements in safety.

The only reliable way to achieve optimum safety is to make risk benefit analyses for each case.

After all, we are doing a risk benefit analysis implicitly with every safety improvement, whether we make it or reject it, whether we use numbers or not. Doing it explicitly simply means we get the best out of every situation and for the company as a whole.

NOTE: You may not agree with the numbers I have used, but these can be negotiated. The main purpose of the note is to demonstrate the principle.

Appendix F: Hard Pipe to Flexible Hose Transition Correspondence

(Documents in this appendix are redacted for confidentiality)

List of Acronyms, Abbreviations, and Terminology

AgProducts	The Agricultural Products Department/Business of DuPont
dry phosgene	liquid phosgene without any water, also called "anhydrous" phosgene
engg spec	engineering specification
ESD	Engineering Services Division of DuPont
SS	stainless steel

INTEROFFICE MEMORANDUM

Date: 9-Jul-1987 06:23pm
From: [redacted]

Dept: AGPRODUCTS
Tel No: [redacted]

TO: See Below

Subject: SLM'S PHOSGENE CYLINDER PIGTAILS

We have had several incidents where the brass fittings on the pigtails connecting the copper tubing to the phosgene cylinder valve has failed. The latest occurrence was on 7/5/87. In all cases only minor amounts of phosgene were released to the atmosphere and the failures typically, although not always, occurred while a fully protected operator had switched cylinders and was reconnecting the pigtails.

I sent a sample of a damaged brass fitting to Metallurgical lab to be evaluated by [redacted] and [redacted]. Their conclusion was that the brass was failing due to chemical attack by the ammonium hydroxide we use to detect leaks. The practice of spraying ammonium hydroxide on the brass along with the stress of tightening the fittings resulted in stress corrosion cracking (SCC). [redacted] recommends going to Monel 400 which is immune to SCC. He also recommends replacing the copper tubing with braided hose made of a corrugated Monel core with Monel external braiding. I believe that Laporte uses a monel-braid covered Teflon hose. The Laporte plant was considering testing a Kynar-braid covered Teflon hose because of discoloration and gradual deterioration of the Monel. One point to make about these hoses is that they are not easily fabricated and poor fabrication will lead to an increase in minor phosgene releases. I will work with [redacted] and the Laporte plant to come up with our best option.

Another point which was brought [redacted] and [redacted] brought up was the fact that the valve on the phosgene cylinders are also made of brass. I talked with [redacted] of PPG in Laporte about their leak detection methods. Apparently the spraying of ammonium hydroxide is the commonly accepted method for pinpointing phosgene leaks sources. At PPG they use a ~10-15% ammonium hydroxide solution to detect leaks. They recognize the problems with brass and ammonium hydroxide so their "pigtails" & connections are not made of brass. However, they have never experienced any problems with the brass valves on the cylinders possibly because of the size (thickness?) of the valves. The valves are also changed out on a ~1-2 year frequency. Dupont's Laporte plant uses braided hose as mentioned above and the ammonium hydroxide is not a problem.

Recommendations

Item	Responsibility
0 Replace all brass fittings on a monthly frequency. The "old" fittings will be sent to the Met. lab for visual & dye penetrant inspection for SCC. If evidence of SCC is	[redacted]

found, the frequency of replacement will be increased.

0 Replace existing ammonium hydroxide "squeeze bottles" with spray bottles. The squeeze bottles deliver a liquid stream while a spray bottle can deliver a vapor/mist. This will minimize the contact between the ammonium hydroxide and the brass. [redacted]

0 Verify that our procedures requires use of a dilute (10-15%) ammonium hydroxide solution. [redacted]

0 Incorporate the following steps in the leak detection procedure for the cylinder shed: [redacted]

1. Carefully inspect brass fittings for damage before connecting cylinders. Any questionable fittings should be replace with new ones.

2. After reconnecting pigtails, use Monitox to determine if phosgene is present. If the Monitox does not register any phosgene around fittings, then use of ammonium hydroxide is not required.

3. If phosgene is detected, then use the ammonium hydroxide mist to pinpoint leak.

0 Train operators on the above procedure and emphasize the need to inspect brass fittings before reconnecting cylinders. [redacted]

0 Coordinate efforts with [redacted], [redacted] [redacted] and Laporte plant personnel to develop optimum material of construction and design for phosgene pigtails and connections.

Distribution:

TO: [redacted] ([redacted])
TO:
TO:

CC: [redacted] ([redacted])
CC:
CC:
CC:
CC:
CC:
CC:

DuPont Belle Plant
MAY 17 2010

INTEROFFICE MEMORANDUM

Date: 14-Jul-1987 10:33am
From: [redacted]

Dept: ESD
Tel No: [redacted]

TO: Remote Addressee ([redacted])

CC: Remote Addressee ([redacted])
CC: Remote Addressee ( )
CC: Remote Addressee ( )

Subject: PHOSGENE SYSTEM

I appreciate receiving the copy of your program to improve the materials of construction and handling of phosgene at SLM. I'd like to make a few comments on the subject:

1. My point in the letter to [redacted] about the copper tubing used in the unloading system was that it would probably be OK as is but it seems we could do better (using hoses, etc.). However, we should concentrate on the integrity of the fittings, that being the immediate problem, and work out a program for the tubing later.

Monel is the preferred material of construction for fittings in both chlorine and phosgene cylinder unloading systems. Repeated use from numerous hook-ups may result in thread damage of the fittings, but corrosion and, more importantly, stress corrosion cracking (SCC) is not a concern. I strongly recommend that you move immediately to replacing the existing brass fittings with Monel and eliminate this hazard.

2. Reports from Laporte that Monel braided hoses were corroding in phosgene service are not exactly true, according to [redacted], ESD Materials Engineering, who covered the plant during the time Laporte was developing a program for these hoses. The hoses at that time were Teflon lined, with a Monel outer braid. Due to permeation of phosgene through the Teflon, the Monel was slightly attacked, forming a green surface film known as a "patina" which is common to all copper-based alloys.

3. Laporte supposedly changed to Teflon lined hose with an external braiding of Kynar, at least to address this discoloration "problem". I have not heard of their experience with this type of hose. They use Monel corrugated inner linin with an external Monel braid for chlorine service, mainly becau it conforms to Chlorine Institute specifications. The supplier of both types of hoses is Triplex in Houston (contact is [redacted]), who has been "educated" as to the correct fabrication

The following paragraphs describe SCC of copper alloys by ammonia which you can use in your formal contact with PPG regarding their use of brass valves on phosgene drums:

Stress corrosion cracking (SCC) is a corrosion phenomena that involves the synergistic effect of stress and corrosion to bring about the failure of components fabricated of a susceptible alloy. Chloride SCC of austenitic stainless steels is a common example of this in the chemical processing industry. Lesser known but equally hazardous is ammonia cracking of copper-based alloys. In earlier times this was commonly associated with brass in what was called "season cracking" of rifle cartridge cases; however, it is now known to affect any stressed copper-based alloy.

Metallographic examination has confirmed ammonia SCC of brass fittings that were removed from your phosgene unloading system. The ammonia exposure resulted from spraying the fitting joints with ammonium hydroxide for leak detection. The time-to-failure once the SCC conditions are met is extremely variable and depends on, among others, stress level and corrodent ion concentration.

Reducing the risk of SCC can certainly be helped by reducing the extremes - for instance, by reducing stress, by avoiding long time exposure by frequent replacement of affected parts, or by lowering the concentration of the corrodent. However, the solution to SCC problems is best accomplished by removing one of the variables of the SCC equation -

1. Stress - in this case, residual stress in (any) fittings or applied stress from use can hardly be avoided.

2. Corrodent - apparently, ammonium hydroxide is commonly used for leak detection in phosgene systems.

3. Material - Here we can avoid the problem by upgrading materials to Monel 400, a nominally 65% nickel, 30% copper alloy which is essentially immune to ammonia SCC and also offers good corrosion resistance to HCl (wet phosgene).

If I can help out in any way, please call.

6i

INTEROFFICE MEMORANDUM

...fidenti...

Date: 5-Aug-1987 04:30pm
From: [redacted]

Dept: AGPRODUCTS
Tel No: [redacted]

DuPont Belle Plant

TO: Remote Addressee ([redacted])

CC: [redacted] ([redacted])

Subject: Laporte's Phosgene Hose

I sent an informal survey to Laporte to determine what they use for phosgene "pig tails". The questions and responses are as follows:

1. Please provide a simple description of your phosgene handling and operation. This will allow a better understanding of your design and process needs versus ours.

   * Simple diagram to be sent via FAX.

2. What is the frequency of cylinder changes?.

   * 3-4 times/day

3. What unloading nitrogen pressure do you use for phosgene?

   * 165 psig

4. What is material of construction of hoses or piping that connects the cylinders to the process?

   * Hose is Teflon lined with SS weld necks and SS overbraid.

5. What is length of hose, diameter and type of end fittings?

   * To be sent via FAX.

6. What is frequency
   * Hoses replaced every 3 months. Inspection and pressure testing of hoses done by manufacturer.

7. What materials and design with respect to hoses have you tried?

   * Same hose design but with monel ends and overbraid.

8. What type of failures or leaks have you experienced with current

hoses and those which you may have used in the past.

* Most failures due to fatigue from hose manipulation.

9. Have you considered using a corrugated monel core hose with monel external braiding, which is typical for chlorine service?

   * Yes, but concerns center around flexibility. Hoses must be able to bend 180 degrees and take the abuse of several changes a day.

10. How long has your current design (Hose) been in use. Are there any upgrades you would apply to this system?

   * 3-4 years in use. Contemplated Kynar overbraid but didn't use because of concern around fatigue failure. Would end up changing out hoses on some frequency and hoses are expensive.

11. Just out of curiosity, what type (model) and manufacturer of manual valves do you use in your phosgene system?

   * Engg Spec - T35E Globe Valve - which is the recommended chlorine service valve.

Based on the response from Laporte, it is still possible to use the monel corrugated hose you recommended since we would not apply undue bending stresses. However, we may be applying some twisting stresses as the nut is tightened onto the cylinder valve. Do you still consider this hose as a good candidate or are we better off using SS like Laporte and changing out the hoses on a 3 month interval?

DuPont - Co

INTEROFFICE MEMORANDUM

DuPont Belle Plant
MAY 17 2010

Date: 6-Aug-1987 07:40am
From: [redacted]
Dept: [redacted]URAL PROD DEPT

TO: [redacted] ([redacted])

CC: [redacted] ([redacted])
CC: ( )
CC: ( )

Subject: RE: Laporte's Phosgene Hose

[redacted], you asked a lot of good questions in the questionnaire, but the one that appears to to missing is whether their hose failure frequency is better or worse than ours. I do not think that changing the type of hose we use on our cylinders is one that we can make over an electronic device such as this. I think we need to put down the key factors to consider for each type of hose that we feel is a candidate (which is what I believe that you are doing). Things like resistance to attack by phosgene and ammonium hydroxide, resistance to failure due to external stresses applied, expected failure frequency from whatever cause, frequency of change-out required, cost, availability of supply, etc. Then we ought to get the involved parties together to talk about making a change to be sure that we have not missed something. A change from what we are using may very well be in order, but again I caution that we need to be very certain that we are not making changing to something that is not as good as what we have now. We have to remember that what we are looking at is probably the "weakest link" in a system that routinely handles a very hazardous material. So far I think that the approach you are taking is fine. While we evaluate and make the decision, we need to be absolutely sure that we are replacing what we have frequently enough to assure that we will not have any kind of incident from its use.

INTEROFFICE MEMORANDUM

Date: 12-Aug-1987 03:03pm
From: [redacted]
Dept:
Tel No: [redacted]

TO: Remote Addressee ([redacted])

CC: Remote Addressee ([redacted])
CC: Remote Addressee
CC: Remote Addressee

Subject: PHOSGENE HOSES

I finally got a chance to look at the message you sent about LaPorte's use of phosgene hoses - sorry this reply is so late.

I still believe that Monel is the best choice for material of construction for phosgene unloading hoses (and definitely for fittings). I am surprised that LaPorte is using Teflon-lined hose with stainless overbraid since Teflon is known to be permeable and the phosgene will attack the stainless. But the reason is that they replace them every 3 months because of fatigue problems. Fatigue to the point of hose failure is directly related to the applied stress and the quality of hose construction and is for the most part independent of the material of construction when the candidates are Monel or stainless steel.

Admittedly, the Monel hose will cost more than its stainless counterpart. However, with proper construction, and design so that stresses are minimized (no bends in the hose, a solid jumper used at the cylinder valve so that no torque is applied to the hose), useful life should be much greater than 3 months. Costs will be less in the long run and safety will also be improved.

c.

INTEROFFICE MEMORANDUM

Date: 5-Feb-1988 01:16pm
From: [redacted]

Dept:
Tel No:

TO: [redacted]
TO:

DuPont Belle Plant
MAY 17 2010

Subject: RE: Phosgene Handling

From: NAME: [redacted]
FUNC:
TEL: ([redacted]

Materials compatability with phosgene:

1. Quote from a publication by [redacted], retired Principal Materials Engineering Consultant:

"Phosgene - reacts violently with aluminum, particularly when wet. When wet, can stress crack and corrode austenitic stainless steels (304, 316, etc.). Has cracked stainless steel braid on Teflon transfer hoses. Also has corroded stainless steel cage in Teflon heat exchangers. Ferric chloride formed in phosgene lines has pitted through Incoloy 800 heat exchanger tubes. Natural rubber, neoprene, butyl, and buna N elastomers are unsatisfactory. Hypalon is resistant. Steel is satisfactory for dry phosgene."

2. NACE Corrosion Data Survey shows only the following for phosgene:

Good for steel and cast iron when anhydrous up to 200 F.

Marginal resistance (<20 mpy) by 304/316, copper, and bronze up to 200 F when anhydrous. Unacceptable at less than 100% concentration.

Copper-nickel acceptable up to 200 F when anhydrous. Acceptable at 95% concentration at room temperature.

Monel and Nickel 200 acceptable up to 300 F when anhydrous.

Hastelloy B-2 and C-276 acceptable at 300 F at 10% concentration.

Aluminum has unacceptable corrosion rates at all temperatures and concentrations except anhydrous, where it is good to 200 F.

3. Metals Handbook, volume 13, "Corrosion":

"Under most conditions, particularly at room temperature, aluminum alloys resist halogenated organic compounds, but under some conditions, they may react rapidly or violently with some of these chemicals. If water is present, these chemicals may hydrolyze to yield mineral acids that destroy the protective oxide film of aluminum."

Based on this I would say that you should avoid using aluminum in the presence of phosgene. I do not know what special conditions are needed to cause the rapid reaction or explosion of phosgene with [redacted], but I can certainly find out if you need more info. Corrosion may still be a problem, though, if it is diluted with water and may preclude its use anyway.

The Hastelloy and Monel diaphragms should be inspected occasionally, at least initially, to see how they are doing, but I wouldn't expect a corrosion problem with them unless they see phosgene at less than 100% concentration. Service in this case would be unknown - the data I have on these materials below 100% is incomplete.

Aluminum with alkalies:

Aluminum is not recommended for use or in the presence of any hydroxide solution. The corrosion rate is extremely rapid - ask American Airlines!

[redacted]

DuPont Belle Plant
MAY 17 2010

Appendix G: PHA Recommendation Delay Letter

(Documents in this appendix are redacted for confidentiality)

List of Acronyms, Abbreviations, and Terminology

COCL2	Phosgene
FEL	Front-end loading
PM	Preventive Maintenance
Rec	Recommendation
Rx	Reactor

[redacted] Date 5/17/05

To:
(for approval) [redacted]

From: [redacted]

PHA Recommendation Delay

Area Reviewed: SLM Front End

Year of PHA: 2004

Recommendation ID: 8, 15, 21

Original Due Date: 12/31/05

New Due Date: 12/31/06

Original Recommendation:
8.Complete 2003 Building PHA Recommendation #2.
15. Provide appropriate mitigation to prevent multiple fatalities from the release of a 2000 lb phosgene cylinder.
21. Provide appropriate mitigation to prevent multiple fatalities from phosgene relase as a result of vaporizer tube failure.

Hazard:
8. Fatality from rupture of Rx2, or Rx5, or from phosgene release.
15. Multiple fatalities on and off site from large phosgene release.
21. Fatality from phosgene release

Deficiency:
8. If #2 vent header is being used to purge phosgene from Rx2 or Rx5 for emergency repair of a leaking flange, low eductor flow could cause backflow of water into the reactors and cause reaction of [redacted] and water in reactor and rupture. Also, if #2 vent header is being used to purge phosgene from phosgene system, backflow of water into the phosgene lines could cause corrosion and failure of the phosgene piping.
15. If the full phosgene cylinder were moved with hoist in error instead of the empty cylinder, the phosgene pipes would break and up to 2000 lbs of phosgene could be released.

[redacted]

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21. If there were a vaporizer tube leak during phosgene cleanout, steam pressure would be higher than vaporizer pressure, and steam ingress into the shell side of vaporizer could occur, causing corrosion and failure of the vaporizer. One layer of protection is material of construction of tubes makes tube leak highly unlikely, and there is a PM program for the tubes.

Interim Measures To Be Followed (If none, why not?)
The current operating procedures and practices help prevent any issues with the above deficiencies. After a cleanout of the vaporizer, the system is pressure tested, so if there was an issue with the tubes corroding this is one potential way to detect this issue. A $COCl_2$ generation system is currently being evaluated, and if this was installed the shed enclosure may be designed differently to handle the appropriate chemicals.

[redacted]

 [redacted]

To: [redacted] Date _12/20/06__
(for approval)

From:

PHA Recommendation Delay

Area Reviewed: SLM General Building

Year of PHA: 2004

Recommendation ID: 8,15,21

Original Due Date: 12/31/05

Extended Due Date: 12/31/06

New Due Date: 12/31/08

Original Recommendation:

8. Complete 2003 Building PHA Recommendation #2
15. Provide appropriate mitigation to prevent multiple fatalities from the release of a 2000 lb. phosgene cylinder.
21. Provide appropriate mitigation to prevent multiple fatalities from phosgene release as a result of vaporizer tube failure.

Hazard:

8. Fatality from rupture of Rx 2, or Rx 5, or from phosgene release
15. Multiple fatalities on and off site from large phosgene release
21. Fatality from phosgene release.

Deficiency:

8. If # 2 Vent header is being used to purge phosgene from Rx 2 or Rx 5 for emergency repair of a leaking flange, low eductor flow could cause backflow of water into the reactors and cause reaction of [redacted] and water in reactor and rupture. Also, if #2 vent header is being used to purge phosgene from phosgene system, backflow of water into the phosgene lines could cause corrosion and failure of the phosgene piping.
15. If the full phosgene cylinder were moved with hoist in error instead of the empty cylinder, the phosgene pipes would break and up to 2000 lbs. of phosgene would be released.
21. If there were a vaporizer tube leak during phosgene cleanout, steam pressure would be higher than vaporizer pressure, and steam ingress into the shell side of vaporizer could occur, causing corrosion and failure of the vaporizer. One layer of protection is material of construction of the tubes, making tube leak highly unlikely, and there is a PM program for the tubes.

Why Can Extended Due Date Not Be Met?
Work to define the scope on this item is progressing but not yet complete. We are evaluating potential lower cost alternatives to total shed enclosure.

Summary of Progress To Date:
- Initial front-end loading was completed and a [redacted] prepared to install an enclosed phosgene shed with scrubber.
- Facilities have been changed and procedures put in place to disconnect Rx 2 & Rx 5 from # 2 vent header except for emergency situations and install a Class B interlock to prevent liquid backflow into #2 Vent header. This closes the first deficiency of 2004 PHA Rec. 8.

Interim Measures To Be Followed (If none, why not?)
The current operating procedures and practices help prevent any issues with the above deficiencies. After a cleanout of the vaporizer, the system is pressure tested, so if there were an issue with the tubes corroding, this is one potential way to detect this issue.

To: [redacted] Date: 12/3/08
(for approval)

From:

PHA Recommendation Delay

Area Reviewed: SLM Front End

Year of PHA: 2004

Recommendation ID: #15

Original Due Date: 12/2005

New Due Date: 11/30/09

Original Recommendation: Provide appropriate mitigation to prevent multiple fatalities from the release of a 2000 lb phosgene cylinder.

Why Can Original Due Date Not Be Met? The project is in FEL3 and the schedule indicates completion by August 2009.

Summary of Progress To Date:

The capital project completed most of FEL2 in 2003 but was placed on hold. A Blackbelt study was done in 2005. The capital project was reactivated in 2006 and again placed on hold. The capital project was reactivated again in 2008. The holds on the capital project were due to uncertainty of the future of the facility and due to the cost of the project.

Interim Measures To Be Followed (If none, why not?)

None. No interim measures were identified by the Blackbelt project.

[redacted]

RGA 8/30/00

Date : 11/18/09

To : [redacted] ____________________

[redacted] ____________________

[redacted] ____________________

From : [redacted] ____________________

PHA Recommendation Extension Request

Area Reviewed : SLM General Building

Year of PHA : 2004

Recommendation ID : 15, 21

Original Due Date : 12/31/05

Extended Due Dates : 12/31/06, 12/31/08, 11/30/09

New Due Date : 11/30/2010

Original Recommendations :

15. Provide appropriate mitigation to prevent multiple fatalities from the release of a 2000lb. phosgene cylinder.
21. Provide appropriate mitigation to prevent multiple fatalities from phosgene release as a result of vaporizer tube failure.

Hazards :

15. Multiple fatalities on and off site from large phosgene release.
21. Fatality from phosgene release.

Deficiency :

15. If a full phosgene cylinder was moved with hoist in error instead of the empty cylinder, the phosgene pipes would break and up to 2000 lbs of phosgene would be released.

21. If there were a vaporizer tube leak during phosgene cleanout, steam pressure would be higher than vaporizer pressure, and steam ingress into the shell side of the vaporizer could occur, causing corrosion and failure of the vaporizer. One layer of protection is material of construction of the tubes, making tube leak highly unlikely, and there is a PM program for the tubes.

[redacted]

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Why Can Extended Due Date Not Be Met ?

During FEL 3 for a project to install a phosgene scrubber to address these recommendations, an error in basic data was discovered. This invalidated the original design basis for the scrubbing system, and required a halt to the project activity.

Since that time, a corporate team has been formed and chartered to determine the best means to address the recommendations. The completion date for the team to submit their plan is 11/30/09. The team charter is attached below.

[redacted]

Summary of Progress To Date :

The capital project completed most of FEL2 in 2003 but was placed on hold. A Blackbelt study was done in 2005. The capital project was reactivated in 2006 and again placed on hold. The capital project was reactivated again in 2008. The holds on the capital project were due to uncertainty of the future of the facility and due to the cost of the project.

Front End Loading (FEL) 1 & 2 was completed and a [redacted] prepared to install and enclosed phosgene shed with scrubber. The Basic Data error was discovered during FEL-3.

Interim Measures To Be Followed (If none, why not?)

1. Vaporizer is inspected annually - Last inspection was completed 10/09.
2. Hose assembly system is replaced every 6 months.
3. Hoses are pressure tested before installation.
4. Entire system is pressure tested before campaign start.
5. Procedures require pressure testing connection when cylinders are changed.

PSM Program Compliance

- Preventative Checks
- Special Procedures

HTM Permit Process

- Operator Training
- Up to Date Operating Procedures
- Phosgene Alarm at Cylinder Connection
- Cylinder Capping Kit/First Responder Training

[redacted]

U.S. Chemical Safety and Hazard Investigation Board

Hoeganaes Corporation: Gallatin, TN
Metal Dust Flash Fires and Hydrogen Explosion

January 31, 2011; March 29, 2011; May 27, 2011

5 Killed, 3 Injured

No. 2011-4-I-TN

KEY ISSUES
- Hazard recognition and training
- Engineering controls
- Fire codes/enforcement
- Regulatory oversight

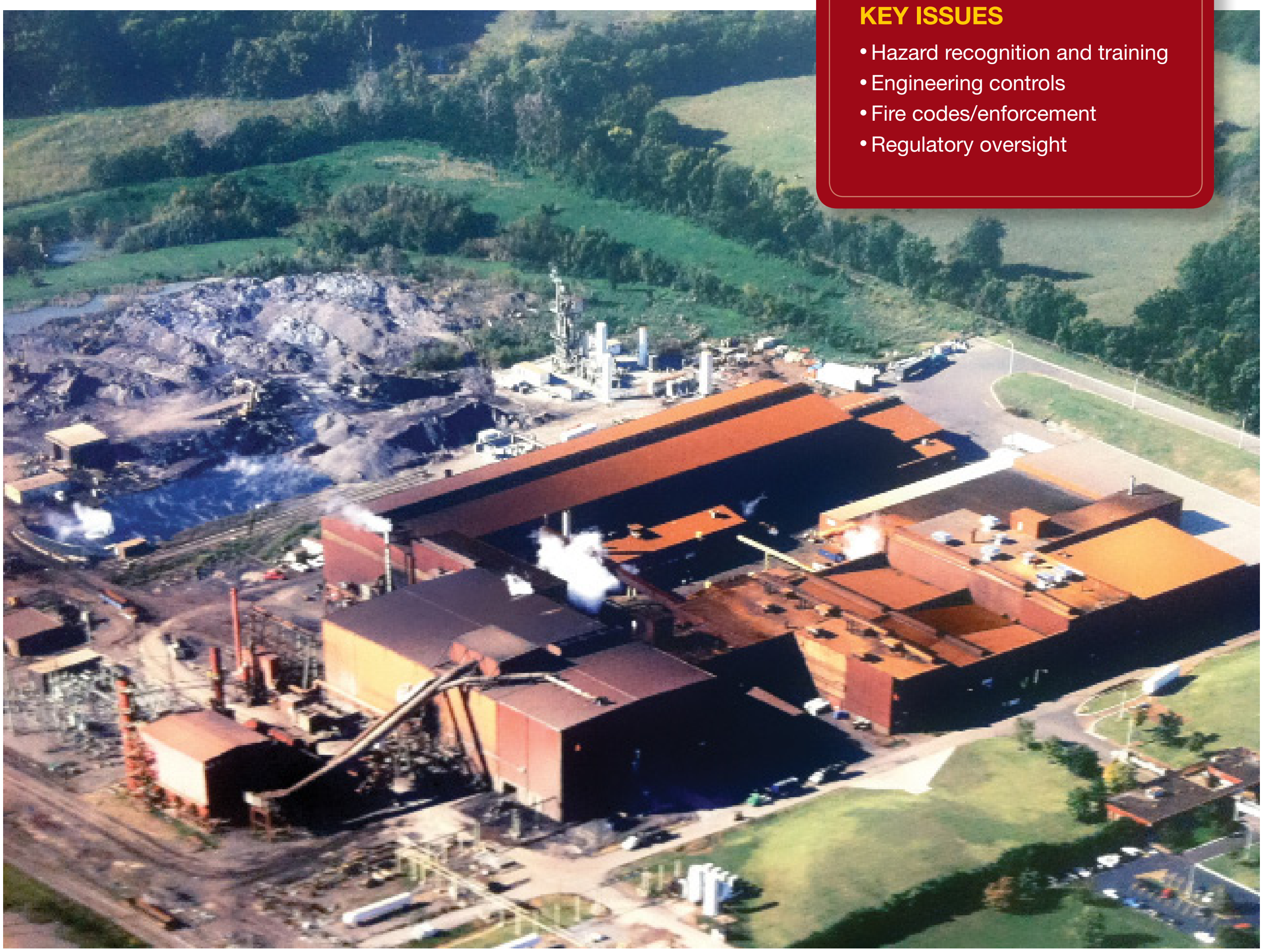

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FIGURE 1

Satellite view of the Hoeganaes Gallatin facility.

1.0 INTRODUCTION

This case study examines multiple iron dust flash fires and a hydrogen explosion at the Hoeganaes facility in Gallatin, TN. The first iron dust flash fire incident killed two workers and the second injured an employee. The third incident, a hydrogen explosion and resulting iron dust flash fires, claimed three lives and injured two other workers.

1.1 HOEGANAES CORPORATION

Hoeganaes Corp. is a worldwide producer of atomized steel and iron powders. Headquartered in Cinnaminson, NJ, Hoeganaes has facilities in the U.S., Germany, China, and Romania.

The Hoeganaes Corp. is a subsidiary of GKN, a multinational engineering company headquartered in the United Kingdom. GKN has businesses in addition to powder metallurgy, including aerospace and automotive driveline industries. GKN acquired the Hoeganaes Corp. in 1999.

The largest consumer for the powdered metal (PM[1]) product is the automotive industry, which presses and sinters[2] the powder into small metal parts.

1.2 FACILITY DESCRIPTION

The Hoeganaes Gallatin facility (Figure 1), located 30 miles northeast of Nashville, Tennessee, employs just under 200 employees. Since becoming operational in the 1980s, they have increased their manufacturing capability over 550 percent from 45,000 to over 300,000 tons.

[1]PM is the accepted acronym by the powdered metals industry.

[2]Sintering is the process of solidifying PM via heat and/or pressure to form a component.

2.0 PROCESS DISCUSSION

Hoeganaes receives and melts scrap steel. Various elements are added to the molten metal to meet customer specifications, but the "workhorse" product, Ancorsteel 1000™, is over 99 percent iron. The molten iron is cooled and milled into a coarse powder that is processed in long annealing furnaces to make the iron more ductile.[3] The furnaces are called "band furnaces," for the 100 foot conveyor belt, or band, that runs through them. A hydrogen atmosphere is provided in the band furnace to reduce the iron by removing oxides and preventing oxidation. The hydrogen is supplied to the facility by a contract provider, onsite. Hydrogen is conveyed to the furnaces via pipes located in a trench under the floor and covered by metal plates.

In the process of going through the furnace, the coarse powder becomes a thick sheet called "cake." The cake is sent to a cake breaker and ultimately crushed into the fine PM product. The majority of the finished PM product has a particle diameter between 45-150 microns, or roughly the width of a human hair (Figure 2).

FIGURE 2

Fine PM collected from the Hoeganaes plant (penny shown for scale).

3.0 THE INCIDENTS

3.1 JANUARY 31, 2011 (TWO FATALITIES)

PM product is transferred through the plant by various mechanisms including screw conveyors and bucket elevators. Bucket elevators have a tendency to go "off-track" when the belt pulling the buckets becomes misaligned. Once sufficiently off-track the strain on the motor increases until the torque is too great and the motor shuts down. On January 31, 2011, at about 5:00 am Hoeganaes plant operators suspected bucket elevator #12 of being off-track and a maintenance mechanic and an electrician were called to inspect the equipment.

[3] Ductility is the physical property of a material where it is capable of sustaining large permanent changes in shape without breaking.

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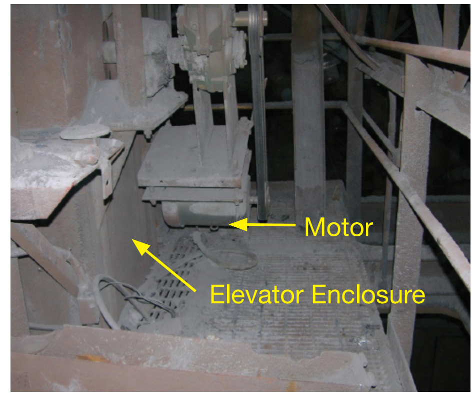
FIGURE 3 (LEFT)

Computer graphic of maintenance workers inspecting bucket elevator #12 just prior to January 31 flash fire.

FIGURE 4 (RIGHT)

Scene of January 31, 2011, incident area.



Based on their observations, they did not believe that the belt was off-track and requested, via radio, that the operator in the control room restart the motor (Figure 4). When the elevator was restarted, vibrations from the equipment dispersed fine iron dust into the air. During a CSB interview, one of the workers recalled being engulfed in flames, almost immediately after the motor was restarted.

FIGURE 5

Computer graphic of January 31 iron dust flash fire.

City of Gallatin emergency responders arrived with ambulances and transported the mechanic and electrician to the Vanderbilt Burn Center in Nashville, TN. Both employees were severely burned over a large percentage of their bodies. The first employee died from his injuries two days later. The second employee survived for nearly four months before succumbing to his injuries in late May 2011.

3.2 MARCH 29, 2011 (ONE INJURED)

As part of an ongoing furnace improvement project, a Hoeganaes engineer and an outside contractor were replacing igniters on a band furnace. The pair experienced difficulty in reconnecting a particular natural gas line after replacing an igniter. While using a hammer to force the gas port to reconnect, the Hoeganaes engineer inadvertently lofted large amounts of combustible iron dust from flat surfaces on the side of the band furnace, spanning 20 feet above him. As soon as the dust dispersed, the engineer recalled being engulfed in flames. He jumped and fell from a rolling stepladder in his attempt to escape the fireball. He received first- and second-degree burns to both thighs, superficial burns to his face, and scrapes from his fall. After seeing the initial flash of the dust igniting, the contractor took evasive action and escaped without injury.

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FIGURE 6 (LEFT)

Computer graphic of the gas line connection involved in the March 29 flash fire.

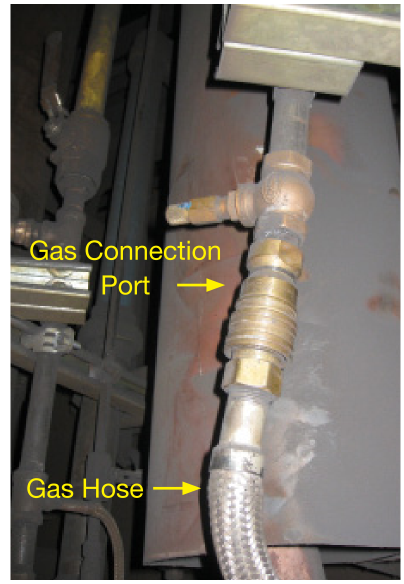

FIGURE 7 (RIGHT)

The gas line connection involved in March 29, 2011, incident.

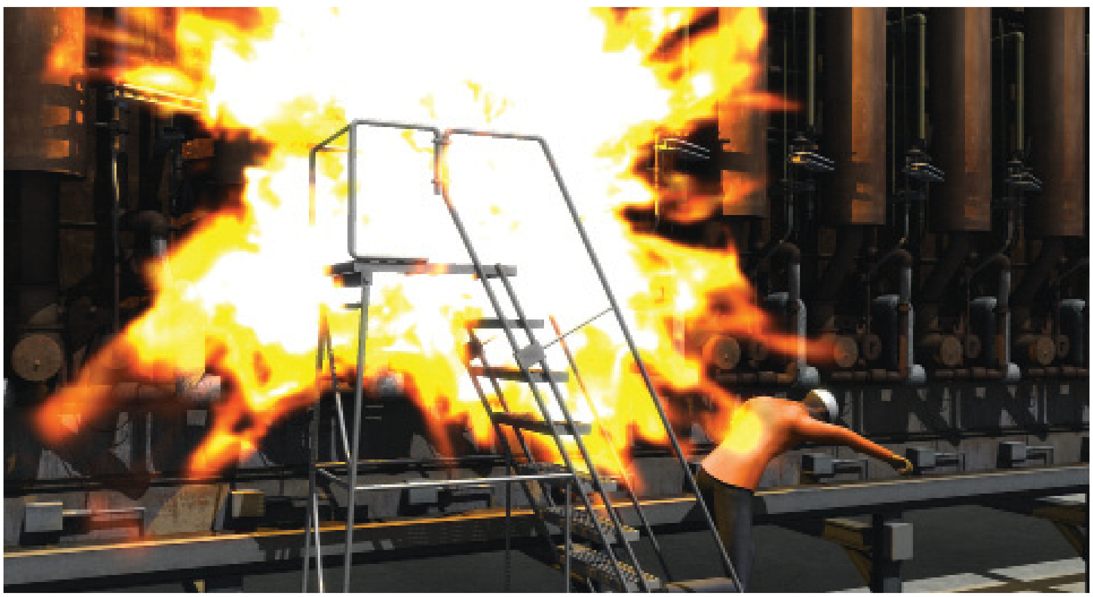

FIGURE 8

Computer graphic of March 29 iron dust flash fire.

The engineer was wearing the Hoeganaes-designated personal protective equipment, which included pants and a shirt that were rated as flame resistant clothing (FRC). He was also wearing an FRC rated jacket that provided extra shielding to his upper torso from the flash fire.

3.3 MAY 27, 2011 (THREE FATALITIES, TWO INJURIES)

Around 6 am on May 27, 2011, operators near band furnace #1 heard a hissing noise that they identified as a gas leak. The operators determined that the leak was in a trench, an area below the band furnaces that contains hydrogen, nitrogen, and cooling water runoff pipes, in addition to a vent pipe for the furnaces. The operators informed the maintenance department about the hissing, and six mechanics were dispatched to find and repair the leak. One annealing area operator stood by as the mechanics sought out the source of the leak.

Although maintenance personnel knew that hydrogen piping was in the same trench, they presumed that the leak was nonflammable nitrogen because of a recent leak in a nitrogen pipe elsewhere in the plant and began to try to remove trench covers. However, the trench

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FIGURE 9 (TOP)

Scene of the May 27 incident before (left, taken during the CSB's January 31 incident investigation) and after (right). Note visible accumulations of iron powder on surfaces. Circled areas show trench cover location.

covers were too difficult to lift without machinery. Using an overhead crane, they were able to remove some of the trench covers. They determined that the leak was near the southernmost trench covers, which the crane could not reach. Shortly after 6:30 am, maintenance personnel acquired a forklift equipped with a chain on its forks, and were able to reach and begin removing the southernmost trench covers.

FIGURE 10 (RIGHT)

Computer graphic of maintenance crews starting to remove the trench covers using a forklift just prior to May 27 explosion.

Interviews with eyewitnesses indicate that just as the first trench cover was wrenched from its position by the forklift, friction created sparks, followed by a powerful explosion. Several days after the explosion, CSB investigators observed a large hole (approximately 3 x 7 inches) in a corroded section of piping that carried hydrogen and ran through the trench (Figure 11).

As the leaking hydrogen gas exploded, the resulting overpressure dispersed large quantities of iron dust from rafters and other surfaces in the upper reaches of the building. Portions of this dust subsequently ignited. Multiple eyewitnesses reported embers raining down and igniting

FIGURE 11 (TOP LEFT)

Hole in 4-inch piping after the May 27, 2011, incident.

FIGURE 12 (TOP RIGHT)

Computer graphic of the May 27, 2011, hydrogen explosion.

FIGURE 13 (BOTTOM)

Upward disturbance of trench covers caused by the hydrogen explosion in the May 27, 2011, incident.

multiple dust flash fires in the area. They also reported visibility so limited in some instances that flashlights were required; one eyewitness said that even with a flashlight, he could see only 3 to 4 feet ahead due to extensive dust and smoke.

The hydrogen explosion and ensuing iron dust flash fires injured four of the responding mechanics and the annealing operator.[4] The two mechanics near the forklift were transported to a local hospital where they were treated for smoke inhalation and released shortly thereafter.

Two other mechanics and the operator who stood by during the operation were rushed to Vanderbilt Burn Center. Less than a week after the incident, two employees succumbed to their injuries. The third seriously injured employee died from his injuries almost seven weeks after the incident.

Due to the extensive nature of the injuries, and the abundance of both hydrogen and combustible dust present at the time of the incident, it is difficult to specifically determine which fuel, if not both, caused the fatal injuries to the victims.

3.4 EMERGENCY RESPONSE

The Gallatin Fire Department (GFD) has responded to 30 incidents of various types over the past 12 years at the Hoeganaes Corp., including the January 31, March 29, and May 27 incidents. In June 1999, the GFD responded to a fire caused by iron dust that ignited in a baghouse. One person suffered smoke inhalation injuries as a result of the incident.

Before the GFD arrived at each of the 2011 incidents, Hoeganaes volunteer first responders cared for the injured. Hoeganaes volunteers participate in annual training that covers first response, CPR, and first aid. They are instructed to provide care until GFD and EMS responders arrive.

Immediately following each incident, the volunteers provided first aid and comfort to the injured by applying water to cool the burns and covering the victims with a burn blanket to keep them comfortable. EMS arrived within minutes of the initial 9-1-1 call and transported the injured personnel to hospitals.

[4] At the time of incident, two of the mechanics and the operator were standing near the trench while the other two mechanics were positioned and possibly shielded by the forklift when the explosion occurred.

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4.0 ANALYSIS

4.1 COMBUSTIBLE DUST TESTING

According to National Fire Protection Association (NFPA) 484, *Standard for Combustible Metals*, a facility that handles metal dust should commission one of two screening tests to determine if a metal dust is combustible and the provisions of the standard apply (Section 4.4.1). If results from either of the two tests show that the dust is combustible or explosible, NFPA 484 would apply to the facility either as a matter of voluntary good practice or as a requirement by a relevant regulatory body.

The first screening test for the determination of combustibility, also known as the "train test," measures the burning rate of a dust layer over the length of a sample.[5] If there is propagation beyond the ignition point or heated zone, then the sample is considered combustible.[6]

The second test, for explosibility determination, serves as a basis to determine if a metal powder or dust is capable of initiating an explosion when suspended in a dust cloud. This test, performed in a Hartmann apparatus, determines the minimum ignition energy of a dust cloud in air by a high voltage spark.[7]

If either of the screening tests produces a positive result for combustibility or explosibility, NFPA 484 requires further explosibility testing be conducted in a 20-L sphere. Several values (below) from the explosibility test results can be used to characterize the severity of a dust explosion.

EXPLOSIVITY VALUES

K_{St}: calculated value that compares the relative explosion severity and consequence to other dusts (bar m/s). The higher the K_{St} number, the more energetic the explosion.

P_{max}: maximum explosion overpressure generated in the test vessel (bar)

$\partial P/\partial t$: maximum rate of pressure rise, predicts violence of the explosion (bar/s)

Explosion Severity (ES): Index to determine if Class II electrical equipment is required as an OSHA requirement.

ES > 0.5, Class II Combustible
ES < 0.4, Combustible but not Class II

4.1.1 CSB COMBUSTIBLE DUST TESTING

4.1.1.1 Combustibility Demonstration

In order to visually demonstrate the combustibility of the Hoeganaes iron samples, a modified "Go/No-Go" test was performed by the CSB. Generally, this test is performed in a closed vessel, but the CSB was interested in directly observing any flames the dust may produce.[8]

[5] UN Recommendations on the Transport of Dangerous Goods: Model Regulations – Manual of Tests and Criteria, Part III, Subsection 33.2.1

[6] NFPA 484 defines a combustible metal dust as a particulate metal that presents a fire or explosion hazard when suspended in air or the process specific oxidizing medium over a range of concentrations, regardless of particle size or shape.

[7] ASTM E2019, Standard Test Method for Minimum Ignition Energy of a Dust Cloud in Air

[8] The "Go/No-Go" test is typically performed in a modified one-liter Hartmann tube; also known as the explosibility screening test as described in NFPA 484.

This test dispersed about 30 grams of iron dust—sampled from the baghouse[9] associated with the bucket elevator from the January 31, 2011, incident—above an 8 inch burner. Upon being released, the dust auto-ignites in air due to the heat given off from the burner below (Figure 14). An intense white flame was produced that reached a peak diameter of 18 inches.

FIGURE 14

CSB iron dust combustibility demonstration, see Section 4.1.1.1.

4.1.1.2 20-Liter (20-L) Test Method

CSB investigators collected iron powder samples from various locations in the Hoeganaes facility and commissioned testing to characterize its combustibility using two different test methods, the 20-liter (20-L) and one-meter cubed (1-m^3) test chambers. The 20-L test laboratory used the standard test method, ASTM E1226, *Pressure and Rate of Pressure Rise for Combustible Dusts*, for the selected iron powder samples. Each dust sample was injected and ignited in a 20-L spherical test vessel equipped with transducers to record a pressure-versus-time profile of the dust deflagration in the sphere.

Table 1 shows data from the CSB's combustibility tests of the Hoeganaes dust and a comparison to dust testing the CSB commissioned for previous dust incidents at other companies.

The CSB test data indicate that the iron powder is combustible and is covered by the requirements of NFPA 484 (Section 4.4.1). Although values indicate that the dust produces a weak explosion relative to other dusts, the dust is considered combustible by the OSHA definition[10] and can result in a flash fire capable of causing injuries and fatalities.

[9] Ventilation equipment that removes airborne particulate by forcing air through a specially designed filtration bag.

[10] OSHA 3371-08 2009: "a solid material composed of distinct particles or pieces, regardless of size, shape, or chemical composition, which presents a fire or deflagration hazard when suspended in air or some other oxidizing medium over a range of concentrations."

TABLE 1

Combustibility data for selected materials.

20-L COMBUSTIBLE DUST TEST DATA FROM CSB INVESTIGATIONS[11]					
	Hoeganaes Iron Dust 20L test[12]	Granulated Sugar	Aluminum Dust	Polyethylene Dust	Phenolic Resin
P_{max} (bar)	3.5	5.2	9.4	8.34	7.58
$\partial P/\partial t$ (bar/s)	68	129	357	515	586
K_{St} (bar m/s)	19	35	103	140	165
Explosion Severity (ES)	0.077	0.22	1.08	1.38	1.43
Classification	Combustible	Combustible	Combustible, Class II	Combustible, Class II	Combustible, Class II

Frequently, the hazards of different combustible dusts are evaluated by their potential explosive capabilities. However, the hazards of combustible dusts are not limited to explosions. The Hoeganaes iron powder propagates an explosion less rapidly compared to other dusts, so there is less overpressure damage, consistent with observations by CSB investigators. Dust testing results from Hoeganaes and prior CSB investigations illustrate that dusts with low K_{St} values can cause flash fires that result in deaths and serious injuries. Although combustible dusts can lead to explosions, combustible dust flash fires also pose a risk that must be addressed in industry.

According to the 20-L standard test method, E1226, a dust sample can be defined as combustible or explosible based on a calculated pressure ratio (PR) using the pressure data recorded in the 20-L test chamber. For sample concentrations of 1,000 and 2,000 g/m^3, a pressure ratio value greater than or equal to 2 is considered explosible. If the pressure ratio is less than 2, the sample is considered non-explosible. However, the test method cautions that the dust can still burn and a dust cloud may experience a deflagration depending upon conditions such as the temperature and particle size.[13] The iron dust sample from baghouse #4 had a PR of 4.0 and 4.7 at concentrations of 1,000 and 2,000 g/m^3 respectively, indicating that the dust sample is explosible.

4.1.1.3 One-Meter Cubed (1-m^3) Test Method

The CSB collected a subsequent sample[14] from baghouse #4 and subjected it to combustibility testing using the one-meter cubed (1-m^3) method, ISO 6184-1 *Explosion Protection Systems: Determination of Explosion Indices of Combustible Dusts in Air*. The 1-m^3 test vessel is larger than the 20-L vessel, and the dust, along with air and a fuel source, is injected into the system differently.

The iron powder from baghouse #4 underwent an explosibility screening test in the 1-m^3 vessel in an attempt to ignite the sample. At several dust concentrations, none of the tests produced significant pressure which exceeded the test qualifications for ignition and therefore the dust sample was considered non-explosible according to this method.

[11] For a more detailed discussion on characteristic combustible dust values, see CSB 2006-H-1 *Combustible Dust Hazard Study.*

[12] CSB investigators collected this iron dust sample from baghouse #4 at the Hoeganaes Gallatin facility after the January 31, 2011, incident.

[13] American Society for Testing and Materials (ASTM), E1226-10, *Pressure and Rate of Pressure Rise for Combustible Dust*, ASTM International, 2010.

[14] At the time this sample was taken in August 2011, the Gallatin facility had not been fully operational for about three months. As such, the sample collected did not contain fines representative of the environment at the time of the 2011 flash fire incidents.

4.1.1.4 Comparing Dust Testing Methods

Both the 20-L and 1-m^3 tests are accepted methods that can characterize dust explosibility; however results from the two tests may differ. There are several factors that can contribute to varying results among the dust test methods. Dust characteristics, such as particle size, moisture content, and degree of oxidation (for metals) can affect the ignitability of the sample in the test chamber.

The 20-L and 1-m^3 test chambers were designed to simulate dust explosions in facility settings, but each test has limitations. The main difference between the two tests is the chamber size and the dust dispersion mechanism. Since the 1-m^3 test is larger, theoretically it can better simulate an open-space dust cloud explosion. However, that larger volume also makes it harder to create a uniform distribution of dust within the testing chamber. In the smaller 20-L test chamber it is easier to create a uniform distribution; however, it is possible that the smaller chamber also creates an "overdriving" effect. Since the 20-L chamber is smaller, the energy exerted by the igniters[15] may combust enough dust creating the appearance of ignition[16] — a situation that would not occur in a facility setting.

NFPA revised the 2012 edition of NFPA 484 to state that explosibility screening tests shall be performed in accordance to the 20-L test standard, E1226. However, NFPA added to the standard annex that the results of the 20-L test can be conservative and an owner or operator of a facility may elect to use a 1-m^3 test for dust explosibility testing as the 20-L test may result in false positives for dusts with lower K_{St} values.

Despite the discrepancies between the two test methods, the empirical evidence from the flash fire incidents at Hoeganaes shows that dusts with lower K_{St} values are capable of fueling flash fires with severe consequences. This further suggests that facilities should not rely on the 1-m^3 test as a sole determination of dust combustibility hazards. Dusts with lower K_{St} values and characteristics similar to the iron powder at Hoeganaes may not ignite in the 1-m^3 chamber but still have the ability to result in fatal flash fires.

It should be noted that both tests are for *explosibility* screening, and alone may not convey the full *combustibility* hazard.

4.1.2 HOEGANAES COMBUSTIBLE DUST TESTING

4.1.2.1 Minimum Ignition Energy (MIE)

In 2010, Hoeganaes contracted to test iron dust samples from the plant for combustibility as a result of an insurance audit recommendation. The test had one sample that was similar in particle size, moisture content, and location to the dust involved in the 2011 incidents. That sample gave the results seen in Table 2.

The minimum ignition energy (MIE) testing determined that a continuous arc did ignite the representative samples from 2010, but a 500 mJ source did not. The conclusion from the testing was that the minimum ignition energy was greater than 500 mJ. This information is valuable in determining potential ignition sources for each of the incidents.

[15]The igniter may increase the temperature in the smaller 20-L chamber, raising the overall temperature of the system and allowing a non-explosive system to appear explosive.

[16]Going, J et al., "Flammability limit measurements for dust in 20-L and 1-m^3 vessels." *Journal of Loss Prevention in the Process Industries*. May 2003

TABLE 2

Combustible dust test results commissioned by Hoeganaes in 2010.

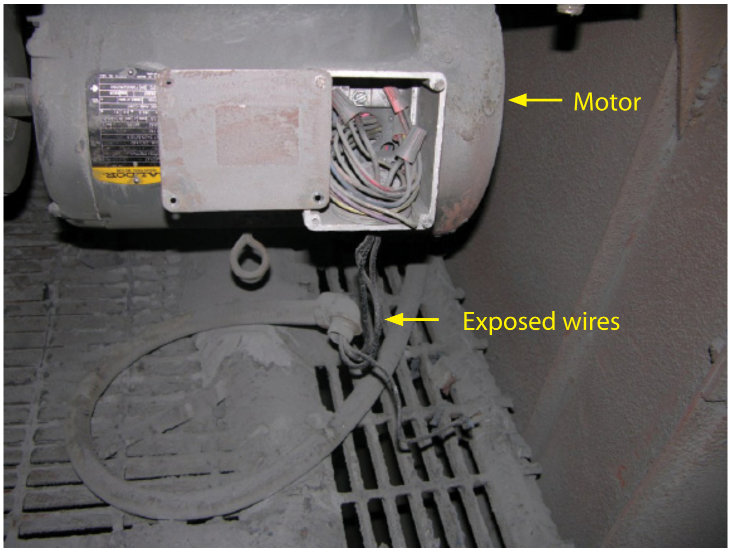
HOEGANAES MINIMUM IGNITION ENERGY (MIE) TEST RESULTS	
Sample	Iron Dust
Particle size (%<75 μm)	99%
P_{max}(bar)	3.3
$(\partial P/\partial t)_{max}$ (bar/s)	51
K_{St} (bar*m/s)	15
MIE (mJ[17], Cloud)	>500
MIT[18] (°C,Cloud)	560-580
MEC[19] (g/m³)	200-250

4.2 IGNITION SOURCES

Witnesses indicated that the May 27, 2011, hydrogen explosion was ignited by sparks generated during the lifting of the trench cover. This is reasonable considering that the MIE of hydrogen is 0.02 mJ, and the energy of mechanical sparks from metal to metal contact can be several mJ.[20]

FIGURE 15

Exposed electrical wiring on elevator motor near January 2011 incident site (motor panel cover was rotated post incident by fire department).



The testing contracted by Hoeganaes in 2010 determined that the minimum ignition energy for representative iron dust samples was greater than 500 mJ, and that a continuous arc would ignite the samples. One witness at ground level reported hearing an "electric sound" at the time of the incident. The motor operating bucket elevator #12 was a likely source of ignition since it had exposed wiring, was not properly grounded, and was within a few feet of the dust cloud source. The wiring was exposed because the electrical conduit supplying power to this motor was not securely connected to the motor's junction box.

[17]mJ is an abbreviation for millijoules, which is a unit of energy. One Joule is equal to 1000 millijoules or approximately 0.24 calorie.

[18]Minimum Ignition Temperature.

[19]Minimum Explosible Concentration.

[20]V. Babrauskas, Ignition Handbook, Fire Science Publishers, Issaquah, WA, 2003.

Prior to the CSB notifying Hoeganaes that evidence from the incident area needed to be preserved, the company removed and modified evidence from the scene, including the elevator motor, wiring, and conduit. However, on examination, there were spots that appeared to be arc marks both inside the junction box, and on the outside of the motor housing.

4.3 HOEGANAES

4.3.1 HAZARD RECOGNITION

FIGURE 16

Mounds of iron dust along elevated surfaces at the Gallatin plant, February 3, 2011.

In general industry the combustibility of metal dust is a well-established hazard, but metal dust fires and explosions continue to claim lives and destroy property. The CSB reviewed three publications dating back to the 1940s and 1950s that addressed metal dust (including iron dust) hazards and explosion protection methods. The National Fire Protection Association (NFPA) code for the Prevention of Dust Explosions, published in 1946,[21] lists general precautions for all types of dusts, including metal powder, and specific provisions for certain types of dusts.

The Building Construction section of the code states, "Avoid beams, ledges or other places where dust may settle, particularly overhead." The Gallatin facility, built in the 1980s, was not designed to avoid significant overhead accumulations of dust. The code calls for designing and maintaining dust-tight equipment to avoid leaks and, where this is not possible, to enforce good housekeeping procedures.

The code also cautions against sources of ignition in areas containing dust and recommends locating dust collectors outdoors or in separate rooms equipped with explosion venting.

In 1957, the NFPA published the *Report of Important Dust Explosions* which included a summary of over 1,000 dust explosions between 1860 and 1956 in the U.S. and Canada.[22] The report listed 80 metal dust fires and explosions, including one iron dust incident that resulted in a fatality in 1951.

A 1958 article in an American Chemical Society publication states, "Powdered metals dispersed in oxygen or air form explosive mixtures… their flammability and explosibility have been reported in considerable detail…"[23]

[21] National Fire Codes, Vol. II. The Prevention of Dust Explosions 1946. National Fire Protection Association, Boston, MA., 1946.

[22] National Fire Protection Association, *Report of Important Dust Explosions*, NFPA, Boston, MA, 1950.

[23] Grosse, A.V., and J.B. Conway. "Combustion of Metals in Oxygen." *Industrial & Engineering Chemistry* 50.4 (1958): 663-72.

In the 1990s and 2000s, the Pittsburgh Research Laboratory of the National Institute for Occupational Safety and Health (NIOSH) conducted a study of the explosibility of various metals, including iron. The results of these experiments, published in scientific journals,[24] showed the explosibility characteristics of iron powder to aid hazard evaluation in metal processing industries. However, management within the Hoeganaes Corp. and GKN Corp. did not commission an analysis of its own potentially combustible PM products and constituents until January 2009, as a result of an insurance audit conducted in 2008. This combustible dust testing concluded that all three iron powder samples collected from various locations in the plant were explosible (Section 4.3.6.1). However, these results did not trigger an effective overhaul of the dust containment and housekeeping procedures at the Gallatin facility.

Representatives from Hoeganaes told the CSB that the dust analysis results did trigger an operator training program for the recognition of combustible dust hazards. However, Hoeganaes did not mitigate the dust hazard. Since Hoeganaes did not control the combustible dust hazard, operators were forced to tolerate the conditions at the facility. Over time, these flash fires became normalized, since they did not result in any serious injuries prior to the fatal incident on January 31, 2011.

Operators and mechanics reported being involved in multiple flash fires during their employment at the Gallatin facility. At the time of the incidents, many were aware that the iron dust could burn or smolder. However, they were not trained to understand the potentially severe hazard when accumulated dust is dispersed in air. Rarely would operators report the minor flash fires and near-misses that periodically occurred.

4.3.2 ENGINEERING CONTROLS

4.3.2.1 Combustible Dust

Thorough hazard recognition is key to effectively managing the risk from combustible dust. Once the hazard is recognized, applying the “hierarchy of controls” for fire and explosion prevention helps address the fugitive dust issue at the source: the material itself, the processing equipment, and the work procedures. The hierarchy of controls is a safety concept in which a hierarchal ordering of control mechanisms is applied to reduce risk. It covers the spectrum from elimination at the source, at the top of the hierarchy, through engineering and administrative (procedural) controls to personal protective equipment (PPE), at the bottom of the hierarchy.[25]

Installing and maintaining engineering controls to eliminate fugitive dust accumulation is the most effective method to prevent dust fires and explosions. Conveyance systems and appropriately sized dust collection equipment are examples of engineering controls that eliminate or mitigate fugitive dust generation at the source. Engineering controls are preferred over housekeeping, but a robust housekeeping program is important to manage fugitive dust accumulations in areas where engineering controls need maintenance or improvement. Additionally, administrative controls, such as worker training and operating procedures, complement robust engineering controls.

Significant quantities of iron dust escaped from equipment throughout the Hoeganaes facility. Enclosures on the conveyance equipment leaked fugitive emissions of iron dust.. In addition, the dust collection systems were historically unreliable and did not prevent large amounts of combustible iron dust from becoming airborne and accumulating on elevated surfaces throughout the processing areas.

[24]Cashdollar, K., Flammability of Metals and Other Elemental Dust Clouds. Loss Prevention Symposium. AICHE 1994.
Cashdollar, K., Zlochower, I., Explosion Temperatures and Pressures of Metals and other Elemental Dust Clouds. Journal of Loss Prevention in the Process Industries 20 (337-348) 2007.

[25]Kletz, T., Amyotte, P., *Process Plants: A Handbook for Inherently Safer Design*. CRC Press, 2010.

4.3.2.2 Hydrogen

The trench involved on the May 27, 2011, incident contains many pipes including nitrogen and hydrogen supply and vent pipes for the band furnaces. In addition to housing pipes, the trench also acts as a drain for the cooling water used in the band furnaces. At the time of the incident this water came out of the furnaces hot and drained directly onto the pipes and into the trench (Figure 17).

FIGURE 17

Water flow (upper left of photo) and externally corroded pipes in the trench involved in the May 27, 2011, incident.

STANDARDS THAT ADDRESS THE HYDROGEN SUPPLY AND VENT PIPES IN THE TRENCH INCLUDE:

- ASME[26] B31.3, Process Piping
- CGA[27] G-5.4-2010, Standard for Hydrogen Piping Systems at User Locations
- NFPA 2, Hydrogen Technologies Code
- NFPA 55, Compressed Gases and Cryogenic Fluids Code.

According to ASME B31.3, design concerns about ambient conditions around process pipes focus on environments and changes that can create physical stresses in the piping. Section 10.5.3 of NFPA 55 requires annual maintenance including inspection for physical damage and leak tightness. CGA G-5.4 similarly requires regular inspection for physical damage and leak tightness. However, Hoeganaes did not regularly inspect the pipes in the trench. The design and maintenance of this trench, should have addressed the issue of slow corrosion over time caused by the hot water runoff and solids accumulation.

Both NFPA 55 and NFPA 2 state, "Provisions shall be made for controlling and mitigating unauthorized discharges." NFPA 2 further requires that "the storage, use, or handling of [hydrogen] in a building or facility shall be accomplished in a manner that provides a reasonable level of safety… from illness, injury or death…" However, the CSB found no evidence of a Hoeganaes procedure to inspect piping within the trench to ensure that corrosion had not compromised the piping systems which would allow an uncontrolled release of hydrogen. Moreover, Hoeganaes had no written procedure or protocol to mitigate gas leaks, and maintenance crews were allowed to begin investigating a suspected leak without testing the atmosphere for concentrations of explosive gas.

4.3.3 ADMINISTRATIVE CONTROLS

4.3.3.1 Housekeeping

Observations by CSB investigators at the Gallatin facility shortly after the first incident indicated that combustible dust was leaking from equipment and that housekeeping was ineffective (see Figures 16, 18, 19, 20 and 21). Combustible iron dust coated almost every

[26] The American Society of Mechanical Engineers (ASME) is a professional body focused on mechanical engineering. The organization is known for setting codes and standards for mechanical devices. The ASME conducts one of the world's largest technical publishing operations through the ASME Press. The organization holds numerous technical conferences and hundreds of professional development courses each year, and sponsors numerous outreach and educational programs.

[27] The Compressed Gas Association (CGA) develops and publishes technical information, standards, and recommendations for the manufacture, storage, transportation, distribution, and use of industrial gases.

FIGURE 18 (LEFT)

Iron dust on rafters, February 3, 2011.

FIGURE 19 (RIGHT)

Iron dust on overhead surfaces, February 3, 2011.

surface up to 4 inches deep and was visible in the air. Mitigation of the combustible dust hazard by Hoeganaes was limited to a less-than-adequate vacuuming service, sparsely enclosed conveyance equipment, and an inadequate baghouse filtration system.

Although bucket elevators and some conveyance equipment were enclosed, fugitive dust emissions were evident throughout the facility. Moreover, the CSB investigators observed leaks of fugitive dust to the atmosphere when the bags used in the baghouse filtration system were pulsed, which allowed dust to escape into the work areas many times each hour. The baghouse filters are designed to collect the smallest, and consequently most dangerous, dust particles. Yet, the CSB found that the baghouses were often out of service. Employees reported that the baghouse associated with bucket elevator #12 was out of service sporadically for the 7 days leading up to the fatal incident on January 31, 2011, allowing fine combustible iron dust to remain in the area, from which it was dispersed when the elevator was restarted during maintenance.

FIGURE 20

Iron dust on structural supports, February 3, 2011.

4.3.4 PERSONAL PROTECTIVE EQUIPMENT

4.3.4.1 Flame Resistant Clothing (FRC)

Workers in production-related operations wear flame resistant clothing (FRC) to reduce risk of thermal injury from flash fire incidents. As part of the Personal Protective Equipment (PPE) Standard (29 CFR 1910.132), OSHA requires employers to provide workers with FRC in workplaces when flash fire or explosion hazards are present.

FRC can reduce the severity of burn injuries sustained during a flash fire when engineering and administrative controls fail. FRC, usually worn as coveralls, is made of treated natural or synthetic fibers that resist burning and withstand heat.

There are two NFPA standards that provide guidance on the design and use of FRC. NFPA 2112, *Standard on Flame-Resistant Garments for Protection of Industrial Personnel Against Flash Fire*, provides the minimum requirements for the design, testing, and certification of FRC. NFPA 2113, *Standard on Selection, Care, Use, and Maintenance of Flame-Resistant Garments for the Protection of Industrial Personnel Against Flash Fire*, provides guidance for the selection, use, and maintenance of FRC. The 2009 edition of NFPA 484 included a requirement for workers to wear FRC if working in metal dust-handling operations, but it did not specifically reference NFPA 2112 or 2113 in the standard. The 2012 edition of NFPA 484 requires that new and existing facilities covered by the standard adhere to the requirements of NFPA 2113 for FRC.

Hoeganaes employees were required to wear FRC, and the injured and fatally injured employees were wearing the Hoeganaes-designated FRC at the time of the 2011 flash fire incidents. Though FRC is intended to reduce the severity of thermal injuries, five severely burned employees died following the January and May incidents. The specific FRC worn did not provide any significant protection against the combustible iron dust flash fires and the hydrogen explosion at Hoeganaes.

4.3.5 1992 INCIDENT

On May 13, 1992, a hydrogen explosion and iron dust flash fire similar to the May 2011 incident in Gallatin severely burned an employee working at the Hoeganaes facility in Cinnaminson, NJ. CSB investigators interviewed the injured employee from the 1992 incident and learned that a hydrogen explosion event in a furnace dispersed and ignited significant accumulations of iron dust which resulted in thermal burns over 90% of his body. The injured worker spent a year in a burn unit and is still recovering from his burn injuries.

4.3.6 INSURANCE INSPECTIONS

4.3.6.1 Allianz

TABLE 3

Dust explosibility test results commissioned by Hoeganaes in 2009.

HOEGANAES IRON DUST EXPLOSIBILITY TESTING			
(20-L)			
Sample	Base Iron	Furnace Feed	Baghouse Dust
P_{max}(bar)	1.9	2.8	3.8
$\partial P/\partial t$ (bar/s)	273	63	80
K_{St} (bar m/s)	74	17	22

In November 2008, Allianz, a German-based risk insurer, conducted a routine audit of the Hoeganaes facility. The audit report noted that improved housekeeping was needed in several areas of the facility. In the list of risk improvement proposals, the Allianz report stated, "The potential for explosions caused when clouds of powdered metal are aroused in equipment… should be analyzed by an independent consultant." The proposal recommended an independent dust hazard analysis and a subsequent hazard study to identify suitable mitigation techniques, should the iron dust in the facility be found to be explosible.

In January 2009, Hoeganaes collected samples of base iron dust, furnace-feed dust, and baghouse dust and commissioned explosibility testing as Allianz recommended (Table 3). In September 2010, Hoeganaes requested another test of various powdered metals. Test results showed that 5 of the 9 iron samples had K_{St} values greater than 1.

The Allianz audit findings initiated several action items as part of the Hoeganaes Combustible Dust Program at the Gallatin facility. The scope of the program was to understand and align company practices with the OSHA Combustible Dust National Emphasis Program (NEP) (Section 4.5.1). Action items included combustible dust training for employees and understanding relevant NFPA codes at the facility. Although the majority of the Hoeganaes Combustible Dust Program action items had planned completion dates prior to the 2011 flash fire incidents, the program did not effectively mitigate the combustible dust hazards at the facility.

4.4 FIRE CODES

4.4.1 NFPA 484

NFPA 484, *Standard for Combustible Metals*, an industry consensus standard, applies to facilities that produce, process, finish, handle, recycle, and store metals and alloys in a form capable of combustion or explosion. NFPA codes involving combustible metal dusts have evolved several times since the 1946 *The Prevention of Dust Explosions* (Section 4.3.1). In the 1950s, the NFPA divided the 1946 document into several codes for specific materials, such as magnesium and titanium. In 2002, all of the NFPA combustible metal dust standards were combined into NFPA 484. NFPA 484 describes the tests and methods for determining metal dust combustibility and provides guidelines for preventing dust explosions and flash fires for all types of metal dusts.

The CSB commissioned testing similar to the 2009 edition of NFPA 484 explosibility determination test requirements (Section 4.1). The testing concluded that the Hoeganaes metal dust sample is explosible and therefore NFPA 484 applies.

Had Hoeganaes voluntarily followed, or been required to follow, NFPA 484 by the GFD (authority having jurisdiction[28]) the January and March incidents may have been prevented, and the effects of the May accident could have been reduced. As with many NFPA standards, NFPA 484 has a retroactivity clause for certain chapters, stating that requirements for all existing equipment, installed prior to the current edition of the code, are not enforceable by the authority having jurisdiction, unless it is determined that the existing situation presents an unacceptable safety and health hazard.

FIGURE 21

Photo of equipment obscured by airborne dust, taken by CSB investigators, February 7, 2011.

Neither the City of Gallatin nor the GFD identified combustible metal dust as a concern or hazard during previous inspections conducted prior to the 2011 incidents (Section 4.4.3).

Chapter 12 of NFPA 484, "Requirements for Combustible Metals" includes provisions to control or eliminate dust fires and explosions. It requires engineering controls for dust-producing processes such as enclosures and capture devices connected to dust collection systems. The standard describes recommended housekeeping practices and frequencies, and how to control ignition sources.

Practices at Hoeganaes did not conform to the safety recommendations set forth in NFPA 484. Under "Building Construction," NFPA 484 requires that floors, elevated platforms, and gratings where dust can accumulate be designed to minimize dust accumulations and facilitate cleaning.[29] The Hoeganaes facility has numerous flat surfaces overhead upon which the CSB investigators observed significant accumulations of combustible iron dust. Since Hoeganaes has an iron powder-producing operation, specific engineering controls outlined in NFPA 484 apply to the machines that manufacture and convey the PM. All machines that produce fine particles of iron should be connected to a dust collection system that has the appropriate velocity to capture all dust. The CSB investigators observed that some of the PM conveyance equipment at

[28]The organization, office, or individual responsible for approving equipment, materials, an installation, or a procedure.

[29]Chapter 12 is not retroactive to existing facilities.

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Hoeganaes's was not enclosed; as such, it was not designed to control significant dust emissions, and employees further reported that baghouse dust collectors were often down for maintenance. This section of the standard also requires that dust collection systems be located outdoors; at Hoeganaes, the baghouses are located inside, posing a serious fire and explosion hazard.

Chapter 13 of NFPA 484 includes provisions for housekeeping and applies to all new and existing facilities. It requires that accumulations of excessive dust on any portions of buildings or machinery not regularly cleaned in daily operations be minimized and that fugitive dust not be allowed to accumulate. Hoeganaes used a vacuuming service to reduce quantities of dust that had accumulated. However, inadequate dust collection systems and dust leakages from equipment produced accumulations beyond what could be controlled by the limited housekeeping service that was being provided.

4.4.2 ELECTRICAL CLASSIFICATION

The classification of combustible dust hazardous locations is based on the criteria established by article 500 of NFPA 70, *National Electric Code* (NEC). The NEC defines hazardous locations as areas "where fire or explosion hazards may exist due to flammable gases or vapors, flammable liquids, combustible dust, or ignitable fibers or flyings." The classifications are broken down into three hazardous material classes:

- Class I – flammable gas or vapor
- Class II – combustible dust
- Class III – fibers and flyings

Each class is further categorized into one of two divisions, based on operating conditions:

- Division 1 – Normal: areas where the classified hazardous material is likely to be present under normal operating conditions
- Division 2 – Abnormal: areas where the classified hazardous material is likely to be contained and present only through accidental release

With the proper evaluation of electrically classified areas in an operating facility, appropriately rated equipment can be installed.

4.4.2.1 Combustible Dust

NFPA 499, *Classification of Combustible Dusts and of Hazardous (Classified) Locations for Electrical Installation in Chemical Process Areas*, specifies the type of electrical equipment acceptable in atmospheres containing combustible dust. It applies to locations where combustible dusts are produced, processed, and handled, or where surface accumulations of dust could be ignited by electrical equipment. Based on the requirements of NFPA 499 and the NEC, classified electric services and equipment would be required in a facility where combustible metal dust was present. Specifically, NFPA 499 states that Division 1 electrical equipment should be used in areas where combustible dust can accumulate to 1/8 of an inch (3 mm).

OSHA 1910 Subpart S includes definitions and requirements for hazardous or electrically classified locations. To determine whether classified electrical equipment is needed for a combustible dust, a Class II combustibility test is conducted with dust samples from the facility and the explosion severity (ES) ratio calculated. An ES of greater than 0.5 signifies an appreciable explosion hazard, which means either that Class II electrical equipment must be installed or dust accumulations near electrical equipment must be prevented. ES values less than 0.5 are generally considered to be lower explosion hazards, and non-rated electrical equipment in those atmospheres is acceptable.

In January 2009, Hoeganaes submitted samples for explosibility testing. Although several samples were determined to be explosible, the ES values were low, precluding the need for classified electrical installations in the Hoeganaes facility. The CSB tested iron dust samples and found an explosion severity ratio of 0.01 to 0.1, significantly less than the ratio that would require classified equipment under existing codes.

4.4.2.2 Flammable Gases

Test results on the iron samples in the vicinity of the Hoeganaes incidents did not require the installation of classified electrical services. However, the flammable hydrogen in the band furnaces did. NFPA 497, *Recommended Practice for the Classification of Flammable Liquids, Gases, or Vapors and of Hazardous (Classified) Locations for Electrical Installations in Chemical Process Areas*, lists hydrogen as a Class I flammable gas. Areas with Class I materials are further classified as Division 2 if the material is normally contained inside the equipment, or Division 1 if the material is normally present in flammable concentrations outside the equipment, such as during maintenance. Because hydrogen normally vents into the work area at one end of the annealing furnace, the area around the annealing furnace should have been designated as Class I Division 1, and the electrical equipment in that area designed, installed, and maintained to meet those recommendations.

Moreover, the standard states that if no physical boundary surrounds a Division 1 area, the transitional area between Division 1 and an unclassified area is designated as Division 2. In addition, because the hydrogen piping system includes potential leak points, such as valves and flanges, these areas should have been designated as Class I Division 2. As such, large areas in the annealing building would be required to have Class I Division 1 or Class I Division 2 electrical service installed.

Despite these classifications and their recommendations, the CSB observed inappropriate electrical installations, including large electrical cabinets that were open to the atmosphere and that had significant iron dust accumulations, incomplete conduit, and regular 110-volt cord-plug outlets instead of ignition-proof electrical devices approved by the NEC for Class I atmospheres.

4.4.3 INTERNATIONAL FIRE CODE

The International Fire Code (IFC) establishes minimum requirements for fire protection and prevention systems. The International Code Council (ICC), a membership association responsible for developing safety codes in residential and commercial buildings, publishes the IFC. Chapter 13 of the IFC, "Combustible Dust-Producing Operations," (2006 edition) briefly addresses the prevention of ignition sources and housekeeping for areas where combustible dust is generated, stored, manufactured, or handled.[30] The IFC also references several NFPA standards, such as NFPA 484, but language in section 1304 is vague as to whether the compliance with the listed NFPA standards is mandatory or voluntary. The IFC authorizes the authority having jurisdiction, such as the fire department or municipality, to enforce "applicable provisions" of these NFPA standards; the word "authorizes" does not carry the same weight as "shall enforce" and might be interpreted as a discretionary rather than mandatory code requirement.

Companies are required to comply with the IFC only if promulgated through local, state, or federal regulations.[31] The State of Tennessee Division of Fire Prevention and the City of Gallatin both adopted the 2006 version of the IFC into their codes. Though the general precautions for housekeeping and ignition sources are required through code adoption of the IFC, the noted

[30]Combustible Dust-Producing Operations" is located in Chapter 22 of the IFC 2012 edition.

[31]In a previous investigation of a serious dust explosion at West Pharmaceutical Services in North Carolina in 2003, the CSB recommended that the state require mandatory compliance with the detailed provisions of the relevant NFPA dust standard (NFPA 654) rather than the much briefer and less prescriptive requirements of IFC Chapter 13.

NFPA standards could be interpreted as voluntary. The Tennessee Fire Code specifically declares that the state does not enforce "optional or recommended" standards or practices.

Practices at the Hoeganaes facility did not conform with the requirements set forth in Chapter 13 of the IFC. The code prohibits devices using an open flame and the use of spark-producing equipment in areas with combustible dust. It also states that accumulated combustible dust will be kept to a minimum inside buildings. However, adhering to the much more detailed design and engineering requirements of NFPA 484 would have further reduced the likelihood that the three serious incidents would have occurred.

At the time of the 2011 flash fire incidents, the Hoeganaes facility was operating under the provisions of the 2006 IFC. The GFD has the authority to inspect facilities against the IFC, issue violations, and stop-work orders if buildings or operations are declared unsafe based on the code's provisions. All construction and design provisions apply to new or existing structures if, in the opinion of the code official, a distinct hazard to life or property exists. All administrative, operational, and maintenance provisions apply to new and existing conditions and operations.

For the City of Gallatin, the fire chief is responsible for enforcement of the IFC. CSB investigators reviewed the GFD's inspection history at the Hoeganaes facility. The fire department conducted three inspections in the previous 12 years, in 1999, 2002, and 2011. The 2011 inspection was performed just two weeks prior to the May 27, 2011, incident. The report for this inspection documented observations at the facility related to fire suppression and emergency egress, but did not mention combustible dust hazards even after the January and March 2011 incidents. The CSB found no evidence that the GFD inspected Hoeganaes against the provisions of the 2006 IFC for the hazards associated with combustible metal dust, electrical installation, and operations that use flammable gases.

4.5 REGULATORY OVERSIGHT

4.5.1 OSHA

4.5.1.1 Combustible Dust

In 2006, following three catastrophic dust explosions that claimed 14 lives in 2003, the CSB issued its *Combustible Dust Hazard Study*. The study identified 281 dust fires and explosions in the U.S. between 1980 and 2005 that resulted in 119 fatalities and 718 injures.

The absence of an OSHA comprehensive combustible dust standard was a key finding in the 2006 study and resulted in a CSB recommendation to OSHA to initiate rulemaking for a general industry combustible dust standard. The recommendation remains "open-acceptable"[32] as of the publication of this report.

A significant reduction in grain dust incidents resulted from a prior dust regulation enacted by OSHA for grain handling facilities. In 1987, OSHA promulgated a grain facilities standard in response to a series of major grain dust explosions. A 2003 OSHA analysis of grain dust incidents showed that fatalities dropped 60 percent after the regulation was enacted.

Another recommendation from the 2006 *CSB Combustible Dust Study* was for OSHA to develop a national special emphasis program[33] (SEP) to address dust in industry while the comprehensive standard was being developed. In October 2007, OSHA initiated a Combustible Dust National Emphasis Program (NEP) to target industries that generate, store, or handle combustible dusts. The program provides guidance to OSHA inspectors about how to apply

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[32] In 2009, the CSB voted to change the status of the OSHA recommendation to "open-acceptable" after OSHA initiated an advance notice of proposed rulemaking (ANPR) for the combustible dust regulation.

[33] SEPs and NEPs are not regulations but rather are enforcement tools that allow OSHA to focus resources on inspections.

existing safety statutes or standards, such as the General Duty Clause (OSH Act 5(a)(1)) and the Walking-Working Surfaces standard (29 CFR 1910.22), to facilities with combustible dust.

Although the scope of the NEP applies to various types of combustible dusts including metal dusts at Hoeganaes, only those facilities assigned to particular North American Industry Classification System (NAICS) codes are specifically targeted for inspections by OSHA under the NEP. These NAICS codes classify facilities by primary business activity. If a facility that handles combustible dust is not included in the NAICS code list, OSHA can initiate an NEP inspection only as a result of a complaint, referral, or occupational injury. The NAICS code for the Hoeganaes Gallatin facility (331111, Iron and Steel Mills) is not included in the list of industries targeted by the NEP, although similar industries that handle metals are. According to the U.S. Census Bureau 2007 Economic Census, there were 352 facilities in the Iron and Steel Mills industry code (331111) employing over 106,000 workers.

The CSB 2006 dust study found that 20 percent of documented dust incidents from 1980 to 2005 occurred in the metals industry. During that period, the CSB documented three iron dust incidents that resulted in three fatalities and four injuries. One of those documented incidents occurred at the Hoeganaes Gallatin facility in 1996 when iron powder caught fire in a dust collector and one worker received a smoke inhalation injury.

In February 2008, a catastrophic sugar dust explosion at Imperial Sugar killed 14 and injured 36. A month later, OSHA revised and reissued the Combustible Dust NEP to include facilities that handle sugar. As a result, OSHA notified all facilities covered by the sugar industry codes that they were subject to inspection.

The Combustible Dust NEP is the only national OSHA program to specifically promote effective combustible dust hazard management. OSHA did not initiate rulemaking on combustible dust, as the CSB had recommended in November 2006, until April 2009. In its final report on the Imperial Sugar disaster in September 2009, the CSB recommended that OSHA "proceed expeditiously" with the new dust standard. Although OSHA issued an advance notice of proposed rulemaking (ANPR) for combustible dust in October 2009 and has since convened various stakeholder meetings, no proposed or final rule has been published.

Combustible dust fires and explosions have continued to occur at industrial facilities across the country; since issuing the 2006 CSB *Combustible Dust Study*, the CSB has recorded a number of significant combustible dust incidents. Until a combustible dust standard is enacted, the NEP remains OSHA's primary tool for addressing combustible dust in the workplace.

4.5.1.2 Process Safety Management

The Process Safety Management Standard, 29 CFR 1910.119 (PSM), is an OSHA regulation for processes that contain highly hazardous materials or significant quantities of flammables. The intent of PSM, as stated in the standard, is "preventing or minimizing the consequences of catastrophic releases of toxic, reactive, flammable, or explosive chemicals." PSM applies to processes using or producing any of 137 listed highly hazardous chemicals at or above threshold quantities and processes with flammable liquids or gases onsite in quantities of 10,000 pounds or more in one location. If applied to Hoeganaes, elements of PSM would have required practices and procedures that could have prevented or lessened the severity of the May 27, 2011 incident.

In the May 2011 incident, there was a hydrogen leak and subsequent hydrogen explosion and dust flash fires that ultimately killed three workers. The hydrogen provided to the Hoeganaes facility originates from an onsite generation and storage unit, owned and operated by a

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contractor on land leased from Hoeganaes. Since the hydrogen generation facility's total intended operational capacity exceeds 10,000 pounds of hydrogen, it is covered by PSM.

4.5.2 TOSHA

Tennessee is one of 24 states with a state-specific occupational safety and health plan. It develops and operates its own safety and health programs with approval from federal OSHA.

In November 2011, TOSHA issued citations to the Hoeganaes Gallatin Facility for the May 27, 2011, incident. Hoeganaes received 15 OSHA PSM Standard violations related to the hydrogen system. OSHA concluded that the company lacked appropriate procedures to ensure mechanical integrity of the hydrogen piping, failed to develop an emergency response plan for leak detection and response, and did not perform a hazard assessment on the hydrogen process.

Although the Combustible Dust NEP encourages but does not require state plans to adopt the NEP, Tennessee OSHA adopted the dust NEP in March 2008.

The NEP allows OSHA Area Offices to add NAICS codes to the list of facilities targeted by the NEP. However, TOSHA has not added the NAICS code that includes Hoeganaes as of the issuance of this study.

4.5.3 METAL DUST AWARENESS

Since Hoeganaes has been in operation, several opportunities have arisen to increase awareness and address metal dust issues at the facility through technical literature, audits, inspections, and regulatory oversight. These resources have not been effectively used by Hoeganaes. Gaps in codes and regulations, inadequate inspections, and poor hazard recognition all contributed to the three incidents at the Gallatin facility.

Table 4 lists a timeline of events from 1956 to the present related to combustible metal dust and the lack of effective controls at Hoeganaes until the third incident in May 2011.

TABLE 4

Timeline of metal dust publications, oversight, and opportunities to address metal dust hazards in industry and at Hoeganaes.

KEY MILESTONES FOR COMBUSTIBLE METAL DUST CONTROL IN INDUSTRY AND AT HOEGANAES

Year	Action
1946	NFPA publishes Code for the Prevention of Dust Explosions that includes general requirements for metal dusts
1958	American Chemical Society publication discusses powdered metals and iron dust explosibility
1980	Hoeganaes Gallatin facility established
1987	OSHA promulgates Grain Dust Standard, which decreases the number of explosions 44% and fatalities 60%[34]
1992	Hydrogen explosion and iron dust flash fire severely burns employee at the Hoeganaes facility in Cinnaminson, NJ
1996	Employee of Hoeganes Gallatin facility suffers smoke inhalation in dust collector fire. Metal dust ignites inside dust collector (ignited during a cutting operation)
1999	Gallatin FD inspects Hoeganaes; no mention of dust accumulations
2002	Gallatin FD inspects Hoeganaes; no mention of dust accumulations
2002	NFPA 484 is issued which addresses additional combustible metals that would include iron dust
2006	The CSB issues recommendation to OSHA to promulgate a comprehensive combustible dust standard
2006	City of Gallatin adopts International Building and Fire Codes
2007	OSHA issues Combustible Dust National Emphasis Program (NEP)
2008	Tennessee OSHA adopts federal Combustible Dust NEP (March)
2008	Tennessee OSHA inspects Hoeganaes facility. Conducts respirable metal dust sampling. Cites Hoeganaes for hearing conservation[35] (Oct.) No observation of a combustible dust hazard
2008	Allianz conducts insurance audit at Hoeganaes, recommends combustible dust testing and independent consultant (Nov.)
2009	Hoeganaes conducts combustible dust testing of three iron powder samples as recommended by 2008 Allianz audit; all three samples found to be combustible.
2010	Hoeganaes conducts combustible dust testing of 23 powdered metals; 5 of 9 iron samples found to be combustible. No substantial actions to mitigate combustible dust hazard
2011	January 31 incident; fatal combustible dust flash fire at Hoeganaes Gallatin facility
2011	March 29 incident; combustible dust flash fire at Hoeganaes Gallatin facility
2011	Gallatin FD inspects Hoeganaes, no mention of dust accumulations (May 11)
2011	May 27 incident; fatal hydrogen explosion/combustible dust flash fire at Hoeganaes Gallatin facility

4.6 METAL POWDER PRODUCERS ASSOCIATION

The Metal Powder Producers Association (MPPA) is one of six trade associations that make up the Metal Powder Industries Federation (MPIF). MPPA membership is open to manufacturers of metal powders, metal flakes, metal fibers, or non-metallic powder additives used with these materials. The stated objective of the MPPA is to “arrange for the collection and dissemination of information pertaining to the metal powder producing industries; provide technical facts, data, and standards, fundamental to metal powders and to the applications of metal powders...”[36]

[34] OSHA Office of Program Evaluation, Regulatory Review of OSHA’s Grain Handling Facilities Standard (29 CFR 1910.272). February 2003.

[35] OSHA regulated program to prevent noise induced hearing loss (29 CFR 1910.35).

[36] http://www.mpif.org/aboutmpif/mppa.asp.

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To achieve this, the MPPA offers a monthly newsletter and bi-annual meetings (fall and spring) to promote shared learning within the PM industry. In recent years, the spring meeting, which spotlights many safety topics, has begun focusing on the issue of combustible dust hazards in the PM industry. The MPPA has sought out external combustible dust expertise and OSHA has presented and participated in its safety meetings.

5.0 KEY FINDINGS

Over the course of investigating the events at the Hoeganaes facility, the CSB made the following key findings:

1. Significant accumulations of combustible iron powder at the Hoeganaes facility fueled fatal flash fires when lofted near an ignition source.
2. Hoeganaes facility management were aware of the iron powder combustibility hazard two years prior to the fatal flash fire incidents but did not take necessary action to mitigate the hazard through engineering controls and housekeeping.
3. Hoeganaes did not institute procedures – such as combustible gas monitoring – or training for employees to avoid flammable gas fires and explosions.
4. OSHA did not include iron and steel mills (NAICS code 331111), the industry classification code for Hoeganaes, in its Combustible Dust National Emphasis Program when it was first issued in 2007 or when it was re-issued in 2008.
5. The 2006 International Fire Code Chapter 13, *Combustible Dusts*, which was adopted by the City of Gallatin at the time of the incidents, does not clearly require jurisdictions to enforce the more comprehensive and rigorous NFPA standards for the prevention of dust fires and explosions.
6. The Tennessee Fire Code and the City of Gallatin do not enforce "optional or recommended" standards or practices of the IFC.
7. The Gallatin Fire Department inspected the Hoeganaes facility after the first two iron powder flash fires but did not cite or otherwise address combustible dust hazards present at the facility just weeks before the third fatal hydrogen explosion and dust flash fire.
8. The flame-resistant clothing (FRC) supplied by Hoeganaes to its employees did not provide any significant protection against the combustible iron dust flash fires and the hydrogen explosion that caused the fatalities.
9. GKN and Hoeganaes did not provide corporate oversight to ensure the Hoeganaes Gallatin facility was adequately managing combustible dusts prior to and throughout the succession of serious incidents at the Gallatin facility.

6.0 RECOMMENDATIONS

6.1 OSHA

2011-4-I-TN-R1

Ensure that the forthcoming OSHA Combustible Dust Standard includes coverage for combustible metal dusts including iron and steel powders.

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2011-4-I-TN-R2

Develop and publish a proposed combustible dust standard for general industry within one year of the approval of this case study.

2011-4-I-TN-R3

Revise the Combustible Dust National Emphasis Program (NEP) to add industry codes for facilities that generate metal dusts (e.g., North American Industrial Classification System, NAICS, code 331111 Iron and Steel Mills, and other applicable codes not currently listed). Send notification letters to all facilities nationwide under these codes to inform them of the hazards of combustible metal dusts and NEP coverage.

6.2 INTERNATIONAL CODE COUNCIL

2011-4-I-TN-R4

Revise IFC Chapter 22[37] Combustible Dust Producing Operations; Section 2204.1 Standards, to require mandatory compliance and enforcement with the detailed requirements of the NFPA standards cited in the chapter, including NFPA 484.

6.3 TOSHA

2011-4-I-TN-R5

Revise the state-adopted Dust National Emphasis Program (NEP) to add industry codes for facilities that generate metal dusts (e.g., North American Industrial Classification System, NAICS, code 331111 Iron and Steel Mills, and other applicable codes not currently listed). Send notification letters to all facilities statewide under these codes to inform them of the hazards of combustible metal dusts and NEP coverage.

6.4 HOEGANAES

2011-4-I-TN-R6

Conduct periodic independent audits of the Hoeganaes Gallatin facility for compliance with the following NFPA standards, using knowledgeable experts, and implement all recommended corrective actions:

- NFPA 484, *Standard for Combustible Metals, Metal Powders, and Metal Dusts*
- NFPA 499, *Recommended Practice for the Classification of Combustible Dusts and of Hazardous Locations for Electrical Installations in Chemical Process Areas*
- NFPA 497, *Recommended Practice for the Classification of Flammable Liquids, Gases, or Vapors and of Hazardous (Classified) Locations for Electrical Installations in Chemical Process Areas*
- NFPA 2, *Hydrogen Technologies Code*
- NFPA 2113, *Standard on Selection, Care, Use, and Maintenance of Flame-Resistant Garments for Protection of Industrial Personnel Against Flash Fire*

[37] Combustible Dust Producing Operations, Chapter 13 of the IFC, was moved to Chapter 22 in later editions.

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2011-4-I-TN-R7
Develop training materials that address combustible dust and plant-specific metal dust hazards and train all employees and contractors. Require periodic (e.g., annual) refresher training for all employees and contractors.

2011-4-I-TN-R8
Implement a preventive maintenance program and leak detection and leak mitigation procedures for all flammable gas piping and gas processing equipment.

2011-4-I-TN-R9
Develop and implement a near-miss reporting and investigation policy that includes the following at a minimum:

- Ensure facility-wide worker participation in reporting all near-miss events and operational disruptions (such as significant iron powder accumulations, smoldering fires, or unsafe conditions or practices) that could result in worker injury.
- Ensure that the near-miss reporting program requires prompt investigations, as appropriate, and that results are promptly circulated throughout the Hoeganaes Corporation.
- Establish roles and responsibilities for the management, execution, and resolution of all recommendations from near-miss investigations
- Ensure the near-miss program is operational at all times (e.g. nights, weekends, holiday shifts).

6.5 METAL POWDER PRODUCERS ASSOCIATION (MPPA)

2011-4-I-TN-R10
Communicate the findings of this report to all your members, e.g. through a safety article in an upcoming monthly newsletter.

6.6 CITY OF GALLATIN, TN

2011-4-I-TN-R11
Require all facilities covered by IFC Chapter 13 (2006 edition) to conform to NFPA standards for combustible dusts including NFPA 484.

6.7 GALLATIN FIRE DEPARTMENT

2011-4-I-TN-R12
Ensure that all industrial facilities in the City of Gallatin are inspected periodically against the International Fire Code. All facility inspections shall be documented.

2011-4-I-TN-R13
Implement a program to ensure that fire inspectors and response personnel are trained to recognize and address combustible dust hazards.

APPENDIX A: DETERMINATION OF IRON POWDER EXPLOSIBILITY FROM PRESSURE RATIO CALCULATIONS

BACKGROUND

The CSB commissioned testing of four Hoeganaes iron dust samples in a 20-L Test Chamber (ASTM Standard E1226-10, *Standard Test Method for Explosibility of Dust Clouds)*. The test method states that dust explosibility can also be characterized through the calculation of a pressure ratio (PR). The pressure ratio calculation is also known as the explosibility screening test (Section 13). The 20-L test chamber records the maximum explosion pressure reached during a single deflagration test at a dust concentration of 1,000 and 2,000 g/m^3 .

If PR > 2, the dust is considered explosible

If PR < 2, it is classified as "not explosible" under those test conditions and the standard goes on to caution that it is not necessarily "not combustible" and still may be capable of deflagrative combustion.

CALCULATIONS

The CSB calculated the pressure ratio based on the 20-L test results from the baghouse dust. According to E1226-10:

$$Pressure\ ratio = PR = (P_{ex,a} - \Delta P_{ignitor}) / P_{ignition}$$

Where:

$P_{ex,a}$ = maximum explosion pressure (bar absolute)

$\Delta P_{ignitor}$ = maximum pressure rise in chamber due to igniter = 2.5 (bar absolute)

$P_{ignition}$ = absolute pressure at the time of ignition = 0 bar gauge = 1.0123 (bar absolute)

The test value $P_{max,a}$ already corrects for the igniter pressure:

$$P_{max,a} = (P_{ex,a} - \Delta P_{ignitor})$$

$P_{max,a}$ values obtained from 20L testing of Hoeganaes dust:

$P_{max,a}$	DUST CONCENTRATION
3.1 bar gauge	1,000 g/m^3
3.8 bar gauge	2,000 g/m^3

Convert bar gauge to bar absolute:

$0\ bar\ gauge = 1.0125\ bar\ absolute$

$3.1\ bar\ gauge + 1.01325 = 4.1\ bar\ absolute$

$3.8\ bar\ gauge + 1.0125 = 4.8\ bar\ absolute$

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The equation reduces to:

$PR = P_{max,a} \, / \, P_{ignition}$

Thus:

$PR_{1,000} = 4.1/1.01325$

$\boldsymbol{PR_{1,000} = 4.0}$

$PR_{2,000} = 4.8/1.01325$

$\boldsymbol{PR_{2,000} = 4.7}$

The pressure ratios at 1,000 and 2,000 g/m^3 are both **greater than 2** and the iron dust sample is considered **explosible** based on ASTM E1226.

APPENDIX B: DETERMINATION OF IRON POWDER CLASSIFICATION FROM EXPLOSION SEVERITY CALCULATION

BACKGROUND

The CSB commissioned testing of four Hoeganaes iron dust samples in a 20-L Test Chamber (ASTM Standard E1226-10, *Standard Test Method for Explosibility of Dust Clouds*). OSHA cites the National Materials Advisory Board (NMAB) 353-3-80, *Classification of Combustible Dusts in Accordance with the National Electric Code*, for the determination of a Class II combustible dust location. The NMAB 353-3-80 states that Class II dusts can be characterized through the calculation of an explosion severity (ES). According to the NMAB 353-3-80:

> If ES > 0.5, the dust is considered an appreciable explosion hazard that requires suitable electrical equipment for Class II locations.

CALCULATIONS

The CSB calculated the pressure ratio based on the 20-L test results from the baghouse dust. According to NMAB 353-3-80:

$$\textit{Explosion Severity} = ES = \frac{P_{max\ (sample)} \times \left.\frac{\partial P}{\partial t}\right._{max\ (sample)}}{P_{max\ (reference\ dust)} \times \left.\frac{\partial P}{\partial t}\right._{max\ (reference\ dust)}}$$

Where:

P_{max} = maximum explosion pressure, (bar gauge)

$\left.\frac{\partial P}{\partial t}\right._{max\ (reference\ dust)}$ = maximum rate of pressure rise, (bar gauge per second)

Reference dust = Pittsburgh coal dust

P_{max} values obtained from 20L testing of Hoeganaes dust:

DUST SAMPLE	P_{max}	$\partial P/\partial t_{max}$
Hoeganaes Baghouse	3.5 bar gauge	68 bar gauge per second
Pittsburgh Coal	7.3 bar gauge	426 bar gauge per second

Thus:

$$ES = \frac{(3.5\ \textit{bar gauge}) \times (68\ \frac{\textit{bar gauge}}{s})}{(7.3\ \textit{bar gauge}) \times (426\ \frac{\textit{bar gauge}}{s})}$$

$$ES = \frac{238}{3{,}110}$$

$$\mathbf{ES = 0.077}$$

The explosion severity of the baghouse dust is **less than 0.5** and the iron dust sample is **not considered a Class II combustible dust.**

U.S. CHEMICAL SAFETY AND HAZARD INVESTIGATION BOARD

INVESTIGATION REPORT
VOLUME 2

EXPLOSION AND FIRE AT THE MACONDO WELL

(11 Fatalities, 17 Injured, and Serious Environmental Damage)

DEEPWATER HORIZON RIG

MISSISSIPPI CANYON BLOCK #252, GULF OF MEXICO

APRIL 20, 2010

KEY ISSUES IN VOLUME 2

- BOP TECHNICAL FAILURE ANALYSIS
- BARRIER MANAGEMENT AT MACONDO
- SAFETY CRITICAL ELEMENTS

REPORT NO. 2010-10-I-OS
6/5/2014

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Volume 2

Technical findings on the Deepwater Horizon blowout preventer (BOP) with an emphasis on the effective management of safety critical elements

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Acronyms and Abbreviations

ALARP	As Low As Reasonably Practicable
AMF	Automatic Mode Function
API	American Petroleum Institute
BOEM	Bureau of Ocean Energy Management (United States)
BOEMRE	Bureau of Ocean Energy Management, Regulation, and Enforcement (United States); the US offshore safety regulator between June 18 and October 1, 2011[a]
BOP	Blowout Preventer
BSEE	Bureau of Safety and Environmental Enforcement (United States); US offshore safety regulator since October 1, 2011[b]
BSR	Blind Shear Ram
CCPS	Center for Chemical Process Safety
CSB	U.S. Chemical Safety Board
CSR	Casing Shear Ram
DNV	Det Norske Veritas
DOI	Department of Interior (United States)
DOSH	Division of Occupational Safety and Health
DWH	Deepwater Horizon
EDS	Emergency Disconnect System
GoM	Gulf of Mexico
HSE	Health Safety Executive (United Kingdom)
LCM	Loss Circulation Material
LMRP	Lower Marine Riser Package
LOWC	Loss of Well Containment
MAHRA	Major Accident Hazard Risk Assessment

[a] Department of Interior, Order No. 3302, Change of the Name of the Minerals Management Service to the Bureau of Ocean Energy Management, Regulation, and Enforcement (June 18, 2011), http://www.doi.gov/deepwaterhorizon/loader.cfm?csModule=security/getfile&PageID=35872. Accessed February 19, 2014.

[b] The Reorganization of the former MMS, http://www.bsee.gov/About-BSEE/BSEE-History/Reorganization/Reorganization/. Accessed February 19, 2014.

MGS	Mud-Gas Separator
MAE	Major Accident Event
MMS	Minerals Management Service (United States); US offshore safety regulator at the time of the Macondo accident until June 18, 2011[a]
MODU	Mobile Offshore Drilling Unit
NOPSA	National Offshore Petroleum Safety Authority (Australia)
NOPSEMA	National Offshore Petroleum Safety and Environmental Management Authority (Australia, successor to NOPSA)
NTL	Notice to Lessee
OCS	Outer Continental Shelf
POSC	Presidential Oil Spill Commission
PSM	Process Safety Management
PETU	portable electronic test unit
PLC	programmable logic controllers
ppg	pounds per gallon
PSA	Petroleum Safety Authority (Norway)
psi	pounds per square inch
SCE	safety critical element
SEM	subsea electronic module
SEMS	Safety and Environmental Management System
SPPE	Safety and Pollution Protection Equipment
UK	United Kingdom
US	United States
USCG	United States Coast Guard
VBR	Variable Bore Ram

[a] Department of Interior, Order No. 3302, Change of the Name of the Minerals Management Service to the Bureau of Ocean Energy Management, Regulation, and Enforcement (June 18, 2011), http://www.doi.gov/deepwaterhorizon/loader.cfm?csModule=security/getfile&PageID=35872. Accessed February 19, 2014.

Volume 2 – Approach to Analysis

Macondo is an international problem whose lessons extend beyond the United States. The global business of offshore exploration and production continues to advance in complexity. Meanwhile, the catastrophic consequences of another incident on par with Macondo threaten not only the welfare of the workforce, public, and environment, but the industry's long-term viability. The international nature of this business allows for all stakeholders to learn from each other—many companies operating offshore do so on a global level. Companies can bring their individual best practices wherever they go; the equipment, facilities, and people used to conduct offshore operations travel between regions as needed; and regulators worldwide have recognized the need to disseminate knowledge through information sharing forums.[a]

No one offshore region operates within a framework that provides an undisputed panacea to prevent all accidents. Challenges and undiscovered hazards exist in every offshore location. For example, within this volume, the CSB has identified a key weakness in BOP function testing promulgated in internationally accepted industry guidance.

Regulatory regimes can only provide the foundation for effective major accident hazard management, and failures by any one company to carry out the intent of the regulatory requirements may occur in any offshore region. Yet a foundation is essential for ensuring that all those operating offshore are reducing risk to a level acceptable to themselves, the regulator, and society as a whole. Examining the strengths and weakness of the various major accident prevention approaches used by industry and the regulator—both in the US and elsewhere—can identify and improve attributes that provide for more effective safety management. This is a primary aim of the CSB's overall investigation into the Macondo incident and the focus of this volume.

Volume 2 Overview

Chapter 1 *– The focus of this volume and the key investigation findings that support the CSB analysis.*

Chapter 2 *– The sealing capabilities of a BOP as a physical barrier and the incident events pertaining to the DWH BOP's integrity at the time of the incident.*

Chapter 3 *–The CSB failure analysis of the DWH BOP, and the implications for BOPs used offshore.*

Chapter 4 *– Concepts underlying technical, organizational and operational barriers for major accident prevention.*

Chapter 5 *– The lifecycle of a safety critical element and deficiencies in the treatment of Deepwater Horizon BOP emergencies systems.*

Chapter 6 *– Recommended practices and regulations pre- and post-incident for the BOP and other safety critical elements.*

Chapter 7 *–Major conclusions to illustrate important lessons for industry and the US regulator.*

Chapter 8 *– Recommendations for industry and the US regulator.*

[a] Some examples include the International Regulators' Forum (http://www.irfoffshoresafety.com/) and the North Sea Offshore Authorities Forum (http://www.ptil.no/nsoaf/category999.html; http://www.ens.dk/en/oil-gas/health-safety/international-cooperation-2/north-sea-offshore-authorities-forum).

The CSB provides its failure analysis of the BOP to spark a global reexamination of how industry is managing safety critical elements[a] as well as regulatory requirements and approaches used to ensure that these management practices are effective.

1.1 Volume 2 Synopsis[b]

The Macondo well blowout began when the Deepwater Horizon (DWH) crew was in the final stages of temporarily abandoning the well so that a production facility could return later to extract oil and gas. BP's temporary abandonment plan[c] called for removing the upper portion of the drilling mud in the well before installing a surface cement plug.[d] The decision proved fateful because both BP and Transocean personnel on the DWH rig had misinterpreted test results [e] concerning the cement integrity at the bottom of the well. This error led the personnel to believe that the hydrocarbon bearing zone at the bottom of the well had been sealed when it was not. Ultimately, the blowout preventer (BOP) was the only physical barrier that could have potentially contained well fluids, but only if the crew or emergency systems could have successfully engaged it. [f] As the events of April 20, 2010 indicate, the BOP did not seal the well.

In analyzing the BOP failure to seal the well during the incident, Volume 2 of the CSB Macondo Incident Investigation report has five objectives:

1. To discuss key preventable hardware shortcomings affecting the reliability of the Deepwater Horizon BOP throughout the drilling activities at Macondo.
2. To account for all conditions that can cause drillpipe to buckle in a well, leaving it off-center in a BOP and potentially interfering with the BOP's ability to seal a well. These conditions include having buckled drillpipe even when a rig crew has successfully shut in a well.
3. To explore safeguards, or barriers, that help prevent major accidents, recognizing they extend beyond physical equipment into operational and organizational elements.
4. To describe the necessity for effective identification and management of safety critical elements—technical, organizational, and operational—for preventing Macondo-like events.

---

[a] Safety critical elements are controls (hardware, people systems, or software) or tasks whose failure could cause or contribute to a major accident event or whose purpose is to prevent or limit the effects of a major accident event. (See Section 4.2.3.1)

[b] See Volume 1 for a basic introduction to deepwater drilling and physical barriers that can prevent a blowout.

[c] A well may be sealed temporarily with cement or mechanical plugs to allow removal of the blowout preventer and departure from the drilling rig.

[d] Cement plugs are portions of cement put into a wellbore to seal it. "Surface" is typically used to refer to the most shallow cement plug used in a well.

[e] A number of human and organizational factors contributed to how the events unfolded leading to accepting the test results. The CSB plans to address these factors in Volume 4 of the CSB's Macondo Investigation Report.

[f] Well integrity also includes the casing lining the wellbore, float valves (check valves) placed at the bottom of the casing, and crossovers where casing of different sizes are connected to one another. Analysis in Appendix 2-A indicates the major source of hydrocarbons during the incident did not come from casing or crossover failures. While check valves can act as a physical barrier, they are unreliable and cannot be independently tested. For the analysis in this report, they are not considered a barrier because at Macondo they were either not converted or had to have failed.

5. To identify additional opportunities for improvement in the US offshore safety regulations that do not include clear and systematic requirements to ensure the successful performance of all safety critical elements (SCE) for reducing major accident events.

1.2 Key Findings

The redundant controls of Deepwater Horizon BOP should have increased the reliability of the BOP to seal the Macondo well during normal drilling operations and emergency situations. Two rounds of post-incident testing, including one non-public, court-ordered round and additional CSB testing, reveal new failure mechanisms in which these redundant controls can be compromised and go on undetected. From this analysis and an examination of how the BOP, was managed and regulated as a safety critical element, the following key findings demonstrate the need for further offshore safety improvements:

BOP Failure in Loss of Well Control

1. The BOP is subject to design capability limitations. A BOP can act as a barrier only if it is closed manually by the drilling crew or automatically as a result of a catastrophic event, such as a fire and explosion, which can trigger emergency backup systems. In manual operations, successful closure of the BOP depends on several human decisions that must be made before a well kick can develop into a blowout. Otherwise, well pressures and well flow can exceed the design capabilities of the BOP elements, leaving them unable to prevent or stop an active blowout (Sections 2.1 and 2.3).

2. No effective testing or monitoring was in place to verify the availability of the redundant systems in the emergency Automatic Mode Function (AMF)/deadman system.[a] (Sections 2.3.1, 5.3.1, and 5.4). This emergency system was programmed to activate a blind shear ram (BSR) within the BOP to shear drillpipe and seal the well (Sections 2.3.3).

   The AMF/deadman uses two redundant control systems, the yellow pod and the blue pod, to initiate closure of the blind shear ram. This redundancy is intended to increase the AMF/deadman reliability, but on the day of the incident only one of the two pods was functioning:

   a. The blue pod was miswired, causing a critical battery to drain and rendering the pod inoperable on the day of the incident (Section 3.2.1.1).

   b. A critical solenoid[b] valve in the yellow pod had also been miswired. Redundant coils were designed to work in parallel to open the solenoid valve, but the miswiring caused them to oppose one another. Had both coils been successfully energized during the incident, the solenoid valve would have remained closed and unable to initiate closure of

[a] “Deadman” is defined by API Specification 16D 2nd Ed, *Specification for Control Systems for Drilling Well Control Equipment and Control Systems for Diverter Equipment* 2nd Edition: a blowout preventer safety system “designed to automatically close [and seal] the wellbore in the event of a simultaneous absence of hydraulic supply and signal transmission capacity in both subsea control pods.” Activation can occur as the result of a catastrophic event such as a fire and explosion on the rig. AMF (Automatic Mode Function) is Cameron’s version of a deadman system.

[b] Solenoid valve: A valve that opens and closes as the result of an electrically initiated magnetic switching device to control the flow of liquid or gas.

the BSR. However, a drained battery likely rendered one of these coils inoperable. This would have allowed the other coil to activate alone and initiate closure of the BSR, but buckled off-center drillpipe in the BOP prohibited the BSR from fully closing and sealing the well. (Section 3.2.1.2, 3.2.1.3, and 3.2.2).

3. Large pressure differences were established between the inside and outside of the drillpipe when well control actions by the crew sealed the well shortly after oil and gas were released onto the rig. This likely caused drillpipe in the BOP to buckle due to a phenomenon known as "effective compression"[a] (Section 3.2.3).

BOP Safety Management Deficiencies

4. The BOP systems responsible for shearing drillpipe in emergency situations are vulnerable to failures in rarely or inadequately tested equipment. Transocean and BP conducted routine inspection and weekly function testing of operational BOP components necessary for daily drilling operations, but these were insufficient to identify latent failures of the emergency systems that existed in the Deepwater Horizon BOP; thus, the safety critical systems responsible for shearing drillpipe in emergency situations had performance deficiencies even before the BOP was deployed to the Macondo wellhead. (Chapter 5.0).
5. The blind shear ram[b] in the Deepwater Horizon BOP did not meet the manufacturer's published design shearing capabilities for the diameter of drillpipe used during all of the DWH drilling operations except on April 20; thus, for an extended time during the drilling process, the DWH BOP could not have reliably sheared the drillpipe during an emergency situation. (Section 5.2.1).
6. The miswired solenoid valve in the yellow pod and the deficient wiring in the blue pod could not have passed the manufacturer's factory acceptance testing procedures (Sections 5.3.1and 5.3.2).

Regulatory Gaps

7. While US offshore regulations have undergone important changes since Macondo, more can be done to ensure a focus on preventing major accident events and to drive continuous safety improvement. The primary US offshore safety management regulation, Safety and Environmental Management Systems,
    a. Is not risk-based nor does it have an explicit focus on major accident events (Chapter 4.0);
    b. does not require demonstration by industry that process safety concepts for hazard assessment and management, such as layers of protection[c] and hierarchy of controls, have been used in managing major accident hazards[a] (Chapter 4.0);

---

[a] Effective compression: Pipe buckling resulting from the combined effect of 1) large pressure differences inside and outside of a drillpipe and 2) axial forces. Even in the absence of axial forces, pipe can buckle as a result of the pressure differences alone.

[b] Blind shear rams are a part of the BOP that can shear drillpipe and seal a wellbore.

[c] Layers of protection are preventions, safeguard, barriers, or lines of defense that are designed to eliminate, prevent, reduce, or mitigate a hazardous scenario.

c. does not require demonstration that barriers to prevent major accidents are effectively implemented to a targeted risk reduction level (Section 4.1).

d. does not require industry to identify and manage all safety critical elements and tasks through defined performance standards,[b] nor does it require assurance and verification activities to ensure a safety critical element is appropriate, available, and effective throughout its life cycle. (Chapter 5.0).

8. At the time of the incident, neither recommended industry practices nor US regulations required testing of the AMF/deadman system. Despite post-incident changes that call for function testing the AMF/deadman, deficiencies identified during the failure analysis of the Deepwater Horizon BOP could still remain undetected in BOPs currently being deployed to wellheads (Section 5.3.2).

[a] Hierarchy of controls is an effectiveness ranking used to mitigate hazards and risks. The higher up the hierarchy, the more effective the control is in reducing risk.

[b] A defined performance standard is a qualitative or quantitative statement that describes the required performance of a safety critical element or task. (See Section 5.2.)

2.0 Controlling Formation Pressures with the Deepwater Horizon Blowout Preventer

Chapter 2 Overview

This chapter describes the DWH BOP's components, the BOP's role in controlling formation pressures, the manual and automated systems designed to close the DWH BOP, and the events leading to the failure to shut in and seal the Macondo well on April 20, 2010.

Drilling crews depend on blowout prevention equipment to confine kicks, circulate or inject well kill materials,[a] and allow for safe removal of hydrocarbons from the wellbore.[b] Activating a subsea blowout preventer (BOP) creates a barrier designed to protect against blowouts by sealing the well at the seafloor, preventing hydrocarbons from entering and traveling up the riser[c] to the rig.

While subsea BOPs share general physical characteristics, such as the style and construction of components, their actual configuration, control system, and performance requirements depend on well conditions, a rig owner's technical standards, and the date of construction because newer models may have upgraded technologies. The Deepwater Horizon's BOP was built by Cameron and had been used on the DWH since the rig began its service in 2001.[1] As depicted in Figure 2-1, the BOP consisted of two sections, the lower marine riser package (LMRP) and the lower BOP.

[a] In the event of a kick, heavy well kill materials are circulated under pressure or injected into a wellbore to increase the hydrostatic pressure of column of fluid that fills the wellbore and riser. This activity reestablishes an overbalanced condition and prevents the well from flowing. (See Section 2.1 in Volume 1.)

[b] API Recommended Practice 53, 4th ed. *Blowout Prevention Equipment Systems for Drilling Wells*, defines blowout prevention equipment systems to include blowout preventers, choke and kill lines, choke manifold control systems, and auxiliary equipment. The primary function of these systems is "to confine well fluids to the wellbore, provide means to add fluid to the wellbore, and allow controlled columns to be removed from the wellbore."

[c] The riser is a large diameter pipe which connects a drilling rig to the wellhead.

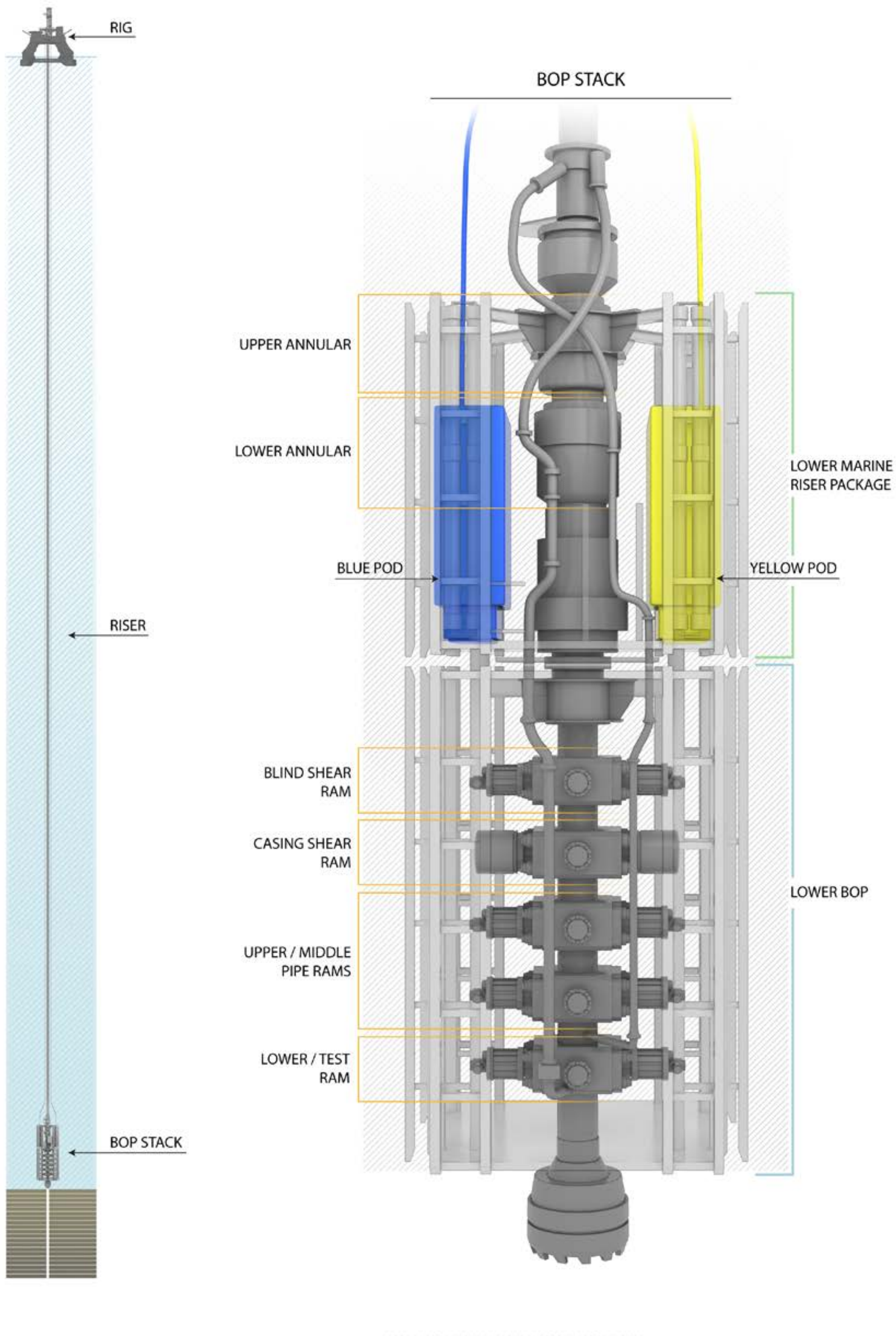

Figure 2-1. The DWH BOP stack

2.1 BOP Sealing Elements

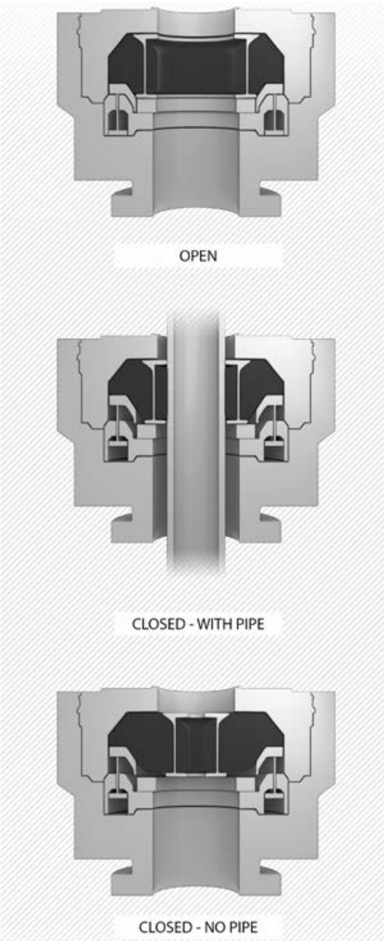

Figure 2-2. An annular preventer can seal the annular space around a drillpipe or an open hole. Pistons press up on the rubber component which pushes it inward to seal around the pipe or open hole.

During a kick, a BOP has multiple rubber components that the crew can close to seal the well (Table 2-1).[a] Annular preventers and pipe rams are designed to seal the annular[b] space around a drillpipe or tool passing through the BOP, but each has unique strengths.[2] For example, annular preventers are designed to seal around virtually any object that passes through them as well as an open hole when no drillpipe is present (Figure 2-2). Due to the BOP's capability to seal around a broad range of objects, typically a rig crew's initial priority during well control response is to close an annular preventer. The lower marine riser package (LMRP) illustrated (Figure 2-1) of the DWH BOP stack contained two annular preventers (referred to as the upper and lower annulars).

Some pipe rams seal only around one size of pipe, but variable bore rams (VBRs) seal a range of pipe sizes.[c] Pipe rams cannot seal an open hole if no drillpipe is present (Figure 2-3). The lower BOP of the DWH had an upper pipe ram, middle pipe ram, and lower pipe ram[d] (Figure 2-1). The pipe rams were VBRs capable of sealing around pipes with outside diameters from 3½" to 6⅝".

A subsea BOP can also have a blind shear ram (BSR) and a casing shear ram (CSR). A blind shear ram consists of specially designed blades that extend from opposite sides of the blowout preventer to cut (or shear) drillpipe. After cutting the drillpipe, the blades extend across the blowout preventer to form a seal that stops the flow of oil and gas from leaving a well and reaching the surface. Regarded as emergency response devices, blind shear rams can seal a well without first removing the drillpipe, but they also can seal an open wellbore when no drillpipe is present. BSRs are limited in the size and type of drillpipe they can cut, determined, in part, by the model of BSR, the wellbore

[a] Pipe rams are backed by metal supports while annular preventers are not.

[b] The annular space is located between the BOP and the drillpipe.

[c] Pipe rams are capable of holding back more pressure than an annular, but they fit only one size of pipe. VBRs mitigate that limitation to some extent.

[d] Pipe rams are designed to hold pressure from one direction, usually below. The lower pipe ram on the Deepwater Horizon BOP was intentionally installed upside down to hold pressure from above, and it was designated as a test ram. This arrangement saves time in conducting periodic subsea pressure tests of the BOP stack. In this role, it serves no purpose in dealing with a well control event.

pressure, and the hydraulic control system[a] used to power the BSR closure.[b] CSRs, which are stronger than BSRs, do not seal but can cut thicker drillpipe and even more difficult-to-cut casing. Subsequent sealing of a well after using a CSR would occur by allowing any remaining pipe or casing to drop into the well or to be lifted and clear the BSR before closing the BSR. The Deepwater Horizon BOP had both a BSR and a CSR located above the pipe rams in the lower BOP (Figure 2-1).

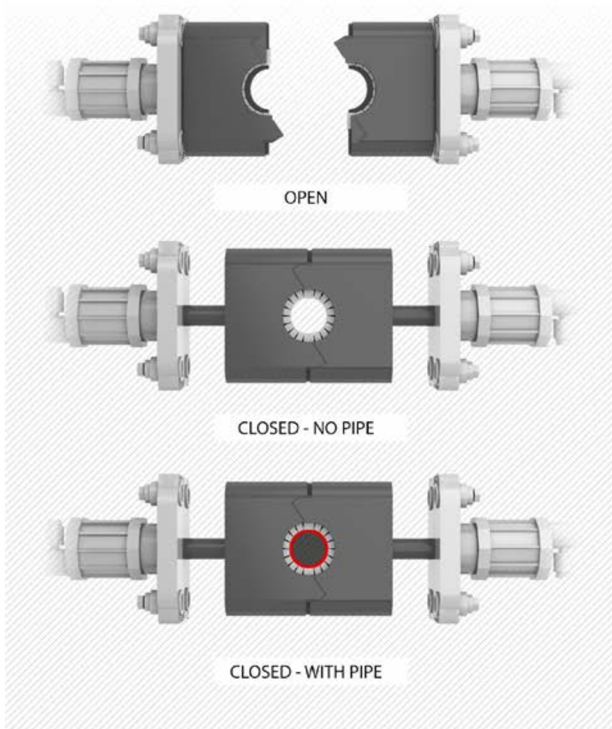

Figure 2-3. A pipe ram can seal the annular space around a drillpipe, but not an open hole without drillpipe present.

[a] A hydraulic control system uses pressurized fluid to open or close mechanical devices.

[b] BOP manufacturers specify the shearing capabilities of their BSRs. See Oil & Gas UK, *Guidelines on the subsea BOP systems*, Issue 1 (July 2012), p. 74.

In general, blind shear rams are not designed to cut threaded, thick-walled ends of drillpipe, called tool joints, though casing shear rams sometimes can. To minimize the risk of this situation, well control procedures involve clearly defined steps for spacing the drillpipe in the BOP stack to ensure tool joints are clear of the BSR.[3] Table 2-1 summarizes the various BOP components.

Table 2-1. Various components of a BOP and their uses[a], [b] (See Appendix 2-A for model numbers and capabilities of the DWH BOP elements)

BOP Component	Seals well space around drillpipe in wellbore	Seals open well hole (wellbore)	Shears drillpipe	Benefits / Drawbacks	Number of each on DWH BOP
Annular Preventer (AP)	●	●		Designed to seal around virtually any object; commonly activated first during well control response activities	2
Pipe Ram / Variable Bore Ram (VBR)	●			Cannot seal open wellbore; VBR's seal around a variety of pipe sizes	3
Blind Shear Ram (BSR)		●	●	Cannot shear tool joints or casing	1
Casing Shear Ram (CSR)			●	Also shears casing and potentially tool joints, [a]but cannot seal the well after shearing is completed	1

2.2 The BOP as a Physical Barrier

At the time of the Macondo incident, US regulations did not address the number or effectiveness of physical barriers required to prevent the flow of hydrocarbons during drilling and abandonment operations. Current regulations require a description of the number and types of independent barriers used during drilling[c,4] and a minimum of two independent barriers during completion or abandonment activities.[5]

[a] Oil & Gas UK, *Guidelines on the subsea BOP systems*, Issue 1 (July 2012), p. 51; A recent BSR model can shear and seal on a tool joint (GE/Hydril http://www.genewscenter.com/Press-Releases/GE-Introduces-Deepwater-BOP-Blind-Shear-Rams-with-Advanced-Capabilities-3826.aspx. Retrieved March 7, 2014.

[b] Pipe rams are designed to hold pressure from one direction, usually below. The lower pipe ram on the Deepwater Horizon BOP was intentionally installed upside down to hold pressure from above, and it was designated as a test ram. This arrangement saves time in conducting periodic subsea pressure tests of the BOP stack. In this role, it serves no purpose in dealing with a well control event.

[c] Of the two barriers required during completion activities, one of them must be a mechanical barrier as defined in API RP 65–Part 2, Isolating Potential Flow Zones During Well Construction which has been incorporated by reference in 30 C.F.R. § 250.198.

Internal Transocean[6] and BP[7] standards in place at the time of the Macondo incident also required two barriers during various phases of drilling and completion activities. In terms of the two-barrier policy, an open BOP was perceived as an acceptable barrier because it was assumed the BOP could either be closed manually to control the well during an influx of formation fluids, or automatically by backup emergency systems in the event of loss of well control.

On detection of an influx, well control response by the crew should result in the manual activation of BOP annular preventers, pipe rams, or blind shear ram through push-button panels on the rig. (See Sections 2.3.1.) Manual or automated emergency systems to seal the well might be initiated if a well control situation were to progress. On the Deepwater Horizon, the following secondary intervention control systems were designed to ensure access to BOP functions as a last line of defense against a significant unplanned event, such as a fire, riser failure, explosion, or accidental detachment of the LMRP from the BOP stack:

- The Emergency Disconnect System (EDS), manually initiated by someone onboard the rig, activated the blind shear ram and then disconnected the LMRP and riser from the wellhead;
- The Automatic Mode Function (AMF)/deadman automatically activated the blind shear ram to cut drillpipe and then seal the well in the event of a riser failure or a major explosion or fire severed communications from the rig to the BOP (the AMF/deadman did not disconnect the LMRP and riser from the wellhead);
- The autoshear system automatically closed the blind shear ram if the LMRP accidentally detached from the lower stack;
- Remotely operated vehicles (ROVs) could have been deployed to seafloor and manual activation of certain BOP functions. For example, closing the blind shear ram could have been initiated robotically.[8]

A BOP can act as a barrier only if it can be closed, and manual closure of a BOP by a rig crew depends on additional human and process controls, sometimes referred to as operational barriers,[9] which must:

- Detect an influx into the well;
- Recognize the need to respond;
- Respond appropriately (i.e., activate the various mechanisms of the BOP to successfully seal or shear the well quickly);
- Ensure proper design and functioning of the BOP components (i.e., ensure the sealing elements and valves function as designed).

These decisions must be made before a well kick develops into a blowout, as well flow may exceed the capabilities of the BOP elements, leaving them unable to close and stop an active blowout. The first two bullets identify the reliance on drilling crew vigilance and response, suggesting that human performance is both a necessity and a threat to the effectiveness of the BOP barrier as currently designed. Volume 4 of the CSB Macondo Investigation Report details the factors that affect human response and the tools people need to complete their critical tasks effectively.

2.3 Functioning the Deepwater Horizon BOP

2.3.1 BOP Control System

To operate the BOP, the Deepwater Horizon had a control system that included multiple, rig-mounted control panels and two redundant subsea control pods located on the LMRP (designated as blue and yellow). Each contained two computer systems sealed in a subsea electronics module (SEM) vessel that shielded the electronics from high subsea ambient pressures.[10] The yellow and blue pods worked independently of each other and contained identical sets of solenoid valves. Manually activated push buttons on the control panels sent electronic signals from the rig through armored cables[a] to the yellow and blue pods that the SEMs used to open and close the solenoid valves. (See Figure 2-4.) This process allowed hydraulic fluid[11] to flow through the valve, triggering the BOP functions, such as opening or closing the various rams and annular preventers.

Figure 2-4.Control panel (left) and partial closeup of control panel on the Deepwater Horizon found in the driller's cabin and on the bridge of the rig. These controls are used to activate the BOP.[12]

During normal operations, or if the Emergency Disconnect System were initiated, the rig supplied the solenoid valves with electrical power and hydraulic fluid. Loss of this power and hydraulic supplies would have triggered the emergency AMF/deadman. In that case, the yellow and blue control pods each had an emergency backup 27-volt battery to power their respective solenoid valves and hydraulic fluid from backup accumulators, pressurized storage bottles, on the BOP stack (Figure 2-5).

[a] Armored cables: Multiplexed (MUX) cables that could send multiple simultaneous signals over a single communications cable.

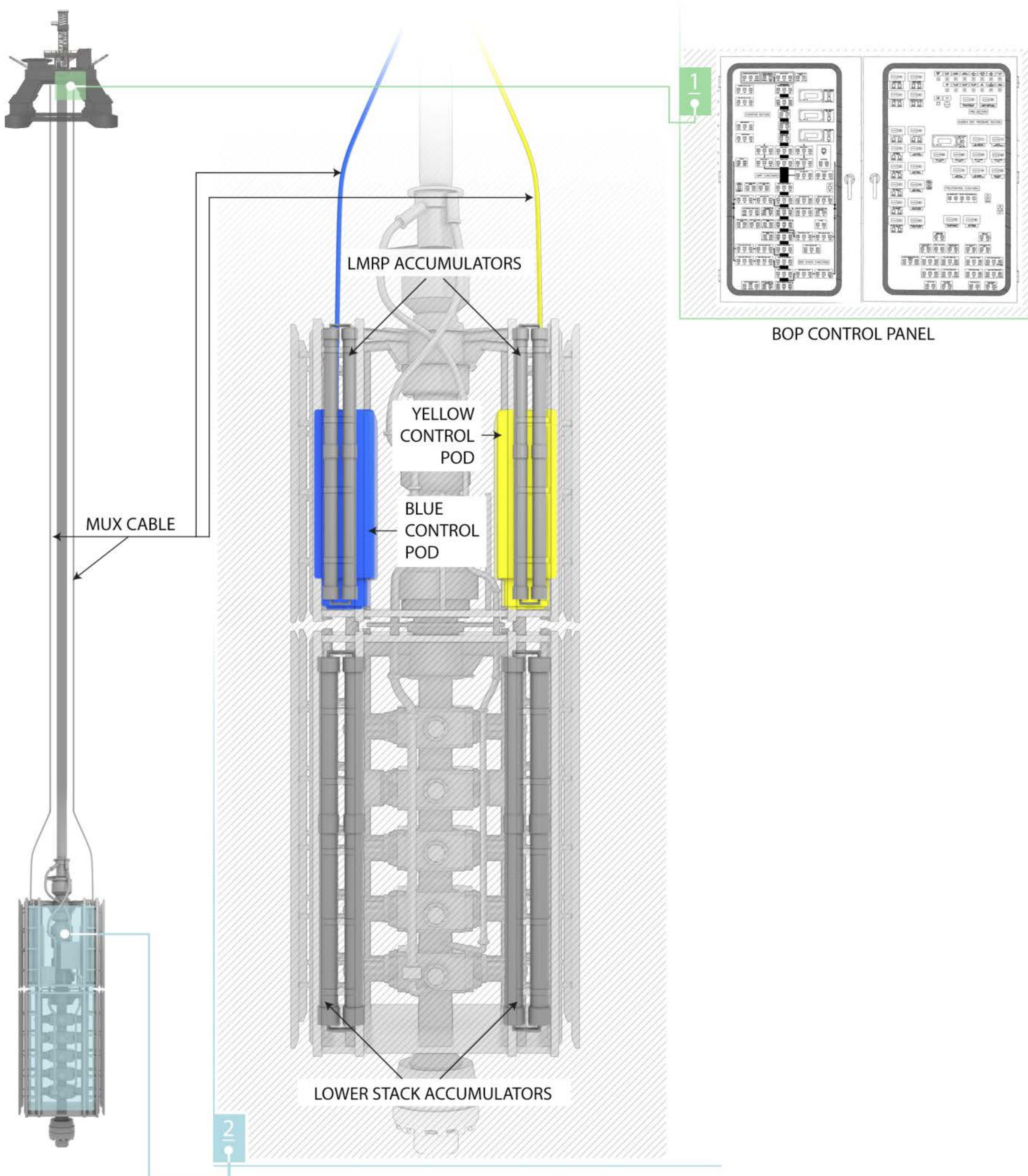

Figure 2-5. Pressing a pushbutton on a BOP control panel sent an electronic signal through the MUX cable down to the yellow and blue BOP control pods located in the LMRP. Accumulators on the BOP stack supplied hydraulic power to the control pods during emergencies.

2.3.1.1 Functioning Solenoid Operated Valves

A critical solenoid valve in the yellow pod of the Deepwater Horizon BOP was miswired, which could have prevented it from opening during the AMF/deadman sequence. (See Section 3.2.1.2.) A solenoid-operated valve, such as the one that was miswired, opens and closes as the result of an electric/magnetic action (Figure 2-6). The solenoid valve has a spring which pushes a plunger down, blocking the flow of fluid through the valve. Surrounding the spring is a tightly wound wire coil that produces a magnetic field when current runs through it. To move the plunger, the coil is energized and a resulting magnetic field attracts the iron plunger, which then pulls it up, thus allowing fluid to pass through.[a]

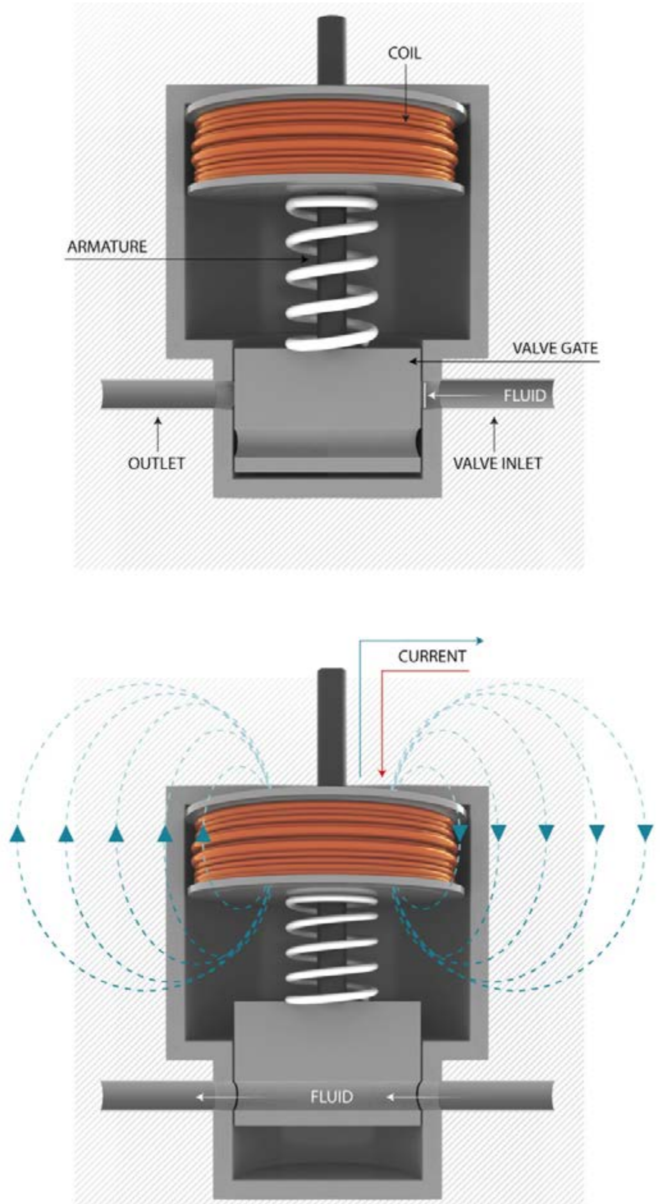

Figure 2-6. The top image depicts a solenoid with no current running through it. The plunger is down, and no fluid can flow through the solenoid. When actuated, current running through the solenoid produces a magnetic field which creates a force that pulls the plunger up, allowing fluid to flow.

The Cameron solenoid valves on the DWH contained two separate wire coils that could be energized independently to open the valve. The solenoid valves were designed to open from the magnetic field generated by just a single coil, so the design provided redundancy to the system in case one of the coils failed.

Each coil was controlled independently by one of the two digital computers (SEM A and SEM B) contained in the SEM enclosure. During activation of the emergency AMF/deadman system, SEM A and SEM B were powered by separate 9-volt backup batteries located in the SEM enclosure. SEM A and SEM B were designed to simultaneously initiate the command to power their respective coils. Once the command was sent, the solenoid valves drew power from the shared 27-volt battery to open (Figure 2-7). If

[a] The converse is true as well. When power to the solenoid valve is stopped, the magnetic field disappears, and the spring pushes the plunger back to its original, closed position.

either the SEM A or SEM B 9-volt battery were to fail, the initiating command would not be sent; thus, the remaining SEM would send its command, and the solenoid valve would open from one coil. If both 9-volt batteries were operable but the shared 27-volt battery failed, neither coil would receive power, and the solenoid valve would remain closed. (See Appendix 2-B for more details.)

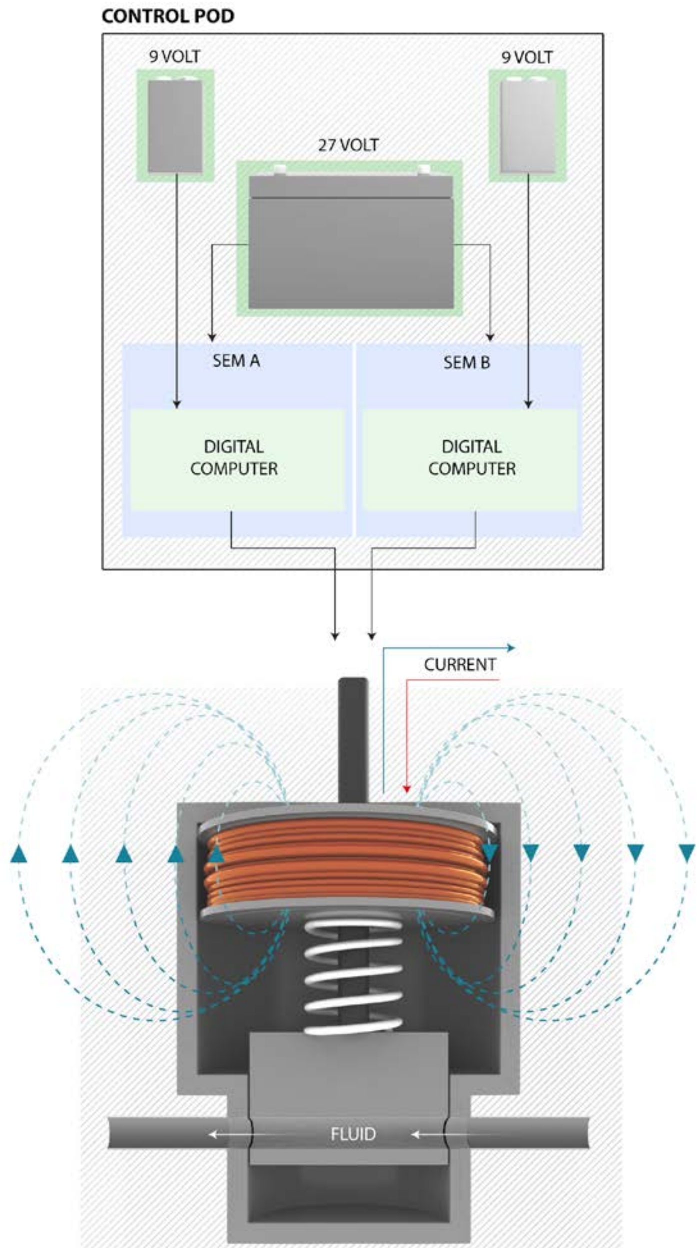

Figure 2-7. Simplified schematic of the control pod battery arrangement.

2.3.2 BOP: Closing the Blind Shear Ram

Closure of the blind shear ram in a BOP may be initiated both during normal drilling operations and in emergencies. When the blind shear ram is closed and no drillpipe is in the BOP, much less force is required than when the BSR is activated to shear drillpipe. Accordingly, the DWH's BOP had two different functions to close the BSR: the low-pressure blind shear ram close function (LP) when the BOP was free of drillpipe, and the high-pressure shear close function (HP) when shearing drillpipe was anticipated. These LP and HP functions were controlled by different solenoid valves. The EDS and AMF/deadman systems both used the HP close function, as it was necessary to account for the possibility of drillpipe in the BOP during an emergency.

The distinction between the high- and low-pressure BSR functions is highlighted here because post-incident examination of the Deepwater Horizon BSR revealed latent defects in the yellow pod HP solenoid valve responsible for closing the BSR.

2.3.3 Initiating the AMF/Deadman Sequence

On the Deepwater Horizon, the AMF/deadman had to be manually armed from one of the two control panels on the rig. Once armed,[a] SEM A and SEM B in each of the two control pods monitored for three conditions:

1. loss of surface electrical power and communication coming from the rig;
2. loss of communication between the yellow and blue pods;
3. loss of hydraulic fluid pressure from the rig.[13]

If all three conditions were met, the AMF/deadman sequence initiated. A fire and explosion like the one on the DWH could damage power and communication cables and the conduit line carrying hydraulic fluid from the rig, thus establishing the conditions necessary to trigger the AMF/deadman sequence. Once this occurred, all four SEMs would power themselves by their internal batteries and initiate solenoid valves to execute BOP functions, including closing the blind shear ram by using hydraulic fluid from the subsea accumulators. All four AMF control systems—yellow SEM A, yellow SEM B, blue SEM A, or blue SEM B—would simultaneously respond, but by design any one of the SEMs should have been able to complete the AMF/deadman sequence independently.

[a] Screen shots of the computer used to first examine the blue pod upon its retrieval indicate the Deadman/AMF system was still active on SEM B (BP-HZN-BLY00061078). Transocean stated a photo taken during a rig assessment on April 10 (Appendix N) shows that the Deadman/AMF on the yellow pod was also active, but upon reviewing the rig assessment report referenced by Transocean, the CSB could not confirm the photograph Transocean referenced.

2.4 Condition of the Well on April 20, 2010—Data Used to Recreate the Incident Events

Drillpipe pressure on the Deepwater Horizon was measured at the rig's surface, but it was also captured in data transmissions recorded onshore.[14] This data has been correlated with witness accounts to determine the actions on the rig in the hours prior to the blowout.[a] The following chronology focuses on the period just after the final negative pressure test was declared a "pass," and it proceeds to the explosion at the well. (See Volume 1 for the incident description and Appendix 2-A for details of the negative pressure tests.)

The CSB also generated a computer simulation[b] of the Macondo well flow for the time beginning with the displacement of the drilling mud, about 4 p.m., up to the blowout that occurred near 10 p.m. (See Appendix 2-A for details concerning the simulation.) The simulation provides the basis for statements made concerning the flow of hydrocarbons from the well and inferences about the BOP's integrity during the incident.

2.5 The Macondo Well Kicks—Incident Analysis of Well Control Response

At 8:00 p.m., after the BP wellsite leaders[c] and Transocean personnel completing the negative pressure test declared the test successful, displacement of the remaining drill mud with seawater began. Soon, as planned, the well became underbalanced and the hydrostatic pressure exerted on the bottom of the well went below the formation pressure. The CSB computer simulation indicates this occurred around 8:51 p.m.[d] The failure of the bottom hole cement job to seal the well allowed the reservoir fluids to flow into the wellbore at this time (Figure 2-8).

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[a] While various investigating parties have reported differences in the timestamps for certain activities, these are not materially significant to understanding the sequence of events. Notes from interviews conducted by BP, http://www.mdl2179trialdocs.com/releases/release201304110900026/TREX-37031.pdf, pp. BP-HZN-BLY00377487 - 489 (Accessed August 9, 2013), just following the incident and a written statement by BP wellsite leaders, http://www.mdl2179trialdocs.com/releases/release201304041200022/TREX-51133.pdf, have been correlated with the real-time data to generate the time stamps found in this section.

[b] The CSB contracted with Engineering Services to complete the simulation using proprietary software. BP and Transocean completed their own simulations as well.

[c] Wellsite leader: The drilling supervisor overseeing all activities including heath and safety, operations, and logistics at the well, http://www.bp.com/en/global/corporate/careers/career-areas/wells/wells-operations.html. Accessed May 16, 2014.

[d] Others have also generated the computer model to simulate when the influx of hydrocarbons from the well began. Transocean estimated the well became underbalanced between 8:38 p.m. and 8:52 p.m. (Transocean investigation report, Volume II, June 2011, Appendix G, p. 98).The BP account was 8:52 p.m. (BP plc, Deepwater Horizon accident investigation report, September 8, 2010, p. 25.)

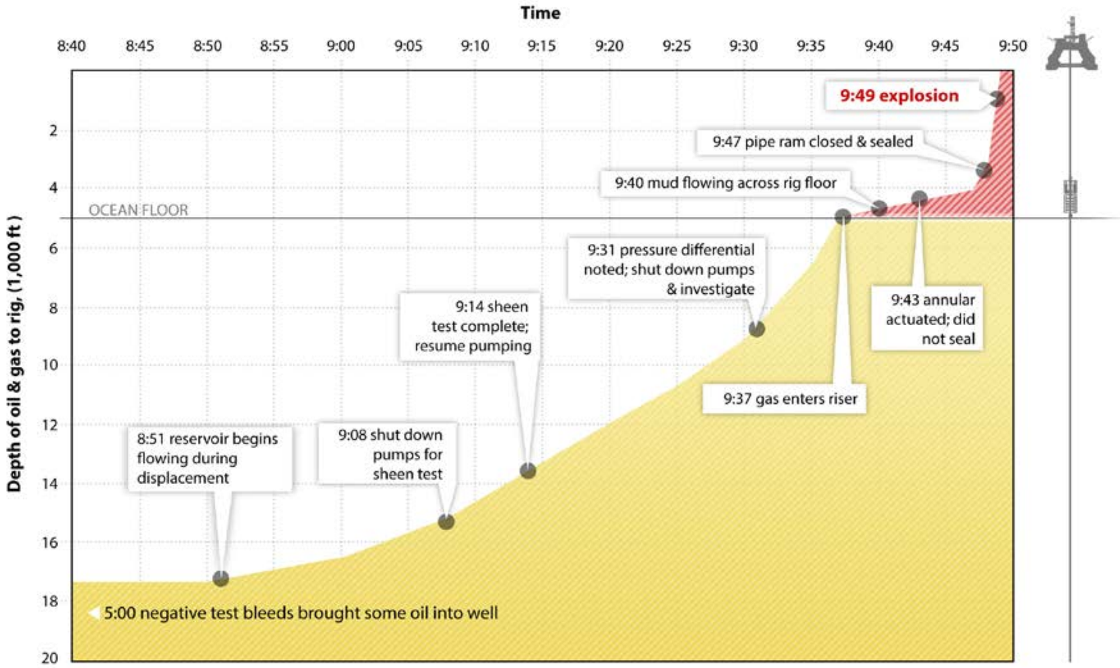

Figure 2-8. Key operation events after reservoir flow began.

Synthetic, hydrocarbon-based drilling mud is expensive, and regulations do not allow for its discharge into the Gulf;[15] therefore, it is typically retained when displaced from a well and transferred to another vessel for transportation to another drilling rig, reprocessing, or proper disposal. The DWH rig had such a vessel, the *Damon Bankston*, available to offload the drilling mud used in the well. At 9:08 p.m., the crew believed it had finished displacing the drilling mud and prepared for a sheen test[a] by shutting down the pumps used to displace the drilling mud. The sheen test was used to verify that the fluids returning from the well onto the rig, referred to as "returns," no longer contained the hydrocarbon-based mud and, thus, could be discharged overboard into the Gulf. This occurred at 9:09 p.m., when the crew declared the returns mud free and diverted their flow overboard, but the CSB computer simulation indicates that at this time the influx rate into the wellbore was sufficient to produce strong flow indicators.[b]

At 9:31 p.m., the driller investigated noticed an anomalous pressure difference.[16] Shortly thereafter, oil and gas that had flowed into the wellbore from the reservoir pushed a mixture of seawater, drilling mud, and hydrocarbons onto the drilling rig.

In response, the drilling crew closed the upper annular (UA) at ~9:43 p.m., which should have sealed the space around the drillpipe and prevented further hydrocarbons from rising above the BOP into the riser.[c]

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[a] Sheen test: A sample is added to water and a visual determination made if it causes a sheen, indicating unacceptable oil content for disposal into the sea.

[b] The computer simulation found in Appendix 2-A indicates about 9 bpm (barrels/minute) were flowing into the well, and the pit gain on the rig was about 60 barrels over 16 minutes.

[c] Witness statements said that the bridge remote control panel indicated that the lower annular was closed. Hearing before the Deepwater Horizon Joint Investigation, May 28, 2010, p. 145. However, upon recovery the lower

However, well data indicates that the UA failed to seal,[a] likely caused by erosion of the preventer rubber. Later a pipe ram with a similar rubber component and finger design successfully sealed the flow, but the pipe ram closes more rapidly than an annular, which reduces erosion potential.[b] As a result, not only did the riser fluids that already passed above the BOP continue to travel up the riser and release onto the drilling rig, but the riser was also being replenished by the flow of even more hydrocarbons through the leaking upper annular.

Immediately after shutting the annular, the rig crew also activated a diverter at the top of the riser to route the well fluids away from the rig floor.[17] When the diverter shut, flow up the riser exiting onto the drilling rig was redirected to the diverter piping. The two potential piping destinations were overboard into Gulf waters or to a mud-gas separator (MGS).[c] On the day of the incident, when the crew activated the diverter, it had been preset to flow directly to the MGS.[d] Due to the magnitude of well fluids coming up the drillpipe, the MGS was overwhelmed moments after the diverter was activated, and hydrocarbons began blowing out of exit points onto the rig.

Pressure data indicates that at ~9:47 p.m., the crew most likely closed the middle pipe rams (MPR) and possibly the upper pipe rams (UPR), successfully shutting in the well but also causing the pressure in the drillpipe to build substantially. Riser fluids above the BOP continued to unload onto the drilling rig, but their replenishment was temporarily halted by the closed pipe ram. At ~9:49 p.m., the first explosions occurred on the rig, and data transmission from the rig to shore ceased.

Between 9:52 p.m. and 9:56 p.m., a crew member pressed the Emergency Disconnect System (EDS) button on the bridge BOP remote control panel.[18] This maneuver should have closed the BOP blind shear ram and disconnected the rig and riser from the BOP, thus allowing the DWH to move away safely from the wellhead. However, there was no indication of EDS actuation. The explosion likely satisfied the criteria for automatic activation of the emergency AMF/deadman backup system by severing power, communication, and hydraulic lines to the BOP, which should have closed the blind shear ram (See Section 3.2.2), but as evident from the major oil spill that ensued, the well remained unsealed.

annular was found open [Bureau of Ocean Energy Management Regulation and Enforcement (BOEMRE), March 11, 2011. Forensic Examination of Deepwater Horizon Blowout Preventer, Report No. EP030842.] http://www.uscg.mil/hq/cg5/cg545/dw/exhib/DNV%20Report%20EP030842%20for%20BOEMRE%20Volume%20I.pdf, p. 27. Accessed August 14, 2013.

[a] If the annular had sealed, the drillpipe pressure at the surface would have rapidly increased to 5,000+ psig, as when the upper pipe ram sealed at 9:47 p.m. Rather, the drillpipe pressure fluctuated between 1,800 and 400 psig in this time period.

[b] See Appendix 2-A for more details.

[c] When gas contamination of mud returning to the rig is suspected, well fluids can be routed to this mud-gas separating system to safely separate and remove the flammable gas from the drilling mud. The MGS is limited in the amount of flow it can handle.

[d] The default lineup of the diverter was routed through the MGS for several potential reasons, including: 1) diverting through the MGS is a normal procedure while drilling; 2) discharging oil-based drilling mud overboard could be a violation of environmental regulations; and 3) diverting through the overboard lines is considered an emergency procedure, a last resort to a large influx of gas above the BOP.

3.0 The Blowout Preventer – Failure of a Barrier

Chapter 3 Overview

This chapter covers the CSB's independent analysis of DWH BOP failure data, much of which was collected after other Macondo investigation reports were published, and the CSB's additional testing. It describes latent failures found in the BOP and their effect on the emergency AMF/deadman system. The chapter also describes how large pressure differences in the Macondo well likely caused drillpipe to buckle within the BOP due to a phenomenon known as "effective compression."

On the day of the incident, the Deepwater Horizon BOP experienced failures that affected its ability to prevent and mitigate the Macondo blowout. The initial failure occurred approximately 6 minutes prior to the first explosion, when the drilling crew attempted to close the upper annular. If the upper annular had sealed, less gas and oil would have entered the riser and then exited onto the drilling rig, likely reducing the severity of the ensuing explosion and duration of the fire. The second failure occurred just after the explosion, when the automated emergency AMF/deadman system would have been triggered, but the blind shear ram did not close and seal the well as designed. Instead, the surviving crew had to evacuate amid an active blowout and major fire.

If either the bottom hole cement job had been successful or the BOP had functioned that day, the blowout could have been avoided. Chapter 4.3 of the *Chief Counsel's Report*[19] by the National Commission on the BP Deepwater Horizon Oil Spill and Offshore Drilling details the cementing process in deepwater drilling and specifically the procedures the Deepwater Horizon crew used at the Macondo well. The National Commission conducted stability studies on foamed cement[20] similar to Macondo's to further investigate a probable failure mechanism. While BP, Transocean, and Halliburton have speculated about why the cement failed, the *Chief Counsel's Report* states that limitations in available data prevented determining a precise failure mechanism. Yet the report indentified several technical and management challenges that increased the risk for failure of the cement at the bottom of the Macondo well.[a]

Due to the National Commission's thorough documentation of the cementing practices at Macondo in the *Chief Counsel's Report*, the CSB chose to focus on the less understood failure of the BOP, which was retrieved from the wellhead and brought onshore for analysis that was not completed until after the *Chief Counsel's Report* was published.

[a] The *Chief Counsel's Report* reviewed the actions of the cement provider, Halliburton, and BP as part of its investigation. It asserts that some Halliburton personnel were aware of potential problems with the cement used at Macondo, but they did not inform BP of the issues. The National Commission attributes the lack of communication and other technical issues with the cement to management problems within the company. The National Commission was unable to specify the management problems because Halliburton did not provide any documents or testimony to indicate if the actions taken by Halliburton personnel were prohibited by the company. Beyond Halliburton, the National Commission asserts that BP's management process did not require identifying and evaluating all the cementing risks at Macondo, which subsequently led to inadequate mitigation of them. This includes identifying risks inherent due to conditions of the Macondo well and others resulting from BP and Halliburton well design and cementing decisions.

3.1 Correlating Physical Evidence from Macondo with the Events of April 20, 2010

Once the Deepwater Horizon blowout preventer was retrieved from the wellhead and examined, it was revealed that the drillpipe was not centered in the BOP when the BSR was activated. This off-center position of the drillpipe inhibited the BSR from fully closing and sealing the well.[a] Consequently, the CSB pursued three major lines of inquiry to determine the most likely cause of the bending, or buckling, of the drillpipe to its off-center position.

- Weight of equipment and drillpipe above the BOP pushing down after the support holding the top of the pipe at the Deepwater Horizon failed due to the explosion and fire;
- A combination of drag forces from high flow of well fluid up the drillpipe and from well pressure pushing up on the bottom of the drillpipe deep in the well;
- Bending forces created from the combined effects of 1) large pressure differences inside and outside of a drillpipe and 2) vertical forces applied to the face of a pipe end, a buckling mechanism referred to as *effective compression*, which has been previously identified in other contexts in the oil and gas industry.[b]

The CSB attempted to obtain BOP performance data from Cameron and BP to assess the viability of the weight theory, but neither company provided the needed information.[c, d] For reasons discussed in Appendix 2-A, the CSB finds the weight theory unlikely[e] but cannot definitively rule it out. CSB modeling indicates that if a sufficient well flow is assumed, the drillpipe may buckle, but the force from fluid flow alone is insufficient to buckle the drillpipe. Bending forces created by effective compression must be considered to calculate sufficient forces to buckle the drillpipe. The CSB concludes the most likely buckling scenario occurred just after the rig crew activated the pipe ram and temporarily sealed the

[a] The Deepwater Horizon BOP was not designed to cut off-center drillpipe. Post-incident modeling of the forces required to cut off-center drillpipe indicated that the DWH BOP was incapable of cutting the off-center drillpipe and subsequently sealing the well. See Appendix 2-A for details.

[b] See Section 3.2.3 for details.

[c] To resolve this theory, it is necessary to quantify the force required to overcome the friction generated against drillpipe being held by closed VBRs under high well pressure. See Appendix 2-A for details. The information could be obtained from stripping performance tests or from an in-field test conducted on a drilling rig.

[d] The CSB did not request this information from Transocean because it refused to acknowledge the Agency's jurisdiction and failed to respond fully to subpoena requests for documents and interviews. The CSB has pursued enforcement actions in federal court. Ultimately, a federal district court ordered Transocean to comply with the CSB subpoenas. United States v. Transocean Deepwater Drilling, Inc., 2013 WL 1345246 (S.D. Tex. Mar. 30, 2013). Transocean has appealed this decision, and at the time of publication of this report, a court decision on the appeal is pending.

[e] In summary, the closed VBRs would need to be able to support the net weight of the drill string, about 178,000 lbs. Undocumented anecdotal field experiences indicate this friction is low (10,000 to 30,000 lbs). If VBR friction were high (e.g., 100,000 to 200,000 lbs.), it could have an adverse implication for offshore drilling. An important situation occurs when deciding to hang-off drillpipe on a closed VBR. This is a well control procedure used by both BP and Transocean, and likely by other operators and contractors. If high VBR friction exceeds the weight of the drill string, lowering the drill pipe onto the rams would be impossible, potentially leaving the tool joint opposite a blind shear ram. See Appendix 2-A for more details.

well. This closure of the pipe ram created the pressure difference necessary for effective compression to buckle the drillpipe. (See Section 3.2.3 for details.)

Any drillpipe buckling scenario at Macondo has to be correlated with closure of the blind shear ram. Two clear opportunities arose for the BSR to have been activated:

- in the moments just after the first explosions on the DWH when the well was shut in and the AMF/deadman emergency system was likely triggered;
- on April 22 when the well was actively flowing and the emergency autoshear function was triggered by ROV intervention efforts.

Video evidence supports the activation of the autoshear function on April 22,[21] but it does not preclude previous closure of the BSR as a result of AMF/deadman activation on April 20. BP, Transocean, the regulator,[a] the National Academy of Engineers, and the National Commission have speculated whether the AMF/deadman functioned on the day of the incident.[22] The reports from these various authors were limited to the diagnostic information available on their publication date; besides the CSB, only Transocean released its report after of all phases of the Deepwater Horizon BOP failure analysis was completed.

Using the full set of BOP testing data and additional independent CSB testing, the CSB determined sufficient evidence supports closure of the BSR during the AMF/deadman activation as the most likely scenario. While this finding contradicts previously published theories, it does not negate the importance of those possible scenarios, in part because a lack of data and evidence prevents an outright rejection of some of them. Instead, in an accident as complex and devastating as Macondo, each scenario provides an important opportunity to explore previously unconsidered pipe buckling mechanisms, failures of the BOP to seal the well, and opportunities for regulations to improve safety in offshore drilling and production activities.

The CSB’s conclusion that the Macondo drillpipe likely buckled due to effective compression reveals an unrecognized potential for drillpipe to buckle even when timely well control actions initially shut in a well. Better understanding of this buckling phenomenon can lead to improvements in equipment design, well control procedures, training, and adoption of more rigorous management methods, each of which could ultimately lessen the likelihood of buckled drillpipe across the BSR of a BOP, as occurred at Macondo.

The complete set of Deepwater Horizon BOP data and additional CSB analysis extend beyond the actions on April 20 and provide new insight for safety improvements in deepwater drilling. This analysis has led to the key technical findings from the day of the incident (Chapters 3.0) and during previous drilling operations (Chapter 5.0) that address why the BOP failed to shear the drillpipe and seal the well during the incident and how post-incident regulatory and industry response has left gaps that could allow for a BOP with similar deficiencies found at Macondo to be put into service:

[a] At the time, the US offshore regulator was the Bureau of Ocean Energy Management Regulations and Enforcement (BOEMRE).

- The AMF/deadman uses two redundant control systems, the yellow pod and the blue pod, to initiate closure of the blind shear ram. This redundancy is intended to increase the AMF/deadman reliability, but on the day of the incident only one of the two pods was functioning.
  - The blue pod was miswired, causing a critical battery to drain and rendering the pod inoperable (Section 3.2.1.1).
  - A critical solenoid in the yellow pod had also been miswired. Redundant coils were designed to work in parallel to open the solenoid valve, but the miswiring caused them oppose one another. Had both coils been successfully energized on the day of the incident, the solenoid valve would have remained closed and unable to initiate closure of the BSR. However, a drained battery likely rendered one of these coils inoperable. This would have allowed the other coil to activate alone and initiate closure of the BSR, but drillpipe buckled off-center in the BOP prohibited the BSR from fully closing and sealing the well (Section 3.2.1.2, 3.2.1.3, and 3.2.2).
- The AMF/deadman system likely actuated, but buckled, off-center pipe in the BOP prohibited the blind shear ram from fully closing and sealing the well. The BSR punctured and partially severed the pressurized drillpipe, causing flow to resume rapidly. Flow had been temporarily stopped several minutes earlier by a successful sealing with a closed BOP pipe ram (Section 3.2.2).
- The drillpipe within the BOP buckled off-center due to effective compression, a buckling mechanism not yet identified by other investigative reports on the Macondo incident[a] (Section 3.2.3).
- The BSR installed on the DWH was not suitable for the Macondo drilling operation, as it could not reliably shear the 6⅝" drillpipe used during all of the DWH drilling operations except on April 20 (See Section 5.2.1).
- The miswired solenoid valve in the yellow pod and the deficient wiring in the blue pod could not have passed the manufacturer's factory acceptance testing procedures (Sections 5.3.1and 5.3.2).
- At the time of the incident, neither recommended industry practices nor US regulations required testing of the AMF/deadman system. Despite post-incident changes that call for function testing the AMF/deadman, deficiencies identified during the failure analysis of the Deepwater Horizon BOP could still remain undetected in BOPs currently being deployed to wellheads (Section 5.3.2).

3.2 Failure Analysis of the Deepwater Horizon BOP

[a] Stress Engineering Services (SES), serving under contract with Transocean, suggests effective compression to explain the pipe buckling. (Transocean, *Macondo Well Incident - Transocean Investigation Report*, Volume 1, 2011, Appendix M.) However, Transocean did not use the SES explanation in their investigation report. The National Academy of Engineering report notes the differences between the results of Transocean and its contractor SES, but NAE does not acknowledge that SES presents effective compression values, which include the effects of a pressure differential between the inside and outside of the pipe and account for the weight of the drill string and buoyancy forces. (National Academy of Engineering and National Research Council. *Macondo Well Deepwater Horizon Blowout: Lessons for Improving Offshore Drilling Safety.* Washington, DC: National Academies Press, 2011, p.50.)

The failure analysis of the Deepwater Horizon BOP was completed in a three-part process that began just weeks after the incident and concluded almost 14 months later (Table 3-1). The yellow and blue pods of the DWH were individually brought to the surface, and preliminary examinations were completed on May 4, 2010[23] and July 5, 2010,[24] respectively. The solenoid valves of each pod were function tested, and the integrity of pipe, tubing, hoses, and hydraulic lines were verified.[25] Additionally, execution of the AMF/deadman sequence was conducted.[26]

Results of Phase II testing are essential to understand that wiring problems in the blue pod likely caused a critical battery in AMF/deadman system to drain, which rendered it inoperable during the incident. Results also revealed that the yellow pod contained two miswired solenoid valves, one being responsible for closing the blind shear ram, which also could have rendered the AMF/deadman system in the yellow pod inoperable.

During this initial testing, neither the yellow pod nor the blue pod completed the AMF/deadman sequence correctly. The solenoid valve on the yellow pod (Y103) responsible for the high-pressure BSR shear close function would not open. All the solenoid valves on the blue pod functioned, but a critical 27-volt battery showed insufficient charge to power the solenoid valves during the AMF/deadman sequence.[27] After repairs and modifications[a] had been made to the pods, they were redeployed to the BOP subsea to aid intervention efforts to stop the continuing blowout using the BOP.[28]

Table 3-1. In addition to the three phases of DWH BOP testing from May 2010 to April 2011, the CSB completed independent exemplar solenoid valve testing in September 2012.

Preliminary Examination		Phase I		Phase II	CSB Sponsored Testing
YELLOW POD **May 4, 2010**	BLUE POD **July 5, 2010**	YELLOW POD **November 2010 - March 2011**	BLUE POD **November 2010 - March 2011**	**April-June 2011**	**September 2012**
• Solendoid valves functioned • AMF/deadman actuation • Battery voltages measured	• Solendoid valves functioned • AMF/deadman actuation • Battery voltages measured	• Solendoid valve (Y103) bench testing • Solendoid valve (Y103) functioned while installed in the pod • AMF/deadman actuation • Battery load testing	• AMF/deadman actuation • Battery load testing	• Solendoid valve (Y103) disassembly • PETU characterization • Battery load testing	• Exemplar solendoid valve testing

The Deepwater Horizon's blowout preventer, including the yellow and blue pods, was recovered from the wellhead on September 4, 2010, and ultimately was transferred to the NASA-Michoud facility in New

[a] Repairs and modifications included removing the original Y103 and installing a replacement in the yellow pod. During the forensic testing of the BOP, the original Y103 was reinstalled on the yellow pod. The batteries in the blue pod were not modified during these repairs.

Orleans, Louisiana. The Joint Investigation Team (JIT)[a] awarded Det Norske Veritas (DNV) a contract to conduct a forensic investigation of the Deepwater Horizon BOP.[29] The CSB was present for Phase I testing, and the results from this phase were made public.[30]

A Court Order on March 25, 2011 granted BP a motion for access to the Deepwater Horizon blowout preventer for further forensic inspection. The Court considered proposed protocols and hearings on the matter, which resulted in a Court-ordered Phase II testing protocol to be performed by DNV[b] under the Court's auspices.[31] The CSB was excluded from Phase II testing by the Court, but obtained the testing results and interviews to document the activities.

Complete results from Phase II testing have not previously been made public, but they are essential to understand that wiring problems in the blue pod caused a critical battery in AMF/deadman system to drain, rendering the blue pod AMF/deadman inoperable during the incident. Phase II results also revealed that the yellow pod contained two miswired solenoid valves,[c] one being Y103—the high-pressure shear close function solenoid—which also could have rendered inoperable the AMF/deadman system in the yellow pod.

To understand results from Phase I and II testing, the CSB also sponsored testing of an exemplar solenoid valve that determined the effect of a miswired solenoid valve. The CSB determined that despite the miswiring of Y103, a coincident failure of a battery in the yellow pod likely allowed Y103 to function on only one coil and actuate the AMF/deadman on the day of the Macondo incident. Nevertheless, the Macondo well remained unsealed because drillpipe buckled off-center in the BOP which impeded closure of the BSR. These findings are briefly summarized in this chapter with details of the full analysis provided in the supplemental technical reports on the BOP Failure Analysis in Appendices 2-A and 2-B.

3.2.1.1 Blue Pod: Disconnected Wires and the Drained Battery

Part of Phase II testing included tracing the circuitry within the SEMs to verify it matched the original Cameron drawings. The results indicate several wires from the blue pod SEM were missing, broken, disconnected, or miswired. No tests were completed to examine how, why, or when the wires came to

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[a] The Bureau of Ocean Energy Management, Regulation and Enforcement (BOEMRE) and the United States Coast Guard (USCG) formed a joint investigation team (JIT) to investigate the Deepwater Horizon incident. BOEMRE contracted Det Norske Veritas (DNV) to conduct a physical examination of the BOP. At the request of the US House Committee on Energy and Commerce and in accordance with its statutes, the CSB initiated an independent investigation into the incident. The CSB, JIT, and other parties agreed to participate in the BOP examination. During the examination of the BOP, the CSB participated as part of the technical working group (TWG), which reviewed testing protocols and provided feedback during testing.

[b] During this phase of the testing, by Court order, DNV was to run the testing, produce the data, and disseminate the results to the various parties. DNV and its subcontractors were not allowed to interpret the results, provide an opinion on further testing, or write a report based on the results.

[c] A second solenoid, 3A in the yellow pod, was also found miswired similar to Y103. Since solenoid valve 3A controlled the upper annular regulator pressure, it was used during normal drilling operations to close off the annular space around the drillpipe. A review of the daily drilling reports from the Deepwater Horizon did not reveal any reported problems with closing pressure of the upper annular. An underlying question, then, is how could miswired solenoid 3A not have been discovered during normal drill operations when tests show neither Y103 nor 3A could have functioned normally? See *How a Miswired Solenoid Valve Operates* in Appendix 2-B for one possible explanation.

their deficient condition, but the discovery supports an alternative explanation of why a critical 27-volt battery in the blue pod was found drained.[a]

The CSB believes that once the AMF/deadman was armed from the rig, missing or disconnected wires in the blue pod erroneously indicated that power and communications from the rig to the pod had failed. This likelihood established one of the three conditions necessary to initiate the AMF/deadman (Section 2.3.3). As a result, the blue pod, powered by the 27-volt battery, began to monitor for loss of hydraulic pressure until the battery was drained before the day of the incident. Subsequently, the blue pod was incapable of initiating the AMF/deadman sequence during the incident due to the inability of 27-volt battery to power the opening of the solenoid valves. (See Appendix 2-B for more details.)

3.2.1.2 Yellow Pod: Miswired High-Pressure Shear Closes Solenoid

Phase II analysis of the Y103 solenoid valve from the yellow pod revealed that it had been miswired. Figure 3-1 shows where pins 1 and 3 should be attached to the white wires and pins 2 and 4 to black wires, which was not the case with Y103. As a result, when both solenoid coils were energized during bench testing, the miswiring produced opposing magnetic fields, which canceled out each other and caused the solenoid valve to remain closed.

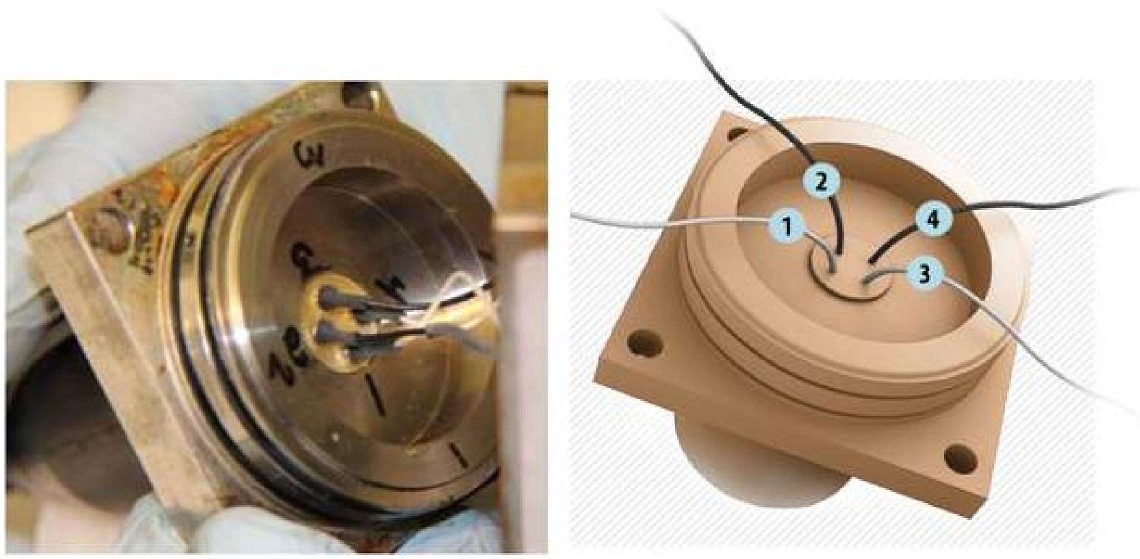

Figure 3-1. (Left) Photograph of Y103 wire arrangement from Phase II testing with pins 1 and 4 connected to white wires and 2 and 3 connected to black wires. (Right) Schematic of correct arrangement of wires, with pins 1 and 3 connected to white wires and 2 and 4 connected to black wires.

Previously published investigation reports assert that attempts to actuate the miswired Y103 solenoid were successful even when both coils were simultaneously energized,[32] but Phase II testing revealed

[a] Transocean presented a theory (Transocean, *Macondo Well Incident - Transocean Investigation Report*, Volume 1, 2011, Appendix N, p. 6) asserting the 27-volt battery drained in the blue pod after the AMF/deadman had successfully fired on April 20, 2010. The CSB does not accept this theory, nor does it support that the blue pod successfully actuated the AMF/deadman system on the day of the incident.

incorrect assumptions made during Phase I. DNV believed switches on test equipment used during Phase I could control whether to energize one or two coils of a solenoid valve.[33] Phase II characterization of the test equipment discovered that during an attempt to activate just one coil, both coils were energized, and vice versa. In light of Phase II information, Phase I test results needed reinterpretation. Ultimately, with just one exception, Y103 did not open when both coils were energized and always opened when just one coil was energized. (See Appendix 2-B for full details.)

3.2.1.3 Successful AMF/Deadman Tests on the Yellow Pod

The AMF/deadman was designed to simultaneously energize both coils of the solenoids it activated, yet—despite the miswiring of Y103 in the yellow pod—the system successfully completed the AMF/deadman sequence each of the three times it was initiated during Phase I testing. Although all three tests resulted in closure of the BSR, the closure was delayed during the first test.

SEM A and SEM B were powered by separate 9-volt batteries (Section 2.3.1.1). Failure of SEM A or SEM B due to a dying or dead battery would enable the miswired solenoid to function because it would prevent sending a command to the associated coil to energize. As a result, the remaining coil would function unopposed and open the solenoid valve.

Battery testing conducted during Phase II clearly shows that the SEM B yellow pod 9-volt battery failed.[a] Accordingly, the successful AMF/deadman test results on the yellow pod from Phase I indicate that during the first AMF/deadman test, the BSR initially failed to open until the SEM B battery died during testing operations, upon which Y103 opened. After this initial delayed response, the BSR opened without delay in all the subsequent AMF/deadman tests because the battery had been spent during the first test.

3.2.1.4 Independent CSB Exemplar Solenoid Testing

To further understand Phase I AMF/deadman results, the CSB obtained an exemplar solenoid valve and simulated the miswiring found in Y103. The CSB also simulated the effect of a battery dying while powering one of the SEMs during actuation of the AMF/deadman sequence. The CSB testing demonstrates that when both coils in a miswired solenoid are initially fired, the valve fails to open, but if the power source for one of the SEMs is cut off (i.e., a battery dies), the solenoid valve subsequently opens. (See Appendix 2-B for more details.)

For solenoid valve bench tests conducted in Phase I, a constant power source was utilized and each coil was energized separately.[34] During a normal AMF/deadman sequence, both coils would be energized and the power would be pulsed to minimize heat buildup in the solenoid valve. CSB testing on the exemplar solenoid valve simulated the AMF/deadman power conditions. This testing indicates that a miswired solenoid valve could intermittently open if the two coils were activated with a small time lag to each

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[a] The BOP battery has a very flat discharge curve over its lifecycle. The voltage will remain in operating range unless the battery is put under some type of demand (or load) by connecting it to a system that draws current from the battery. When not under load, the battery can recover some voltage after a load has been removed. No load was used during battery testing on the Q4000 and a non-representative load was used during the subsequent Phase I testing. During Phase II testing, a load that represented the normal operating condition of the 9-volt battery was used. This is when it was observed that the battery had failed. See Appendix 2-B for more details.

other, but this probably would only partially close the BSR.[a] Without evidence of intermittent opening behavior of Y103 on April 20, the CSB finds it unlikely that the miswired Y103 solenoid valve would have closed the blind shear ram during an actuation of the AMF/deadman system if both SEM A and SEM B were functioning. (See Appendix 2-B for more details.)

3.2.2 The AMF/deadman Successfully Fires on April 20, 2010

Because the miswiring in the blue pod would have caused the critical 27-volt battery to drain, rendering the pod inoperable during the incident (see Figure 3-2), the AMF/deadman sequence could actuate only if the yellow pod was able to function.

Temperature affects a battery's performance.[35] Consider a common problem automobile owners experience when they try to start a car during very cold weather. A battery does not produce as much power at lower temperatures; as a result, it can become incapable of starting a car engine. The batteries of a BOP are subject to the same limitations. Before the Macondo incident, Cameron, the manufacturer of the DWH BOP, completed AMF/deadman simulation tests that demonstrate the AMF/deadman batteries produce less completed sequences at colder temperatures.[36]

[a] The design of the BSR has a connecting rod exposed to the subsea pressure on one side and the well pressure on the other. After power to the BOP was lost due to the explosion, the pressure difference between the seawater and wellbore pressure above the closed pipe ram would have generated a closing force on the BSR. This would have pushed the BSR up to the drillpipe before the AMF/deadman sequence began. Once the AMF/deadman sequence began, further closure of the BSR to shear the drillpipe could have occurred if Y103 did open intermittently. The CSB has no evidence to support any intermittent opening behavior of Y103 on April 20, but at this time the CSB cannot definitively rule out the possibility either.

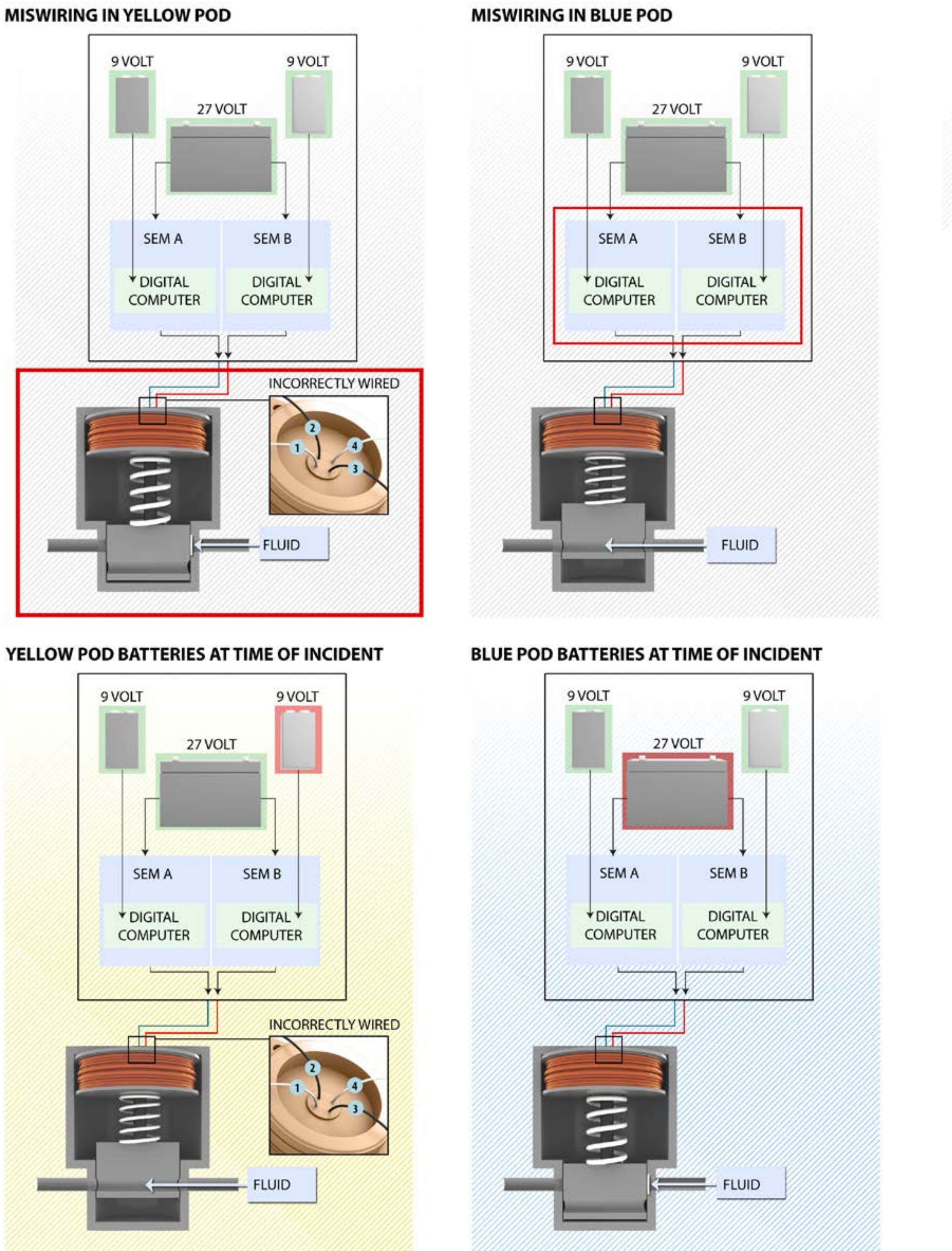

Figure 3-2. Miswiring in the blue pod caused the critical 27-volt battery to drain, rendering the pod inoperable during the incident. A drained 9-volt battery in the yellow pod left one of the coils in the miswired Y103 solenoid valve inoperable, allowing the other coil to activate unopposed and initiate closure of the blind shear ram.

The failure of the SEM B battery during the yellow pod AMF/deadman tests in Phase I occurred when the SEM was operating in an ambient temperature near 21°C (70°F). Borrowing from the car analogy, an SEM battery that barely produced sufficient power when operating in ambient temperatures might not have functioned when operating in subsea temperatures near 2°C (36°F).[a] Therefore, on the day of the incident, SEM B in the yellow pod was likely not operational, allowing the SEM A coil of Y103 to function unopposed and successfully execute the AMF/deadman sequence. (See Figure 3-2 and Figure 3-3.)

The likely actuation of the AMF/deadman and closing of the BSR might have been successful during the incident had the drillpipe been centered in the BOP. However, post-incident examination of the drillpipe reveals this was not the case[37] (Figure 3-4). Instead, a portion of the drillpipe was found outside of the blind shear ram blades, so it was not cut but rather squeezed between the non-blade segments of the BSR. As a result, the drillpipe was not completely severed, and the BSR did not fully close and seal the well. The partial closure of the blind shear rams punctured the drillpipe and caused flow from the well to the environment to reestablish. This reopening of the well took place minutes after closure of the pipe rams had actually sealed around the drillpipe.

[a] The actual temperature of the vessel containing the SEM would have been greater than the surrounding environment because of heat produced by all the electronics. Accordingly, the temperature of the SEM vessel was greater than 21°C (70°F) during Phase I and greater than 2°C (36°F) when operating subsea. Testimony given in the U.S. District Court for the Eastern District of Louisiana under the Multi-District Litigation docket MDL No. 2179, see Coronado Designations Vol. 1, p. 45, indicates the operating temperature subsea might be 16°C (60°F). Calculations in Appendix 2-B demonstrate this temperature is sufficient to affect AMF/deadman battery performance.

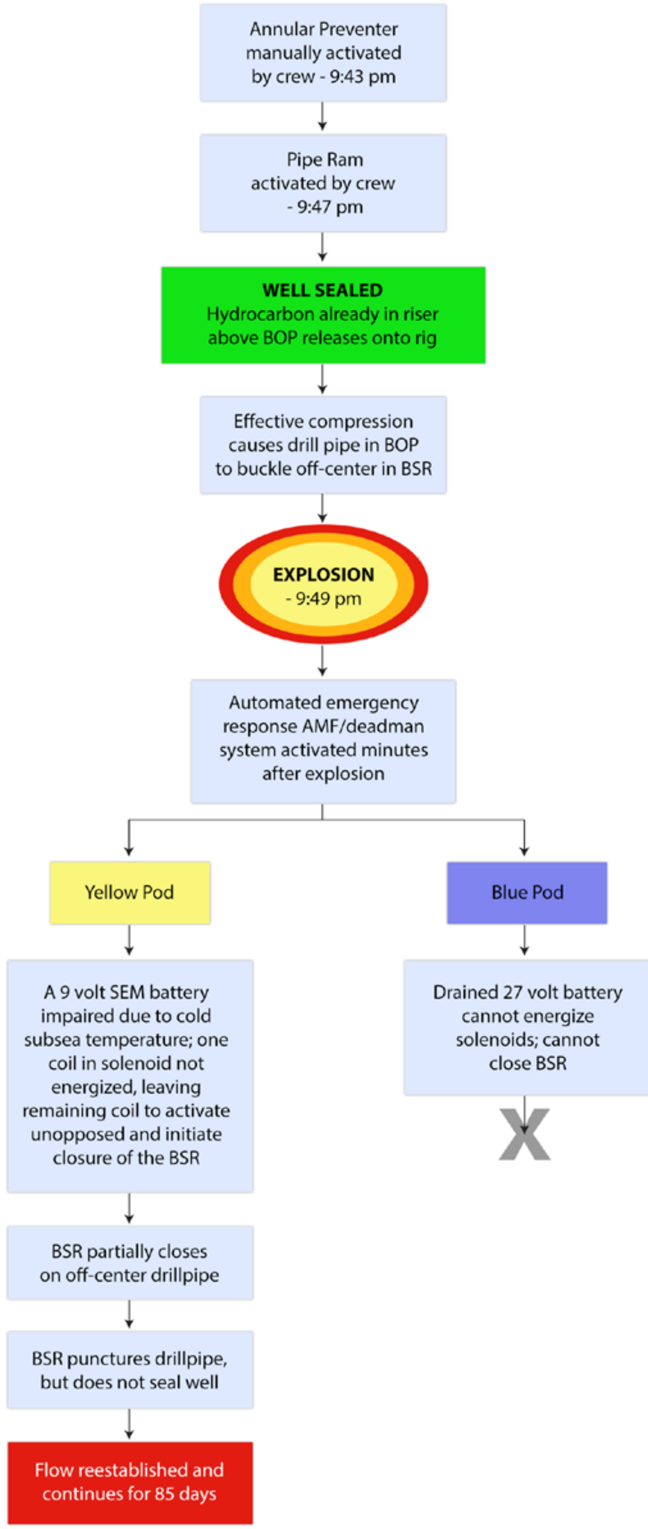

Figure 3-3. The events that led to the likely partial closure of the BSR after the emergency AMF/deadman system activated on April 20.

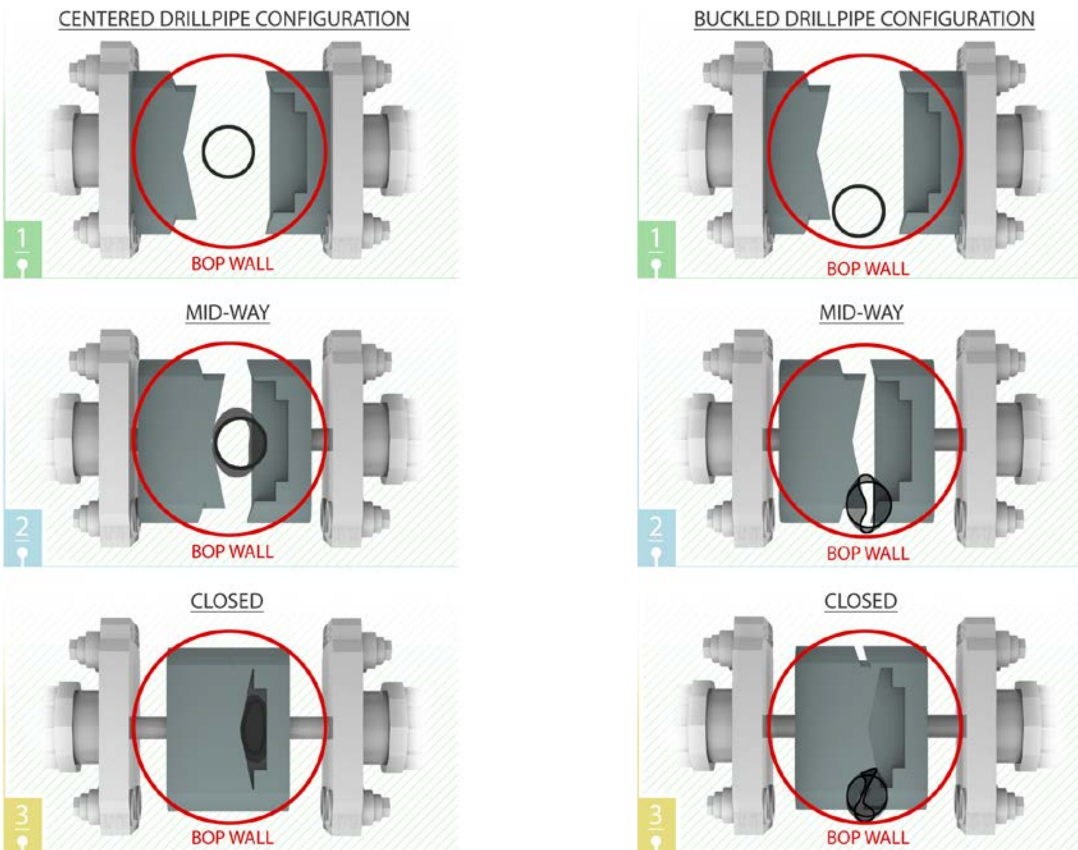

Figure 3-4. The Deepwater Horizon BOP was designed to shear centered drillpipe (left) in the BSR and then seal the well. During the Phase I examination of the BOP, the drillpipe was found off-center (right), causing the BSR to close only partially, leaving the well unsealed.

3.2.3 The AMF/deadman Fails to Seal the Well: Buckled Drillpipe

Previous incident investigation reports have concluded that the drillpipe moved off-center as a result of forces acting to compress the pipe from the ends (axial compression) or forces created from high well flow.[38] The reports did not recognize that buckling can also be caused by significant differences in pressure inside and outside of the drillpipe (differential pressure). The concept *effective compression* can be used to describe the combined effect of differential pressure and axial forces on pipe buckling. [a]

[a] The rigorous mathematical proofs involve either vector calculus or differential equations and may be found in one of several references: A. Lubinski, W.S. Althouse, and J.L. Logan, "Helical Buckling of Tubing Sealed in Packers," *Journal of Petroleum Technology, 14:6,* (1962): pp. 655-670; S. A. Christman, "Casing Stresses Caused by Buckling of Concentric Pipes," paper presented at *Society of Petroleum Engineers Annual Fall Technical Conference and Exhibition: Paper Number SPE 6059*, New Orleans, Louisiana, 1976; R.F.Mitchell, "Casing Design with Flowing Fluids, *SPE Drilling and Completion, 26:3* (2011): pp. 432-435.

Effective compression has been well understood as a potential hazard in other oil and gas industry applications, including the design and operation of pipelines,[39] well casing and well tubing,[40] and of marine risers in deepwater drilling service such as those on the Deepwater Horizon.[41] By incorporating effective compression, the CSB calculations show the DWH drillpipe could have been buckled at the time the AMF/deadman actuated. (See Appendix 2-A for more details on the concept presented in this section.)

Significant differential pressures leading to buckling were likely between the inside and outside of the drillpipe within the BOP. Real-time pressure data from the Deepwater Horizon indicates that the crew had successfully shut in the well just before the first explosion on the rig by closing a pipe ram. Pressure from the wellbore was contained below the pipe ram but also transmitted through the drillpipe extending through the closed ram. Above the pipe ram, the pressure outside the drillpipe was limited to just the hydrostatic pressure of the fluid in the space between the drillpipe and the riser. This pressure would have continued to drop as hydrocarbons, drilling mud, and seawater unloaded onto the rig.

Figure 3-5 illustrates conceptually the effect on a pipe when the inside pressure is much higher than outside, and how this differential pressure can cause buckling. On the left side of the figure is an ideally straight pipe. It is shown with equal pressure (represented by the arrows) acting on both the inside and outside walls. In reality, no pipe is perfectly straight, as shown in an exaggerated manner in the figure. The result of this minor inherent curvature is that the wall of the pipe on the right side is slightly longer than the left side.[42] With the same pressure acting on the unequal areas of the walls, the right side of the pipe, having a larger area, actually experiences a greater net force.[a] If the pressure inside the pipe is increased further, the force imbalance (as a bending moment) also increases and eventually overcomes the bending resistance of the pipe, causing it to buckle.

Well pressures and forces on the drillpipe during most of the Macondo well-control event are not fully known due to the uncertainties of blowout flow rates and physical properties of the well fluids. However, a critical period occurred shortly before the initial explosion, when the well was essentially static with no new flow from the well into the riser. Computer modeling of this period presented in Appendix 2-A demonstrates that effective compression of drillpipe would have resulted in buckled, off-center drillpipe in the well as a pipe ram was closed. The subsequent explosions then likely triggered the AMF/deadman emergency system.

[a] Force = pressure × area

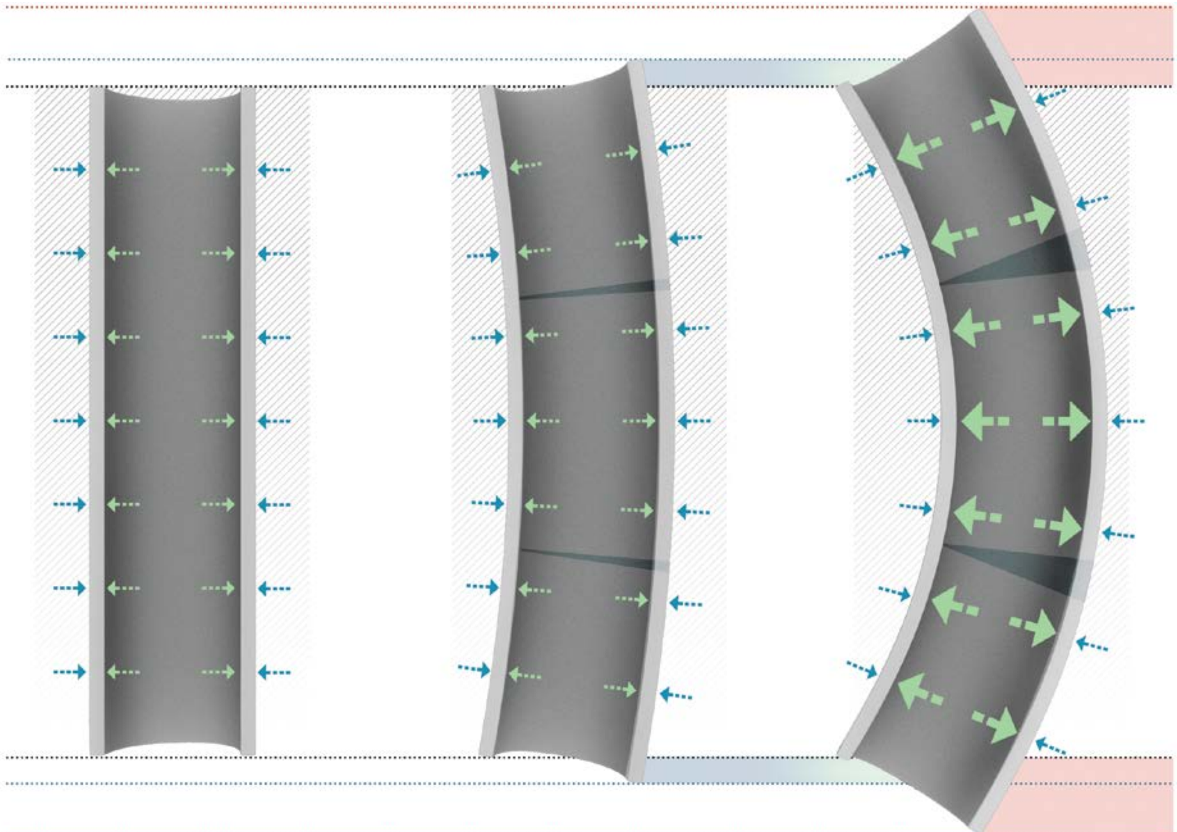

Figure 3-5: Theoretically straight pipe with equal inside and outside pressure (left); real pipe with a curve imperfection with equal internal and external pressure (center); pipe buckling as a result of increased internal pressure (right). The black wedges show the relative change in length and area of the two sides of the pipe.

3.3 Conclusion

Both the manual intervention and emergency systems within the BOP were activated to shut in the Macondo well. The annular preventer activated by the crew failed to seal the well, but subsequent closure of a pipe ram did seal it. Yet, shortly thereafter an explosion on the rig likely triggered the AMF/deadman and led to the blind shear ram partially closing and puncturing the drillpipe, which reestablished flow from the well.

Both redundant control pods responsible for initiating the AMF/deadman had latent failures that could have inhibited closure of the blind shear ram. The blue pod was miswired, resulting in the draining of critical the 27-volt battery that was needed for powering the solenoid valves during the AMF/deadman sequence. A critical miswired solenoid valve in the yellow pod should have left the AMF/deadman sequence unable to close the blind shear ram. The miswiring should have caused the redundant coils to oppose one another, but a drained 9-volt battery resulted in one of the coils not energizing. This left the remaining coil to activate unopposed and to initiate closure of the blind shear ram as part of the AMF/deadman sequence. Despite activation of the AMF/deadman sequence, effective compression of the drillpipe caused it to buckle off-center within the well. The blind shear ram within the BOP partially sheared this off-center pipe, but it did not seal the well. As a result, flow from the well was reestablished and the personnel on board had to evacuate amid an active blowout.

4.0 Establishing and Maintaining Effective Barriers

Chapter 4.0 Overview

This chapter examines barriers to prevent major accidents. It introduces differences between the US offshore regulatory regime and its international counterparts in how they define major accident events and safety critical elements. Also discussed are process safety concepts, including the hierarchy of controls, defense-in-depth, and Layers of Protection Analysis as tools to determine the type and number of barriers necessary to minimize the risk of a major accident event.

BSEE requires the management of offshore hazards,[43] but it does not distinguish between hazards that could lead to a major accident like Macondo from hazards associated with day-to-day offshore operations. Barriers intended to prevent a Macondo-like accident require a different approach and go beyond the basic barrier definition, which covers a physical barrier to prevent the flow of hydrocarbons in a well. The Petroleum Safety Authority (PSA) of Norway describes barriers as “technical, operational and/or organizational elements which individually or collectively reduce opportunities for specific error, hazard or accident to occur, or which limits its harm/drawbacks.”[44] This expanded definition is important because ensuring a physical barrier like a BOP can prevent or mitigate a Macondo-like accident requires additional organizational and operational elements to determine the barrier is appropriate and effective throughout its lifecycle. This concept is explored in the next two chapters.

This chapter compares the UK, Norwegian, and Australian definitions for major accidents as they relate to offshore activities and the management approaches these countries require for major accident hazards. This comparison highlights opportunities for BSEE to enhance offshore safety in US drilling operations if BSEE were to establish similar features within its safety regulations. Currently, BSEE requires an evaluation of the potential safety, health, and environmental effects that may occur if a technical barrier fails,[45] but not an assessment of a barrier’s effectiveness before drilling operations begin. Furthermore, BSEE has not set forth minimum barrier performance expectations, nor does it address concepts like multiple layers of protection, the hierarchy of controls, or targeted risk reduction. As such, BSEE’s approach contrasts with international regulatory approaches to offshore safety and best practices identified for the onshore oil and gas processing facilities in the US.[46]

4.1 Defining the Role of a Barrier: Major Accident Events

Major accidents, also referred to as major accident events (MAEs), have been defined for offshore drilling operations by governing regulations in the UK, Norway, and Australia. In the UK, offshore MAEs are defined as one of five general scenarios: [47]

1. A fire, explosion or the release of a dangerous substance involving death or serious personal injury to persons on the Installation or engaged in an activity on or in connection with it;
2. Any event involving major damage to the structure at the Installation or plant affixed thereto or any loss in the stability of the Installation;
3. A collision of a helicopter with the Installation;

4. The failure of the life support systems for diving operations in connection with the Installation, the detachment of a diving bell used for such operations or the trapping of a diver in a diving bell or other subsea chamber used for such operations; or
5. Any other event arising from a work activity involving death or serious personal injury to five or more persons on the Installation or engaged in an activity in connection with it.[a]

Norway regulations have a definition that includes environmental and financial effects: “Major accident means an acute incident such as a major spill, fire or explosion that immediately or subsequently entails multiple serious personal injuries and/or loss of human lives, serious harm to the environment and/or loss of major financial assets.”[48] Australia’s offshore petroleum safety regulations define an MAE as “an event connected with a facility, including a natural event, having the potential to cause multiple fatalities of persons at or near the facility.”[49] BSEE offshore regulations in the US do not define major accident events.[b]

The risk associated with a major accident event is a combination of consequence and probability, but the rarity of MAEs can lend a perception of low risk. A Guidance Note provided by Australia’s National Offshore Petroleum Safety and Environmental Management Authority (NOPSEMA) highlights the neglect that high-consequence, low-probability events may receive: “The relative rarity of events with catastrophic consequences may give rise to the situation where potential MAEs receive little attention, as compared with day-to-day operational issues.”[50] Regulations in the UK, Norway, and Australia focus on MAEs by requiring offshore oil and gas operations not only to manage high-probability personal health and safety issues, but specifically to require that MAEs be addressed. Consequently, companies operating in those offshore regions are required to establish safety management systems that explicitly address MAEs. Table 4-1 juxtaposes this approach against US regulations, which require operators[c] to have a safety management system with a goal to promote safety and environmental protection, but without a corresponding MAE requirement.[d]

[a] In this discussion references to MAE (given the jurisdiction of the CSB) concern chemical releases that could have catastrophic consequence, as opposed to ship collisions, major environmental oil spills, etc.

[b] US Coast Guard regulations also govern some offshore activities and do define *serious marine incidents* using several characteristics, including one or more deaths, injuries to crew members, and discharges of oil in excess of 10,000 gallons into navigable waters of the US, 46 C.F.R. § 4.03 (2) (2012).

[c] BSEE defines an operator as “the person the lessee(s) designate as having control of management of operations on the leased area or a portion thereof. An operator may be a lessee, the BSEE-approved or BOEM-approved designated agent of the lessee(s) or the holder of operating rights under a BOEM-approved operating rights assignment.” 30 C.F.R. § 250.105 (2012)

[d] BSEE requires the reporting of many incidents that would fall under the definition of an MAE to the District Manager immediately after their occurrence, but regulations do not require the driller or operator to take any action as a result of the incident [30 C.F.R. § 250.188 (2012)].

Table 4-1. Excerpts from offshore regulations from the UK, Norway, and Australia that specifically require Major Accident Events be addressed; they are juxtaposed with US regulations that promote safety and environmental protection, but without a focus on MAEs.

UK	NORWAY	AUSTRALIA	US
[…] management system is adequate to ensure— […] all hazards with the potential to cause a major accident have been identified; and […] all major accident risks have been evaluated and measures have been, or will be, taken to control those risks to ensure that the relevant statutory provisions will be complied with.	The operator shall set acceptance criteria for major accident risk and environmental risk. [section then references the following regulation] Harm or danger of harm to people, the environment or material assets shall be prevented or limited in accordance with the health, safety and environment legislation […] the risk shall be further reduced to the extent possible. In reducing the risk, the responsible party shall choose the technical, operational or organisational solutions […]	[…] identifies all hazards having the potential to cause a major accident event; and […] is a detailed and systematic assessment of the risk associated with each of those hazards, including the likelihood and consequences of each potential major accident event; and […] identifies the technical and other control measures that are necessary to reduce that risk to a level that is as low as reasonably practicable.	The goal of your SEMS [Safety and Environmental Management System] program is to promote safety and environmental protection by ensuring all personnel aboard a facility are complying with the policies and procedures identified in your SEMS. To accomplish this goal, you must ensure that your SEMS program identifies, addresses, and manages safety, environmental hazards, and impacts during the design, construction, startup, operation, inspection, and maintenance of all new and existing facilities […]

4.2 Barriers to Prevent or Mitigate MAEs

In 2003, Transocean conducted a high-level generic risk assessment for the Deepwater Horizon to identify potential major accident events. The review was not well specific.[a] While not required for operation in the Gulf of Mexico, this assessment aimed to ensure barriers were in place to prevent MAEs or to mitigate the consequences if they did occur.[51] Transocean identified and assessed several potential scenarios, two of which referenced Macondo-like events, "gas in the riser" and a "reservoir blowout." The team completing the assessment created a table to compile the MAEs and their potential consequences as well as preventive and mitigating barriers. Table 4-2 is a sample of the one produced by Transocean.

[a] An analysis of Transocean's risk assessment appears in a subsequent volume of the CSB Macondo Investigation Report.

Table 4-2. Recreated excerpts of Transocean's Risk Assessment for the DWH[52]

MAE	CONSEQUENCES	PREVENTIONS	MITIGATIONS
Reservoir blowout (at Drill Floor)	• Major environmental impact • Multiple personnel injuries and/or fatalities • Major structural damage and possible loss of vessel	• Well control procedures and training of drill crew in well control • Maintenance and testing of BOPs and other subsea and well control equipment • Instrumentation and indication of well status Hydrocarbon/Combustible Gas detection system. • Redundant BOP controls	• Emergency response procedure, training, and drills • Ability to move off station • Firefighting capabilities • Ability to evacuate the rig • Availability of medical treatment including medivac • Redundant BOP controls • Passive fire protection in highly populated area of vessel • EX-rated equipment to prevent ignition of blowout
Gas in riser	• Possible ignition at surface with fire and/or explosion • Possible major structural damage • Possible loss of riser • Possible environmental impact • Possible injury to personnel • Possible fatalities	• Good drilling practices • Instrumentation and indication of well status • Subsea isolation equipment • Training in well control including required drills	• Use of diverter system • Ability to evacuate the rig • Firefighting capabilities • Availability of medical treatment including medivac • Emergency spill response

The "preventions" and "mitigations" listed in the table represent the safeguards designed to eliminate, prevent, reduce, or mitigate the scenario; they are also referred to as barriers, layers of protection, lines of defense, or control measures.[53]

BP's *Exploration and Production Operating Management System Manual* identifies that barriers "are more than just mechanical or instrumented devices" but also include process and people.[54, a] These categories of barriers—technical, organizational, and operational—are all represented in Table 4-2.

[a] BP and Transocean's implementation of risk and barrier management at Macondo is discussed in Volume 4.

Technical barriers include the redundant BOP controls, explosion-rated equipment, [a] and the hydrocarbon/combustible gas detection system. Pre-defined company routines that embrace "good drilling practices" and effective "maintenance and testing" procedures are examples of organizational barriers while "training of drill crew in well control" seeks to improve the operational barriers the crew provides when assessing and then initiating a response to a particular scenario on a drilling rig.

In its *Exploration and Production Operating Management System Manual*, BP warns that all barriers are prone to failure:

> Even the best barrier will not achieve perfect reliability. It will have holes. The holes can be latent or actively opened or enlarged by the action or inaction of people. The robustness of the barriers changes with time, and depends on factors related to people, process and plant.[55]

The quote explains that barriers are vulnerable and their variable robustness affects risk by increasing the probability that a major accident event can happen. As a result, hazards should be controlled by multiple, independent layers of protection. BP indicates the best opportunity for reducing hazards is during the design stage, when inherently safer[b] design processes can be incorporated into the installation. The next best opportunity is in engineered safety in the form of passive or active controls,[c] and finally procedural safety. An effectiveness ranking of safeguards used to mitigate hazards and risks like those described by BP has also been called a hierarchy of controls. One example appears in Figure 4-1.[56]

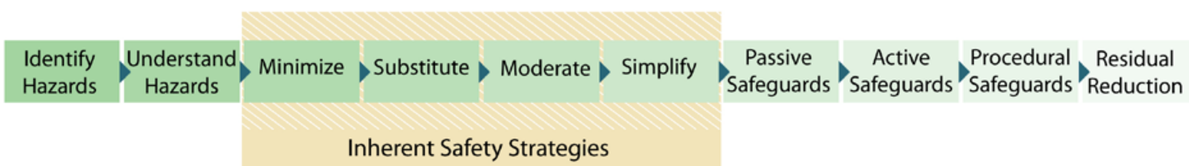

Figure 4-1. Hierarchy of Controls.

Relying on multiple layers of protection to safeguard against major accident events has also been referred to as defense in depth.[57] The key to defense in depth is "creating multiple independent and redundant layers of defense to compensate for potential human and mechanical failures so that no single layer, no matter how robust, is exclusively relied upon."[58] As both the concept of the hierarchy of controls and

[a] Explosion-rated equipment: Electrical equipment designed and constructed to be used in flammable atmospheres (e.g., flammable vapors or dusts).

[b] According to the Center for Chemical Process Safety (CCPS), "inherently safer design solutions eliminate or mitigate the hazard by using materials and process conditions that are less hazardous." Center for Chemical Process Safety (CCPS), *Inherently Safer Chemical Processes – A Life Cycle Approach*. 2nd ed., Section 5.1.1 (2009).

[c] Passive controls do not require a person or system to detect an event or take action to provide protection. Active controls respond to a situation to activate devices or systems intended to interrupt a sequence of events or mitigate a consequence.

BP's written programs highlight, for companies to achieve this goal,[59] they must start with sound designs. If a hazard cannot be eliminated or substituted for a less hazardous one, then equipment should be built according to quality standards to avoid errors and malfunctions during operations. Equipment should have a high tolerance for malfunctions if they occur and should employ redundant systems to ensure reliability and availability. Since a defense-in-depth approach assumes mechanical and human failures will occur, layers of protection should include detection and protection systems to maintain safe operations or to shut down an operation safely when failures do occur. Finally, companies need to incorporate layers of protection that mitigate and minimize the effects of a major accident event. For example, they can plan to physically contain the release of toxic chemicals or rely on emergency response activities to minimize damage or loss of life.

4.2.1 Visualizing Barriers using a Bowtie Diagram

Many plausible scenarios around a particular hazard could result in a major accident event.[60] By using a visual tool known as a bowtie diagram, one can logically follow how a major accident event could evolve during these scenarios while contemplating a series of technical, organizational, and operational barrier failures.

As Macondo has demonstrated, the presence of hydrocarbons in the riser is a serious hazard. Once oil and gas pass above the BOP, no robust barrier exists to stop them from reaching the rig floor. The drilling crew must, after detection, try to divert them to a safer location, but the capabilities of the diversion equipment cannot handle a large volume of unloading riser gas. Ultimately, the hazard posed by expanding gas in the riser could progress to an ignited or unignited blowout if the release subsequently causes loss of drillpipe or BOP integrity.

A kick that results in hydrocarbons in the riser may be initiated by one of several threats, including the following examples:

- Fault during the temporary abandonment process (Volume 1, Chapter 2)
- Insufficient drilling mud properties (Volume 1, Section 2.1)
- Lost circulation event (Volume 1, Section 2.1)
- Unexpected high pressure formation (Volume 1, Section 2.1)

These threats have been listed at the left hand side of the bowtie diagram in Figure 4-2.

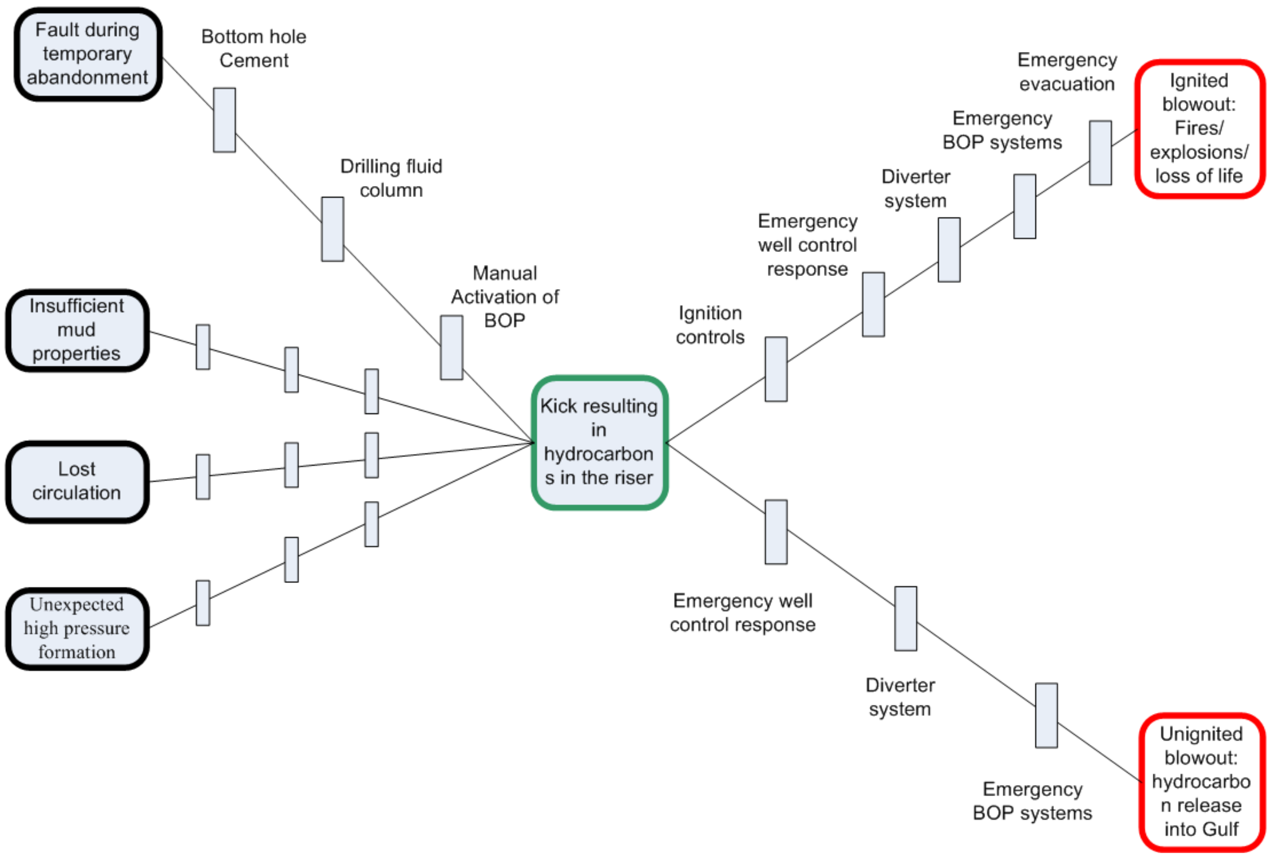

Figure 4-2. Bowtie diagram depicting the relationships between hazards, barriers, and the major accident events they are intended to prevent.[a]

In this figure, technical barriers are represented along the lines connecting the threat and hazard, but only the barriers related to a "faulty temporary abandonment process" have been identified. Other circumstances could compromise the technical barriers, and, as indicated in Figure 4-3 organizational and operational barriers are in place to avoid these potential barrier decay mechanisms.[b]

Often different threats require different barriers. For example, the threat of "insufficient mud properties" is mitigated or avoided by having a robust well program (organizational barrier), whereas the threat of a "lost circulation" event is mitigated or prevented by the drilling crew monitoring and comparing the volume of mud leaving and returning to the rig (operational barrier). Once any of the threats in Figure 4-2

[a] This is not a comprehensive bowtie diagram but rather a sample of some threats, barriers, and consequences.

[b] These are referred to as "barrier decay mechanisms" by DNV GL, http://www.dnv.com/industry/oil_gas/publications/updates/oil_and_gas_update/2013/01_2013/more_control__better_safety_integrated_barrier_risk_management.asp) or "escalation factors" by S. Lewis and K. Smith, *Lessons Learned From Real World Application of the Bow-tie Method*, presentation at the American Institute of Chemical Engineers 2010 Spring Meeting 6th Global Congress of Process Safety, San Antonio, TX, March 2010.

results in the presence of hydrocarbons in the riser, shared potential consequences arise. The bowtie lists several barriers intended to prevent the hazard from progressing to an ignited or unignited blowout.

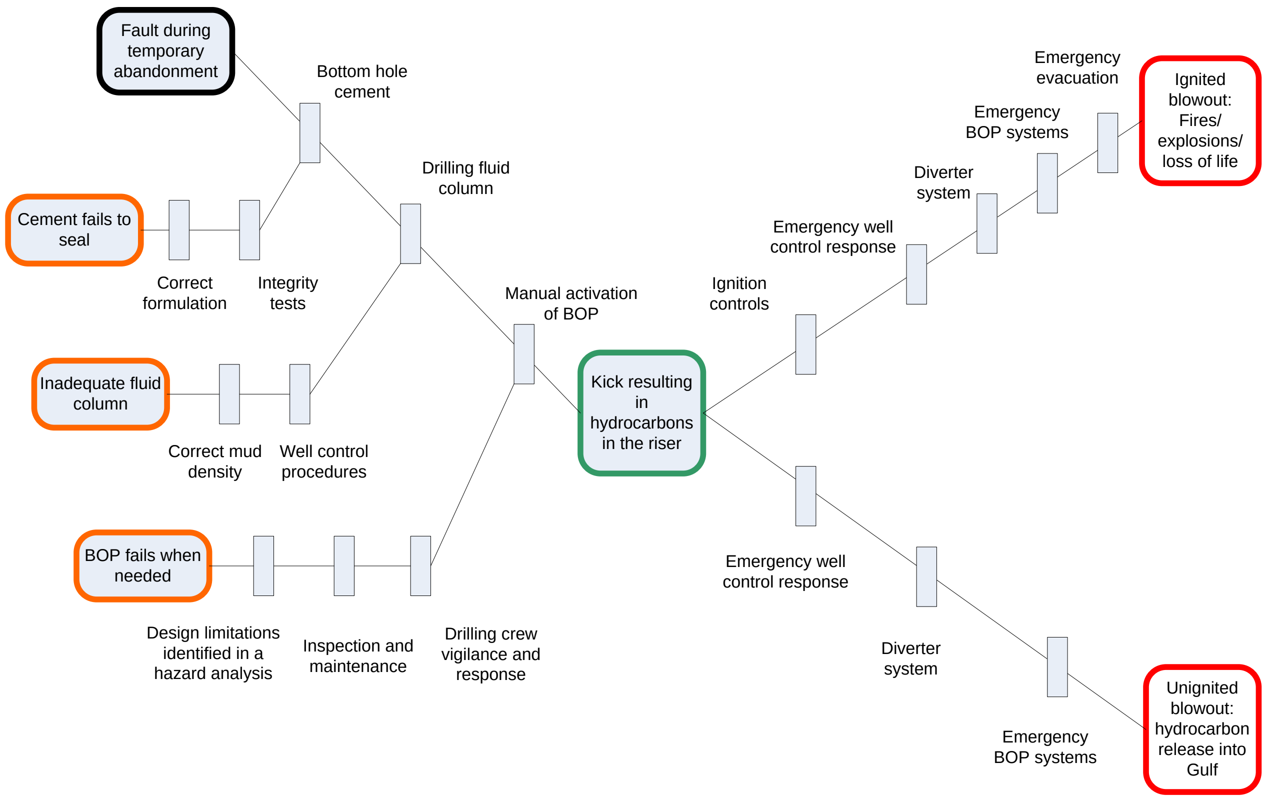

Figure 4-3. Bowtie diagram showing potential decay mechanisms of the technical barriers intended to prevent a fault during temporary abandonment activities.

By tracing the lines leading from a threat to a consequence, and any barrier decay mechanisms listed, one can follow how the scenario would evolve. In the case of a fault during the temporary abandonment process, Figure 4-3 demonstrates that the following must occur:

- The bottom hole cement barrier has to fail as do the tests to detect that failure;
- The drilling fluid column has to either be removed or inadequately formulated;
- Well control actions by the crew have to result in failure to detect changes in density, volume, and flow rate of the circulating (or displaced) drilling fluid column, which would indicate a kick has occurred;[a]

[a] The Transocean Well Control Handbook definition of well control principles includes “continuously monitor active pit volumes” and “immediately detecting changes in the density, volumes and flow rate of the drilling fluids from the wellbore and taking the appropriate action.” *Transocean - Well Control Handbook - Level: L1B*, Issue #3, Revision #1 - HQS-OPS-HP-01. Publicly accessed at

- The drilling crew has to then fail to activate the BOP, or the BOP fails to shut in the well upon manual activation due to inadequate design, inspection, or maintenance.

Once hydrocarbons have entered the riser, a blowout (ignited or unignited) can result if the diverter system is unsuccessful and/or ignition controls fail and an explosion occurs. The degree of fire and loss of life will escalate if the emergency well control response, BOP emergency systems, or abandonment activities do not successfully shut in the well or the crew cannot (or fails to) safely and efficiently evacuate the rig.

The BOP is the only barrier to appear on both sides of the bowtie diagram in Figure 4-2, because the BOP is a collection of well control devices and emergency systems. As described in Section 2.2, well control actions by the crew should result in manual activation of the BOP, but automated emergency shear functions may also be initiated.

4.2.2 Determining the Type and Number of Barriers to Reduce Risk

The process complexity and potential severity of an event will dictate the type and number of barriers needed to demonstrate that the risk of an MAE is reduced to a targeted level, such as "as low as reasonably practicable" (ALARP). Higher risk situations will require either more barriers or barriers with better reliability, and when striving for ALARP, efforts for risk reduction are instituted until the effort to reduce risk further becomes grossly disproportionate to the level of actual risk reduction.[61]

In general, the UK and Australian offshore regulatory regimes accept proof of adherence to codes, standards and relevant good practice as ALARP for broadly recognized risks.[62] For more complex situations, when an operator is proposing a new technology or where high-hazard scenarios affect a large population, there may not be good practice for the operator to follow or the regulator may decide industry standards are sufficient to constitute ALARP. In these situations, the regulator may consider risk assessment tools, possibly in conjunction with a cost-benefit analysis in determining if the risk of an operation has been reduced to an ALARP level. The CSB has explored concepts related to ALARP as a result of onshore investigations[63] and returns to the offshore implications in Volume 3.

The Principle of ALARP

"As low as reasonably practicable" was first defined legally in English courts in 1949.[a] Lord Justice Asquith suggested that "physically possible" is distinct from "reasonably practicable." "Reasonably" should be determined by comparing the time, money or effort necessary to reduce risk. If one can show that "the risk [is] insignificant in relation to the sacrifice," then the onus of further expenditure is dismissed. This concept is explored more fully in the CSB's Macondo Investigation Report, Volume 3.

A company might use several tools to assess risk, including, but not limited to,

- Risk Matrix

http://www.mdl2179trialdocs.com/releases/release201303071500008/TREX-00596.pdf, Section 2 (Well Control Principles), Subsection 1 (Definition).

- What-if Checklist
- Hazard and Operability Study (HAZOP)
- Facility Siting study
- Qualitative Risk Assessment (QRA)
- Layers of Protection Analysis (LOPA).[64]

As part of LOPA, independent layers of protection (IPLs) are analyzed for their effectiveness, and their combined protection is measured against risk tolerance acceptance criteria.[a,65] This approach is explored in depth here more than the others because, as discussed in Section 5.2.2, a movement is afoot toward using the technique to define BOP performance requirements.

IPLs are devices, systems, or actions capable of preventing an initiating event from progressing to an undesired consequence. The LOPA method uses event severity, initiating event frequency, and likelihood of failure of the IPLs to calculate a level of risk. If the calculated risk level as determined by LOPA is not considered acceptable, then additional IPLs can be added to a scenario, and the analysis can be repeated. As a result, LOPA is used to evaluate the value of implementing additional protection layers with the goal of reducing risk to below a maximum acceptable threshold.

Applying LOPA requires clearly defining the initiating event, and each IPL must be: 1) independent of the initiating event and each other, 2) effective in preventing the consequence when it functions as designed, and 3) auditable so that its performance can be validated.[66] These factors imply that not all barriers, or safeguards, can be IPLs for calculating a risk level during LOPA. For example, training and procedures are important safeguards for preventing an accident, but their failure may cause the initiating event, in which case they could not be considered independent layers of protection in the LOPA context.[67]

LOPA can be used to describe IPL performance by calculating the average probability the IPL will perform its required safety functions under stated conditions and within a stated time period.[68] An industry benchmark contextualizes this performance for instruments or equipment by assigning them a discrete value called the safety integrity level (SIL).[69] An SIL ranges from one, the lowest performance level to four, the highest. The higher the SIL, the greater the probability the instrument or equipment will function to successfully prevent an undesired consequence. Each integer

Defining the Initiating Event

Identifying all well control situations that could progress to a blowout is critical to avoid calculating an artificially low level of risk.

In 2009, Transocean reported six kicks that resulted in uncontrolled release of mud and gas onto a rig after well fluids passed above a BOP. Any kick has the potential to develop into a blowout. The number of well control incidents per rig increases from 0.05 to 0.6 when considering the total number of kicks (71).[†]

[†]*Transocean Annual Report 2009, Well Control Events & Statistics 2005 to 2009, TRN-INV-01143142.*

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[a] BP has a group practice that describes the LOPA methodology, GP 48-03 Layers of Protection Analysis (LOPA): Groups Practice – BP Group Engineering Technical Practices (ETP), 5 June 2008 [BP-HZN-CSB00181723]. GP 48-03 also includes references to hazard and operability studies (HAZOP) and inherently safer design options. The ETP was expressly approved "for implementation across the BP Group," which included drilling, but was acknowledged in BP Board records [BP-HZN-BLY00204248] not to have been applied to contractor MODUs in the Gulf of Mexico at the time of the Macondo incident. Volume 4 of the CSB Macondo investigation report analyzes risk assessment at Macondo in greater depth.

increase in SIL corresponds to a ten-fold reduction in the risk frequency that an initiating event will result in the corresponding event consequence. Assigning an SIL to an instrument or piece of equipment accounts not just the initial design; it considers the complete lifecycle, including maintenance and testing. This judgment requires verification of the actual performance of the IPL throughout its lifetime to ensure the availability of the safety integrity action is maintained.[70]

4.2.3 Maintaining Effective Barriers

LOPA and SIL assignments offer one approach to help demonstrate ALARP, but characteristics of effective barriers also can be summarized more generally. NOPSEMA contends that clear linkages between the barriers and the specific hazards they are designed to prevent and mitigate will aid drilling operators in effectively determining if those barriers:

- have been selected in accordance with the hierarchy of controls (order of preference);
- are distributed appropriately with representation of the types of control, namely, engineering, procedural, and administrative;
- have adequate layers of protection;
- cover the full range of operating and emergency circumstances;
- consider common mode failures;
- are effective;
- are reasonably practicable;
- reduce the risk to a level that is ALARP.[71]

Continuously monitoring a barrier's effectiveness throughout its lifecycle is a prominent requirement for international regulatory regimes governing offshore drilling operations.[72] In Norway, regulations require performance standards to continuously monitor threats to barriers: "the operator or the party responsible for operation of an offshore or onshore facility, shall stipulate the strategies and principles that form the basis for design, use and maintenance of barriers, so that the barriers' function is safeguarded throughout the offshore or onshore facility's life."[73] These strategies and principles are often embedded within a company's safety management systems (SMSs).

In part, a company's SMSs ensure the barriers are available, reliable, independent, and effective. Success of an SMS program requires implementing several organizational process assurances, including a mechanical integrity program for the equipment functions as expected; a training program for the human control to have the skills and aptitude to handle the potential hazards/risks of the work, particularly for safety critical tasks, such as responding correctly to an emergency event; and a management of change program for not detrimentally affecting the barriers in place during changes to the drilling plan, equipment, crew, or management. The relationship among these barriers is interdependent. If a piece of equipment fails unexpectedly despite following the planned preventive maintenance inspection schedule, the reliability of the barrier should be reassessed and the mechanical integrity program adjusted to ensure that such a failure cannot recur. Otherwise, the reliability of the barrier does not match performance and the risk levels increase. Ideally, the company would not wait until a failure occurs to assess the health of a barrier, but rather incorporate indicators to measure the ongoing health of the barrier and communicate regularly to the regulators, workforce, and management.

4.2.3.1 Barriers as Safety Critical Elements (SCEs)

The role of SMS is particularly important when the barrier being monitored is equipment or a human action whose:

- failure could cause or contribute to a major accident event;
- purpose is to prevent or limit the effects of a major accident event.

Offshore regulations in the UK refer to such barriers as safety critical elements (SCEs)[74] or, in the case of human actions, safety critical tasks.[a] One author described SCEs in these simple terms: "These are the safety controls (hardware, people systems, or software) that deliver a disproportionate improvement in safety (and conversely, when not functional lead to a disproportionate increase in risk)."[75]

Companies operating offshore in UK,[76] Norway,[77] and Australia[78] must identify safety critical elements and establish performance standards, which are qualitative or quantitative statements that describe the required performance of the SCE. Performance standards can be based on nationally and internationally recognized industry standards, but they may also comprise methods or technical solutions developed by the company.[79]

In 2005, the Energy Institute published revised guidance[b] to provide good practice for offshore installations to follow in managing safety critical elements.

The guidance defines performance standards in terms of:

1. Functionality — What is it required to do?
2. Availability — What will be its performance duration?
3. Reliability — How likely is it to perform on demand?
4. Survivability — What post-event role must it survive to perform?
5. Interactions — What other systems must be functional for it to operate?

Compliance with an appropriate performance standard is the basis for assuring an SCE will act as a barrier to an MAE. In the UK, a written verification scheme, based on the SCE's performance standard, is required to ensure every SCE is appropriate, available, and effective throughout its service.[80]

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[a] UK Safety Case regulations do not specifically require naming safety critical tasks, but UK HSE Safety Case guidance states, "Human performance problems should be systematically evaluated. This should involve evaluating the feasibility of tasks, identifying control measures and providing an input to the design of procedures and personnel training, and of the interfaces between personnel and plant. The depth of analysis should be appropriate to the severity of the consequences of failure of the task." UK HSE, *Assessment Principles for Offshore Safety Cases*, http://www.google.com/url?sa=t&rct=j&q=&esrc=s&source=web&cd=1&cad=rja&sqi=2&ved=0CDUQFjAA&url=http%3A%2F%2Fwww.hse.gov.uk%2Foffshore%2Faposc190306.pdf&ei=jg6OUuTzHaPhygHI7YE4&usg=AFQjCNG9jDdqxIdUGguRCSNxT6GUoIozCg&sig2=6n2lF5b6kPPIzyXlEZA0cA&bvm=bv.56988011,d.eW0. Retrieved November 21, 2013.

[b] After the UK Safety Case regulations were instituted in 1996, Oil and Gas UK (formally the UK Offshore Operators Association) created guidance for the management of safety critical elements. This original guidance was revised by the Energy Institute, *Guidelines for the Management of Safety Critical Elements, 2nd ed.*

While Norway and Australia do not cite verification schemes by name, each country has regulatory language or guidance that mirrors the verification scheme requirement in the UK.[81]

In the absence of a verification scheme, a risk assessment could result in an activity that identifies an MAE and then simply assigns what are assumed to be SCEs, but which do not actually reduce the probability or consequence of the MAE. As the UK Health Safety Executive (HSE) states, "Risk assessment alone does little or nothing to reduce risks, particularly if the risk assessment is seen as an end in itself. Rather, risks are reduced by employing the risk assessment process in an active and intelligent way, as a tool to help focus the process on continuous improvement within the safety management system."[82]

In any regulatory regime, there is the potential for performance standards and verification schemes to be generated, but then put on a shelf and do little to actually increase the safety offshore operations. In this manner the regulatory requirements could become a documentation exercise rather than an integrated part of a normal work process. Continuous improvement to reduce the risk of a major accident event requires looking beyond current good practice and naturally implies that ALARP, or any risk reduction target, is a constantly evolving concept. In some instances companies will initiate the push for improvement and in other instances the regulator can lead the way, but only if the regulatory framework is in place to facilitate the process for all parties. The following callout box describes one such example.

The written verification scheme

Also called an assurance scheme, the written verification scheme should ensure the SCE performance is met by:

(1) Identifying those assurance activities, such as maintenance, inspection, and testing, which are required to sustain the SCE in a suitable condition;

(2) Ensuring that these activities are carried out at the appropriate time by competent people;

(3) Maintaining a record of these activities and any findings that arise; and

(4) Addressing any deficiencies arising from assurance activities as soon as possible and taking any temporary measure that may be necessary to maintain risk ALARP until deficiencies have been recertified. Any temporary measures should be subject to review and comment by an independent competent person. [†]

[†] *Guidelines for the Management of Safety Critical Elements, 2nd ed. published by the Energy Institute.*

The Power of Risk Reduction Targets

Norway's offshore safety regulator, the Petroleum Safety Authority (PSA), continuously drives improvements in safety by requiring responsible parties to ensure that risks are "reduced beyond the established minimum level … if this can take place without unreasonable cost or drawback." For instance, in 1992 PSA sought to introduce regulations to require the use of remote-operated pipe handling technologies to reduce work-related injuries associated with handling heavy-duty piping. Numerous complaints were lodged against the regulations; however, PSA enacted the requirements because the social benefits outweighed the cost of compliance. Through a collaborative partnership, industry and regulator worked together to develop technologies capable of improving safety. The result has been a marked improvement in pipe handling safety. Furthermore, due to the global nature of the industry, pipe handling safety improvements have been adopted worldwide. Thus, regulatory initiatives to redefine what is "practicable" or "beyond the minimal level" can result in significant safety change.

Sources: Petroleum Safety Authority Norway, unless noted otherwise, from the following publications, last visited February 7, 2013:

- *Guidelines Regarding the Framework Regulations, Re Section 11 Risk Reduction Principles,* http://www.ptil.no/framework-hse/category408.html#p11;
- *081 – Norwegian Oil and Gas Recommended Guidelines for Remote Pipe Handling Operations,* http://www.norskoljeoggass.no/Documents/Retningslinjer/081-100/081%20-%20Recommended%20guidelines%20for%20remote%20pipe%20handling%20operations%20rev.4,%2011.06.12.pdf?epslanguage=no;
- *Regulations Relating to Health, Safety and the Environment in the Petroleum Activities and at Certain Onshore Facilities (The Framework Regulations), Section 11 Risk Reduction Principles*. http://www.ptil.no/framework-hse/category403.html#_Toc282603288;
- *Mechanical Pipe Handling: Reviled Requirements Paid Off (2011) ,* http://www.ptil.no/news/mechanical-pipe-handling-reviled-requirements-paid-off-article7666-79.html?lang=en_US
- *Invented Safety, Reaped Values (2007),* http://www.ptil.no/news/invented-safety-reaped-values-article3341-79.html;
- Kevin Roche, *Noble Pipe Handling Incident Review – Gulf of Mexico,* http://www.ptil.no/getfile.php/z%20Konvertert/Helse%2C%20milj%C3%B8%20og%20sikkerhet/Sikkerhet%20og%20arbeidsmilj%C3%B8/Dokumenter/presentation%2B%2528noble%2B-%2Bpipe%2Bhandling%2Bincident%2Brev.pdf.

4.3 Conclusion

A natural tendency is to focus on technical barriers because they are physical in nature, and in deepwater drilling they clearly show how they stop the flow of hydrocarbons from the well. Yet all barriers, whether technical, operational, or organizational, are prone to failure; therefore, multiple barriers of sufficient robustness are required to avoid a major accident event. The number of barriers needed to reduce the risk of an MAE may simply require following good guidance practices established by the industry, or they may require additional risk assessment tools to evaluate whether risk has been reduced to some targeted level, such as ALARP.

5.0 Deepwater Horizon BOP not Treated as a Safety Critical Element

Chapter 5.0 Overview

This chapter discusses the BOP as a safety critical element and provides evidence to support that BP and Transocean did not treat it as such. Also reviewed is the lifecycle of a safety critical element, which includes identification, development of performance standards, assurance and verification activities, and gap closure.

A blowout preventer contains multiple well control devices, and it satisfies both definitions of a safety critical element given in Section 4.2.3.1: it is a device intended to prevent a kick from progressing to a blowout and to mitigate potential consequences of a blowout—fatalities, major oil spill, and loss of rig. While Transocean and BP conducted routine inspections and weekly functioning of various operational components necessary for daily drilling operations, they failed to implement inspection and testing activities that would have identified latent BOP failures of the emergency systems components of the Deepwater Horizon BOP. As a result, the safety critical BOP systems responsible for shearing drillpipe in emergency situations were compromised before the BOP was even deployed to the Macondo wellhead.

While this chapter uses the BOP as the vehicle to explore effective management of safety critical elements, the other barriers listed in the bowtie diagram from Section 4.2.1 could be subjected to the same analysis. The bowtie diagram demonstrates that failure of a technical barrier, such as the BOP, is rooted in inadequate operational and organizational barriers. The links between these barriers—technical, operational, and organizational—and major accident events provide a means to identify the systems that operators and regulators should monitor for opportunities to improve risk reduction.[83]

Organizations maintaining effective safety critical elements (SECs), such as the BOP, implement management activities to ensure they meet safety objectives throughout the lifetime of the SCE.[84] These measures appear in the simplified representation of the management system for the lifecycle of an SCE in Figure 5-1.

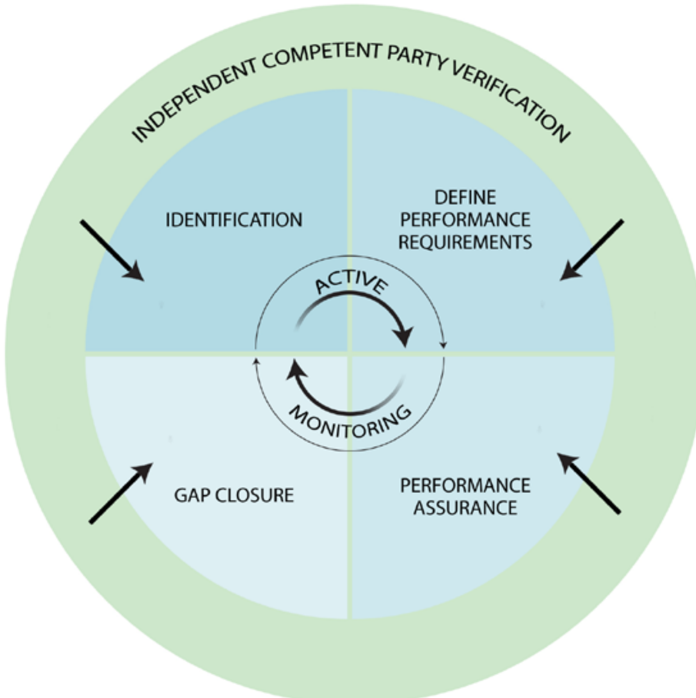

Figure 5-1. Simplified representation of the management system for the lifecycle of a safety critical element

While Transocean identified the Deepwater Horizon BOP as safety critical in a hazard analysis, it operated the BOP beyond its design limits for reliable drillpipe shearing and did not track modifications to individual components that ultimately affected the reliability of the emergency systems. As required by regulations,[85] regular testing of some BOP functions was performed, but this testing did not assess the emergency systems and were could not detect the latent failures presented in Chapter 3.0. The CSB concludes that post-incident testing changes now required in the United States are not sufficient to ensure industry will detect deficiencies like those found in the Deepwater Horizon BOP.

The CSB concludes that post-incident BOP testing changes now required in the United States are not sufficient to ensure industry will detect deficiencies like those found in the Deepwater Horizon BOP

Using the Deepwater Horizon BOP as a model, this chapter highlights opportunities throughout the SCE lifecycle to use or improve effective identification, performance standards, and assurance and verification activities to guarantee a BOP is effective throughout its use. This information culminates with a discussion on gap closure intended not only to maintain the performance of a BOP and the operational and organizational barriers that support it, but to improve them over time.

5.1 Identification of a SCE

Failure of safety critical elements and tasks could cause or contribute to major accident events. (See Section 4.1.)[86] Operators and drilling contractors should clearly document SCEs to distinguish them from other equipment and tasks.[a] The first step in identifying them depends on determining potential major accident events through a hazard analysis (Figure 5-1),[87] which should identify the sequence of events that could lead to a major accident and the factors that can contribute to it, including human errors.[88] Companies will typically use internal equipment lists as a starting point for identifying safety critical elements, but the depth to which they should define the SCEs depends on their direct link to the major accident event.[89] For example, while a BOP as a whole is safety critical, not every component of a BOP necessarily is.

5.1.1 BOP Component Failure Identified in DWH Hazard Analysis

In the 2003 Major Accident Hazard Risk Assessment conducted by Transocean,[90] a Statement of Approval that accompanied the MAHRA reads:[91]

> The [MAHRA] performed for the Deepwater Horizon identified reasonably foreseeable hazards that might lead to a major accident. It has been demonstrated that adequate controls are in place so that HSE [health, safety, and environmental] risks on the Deepwater Horizon can be considered both tolerable and ALARP (As Low As Reasonably Practicable). This assessment has been reviewed and recommendations which were developed have been followed up.

The MAHRA identified the BOP system as "critical" and recorded hazards specific to the BOP system that could lead to a major accident. The MAHRA also documented the preventions and mitigations related to the BOP system. One of the hazards listed for the BOP system was "a component failure," which, in light of the evidence presented in Section 3.0, is appropriate since the failure of a solenoid or battery in a BOP could be sufficient to inhibit the emergency AMF/deadman system. The accompanying consequences, preventions, and mitigations associated with a component failure, as identified by Transocean, are listed in Table 5-1.

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[a] The term "safety critical element" is akin to American National Standards Institute's use of "process safety safeguard" when addressing risk management in the process industry in the ANSI/ISA-84.91.03-2012, *Identification and Mechanical Integrity of Safety Controls, Alarms, and Interlocks in the Process Industry*, September 20, 2012, p. 12.

Table 5-1. Recreated excerpt of Transocean's MAHRA for the Deepwater Horizon[92]

Hazard	Consequences	Preventions	Mitigations
BOP component failure	• Reduced well control capability depending on component. • Possible blowout with possible multiple fatalities and possible loss of rig. • Possible environmental impact.	• Testing, inspections and maintenance.	• Redundant BOP components. • Spare parts on board. • Ability to effect repairs. • Availability of medical treatment including medivac. • Spill response procedures.

Completing the MAHRA was only the first step toward identifying the safety critical elements. A second step would be to identify which components of the BOP were actually safety critical and could be directly linked to major accident events. As is discussed in subsequent sections, those components deemed safety critical should have been subjected to the remaining steps in the lifecycle of an SCE as represented in Figure 5-1.

5.1.2 DWH Hazard Analysis Did Not Address BOP Design Capabilities

Transocean's MAHRA missed the opportunity pre-incident to identify that the BOP system could fail to seal a well because BOP design capabilities had been exceeded. The CSB identified two such scenarios existed during the drilling operations at Macondo. First, throughout the drilling operation, drillpipe was used that exceeded the BOP manufacturer's recommendations for the Deepwater Horizon's blind shear ram (Section 5.2). Second, while the Deepwater Horizon BOP was rated by the manufacturer to shear centered 5½" drillpipe, the ability to do so was affected by the shut-in well conditions. Under likely conditions at Macondo, the Deepwater Horizon BSR would not have been able to shear a centered 5½" drillpipe if the annular preventer in the BOP had sealed.

Under likely shut in well conditions at Macondo, the Deepwater Horizon BSR would not have been able to shear a centered 5½" drillpipe if the annular preventer in the BOP had sealed.

A design limitation of a BOP is the wellbore pressure that the BSR will have to close against. At the time of the incident, offshore US regulations did not specify a minimum design pressure, but a practice was to assume that the annular preventers would be open, and the pressure in the BOP would be the hydrostatic head of the drilling mud in the well and riser.[a] A more conservative

[a] Pre-Macondo, no industry guidance covered this issue. Conversations with individuals in the drilling industry indicated an assumption that one would not shear drillpipe until after it was hung off on a closed pipe ram and the annular had been reopened. In that scenario, the design wellbore pressers for shearing would have been the

approach would have been to assume that an annular preventer was closed and the BSR would have to close against the maximum anticipated surface pressure (MASP)[a] for the well. (See Appendix 2-A for more details.) The Deepwater Horizon accumulator system was not designed to overcome the increased wellbore pressure that would have occurred at Macondo if the DWH annular preventer had been closed. BSEE regulations now require that the blind shear ram be able to shear against maximum anticipated surface pressure (MASP).[93]

5.2 Defining Performance Requirements of a SCE

Ultimately, the performance standard is the basis for how an SCE will reduce the risk of a major accident event.[b, 94] Operators and drilling contractors can use a performance standard to define the safety critical element's requirements during all phases of an operation and to address the hazards or potential MAEs that could occur during operational activities.[95]

The performance requirements for an SCE should include all the aspects described in Section 4.2.3.1—the functionality, availability, reliability, survivability, and interactions with other systems that may affect its ability to function properly. The performance requirements should also be verifiable to ensure the SCEs are suitable for the hazards identified in the hazard analysis. Verification may include clarifying the relationship between the hazard analysis and the role of the SCE. For example, a BOP is not designed to stop an active blowout, so ideally it will be activated before oil and gas pass above the BOP.[96] The performance standard may identify safe operating limits, setpoints, or criteria for action to place an operation in a safe state.[97] By implication, the performance standard will include measures to compensate for out-of-service periods.[98] Performance requirements should cover both normal and abnormal situations, including when to respond manually, what actions to take, and in what state to leave the process. Determining the reliability of an SCE will require an accurate estimate of the demand rate on the equipment, as an increased rate could affect reliability predictions.[99] Equipment should meet these requirements, and its approval might be based upon manufacturer's information and historical in-house performance within the organization.[100]

5.2.1 Drillpipe Exceeded Shearing Capabilities of DWH Blowout Preventer

The Transocean well control manual, in effect at the time of the incident, states minimum acceptable requirements for BOPs on all company installations. It does not address all of the performance requirements listed in the preceding paragraph, but the manual does include the following performance statements:

- There must be at least one set of blind/shear type rams;
- The blind/shear rams must be capable of shearing the highest grade and heaviest drillpipe used on the rig … and sealing the well in one operation.[101]

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hydrostatic pressure of the mud column. The Macondo incident demonstrated that this assumption was not adequate. The BP and Transocean well control manuals state that the blind shear rams should be capable of sealing the well in one operation [BP-HZN-2179MDL00327390], that the limitation of the shear capacity should be understood, and that plans should be in place to address any limitations [BP-HZN-CSB00079397].

[a] MASP: Maximum anticipated surface pressure, the maximum pressure that may occur in a well.

[b] Section 4.2.3.1 introduces performance requirements in the form of a performance standard.

The Deepwater Horizon's BOP met the first performance requirement—but the blind shear ram did not meet the second requirement. At the time of the incident, the DWH had 5½" drillpipe in the BOP, but for most of the drilling at Macondo, 6⅝" drillpipe was used.[102] The Deepwater Horizon BOP was not capable of reliably shearing 6⅝" drillpipe.

In 2007, Cameron published a product advisory "to assist Cameron equipment users in defining the shearing requirements for drilling operations."[103] Cameron provides a "method that can be used as a guide to predicting if a tubular [e.g., drillpipe] is shearable or not." The formulas given in the method are based upon empirical data Cameron has collected over the years to validate the ability of a BOP to shear drillpipe. Calculated results based on the method provided in the product advisory demonstrate that the Deepwater Horizon's BSR[a] did not meet the manufacturer's most recent published design shearing capabilities for 6⅝" drillpipe.[b]

Emails exchanged (Table 5-2) indicate that at least one of the DWH senior subsea supervisors was aware the rig BSR was not rated to shear 6⅝" drillpipe.[104] As a result, Transocean had a multistep workaround for the larger pipe,[105] but the procedure contradicted the "one operation" performance requirement Transocean set in its well control manual. The workaround was to first shear the 6⅝" pipe with the casing shear rams, which can shear the heavier pipe but not seal the well, and then close the BSR with no pipe in it. This method could be accomplished manually by the driller or by setting the Emergency Disconnect System into a mode designed to complete this type of two-step operation.[c] However, the AMF/deadman system was not programmed to perform this two-step operation. This protocol increased the risk of a major accident event, because activating the AMF/deadman with the 6⅝" drillpipe would have exceeded the BOP design capabilities, immediately leading to a well blowout.[d] Best practice recommends identifying the interactions of an SCE with other systems because a change to a system may negatively affect the SCE. The two-step operation is an example of a negative impact to an SCE, highlighting the need for establishing management of change procedures for safety critical equipment.[e] (See Appendix 2-A for more details.)

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[a] The Deepwater Horizon BSR was a Cameron model TL 18 3/4" (15,000 psi WP) with a type-SBR shear packer.

[b] When the DWH was completed in 2001, its BOP manual (using then-current Cameron ratings) listed the BSR as capable of shearing 6⅝" pipe (*Deepwater Horizon TL BOP Stack Operation and Maintenance Manual*; *Cameron Engineering Bulletin 702D* (August 1991, Rev. B1), p. 6; CAM-CSB 000005989). Also, a well control equipment commissioning report to BP stated the BSR was sufficient for 6⅝" pipe, apparently also based on the then-current Cameron bulletin (*Report of Well Control Equipment Commissioning*, by In-Spec Inc. (March 2001); BP-HZN-BLY00058800, BP-HZN-BLY00058786.

[c] The EDS can be set to operate in Mode 1 or Mode 2. Mode 1 just closes the BSR. Mode 2 was intended for use when casing was being transferred into the well. Mode 2 closed the CSR first and then the BSR.

[d] Another automated emergency system, the autoshear function, could not access the CSR either, so it would have had the same limitations as the AMF/deadman system in shearing 6⅝" drillpipe. The autoshear function is triggered from a valve sensor installed in the BOP to detect an accidental disconnect of the LMRP, at which time it initiates closure of the blind shear ram.

[e] As defined by the Center for Chemical Process Safety, "Management of change is the process for evaluating and controlling modifications to facility design, operation, organization, or activities—prior to implementation—to make certain that no new hazards are introduced and that the risk of existing hazard to employees, the public, or the environment is not unknowingly increased." *Guidelines for Management of Change for Process Safety*. Center for Chemical Process safety/AIChE, 2008.

At the time of the incident, BP covered the treatment of the BOP in an engineering technical practice (ETP) for well control,[106] which includes, "the essential systems, practices, and training requirements that comprise the BP well control standard." The ETP lists several prescriptive requirements for the BOP, including the configuration of preventers (e.g., annular preventers, pipe rams, shear rams). The ETP states, "The limitations of its [the BSR's] shearing capacity should be known and understood, and a documented risk assessment shall be in place to address any such limitation." The CSB did not find any documented risk assessment by Transocean or BP to address operating the Deepwater Horizon BOP outside of the manufacturer's recommended shearing capacity. The ETP also does not require users to operate within the shearing capacity of the BSR or to ensure temporary measures that maintain safety and/or reduce risk.

Table 5-2. Summary of emails sent between Transocean personnel regarding BSR shearing capability.

DATE	SENDER / RECEIVER	EMAIL CONTENT
November 2008	Comment by DWH's Subsea Supervisor, who was forwarded a 2005 email (attachment referred to was a chart showing the shear ram capabilities of the BSR.)	"Here's the information you requested about the Shear Rams. I just forward the old email by the attachment should answer everything."
January 2010	Question from DWH Senior Subsea Supervisor to a Transocean Subsea Superintendent regarding same 2005 email chain was forwarded once again.	"How could I get the chart in this attachment to change the color on the 4614 psi for shearing the 6.625 [6 5/8-ince] pipe to RED. Would Cameron have to edit this chart? That is what Rod wants. He says if we can't shear it then it should be RED…]"

Contrary to Cameron's advice in its shearing guide, the DWH BSR did successfully shear 6⅝" drillpipe when an EDS function was executed in June 2003.[107] This experience shows that the BSR employed by the Deepwater Horizon could sometimes shear the larger sized drillpipe, but it does not establish that the action is reliable.

5.2.2 Prescribing Minimum Reliability Requirements of a BOP

Safety Integrity Level is a discrete measurement that indicates the reliability of a barrier.[a] the greater the SIL, the greater the probability a barrier will perform its required function upon demand. Establishing an SIL involves making assumptions about the barrier's availability. For example, shearing the 6⅝" drillpipe required a two-step process not available to the AMF/deadman sequence; thus, it would clearly affect the emergency system's reliability even if all the individual components of the system (e.g., batteries, solenoid valves) were fully functioning. Some effort to define the SIL for BOP functions has intended to reduce risk to a targeted level, such as ALARP. But uncertainty remains about establishing an SIL for the BOP shearing function; as a result, a recommended practice is to rely upon the published BOP manufacturer's guidance.

[a] Section 4.2.2 introduces the concept of Safety Integrity Level.

The BOP can be analyzed as a safety instrumented system that,[a] after being actuated manually or automatically, reestablishes a safe condition by sealing a well with annular preventers, pipe rams, or a blind shear ram. The international standard IEC 61511 has been accepted as the basis for specification, design, and operations of safety instrumented systems (SIS) in the process sector.[108] The risk-based approach described in IEC 61511 would require employing one of several suggested methods to determine the SIL of a BOP. All of these methods would depend upon the user making assumptions about the reliability of various components of the BOP.[109] Ultimately, the different methodologies and assumptions could lead companies to identify inconsistent SIL requirements for a BOP.[110]

In an effort to encourage standardization across the industry, Norwegian Oil and Gas Guideline 070 proposes the use of a predefined minimum SIL to ensure a minimum level of safety for the most common safety functions on petroleum installations.[111] PSA management regulations in Norway specifically cite the Norwegian Oil and Gas Guideline 070 as the basis for barrier performance, meaning the guidance and the minimum SIL it contains are enforceable on the Norwegian Continental Shelf. [b] Guideline 070 addresses three standard BOP functions:

1. sealing around drillpipe;
2. sealing an open hole;
3. shearing drillpipe and sealing a well.[112]

After detection of a kick, one of these three BOP functions may require activation to prevent a blowout.[c] For functions one and two, Guideline 070 establishes a minimum required SIL of 2, which implies the probability of the BOP function failing when activated after kick detection is less than 1 in 100 actuations.[d] Ensuring an SIL of 2 is maintained for the BOP functions will require companies to validate the performance of the BOP actively. (See Section 5.3.)

For function three, Guideline 070 does not establish an SIL for shearing drillpipe and sealing a well. Instead, the guideline reports, data exists that may demonstrate that an SIL of 2 might be achieved for this

[a] As defined by IEC 61511, a safety instrumented system is used to implement one or more safety instrumented functions. An SIS is composed of any combination of sensor, logic-solver, and final elements.

[b] These regulations relate to management and the duty to provide information in the petroleum activities and at certain onshore facilities (the management regulations), Section 5: Barriers (http://www.ptil.no/management/category401.html). The regulations specify IEC 61508, which is a generic standard applicable to several industries, but the process industry created a sector-specific standard, IEC 61511. As defined in IEC 61511, "[IEC 61511] applies when equipment that meets the requirements of IEC 61508, or of 11.5 of IEC 61511-1, is integrated into an overall system that is to be used for a process sector application but does not apply to manufacturers wishing to claim that devices are suitable for use in safety instrumented systems for the process sector (see IEC 61508-2 and IEC 61508-3."

[c] More generally, this concept is referred to as functional safety, and has been defined for the International Electrotechnical Commission (IEC) as "the detection of a potentially dangerous condition resulting in the activation of a protective or corrective device or mechanism to prevent hazardous events arising or providing mitigation to reduce the fight consequence of the hazardous event." (http://www.iec.ch/functionalsafety/explained/)

[d] The function is described as follows: "operator pushes the button to close the well and ends when the BOP closes and seals off the well." The approach in 070 is to assign SIL for given functions in a BOP rather than the entire safety loop, which would include the person pushing a button to initiate the BOP function. In practice, it is very difficult to ascribe a safety level to a human because he or she is can subjected to many changing demands.

function. But successful operation of the blind shear ram assumes that an unshearable tool joint is not positioned within the blind shear ram, which cannot be guaranteed, and that the blind shear ram is properly sized to cut the pipe in the well. While unshearable tool joints are not a hazard that can be mitigated by BOPs currently in use in the Gulf of Mexico, using properly sized drillpipe can be achieved by ensuring the safety critical blind shear ram is suitable and reliable for the entire drilling operation.

Guideline 070 highlights that it is not industry practice to regularly test a BOP's ability to shear drillpipe because the act of shearing drillpipe can damage the blind shear rams[113, a] and one successful actuation of a blind shear ram does not establish reliability. Instead, factory acceptance testing and manufacturer recommendations are relied upon to assess a BOP's ability to shear drillpipe.[b] Both factors should be considered during the next phase of a BOP's safety critical element lifecycle—performance assurance and validation.

5.3 Performance Assurance of an SCE

Ensuring an SCE meets its performance standard requires assurance activities[c] by the companies relying on the SCE throughout its design, procurement, construction, and performance lifecycle (e.g., startup, normal operating mode, emergency mode, shutdown mode).[114] Additional verification activities by an independent third party may also ensure the SCE design is adequately specified, fit for the intended use, and maintained to meet the performance standard[115] (Section 5.5).

Safety critical elements should be included in a company's mechanical integrity program,[116] which uses inspection, testing, preventive maintenance, and any other identified activities to ensure SCE integrity. Many offshore regimes require demonstration that SCE integrity reaches a targeted risk level, like ALARP. Assuring the continued reliability of a safety critical element may also include, but not be limited to, reviewing:

- original equipment manufacturer recommendations;
- out-of-service time;
- work orders;
- audits;
- process upsets;
- human factors;
- external events (e.g. extreme weather);
- mechanical integrity failures;
- near miss or incident investigation reports;
- management of change;

[a] BSEE regulations require that if the blind shear rams are activated during a well control situation in which pipe is sheared, the BOP stack to be retrieved after the situation is fully controlled to physically inspect the BOP and to conduct a full pressure test of the stack. 30 CFR §250.451(i) (2012).

[b] The destructive effect that shearing drillpipe can have on blind shear rams is one reason functional testing of blind shear rams is performed on an open hole.

[c] Assurance activities are referred to as a validation plan in IEC 61511:2003 1st ed. *Functional Safety – Safety Instrumented Systems for the Process Industry Sector*.

- training.

This review will require a schedule for assurance activities and their documentation, which may include:[117]

- date of inspection or test;
- name of person who performed the inspection or test;
- serial number or other unique identifier of the equipment on which the inspection or test was performed;
- description of the inspection or test performance;
- results of the inspection or test as compared to the user-defined acceptance criteria;
- required actions to address the findings.

Actively monitoring assurance activities needs to be a part of managerial and supervisory duties from front line staff up through senior management. Ensuring that safety critical equipment, such as a BOP, will function effectively requires operational and organizational support.[118] While a front line manager is responsible for ensuring that a BOP is properly maintained so it can respond when activated, as the bowtie diagram from Section 4.2.1 demonstrates, organizational and operational practices strongly influence the successful operation of a BOP.[a] Accordingly, all levels of management need to continuously monitor work activities, organizational and operational practices, and safety systems that impact safety critical elements. Monitoring is not auditing, which implies an activity that is carried out independent of line managers to verify their actions. Rather it is the formal and informal inquiries into the health of an organization's technical, organization, and operational barriers against a major accident event.[119] A health check like that described here can also provide insight into actual operational practices compared with organizational goals.

5.3.1 No Assurance Activities for the Critical AMF/Deadman Solenoid Valve

The CSB was unable to identify any assurance documentation showing that testing of the miswired solenoid valves found on the Deepwater Horizon BOP ever occurred. Procedures published by both Cameron[120] and Transocean[121] describe tests to be completed on refurbished solenoid valves. The intent of the Cameron procedure is to "ensure they [the solenoid valves] are assembled properly and are free of manufacturing defects." The procedure directs the user to function the solenoid by using each coil individually and then by activating both coils simultaneously.[122] The miswired solenoid valves from the yellow pod would have opened when the individual coils were activated, but then remained closed with both coils were activated.

Internal Transocean emails indicate that Y103[b] was likely rebuilt on the Deepwater Horizon rather than by Cameron, but Transocean was unable to find assurance documentation to confirm this.[c] Transocean

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[a] While the AMF/deadman emergency system is automated, the emergency disconnect systems is a manual emergency systems available to the rig crew.

[b] This also applies for the other miswired solenoid valve found in the yellow pod, 3A.

[c] The sender of the email wrote, "We could not match the SIN's to the D&D rebuilds. They must have come from the Rig inventory of rebuilt solenoids." TRN-INV-01300201.

had published a technical information bulletin in 2002, *Instructions for Rebuilding Cameron Controls Solenoid Valve,* to instruct employees rebuilding Cameron solenoids on the rig.[123] Included in the instructions is a test that will indicate if a "[solenoid] coil is not correctly wired to the cable."[124] Similar to Cameron's procedure, the Transocean test instructed the user to verify the solenoid valve shifted after simultaneously energizing both A and B coils. If the instructions had been followed, the miswired solenoids would have remained closed when both A and B coils were energized together.

Current US regulations, and those in place at the time of the Macondo incident, do not require testing of the high-pressure BSR close function used during emergencies either before or while the BOP is in service.

Another missed opportunity occurred for catching the miswiring of Y103. For the BSR in Deepwater Horizon's BOP to close during an AMF/deadman sequence, the high-pressure close function controlled by Y103 had to actuate. (See Section 2.3.2.) Current US regulations, and those in place at the time of the Macondo incident, do not require testing of the high-pressure BSR close function either before or while the BOP is in service. This safety limitation is in contrast to the weekly testing required for other BOP functions including the low-pressure BSR close function. US regulations reference the third edition of API RP 53,[125] which states "All operational components of the BOP equipment systems should be functioned at least once a week to verify the component's intended operations." The definition of "component" is commonly taken to be the various preventers (annulars, pipe rams, blind shear ram, etc.).[a] Thus, a test using the low-pressure BSR close function would have been in compliance with the American Petroleum Institute (API) recommendation and the US regulatory requirements. While repeated testing of the high-pressure close function might cause excessive wear on the BSR, subsea testing of the HP close function from each pod at the appropriate frequency could ensure the reliability of the function.

5.3.2 Current Deadman System Function Tests Are Inadequate

Prior to the Macondo incident, dynamically positioned (DP) rigs,[b] like the Deepwater Horizon, were not required to have a deadman system.[c,d] Regardless, the Minerals Management Service (MMS), the US

[a] See ANSI/API Specification 16A, 3rd ed. *Specification for Drill-through Equipment*, which refers to the blind shear ram, blind ram, pipe ram, and variable bore ram, as "components." This specification also describes tests for the components but does not mention using the HP function to close the BSR.

[b] Dynamically positioned (DP) rigs use global satellite technology and thrusters to maintain position over the well rather than holding them in place using cables and anchors, such as for a moored rig.

[c] 30 CFR §250.442(b-d) (2010), the requirements for a BOP, included 1) remote controlled, hydraulically operated annular, rams, and blind-shear rams, 2) an accumulator closing system to provide fast closure of a BOP, and 3) a dual-pod control system. Notably, the regulations did not require an AMF/Deadman system. A 2003 report by West Engineering Services and commissioned by MMS, *Evaluation of Secondary Intervention Methods in Well Control*, recommends that a deadman system be the secondary intervention system for a DP rig with a multiplex BOP control system. In the report, West Engineering documents DP rigs with a multiplex BOP control system that did not have a deadman system. After the incident, regulations were changed to require a deadman system with the introduction of the Interim Final rule 30 CFR §250.442 (f) (2010, Interim Final Rule).

[d] Post-Macondo, BSEE required all DP rigs operating on the Outer Continental Shelf to have a deadman system and stated it believed all DP rigs were already equipped with a deadman system. 30 CFR §250.442(e) (2010, Interim Final Rule), also see BOEMRE comments at *Oil and Gas and Sulphur Operations in the Outer Continental Shelf—Increased Safety Measures for Energy Development on the Outer Continental Shelf*, Docket ID BOEM–2010–0034, 75 Federal Register 198 (14 October 2010), p. 63,348.

offshore safety regulator at the time of the Macondo, commissioned a 2003 study to evaluate secondary intervention control systems for BOPs. The study identifies a major shortcoming of the AMF/deadman: "System diagnostics are essentially nonexistent. Deadman systems operate openloop. There are no means to verify functionality of the deadman system. If the sensors, batteries, or electronics fail, the only (and first) indication of unavailability is failure to operate when needed."[126] This was certainly true for the Deepwater Horizon BOP, where the blue pod SEM had been miswired, causing a critical battery required by the AMF/deadman system to drain (see Section 3.2.1.1).

Since the Macondo incident, US regulations require a deadman system on DP rigs.[127] The deadman system is to be function tested on the rig and again after initial installation of the BOP on the wellhead.[128] The procedure for testing the system is not prescribed, but BSEE has stated that may change.[129] BSEE has further asserted it will review the latest edition of API's *Blowout Preventer Equipment System for Drilling Wells* (API Standard-53, 4th edition) to determine whether to incorporate it into regulations, as the third edition had done previously.

The third edition of API RP 53 does not mention deadman systems, but the latest (fourth) edition states "a deadman system shall be installed on all subsea BOP stacks" and that it shall be function tested before the BOP is deployed to the wellhead.[130] In contrast with BSEE regulations, the fourth edition recommends testing only subsea at commissioning or within five years of a previous test.[131] To test the deadman system, API Std 53, fourth edition states the test should be completed by removing electrical power and hydraulic supply to the BOP,[132] presumably to simulate the conditions necessary to trigger the deadman system. Post-incident, BP required rig and subsea testing of the deadman system on the Development Driller III (DDIII), a rig that aided intervention efforts at Macondo post-incident by drilling a relief well to intersect the Macondo well. The DDIII AMF/deadman procedure also required removal of the hydraulic supply and electrical power. [a]

The testing approach in API Std 53 or that used by BP for the DDIII presents a problem. If the blue pod batteries in the DWH blowout preventer were good prior to deployment, the AMF/deadman system could have passed such a test before it was deployed to the Macondo wellhead despite the miswiring problems in the blue SEM and solenoid valve Y103. Successful completion of the AMF/deadman sequence only required either the yellow or the blue pod to function. So, whether all the SEMs in the respective yellow and blue pods successfully actuated, or if only one SEM was functional, the crew would have observed the same successful result—the completion of the AMF/deadman sequence—with no indication of any deficiencies. Proving functionality of the AMF/deadman sequence from each SEM would require the crew to test the four SEMS independently. This requirement is not in API Std 53.

[a] Procedures were developed to test the AMF/deadman on the rig and then the Emergency Disconnect System with the BOP subsea. Development Drill III Dead man (Auto shear) Test Procedure, attached to Application for Permit to Drill a New Well Approval, Lease G32306, Area/Block MC 252, Well 0003. BP-HZN-BLY00074845 - BP-HZN- BLY00074846.

Determining the most effective means to verify a BOP's performance may lie, in part, with factory acceptance testing developed by BOP manufacturers. The deficient wiring found in the blue pod and solenoid Y103 could not have passed Cameron factory acceptance testing (FAT) procedures. In contrast with the testing recommended by API Std 53 and BP, Cameron's FAT procedure for the AMF/deadman system is completed through SEM A and SEM B of each control pod separately. Two tests are completed for each SEM (A and B) to verify that each can independently complete the AMF/deadman sequence (Figure 5-2):[a]

Proving functionality of the AMF/deadman sequence from each subsystem requires the crew to test the subsystems independently. This requirement is not in API Std 53.

<u>Test 1</u>

a. Turn off power and communications via the PETU and confirm for 30 seconds that the AMF/deadman does not activate.
b. Turn off hydraulic pressure and confirm the AMF sequence activates within 15 seconds.

<u>Test 2</u>

a. Turn off hydraulic pressure and confirm for 30 seconds that the AMF/deadman does not activate.
b. Turn off power and communications via the PETU and confirm the AMF/deadman sequence activates within 15 seconds.

Important to highlight is that the user is instructed to switch the sequence in which the power and hydraulics are being disconnected from the SEM. By testing the SEMs in this way, if the wire deficiencies in the blue pod existed at the time of testing, the AMF/deadman system would have initiated after step (a) in Test 1, a result which should have indicated a problem to the user. (See Appendix 2-B.)

[a] Various versions of this test were identified, but the most current version and the one used for testing the Deepwater Horizon BOP post-incident was Factory Acceptance Test procedure for Subsea Electronic module (Horizon AMF/Deadman in Current Situation – Test Procedure, May 11, 2010, Rev. 2 Document No. X-065449-05-03, CAM-CSB-000008041/BP-HZN-BLY00090641.

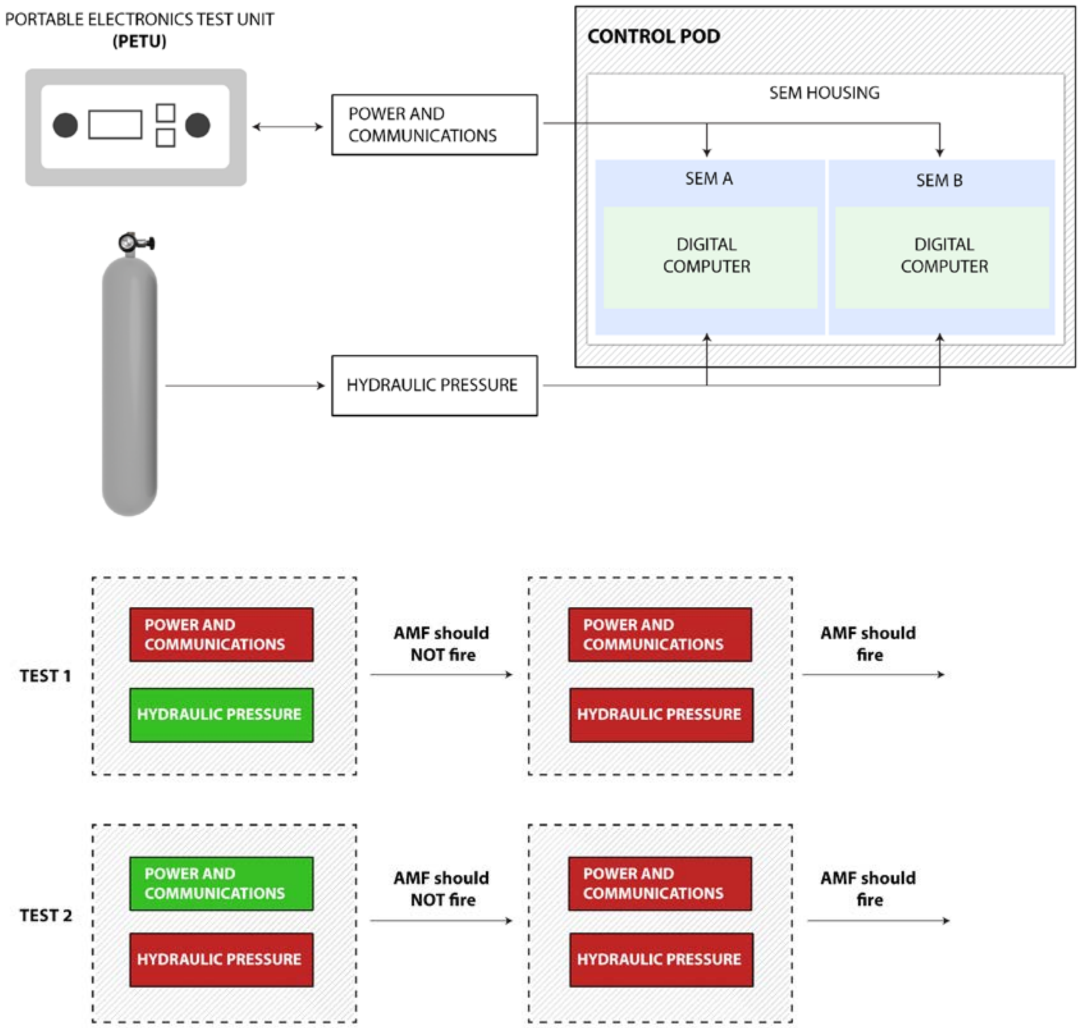

Figure 5-2. Simplified schematic of the Cameron FAT procedure to test the AMF/deadman.

Function Testing of Safety Critical Equipment: Parallel Findings between the CSB Investigations

Inadequate testing of safety critical equipment was also a finding of the CSB's investigation of the 2005 BP Texas City refinery explosion. In this incident, a process unit and its relief system was overfilled with hydrocarbon during a startup. The relief system drum had a high level alarm that should have sounded to alert the board operator of the overfilled process unit, yet it did not sound on the day of the incident. Post-incident testing revealed a defect in the displacer float for the alarm that likely prevented proper alarm operation (p.139).

The high-level alarm was designated by the company as a critical alarm; thus, it was tested by instrument technicians every six months. However, the site did not have testing procedures for the blowdown drum high-level alarm (p.197). The technicians typically used a metal rod to push the float up to test the alarm ("rodding"). This testing method actually obscured the float defect. The technicians did not follow the verification method recommended by the alarm manufacturer and industry guidance to test the functionality of the float, which called for manually raising the chamber liquid level to check the alarm setpoint (pp. 324-325).

(CSB Investigation Report, *BP Texas City, TX, Refinery Fire and Explosion*, 2007, http://www.csb.gov/assets/1/19/CSBFinalReportBP.pdf)

5.3.3 Assurance Activities of Human Actions

The miswiring of the solenoid valves found in the yellow pod highlights the need to consider human factors during the design phase of the valve, and then the importance of subsequent testing. The American Petroleum Institute has published a tool to help operating crews identify human tasks that can introduce latent conditions in equipment.[133] The tool describes human factors as being "about making it easy for people to do things right and hard to do things wrong." In the case of the Cameron solenoids used in the Deepwater Horizon BOP, simple color coding plugs and receptacles might have helped avoid the miswiring. An even more effective approach would be to design an inherently safer wiring system that would make it impossible to assemble the solenoid valves incorrectly. If potential human error cannot be engineered out of a task, then assurance activities must be completed to detect and respond to any mistakes.

Beyond the physical components of the BOP, one of the major challenges of BOP performance verification is the human action required for most of the BOP functions. Even though 070 has offered minimum SIL requirements for BOP functions (see Section 5.2.2), the SIL requirements do not take into account that the system still relies on manual initiation by the crew. In the critical early stages of loss of well control, the BOP has to be initiated by a person, making a human element part of the complete chain of responses required to have the BOP effectively act as a barrier. Having people part of the safety loop makes it very difficult to ascribe an SIL, because people are subjected to many real-time demands that can affect their performances. In fact, achieving an SIL of 1 or 2 is a struggle if the required human response is considered, meaning it is difficult to expect a failure rate of less than 1 in 100 BOP actuations.[134]

Like every other safety critical element or task, the human component must ensure they will "do things right" when summoned. These could include robust well planning activities and effective bridging of company well control and safety management systems, processes, and policies, auditing to ensure accurate and timely well data interface displays and alarms, scenario training on abnormal and high-consequence situations, and use of automated systems as a backup to human actions, among others. The critical role of the human in offshore drilling operations makes the lack of human factors guidance for offshore drilling operations an area that needs to be addressed. The CSB revisits human factors related to offshore drilling in Volumes 3 and 4 of its Macondo Investigation Report.

The critical role of the human in offshore drilling operations demands that industry address the lack of human factors guidance.

5.4 Gap Closure

Gap closure, the final component of the SCE lifecycle, is a necessary process for both maintaining and improving the SCE's performance. Monitoring safety critical equipment through assurance and verification activities will generate opportunities to reduce gaps in desired performance by creating awareness of needed improvements. For example, requiring an SIL 2 for specific BOP functions does not mean a BOP can be designed with an SIL 2, deployed to a wellhead, and then assumed to maintain an SIL 2 rating for the duration of its use. To claim an SIL 2, the BOP's reliability must be continuously verified and documented, as does its demand rate, which means it requires continuous evaluation.[135] If and when the performance degrades below the desired level, improvements must be made to reestablish the target performance.[a]

Beyond specifying an SIL, knowledge gained during the post-incident assessment of the Deepwater Horizon BOP demonstrates that not monitoring a BOP's reliability for both normal operations and emergency situations can result in preventable BOP failures. On the Deepwater Horizon, there were no means to monitor the state of AMF/deadman batteries, and no processes to verify the high-pressure shear close function was functioning or to prevent using improperly sized drillpipe for the BOP.

Real-time data monitoring, including reviewing lessons learned from a near miss or accident, can ensure safety critical elements are continuously maintained and improved. The Macondo incident illuminates several potential gap closure opportunities concerning how BOPs are tested.

Another important opportunity for gap closure exists. Since the off-center drillpipe contributed to the failure of the Deepwater Horizon BOP from sealing the well, a rig crew must account for the complete set of conditions that can cause buckling. This includes having buckled drillpipe across the BSR even when a crew has successfully shut in a well if the pressure differential inside and outside of the pipe is great enough. If the crew does not recognize a buckling condition, they could continue operating under the false

[a] IEC 61508 describes steps necessary to ensure that once SIL requirements are established for a safety system, they are maintained for the complete lifecycle of the system; Guideline 070 simplifies the description of those steps.

assumption that the manual operation of the BSR and all the emergency backup systems (EDS and AMF/deadman) are not at risk of failing due to an off-center drillpipe.

Both the BP and Transocean well control manuals recommend switching from an annular to a pipe ram; thus, they encourage the crew take an action that may actually hasten the likelihood of pipe buckling.

Both BP and Transocean well control procedures recommended closing an annular preventer as an early step in response to a possible well control event. This procedure can result in a large pressure differential in the riser above the BOP, increasing the tendency for the drillpipe to buckle in the riser. However, if a rig crew were to switch from using an annular preventer to a pipe ram in response to the well control event, buckling could progress across the BSR, just as it did in the Macondo event.[a] Both the BP and Transocean well control manuals recommend switching from an annular to a pipe ram;[136] thus, they encourage the crew take an action that may actually encourage the likelihood of pipe buckling.

Some of the failures that occurred in the BOP at Macondo were specific to the make and model of the Deepwater Horizon BOP. For example, not all BOPs use the same solenoid design, so not all BOPs are subject to the same miswiring mistake. Yet pipe buckling due to effective compression effects can happen at any well where large pressures inside the drillpipe can develop. Gap closure in BOP performance post-Macondo then will require all operators to assess BOP arrangements and well control procedures that can minimize the threat of pipe buckling due to effective compression in their wells.

5.5 Verification Activities—The Independent Competent Person

The verification process provides additional confidence that the SCEs remain in compliance with the performance standards and the company's assurance plan is satisfactorily implemented.[137] In this way, verification is an additional layer of confirmation that the identified SCEs are managed effectively throughout their lifecycle.

Verification is typically conducted by an independent third party, appointed by the company. Offshore regulations in the UK,[138] Norway,[139] and Australia[140] all require independent third-party verification to document that SCEs are appropriate and will protect against major accident events. These independent competent persons (ICPs) shall be sufficiently independent and impartial so that they can maintain objectivity, and thus 1) are likely required to be independent of the management system under which the SCE operates and 2) not be responsible for the performance standard or assurance plan governing the SCE they evaluate. In the UK, a written verification scheme defines the activities and frequencies in which verification will be performed and, as such, forms the basis for how the ICP determines and confirms that the SCEs and corresponding performance standards are appropriate throughout their lifecycle.[141] The verification activities conducted by the ICP confirm that the important assurance activities have been taken and the SCEs are maintained in adequate condition to meet the specifications in

[a] As indicated in the Incident Description sections, the DWH crew initially chose to close the upper annular but, when that failed, activated a pipe ram. In the scenario described in this paragraph, the assumption is that closing the annular resulted in effectively shutting in the well and the crew choosing to switch to a pipe ram in a controlled, non-emergency manner.

the performance standards.[142] The findings of the ICP are shared with the company and remedial actions are recommended.[143]The regulator typically documents ICP verification activities, including the scheme itself, any resulting ICP report of findings and recommendations, and the company responses/corrective actions.[144]

The CSB notes that while independent verification can be an important mechanism for achieving safety, it also has some challenges. There may be pressure felt by the company or ICP to accept SCEs performance rather than recommend changes to the SCEs or corresponding performance standards; this is particularly a problem for existing facilities and equipment as opposed to new designs.[145] And, while the ICP plays a critical role in confirming effective management of the SCEs that the regulator often cannot perform due to limited resources, it cannot be a substitute for the role of the regulator to ensure companies are using adequate and appropriate safeguards to prevent MAEs. The role of the regulator in the verification process is important; otherwise, there is a risk the verification activities could devolve into a useless requirement where a company pays another company to tell them they are operating safely. The CSB addresses these issues more fully in Volume 3 of its Macondo Investigation Report.

A written verification scheme can clarify the role of an ICP and establish the activities that assure SCEs are being effectively monitored. Good practice guidance recommends a scheme describing:

- standards used to select the ICP to review to the plan;
- the nature and frequency of the SCE examination;
- record keeping for tests and their results including recommended actions based upon the findings;
- communications between the company and the ICP;
- arrangements for reviewing and revising the scheme.[146]

At the time of the Macondo incident, verification activities conducted by ICPs were not required by US regulations. Transocean did contract a one-time, third-party assessment of the Deepwater Horizon in the weeks leading up the incident focusing on the condition of the drilling equipment, mud system, well control equipment, marine equipment, hull, structure, power plan, electrical equipment and safety equipment.[147] Resulting observations and recommendations from the assessment included the following tasks:

- Apply protective coating/paint;
- Address corrosion;
- Refit missing valve handles;
- Recertify BOP annulars.

The rig condition assessment contracted by Transocean did not have the focus of the verification activities highlighted in a verification scheme description for SCEs. More importantly, it was a one-time activity. Continuous monitoring and verification of safety critical equipment are important roles in the lifecycle of an SCE.

5.6 Conclusion

Latent equipment failures related to the Deepwater Horizon's AMF/deadman system could have been detected before deploying the BOP. The miswring of a critical AMF/deadman system solenoid valve demonstrates a lack of assurance or verification activities to monitor inspections and testing of BOP components. A detailed performance standard and verification scheme should have established testing of BOP components and not just a system integration test. Instead, miswiring in the solenoid valve and the blue pod implies an overreliance on the redundant design of a BOP. Rather than test each deadman control systems independently, current industry best practice is to perform an integrated system function test. Such a test can result in failures within individual controls systems being masked by the successful operation of the other control system. This finding requires a reexamination of current function testing of deadman emergency systems, because a BOP with the same latent failures as those on the Deepwater Horizon could conceivably pass new BSEE and API recommended deadman system testing procedures.

Reliability and availability requirements should be developed into a performance standard that becomes the basis for how an SCE like the BOP will be treated to reduce the risk of a major accident event. Reliance on a BOP to effectively function when activated requires monitoring of the BOP throughout its design, procurement, construction, and performance during normal operations, emergencies, and shut-ins. Such monitoring can identify degradation of performance, which could then be corrected immediately. While Transocean did state that blind shear rams must be capable of shearing drillpipe used on a rig, it did not define the reliability or availability requirements of the BSR. Much of the drillpipe used at Macondo could not be reliably sheared by the Deepwater Horizon's BSR during an emergency situation; as a result, the risk of a major accident event was increased throughout the drilling operations. Crew members were aware of the limitations of the Deepwater Horizon blind shear ram, but they developed a manual operational workaround that was not available to automated emergency systems.

This action highlights the need to actively monitor not only the technical barrier but also the associated organizational and operational barriers, as their performance is also subject to failure, negatively affecting the technical barrier's functionality, availability, and reliability. Furthermore, independent verification can also provide an additional layer of review and assurance that the SCEs are being effectively managed throughout their lifecycle. Finally, Macondo continues to present opportunities for industry-wide BOP performance gap closure as new lessons have emerged concerning the vulnerability of a BOP and conditions that can lead to buckled drillpipe.

6.0 Analysis of Recommended Practices and Regulations Regarding the BOP and Other Safety Critical Devices

At the time of the Macondo incident, US offshore safety regulations did not define “safety critical,” lacking specific language in regulations requiring additional safety management levels for safety critical elements. In the weeks following the Macondo incident, the President of the United States directed the Secretary of the Interior to report on “what, if any, additional precautions and technologies should be required to improve the safety of oil and gas exploration and production operations on the outer continental shelf.”[148] Recommendations from the resulting report were used as a basis for new offshore regulations first promulgated in an Interim Final Rule[149] and then in a final rule that became effective October 22, 2012.[150]

Section 6.0 Overview

This chapter reviews applicable regulations and good practice guidance for the management of BOPs and other safety critical devices, particularly those regulations and guidance that have been updated or created in light of Macondo. The technical findings from the BOP failure analysis, in conjunction with this review, give support to the need for greater adaptability that drives continuous improvement through risk reduction targets, not just prescriptive improvements. All safety critical technical, organizational and operational elements require effective management, including defined performance standards and independent verification to ensure they will function when summoned to prevent a major accident.

BSEE has enacted significant changes in regulations governing offshore operations, including requiring operators to implement a Safety and Environmental Management System (SEMS)[151] that establishes a new Assurance of Quality and Mechanical Integrity of Critical Equipment[152] requirement. New and revised standards and guidance documents have also been published.[a] Yet the changes to the offshore safety regulations and guidance post-Macondo have yet to address the broad issue of safety critical elements and their management for major accident prevention.

As Chapter 4.0 shows, SEMS lacks specific language focusing the responsible party on both major accident prevention (Table 4-1) as well as explicit requirements for the identification and effective management of all safety critical elements (technical, operational, or organizational) that could cause or contribute to a major accident if they fail or whose purpose is to prevent or limit the effects of a major accident (Sections 4.1 and 4.2.3.1). The lack of specific regulatory language requiring overall management of safety critical elements allows for those

[a] In the wake of Macondo, the American Petroleum Institute created and/or revised a number of their standards, recommended practices (RPs), and other guidance to advance offshore safety, including *Bulletin 97, Well Construction Interface Document Guidelines;* RP 96, *Deepwater Well Design and Construction; RP 64, Diverter Systems Equipment and Operations*; Q1 *Specification for Quality Management System Requirements for Manufacturing Organizations for the Petroleum and Natural Gas Industry; Q2, Specification for Quality Management System Requirements for Service Supply Organizations for the Petroleum and Natural Gas industries*;*16D, Control Systems for Drilling Well Control Equipment and Control Systems for Diverter Equipment; Technical Report 1PER15K-1, Protocol for Verification and Validation of High-pressure High-temperature Equipment;* and *Standard 53, Blowout Prevention Equipment Systems for Drilling Wells*.

companies with less robust safety management systems or those with inadequate safety cultures to insufficiently address the major accident hazards they face.

Building on the lifecycle of a safety critical element first presented in Figure 5-1, this chapter identifies areas where the new SEMS requirements take positive steps toward safer offshore operations and highlights gaps that hinder a more robust management of safety critical elements for preventing major accident events.

6.1 Lifecycle of SCEs under BSEE

6.1.1 Hazard Analysis not Focused on Targeted Risk Reduction of Major Accident Events

A hazard analysis is the first step toward identifying safety critical elements and establishing their performance requirements (Sections 5.1.1 and 5.1.2). Before Macondo, US offshore regulations addressed only hazard analyses for production facilities by incorporating regulations in API's *14J, Recommended Practices for Design and Hazards Analysis for Offshore Production Facilities*.[153] Since Macondo, BSEE has implemented the new Safety and Environmental Systems (SEMS) Rule requiring a hazard analysis for all operators' offshore structures, not just production facilities.[154]

The hazard analysis requirement stipulates the analysis must be appropriate for the complexity of the operation, and the hazards identified from the analysis must then be managed.[155] The SEMS regulation does not require that companies control hazards or implement a risk reduction target, such as ALARP, nor does it require the operators to document recognized methodologies, rationale, and conclusions to claim that safeguards to control hazards will be effective. Since terms such as "manage hazards" or "resolve recommendations" are activity-based, they do not include a performance-based requirement to control hazards or prevent major accidents. Thus, companies may conduct a weak or inadequate hazard analysis and not identify the appropriate safety critical equipment or the operating conditions of the SCE yet still be in compliance with the regulation. As a result, the regulations do not drive safety performance improvements during all stages of the SCE lifecycle. In contrast, frameworks established by other regulatory regimes, either in their respective regulations or other good practice guidance documents produced by the regulator, require more detailed descriptions of the intent of the hazard analysis requirement and targeted goals for accident prevention (Table 6-1).

Table 6-1. Excerpts from offshore regulations from the UK, Norway, and Australia concerning a required analysis.[156,a]

UK	NORWAY	AUSTRALIA	US
All significant foreseeable activities associated with the installation should be considered and all major accident scenarios described, including those that may only affect a few people. A structured approach should be taken to ensure that no major accident hazards, initiating events or sequences of events, are overlooked. A comprehensive process for identifying these hazards would normally include consultation with the workforce and if appropriate, contractors and suppliers.	[…] risk analyses that provide a balanced and most comprehensive possible picture of the risk associated with the activities. The analyses shall be appropriate as regards providing support for decisions related to the upcoming process, operation or phase. Risk analyses shall be carried out to identify and assess contributions to major accident, envi-ronmental and other risk, as well as ascertain the effects various processes, operations and modifications will have on major accident and environmental risk. […] The risk analyses shall • identify hazard and accident situations, • identify initiating incidents and ascertain the causes of such incidents, • analyse accident sequences and potential consequences, and • identify and analyse risk-reducing measures.	[…] identifies all hazards having the potential to cause a major accident event; and […] is a detailed and systematic assessment of the risk associated with each of those hazards, including the likelihood and consequences of each potential major accident event; and […] identifies the technical and other control measures that are necessary to reduce that risk to a level that is as low as reasonably practicable.	[…] you must perform an initial hazards analysis […] The hazards analysis must be appropriate to the complexity of the operation and must identify, evaluate, and manage the hazards involved in the operation. You should assure that the recommendations in the hazards analysis are resolved and that the resolution is documented.

A general SEMS Rule requirement is that the operator be responsible for establishing goals and performance measures to carry out an effective SEMS program,[157] yet no risk-reduction target is set requiring the operator to demonstrate to the regulator that major accident risk is adequately managed.[a]

[a] The Offshore Installations (Safety Case) Regulations 2005 state, "all major accident risks have been evaluated and measures have been, or will be, take to control those risks to ensure the relevant statutory provisions will be complied with." The quoted document cited in Table 6-1states, "This document sets out the principles against which HSE's Offshore Division (OSD) assesses safety cases; it represents the distilled experience on which OSD draws when assessing safety cases. The principles should be widely known by industry managers, technical experts and employees, enabling a common understanding of the process." (UK HSE, *Assessment Principles for Offshore Safety Cases*, p. 10)

There is US offshore guidance, developed post-Macondo, that supports a risk reduction target. The API produced a voluntary guidance document on the information to be shared between the operator and the drilling contractor regarding well construction and rig-specific operating guidelines, *API Bulletin 97*.[158] The Bulletin suggests that, as part of the well plan interface document, the risks associated with implementation of the planned well construction activities be identified and that prevention and mitigation plans be established for those identified risks in order to "reduce the possibility as low as reasonably practical." These identified risks and prevention/mitigation plans are to be "communicated to all affected personnel."

6.1.1.1 Lack of Targeted Risk Reduction Requirements: Parallel Findings between the CSB Investigations

The absence of targeted risk reduction parallels findings in two CSB incident investigations of onshore facilities: the Chevron Refinery in Richmond, California, and the Tesoro Anacortes Refinery in Anacortes, Washington. While these onshore sites are regulated by agencies other than BSEE,[b] the regulations parallel the SEMS Rule.[c]

Both incidents demonstrate that hazard identification activities, such as a process hazard analysis, can meet regulatory requirements but not adequately identify major hazards or mitigate major accident events, in part, because the regulatory requirement lacks targeted risk-reduction goal setting requirements. A brief review of both incidents[159] provides regulatory lessons that BSEE could apply to offshore activities.

On August 6, 2012, a pipe containing flammable hydrocarbon process fluids at the Chevron Refinery ruptured, resulting in a large vapor cloud engulfing 19 employees and subsequently igniting and sending a large, uncharacterized plume across the Richmond, California area. The 19 employees escaped injury, but approximately 15,000 people in the vicinity sought medical treatment as a result of the release. The

[a] Some US offshore voluntary guidance developed post-Macondo support a risk reduction target. *API Bulletin 97* provides guidance on the information to be shared between the operator and the drilling contractor regarding well construction and rig-specific operating guidelines. The Bulletin suggests that, as part of the well plan interface document, the risks associated with implementation of the planned well construction activities be identified and that prevention and mitigation plans be established for those identified risks in order to "reduce the possibility as low as reasonably practical." These identified risks and prevention/mitigation plans are to be "communicated to all affected personnel." (API Bulletin 97, Well Construction Interface Document Guidelines (1st Edition), November 2013, Section 5.7.1 and 5.7.2.)

[b] For occupational safety and health, the Chevron Refinery in Richmond, California, is regulated by Cal/OSHA (California Division of Occupational Safety and Health), and the Tesoro Anacortes Refinery is regulated by the Washington State Department of labor and Industries.

[c] SEMS and PSM share similar origins. While the SEMS Rule was not incorporated into regulation until 2011, it existed as the American Petroleum Institute (API) voluntary guidance document, *Recommended Practice 75, Development of a Safety and Environmental Management Program for Offshore Operations and Facilities.* The development of API 75 was largely base upon an existing 1990 API onshore process safety recommended practice, *API 750, Management of Process Hazards,* which was developed for oil refineries and petrochemical facilities. API 750 had ten management system elements; API 75 contained the same elements and included an eleventh, records and documentation. With similar roots, in 1992 the Occupational Safety and Health Administration (OSHA) promulgated a chemical accident prevention process safety standard (CFR 1910.119) with 14 management system elements most of which were similar to API 750. The parallels between PSM and SEMS is discussed in detail in the CSB Macondo Incident Investigation Report Volume 3.

CSB discovered that Chevron voluntarily used an inherently safer design checklist during its hazard analysis but generated only permissively worded recommendations as a result of the exercise. None of the recommendations addressed the hazards that led to the pipe failure, despite Chevron's knowledge of the hazard. Essentially, the process was reduced to a check-the-box activity to meet regulatory requirements without resulting in effective management of corrosion hazards at the refinery. The CSB recommended that the California State Legislature require California petroleum refineries to achieve the goal of driving risk of major accident events to as low as reasonably practicable by documenting 1) their recognized methodologies, rationales, and conclusions to claim that safeguards (safety critical elements) to control hazards will be effective, and 2) their inherently safer systems analysis and the hierarchy of controls in establishing safeguards for process hazards.

On April 2, 2010, a heat exchanger catastrophically ruptured at the Tesoro Refinery due to a damage mechanism called High Temperature Hydrogen Attack (HTHA), whereby the carbon steel material of the exchanger was exposed to hydrogen at high temperatures and pressures over time, causing fissures and cracking that weakened the steel. When it ruptured, highly flammable hydrogen and naphtha at more than 500 degrees Fahrenheit released and ignited, fatally injuring seven employees. The CSB noted that a 1996 process hazard analysis conducted of the unit cited ineffective, non-specific, judgment-based, qualitative safeguards to prevent equipment failure from HTHA. The effectiveness of these safeguards was neither assessed nor documented; instead, the process hazard analysis only listed general safeguards. Subsequent hazard reviews in 2001 and 2006 did not modify the original process hazard analysis, and a 2010 process hazard analysis conducted the year of the incident did not identify HTHA as a hazard for the specific exchangers involved in the incident. The teams conducting these hazard assessments used a number of assumptions, which contributed to ineffective hazard identification and safeguards.

Despite these inadequate hazard assessments, the Washington Division of Occupational Safety and Health (DOSH) did not issue citations after the April 2 incident related to Tesoro's failure to evaluate the effectiveness of the safeguards. The Washington Process Safety Management (PSM) standard does not require such an evaluation and documentation of safeguard effectiveness, nor does the regulation require companies to address the effectiveness of the controls or use the hierarchy of controls. Therefore, a process hazard analysis can satisfy the regulatory requirements even though it might inadequately identify or control the major hazards.

6.1.2 Lack of Defined Performance Standards for all SCEs

Neither Transocean nor BP sufficiently focused on the safety critical emergency systems of the BOP, nor were they specifically required to identify these SCEs and provide defined performance requirements for each by the offshore regulator. (See Chapter 5.0.) Currently, BSEE does not have specific regulations that address the performance requirements of all identified safety critical elements.

Since Macondo, BSEE has implemented more requirements for operating procedures that "provide instructions for conducting safe and environmentally sound activities involved in each operation addressed in your SEMs program."[160] They include specifying actions and personnel roles for various phases of an operation, such as routine startup, normal and emergency operations, shutdowns, and startups after a process upset.[161] BSEE requires that the procedures identify consequences of deviations from operating limits and steps to avoid and correct such deviations.[162] To that end, the procedures should indicate potential impacts to people and the environment, and operators must implement sound work practices for dealing with the hazards identified in those procedures.[163] Operating procedures should also reflect current work practices.[164]

While operating procedures are an important aspect of maintaining safe operations, they fall short of the expectations required for performance standards described in Sections and 4.2.3.1 and 5.2. The SEMS Rule pertaining to operating procedures[165] does not require companies to address the SCEs relied upon during the operation being undertaken, the underlying conditions that may compromise an SCE, an explanation of how each SCE will function, or the identification of interactions the SCE has with other systems. Interactions are important to recognize so that operators can implement effective management of change procedures if safety critical equipment will be affected by a change to another system.

US regulatory requirements do not hold companies to focus safety management activities on safety critical elements. Nevertheless, well written operating procedures could clarify the roles of those safety critical elements and identify setpoints for actions to avoid compromising the SCE. As Chapter 5.0 indicates, neither Transocean nor BP sufficiently focused on safety critical elements voluntarily, even though both companies operate globally within offshore regulatory regimes that require them.[a] Consider, for example, the workaround Transocean employed while drilling the Macondo well with 6⅝" drillpipe, which the Deepwater Horizon BOP could not reliably shear. (See Section 5.2). The two-step operating procedure the crew developed in this case was potentially ineffective but arguably adequate for normal operating procedures. Only in a major accident event, such as a blowout or a power loss resulting in the rig drifting away from the wellhead, would the procedure not have functioned because two of the available emergency systems were incapable of employing the two-step process. The probability of a blowout on the scale of Macondo is low, but the consequences are obviously high. If, at a minimum, an operating procedure has not been developed to focus on the goal of driving risk to a targeted level, such as ALARP, then that operating procedure may unintentionally incapacitate a BOP’s last lines of defense against an MAE. This was, in fact, the case on the Deepwater Horizon for most of the drilling operation at Macondo.

6.1.3 Performance Assurance and Verification Needed for all SCEs

Performance assurance and verification as presented in Chapter 5.0 are intended to be ongoing evaluations of a safety critical element throughout its life. These objectives are achieved through process safety systems, including but not limited to inspection, active monitoring of performance, testing, and overall mechanical integrity.[b]

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[a] This issue is explored in greater detail in the CSB Macondo Investigation Report Volume 3.

[b] As defined by the Center for Chemical Process Safety, “Mechanical Integrity is the programmatic implementation of activities necessary to ensure that important equipment will be suitable for its intended application throughout the life of an operation.” *Guidelines for Mechanical Integrity Systems*. Center for Chemical Process Safety/AIChE, 2006. In a booklet published by the US Occupational Health and Safety Authority (OSHA), mechanical integrity requirements were defined to apply to pressure vessels and storage tanks, piping systems (including pipe components such as valves), relief and vest systems and devices, emergency shutdown systems,

The Macondo incident prompted new offshore mechanical integrity program requirements in the United States that pertain to assurance activities:[166]

> [P]rovide instructions to ensure the mechanical integrity and safe operation of equipment through inspection, testing, and quality assurance. The purpose of mechanical integrity is to ensure that equipment is fit for service. Your mechanical integrity program must encompass all equipment and systems used to prevent or mitigate uncontrolled releases of hydrocarbons, toxic substances, or other materials that may cause environmental or safety consequences.

The mechanical integrity program must address design and maintenance of equipment, inspections, and documentation of testing. Specific references require refraining from operating outside of manufacturers' recommended limits and following manufacturer's recommendations for testing.

Post-Macondo regulations also include some requirements for independent third-party verification. As it pertains to the BOP, BSEE requires third-party verification of blind shear ram capabilities proving that a BOP is designed for the rig and well and that a BOP will operate in the necessary conditions.[167, a] The focus by BSEE on new BOP requirements appears to be in direct response to the conditions that led to the Macondo incident. However, the regulator can make additional safety advances, as the mechanical integrity requirements are only part of a rigorous SCE management system, and the BOP is not the only important safety critical element during offshore drilling and completion activities. Indeed, the explicit focus on the BOP will likely improve how it is being managed as a safety critical barrier; however, other important safety critical elements are necessary to prevent major accidents: pressure relief valves, diverter systems, process containment systems, emergency shutdown systems, fire and gas detection, escape and evacuation systems, etc. All safety critical elements would benefit from similar company assurance and third-party verification requirements now established for the BOP to help prevent future major accidents resulting from their failures.

6.1.4 Gap Closure Important for Continuous Improvement of SCE Effectiveness

Gap closure addresses monitoring the performance of technical, operational, and organizational safety critical elements for opportunities to improve them and to reduce the risk of a major accident event to a targeted level.[168] BSEE identifies SEMS as a "performance-focused tool" with four principal objectives:

1. focus attention on the influences that human error and poor organization have on accidents;
2. establish continuous improvement in the offshore industry's safety and environmental records;
3. encourage the use of performance-based operating practices; and

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controls (including monitoring devices and sensor, alarms and interlocks), and pumps. *Process Safety Management*, OSHA 3132, 2000 (reprinted).

[a] This third-party verification is significantly different from the one discussed in Section 5.5. Issues related to the independence of the third-party verifier are addressed in Volume 3.

4. collaborate with industry in efforts that promote the public interests of offshore worker safety and environmental protection.[169]

To evaluate the effectiveness of continued safety and environmental management improvement, BSEE requires performance data on the number of injuries, illnesses, oil spills, and EPA National Pollutant Disharge Elemenation System (NPDES)[a] permits, but it does not set a targeted goal for reducing risk.[170] This type of data results in a void between BSEE's stated objectives and its requirements for performance measurement because its metrics:

- do not identify which safety system or safety critical element needs improvement;
- focus on lagging indicators monitored only after an incident has occured;
- do not demonstrate any specific target for reducing risk;
- do not clearly address organizational and operational performance.

BSEE also requires that operators learn from incidents and that SEMS programs establish investigation procedues for all incidents resulting in serious safety or envirnmental consequences, or if facility management or BSEE finds an incident had the potential for serious consequences. But "serious" is not defined by the regulations.[171] From the investigation, a corrective action plan is required that identifies human and other factors and recommends changes. Yet again, the regulation does not state a safety target, such as ALARP.[172]

BSEE would be better able to attain the objectives of the SEMS program if it clearly focused on major accident events and required operators to identify the technical, operational, and organizational elements necessary to reduce the risk of an MAE. These elements would then require appropriate leading and lagging performance metrics to extend beyond the injuries, illnesses, and oil discharges that BSEE currently requires operators to monitor. This information, along with real-time diagnostics, could generate key performance indicators (KPI) to help a company determine when it needs to reduce the risks of an operation.[173] KPIs should trigger modifications that will close the gap between defined performance standards and the actual operating conditions. Safety performance indicators, whether in the form of KPIs, metrics, or some other formulation, are detailed in the CSB Macondo Investigation Report Volume 3.

6.2 Regulatory Responses Post-Macondo: Prescriptive Change versus Continuous Improvement

The Macondo incident prompted international review of offshore regulations and practices.

Australia was already grappling with a significant offshore blowout from the Montara well when Macondo occurred.[174] In describing its history, NOPSEMA states, "The two events [Montara and Deepwater Horizon], occurring within eight months of each other and drawing intense media and public scrutiny, provided an impetus for change within the Australian petroleum industry, and sparked moves for

[a] National Pollutant Disharge Elemenation System (NPDES): An EPA permitting program for facilities that discharge pollutants in US waters. See http://cfpub.epa.gov/npdes/home.cfm?program_id=45. Accessed March 9, 2014.

regulatory reform."[175] The reform created a single, independent regulatory body that focused not only on the health and safety of offshore workers, but also on compliance with offshore safety, well integrity, and environmental management.[176] This change did not include prescriptive requirements for BOPs.[177]

The UK[178] and Norwegian[179] regimes decided not to make further prescriptive requirements or major changes, because their regulatory frameworks allowed for continuous advancements toward reducing risk to ALARP[a] without new rule-making or revisions to their goal-setting regulations. As Volume 3 of this CSB report further explores, embedding the ALARP principle in the regulations allows for changes in processes and procedures as new technology and safety advances are developed, maximizing industry flexibility and driving for continuous improvement even in the absence of major accident events.

ALARP does not necessarily equate to identical solutions for every drilling situation, because the unique properties of a well and the BOP equipment will affect risk analyses that justify the drilling plans. Correspondingly, reports produced in response to the Macondo incident by both the UK[180] and Norway[181] regulators highlight risk assessments, reliability requirements, and written verification schemes to ensure the robustness of the BOP as an effective safety critical element. While Australia did not publish a formal response to Macondo, its regulations permit a licensee to drill only if a company has fully assessed the risks involved in a drilling operation, explicitly taking into account lessons learned from significant events in the industry, which would include Macondo. As such, NOPSEMA required BP to describe how it would be managing its wells based on lessons learned from Macondo.[182]

The US established new regulations and many new prescriptive requirements for many aspects of a drilling operation, specifically BOPs. However, US regulations do not contain explicit requirements for incorporating lessons learned from major accidents.

6.2.1 BOP Shearing Capability—An Illustrative Example of Diverse Regulatory Responses

As part of the Interim Final Rule, BOEMRE responded to the recommendation to "establish new blind shear ram redundancy requirements" by stating that most rigs under its jurisdiction would require modifications to their BOPs to comply with the recommendation and that the change could take 12 to 18 months for companies to meet. [183] BOEMRE asserted that such a recommendation was inappropriate for an interim rule intended to take effect immediately.[184] In the Final Drilling Rule, BSEE returned to the two-blind shear ram issue by stating,

> we need to consider all the impacts of such a requirement [two blind shear rams] before requiring it by regulation. BSEE has concluded that the requirements of the IFR [Interim Final Rule], as

[a] Australia uses the actual ALARP phrase in its regulations (http://www.comlaw.gov.au/Details/F2010C00422/Html/Text#param5). UK regulations do not use the exact ALARP phrase, but rather state "that risks with the potential to cause a major accident are reduced to the lowest level that is reasonably practicable" http://www.legislation.gov.uk/uksi/2005/3117/pdfs/uksi_20053117_en.pdf; and Norway regulations state, "In reducing the risk, the responsible party shall choose the technical, operational or organisational solutions that, according to an individual and overall evaluation of the potential harm and present and future use, offer the best results, provided the costs are not significantly disproportionate to the risk reduction achieved." http://www.ptil.no/framework-hse/category403.html#p11. Accessed September 26, 2013.

> modified by this Final Rule, have enhanced operational safety sufficiently until such time that BSEE determines whether to add a requirement for additional blind-shear rams.[185]

Macondo clearly highlights the importance of having a BSR perform successfully, hence the incentive to have a backup, but BSEE's response illustrates the difficulty that can arise from trying to find a single prescriptive requirement to cover all operations. Yet, BSEE does not have alternative mechanisms within its framework to require industry to improve its BSR functionality.

Consider the commitment BP made in the US OCS, both in a letter from the BP Regional President of the Gulf of Mexico to the director of BSEE in July 2011[186] and as part of a guilty plea agreement between BP and the US Department of Justice in November 2012.[187] BP stated it would require "subsea blowout preventers (BOPs) equipped with no fewer than two blind shear rams and a casing shear ram" for all dynamically positioned drilling rigs, but that moored rigs would be equipped with either two blind shear rams or one blind shear ram and one casing shear ram.

The Macondo well was drilled with both a moored rig (the Marianas) and a dynamically positioned rig (the Deepwater Horizon), so it is worthwhile to examine the basis for the approach toward the two types of rigs. Dynamically positioned rigs have the potential to drift offsite as a result of environmental forces (e.g., a storm), or they can be driven offsite accidentally by the dynamically positioning equipment (e.g., equipment malfunction). While moored rigs may also drift offsite, it is much more probable with dynamically positioned rigs.[188] Rationale provided in internal BP guidance stated that these drift-off/drive-off scenarios could result in a tool joint being pulled through the BOP and positioned opposite a blind shear ram.[189] Since most blind shear rams are not designed to cut through tool joints, an unhindered second blind shear ram could mitigate risk introduced by the tool joint.

Two blind shear rams could also help mitigate the risk of a BSR failing because of drillpipe buckling off center and out of the cutting region of the blind shear ram's blades,[a] as happened at Macondo. This risk is present in both moored and dynamically positioned drilling rigs and not addressed by BP's guidance.

While a second BSR may be the best choice for common well scenarios, in cases beyond Macondo:

1. a second shear ram might fail for the same reason that the first does;
2. a second blind shear ram may not be available during an emergency because emergency systems such as the AMF/deadman may not be designed to fire two blind shear rams;
3. a second blind shear ram in place of a pipe ram on BOPs with fewer than five ram cavities could reduce risk for some hazards but increase it for others

These scenarios, as well as additional situations and accompanying considerations presented in Appendix 2-C, illustrate that having two sets of shear rams does not necessarily by itself effectively reduce risk of an MAE to ALARP. Additional measures may be required.

[a] If effective compression is the cause of the drillpipe buckling, the location of closed pipe rams determines how far off-center the drillpipe will buckle and the final position of the drillpipe in the BOP. If pipe rams closer to a BSR are closed, drillpipe will be substantially less off center, so a BSR might be able to seal the well. (See appendix 2-A for more details.)

The UK offshore industry association, Oil and Gas UK, offers post-Macondo guidance on subsea BOPs, detailing a variety of situations when two BSRs might not be optimal, including those offered in Appendix 2-C.[190] As evident from the Macondo findings, much more than adding an additional blind shear ram may be needed to ensure a high degree of performance when the BOP is activated. These possibilities illuminate why a prescriptive requirement to have two sets of shear rams may not result in the most effective means to reduce the risk of a blowout to ALARP, and it may be counterproductive when not considering consequences, intended as well as unintended.

The issue of two sets of blind shear rams has received the attention of a review panel from the UK that included three independent appointees and senior representatives from the three national regulatory bodies with responsibilities for the UK offshore oil and gas sector. The panel observed:[191]

> On the specific issue of whether there should be additional prescriptive standards (and more specifically two blind shear rams) the Panel believes that the key issue is that the system can be demonstrably relied upon to work on demand.
>
> The Panel's view is that specific decisions on the appropriate number of shear rams must be based on the risks presented by the particular circumstances at each well and the range of controls available to deal with them. This consideration will be reflected in the well plan notified to the regulator. If the balance of the evidence suggests that one set of shear rams is adequate, and their operation can be assured, then one set would be sufficient. If there is uncertainty, then the risk controls for the well should be reconsidered as a whole, including the option to use more than one set of shear rams. The Panel emphasizes that a BOP is a secondary means of controlling a well, usually relied upon *after* problems begin. Thus, the Panel believes priority should be given to ensuring the primary methods of well control are sufficiently robust to avoid circumstances that necessitate unplanned operation of the BOP. The decision to include more than one set of shear rams may be appropriate where a risk assessment concludes that specific well and geological factors make the risk of failure of these primary methods unacceptably high.
>
> Consequently, while the Panel does not propose further prescriptive requirements for the number of well control devices, it does affirm the critical importance of testing and maintenance to defined manufacturers' requirements as is proposed by HSE, and the subsequent monitoring of adherence to these by the operators of offshore installations.

The focus of the panel's report, therefore, is not on adding prescriptive requirements for the number of blind shear rams, but on conducting effective risk assessments[a] and ensuring that monitoring of the BOP's

[a] The panel does not mention it, but a risk assessment of the ram configuration of a BOP should also entail examining placement of a casing shear ram in relation to a blind shear ram. Casing can become stuck in a well (See Appendix 2-C for an example). If a casing shear ram is located above the BSR, cut casing may not fall into the well far enough to clear the BSR, which cannot cut the casing. The converse is to have a crew member raise the casing out of the way before closing the BSR, but this adds to the number of actions the crew member must take in a potentially stressful emergency situation.

functionality verifies that it will be reliable and available when needed. The proposed requirements by HSE arise from an internal (formally Offshore Division) group established to review the Macondo incident, the Deepwater Horizon Incident Review Group (DHIRG).[192]

In response to a DHIRG review of findings published in various public reports on the Macondo incident, the HSE is developing criteria for an effective BOP safety management system that will cover the working life of the BOP. The HSE suggests:

1. involving the BOP manufacturer to provide guidance in testing and maintenance of a BOP;
2. reviewing effectiveness of maintenance activities in the context of practical experience;
3. ensuring that acceptance criteria defined by maintenance routines for SCEs reflect performance standards;
4. creating performance indicators that should be reported to senior management and a third-party auditor for enhanced oversight.[193]

Identification, performance standards, assurance and verification activities, and gap closure all play important roles in ensuring functionality of the safety critical elements necessary to avert an uncontrolled blowout. Without them, it is difficult, if not impossible, to effectively manage the major accident hazards and to reduce the risks inherent in offshore operations.

6.2.2 Proposed Regulatory Changes Suggest US Recognition of the Importance of Lifecycle Management of Safety Critical Equipment

In August 2013 BSEE proposed to amend and update regulations pertaining to offshore oil and gas production operations[194] in recognition that "much of the oil and gas production on the OCS has moved into deeper waters and the regulations have not kept pace with technological advancements."[195] BSEE asserts that the changes proposed are "necessary to bolster human safety, environmental protection, and regulatory oversight of critical equipment involving production safety systems," and specifically identifies the importance of conducting and documenting a lifecycle analysis of specific safety and pollution protection equipment (SPPE).[196] Improvements to the required lifecycle analysis are necessary, according to BSEE, "in order to increase the overall level of certainty that this equipment would perform as intended including in emergency situations…[and it] involves vigilance throughout the entire lifespan of the SPPE, including design, manufacture, operational use, maintenance, and eventual decommissioning of the equipment." The proposed rule adds that "a major component of the lifecycle analysis involves the proper documentation of the entire process…[allowing] an avenue for continual improvement throughout the life of the equipment…"[197] The proposed rule is explicitly for operator production installations, not contracted drilling facilities like the Deepwater Horizon, and the lifecycle analysis requirements are for only specified equipment types, which does not include the BOP[a]; however, placing these limitations aside, this proposed rule demonstrates recognition by the regulator of the vital need for more robust management of the complete lifecycle of safety critical equipment. Such advancements need expansion to all identified safety critical elements.

[a] BSEE explicitly requests comment within the Federal Register notice on the possibility of requiring similar lifecycle analysis of the BOP, but this safety critical device is currently not included in the proposed rule language (78 *Federal Register* 163 (August 22, 2013), p. 52251).

7.0 Volume 2 Conclusions: Technical Safety Failures Reveal Broader Regulatory Gaps

A discussion of Macondo-related barriers and safety critical equipment is merely the starting point for an analysis of the broader systemic, organizational, and regulatory factors that influenced safety on April 20, 2010. Some of these broader issues are introduced in this volume. Despite positive steps in the United States toward improved management of BOPs, gaps still exist in contrast with the regulatory frameworks of other global regimes for identifying and managing safety critical devices. Furthermore, the regulator does not require that deepwater drilling owners and operators to maintain and improve performance by identifying and managing all safety critical elements through defined performance standards, assurance and third-party verification activities, and gap closure. Drilling and completion activities in the Gulf of Mexico may still be occurring without adequate barriers in place to prevent major accident events. In sum, the CSB makes several conclusions.

The BOP, a significant barrier to prevent or minimize loss of well control had multiple deficiencies that demonstrate Transocean and BP did not treat or manage it as a safety-critical device. Proof of this assertion includes:

a. A miswired SEM in a control pod (Section 3.2.1.1);
b. Drained emergency batteries responsible for powering the AMF/deadman sequence (Sections 3.2.1.1 and 3.2.1.3);
c. Miswired solenoid responsible for closing the blind shear ram during the AMF/deadman sequence (Section 3.2.1.2);
d. A documented inability to reliably shear the drillpipe used for an extended period during the drilling process (Section 5.2.1);
e. A planned emergency situation 2-step workaround that would have high likelihood of failure in the event of AMF/deadman or autoshear activation (Section 5.2.1);
f. Undocumented and inadequate maintenance and inspection (Section 5.3.1);
g. Inadequate AFM/deadman testing procedures to detect the deficiencies found on the Deepwater Horizon BOP (Section 5.3.2).

The numerous shortcomings in the hardware of the BOP extended to the management systems. No effective maintenance and testing programs were in place to ensure effectiveness and availability of the BOP emergency systems. This weakness left the BOP vulnerable to failure (Section 5.3). Additional details regarding safety management system deficiencies at Macondo are explored further in Volumes 3 and 4 of the CSB Macondo Investigation Report.

US regulations do not require management of all safety critical elements throughout their lifecycle, including identification through a hazard analysis, performance standards, verification/validation, and gap closure activities. SEMS lacks specific language focusing the responsible party on effective lifecycle management of safety critical elements (technical, operational, or organizational) that could cause or contribute to a major accident (Chapters 4.0-6.0). The lack of specific regulatory language requiring overall management of safety critical elements allows for those companies with less robust safety management systems or those with inadequate safety cultures to insufficiently address the major accident hazards they face.

US regulations and industry guidance do not require hazard and risk analyses to include identification and assessment of situations during a drilling operation that could lead to a buckled off-center pipe. Developing new BOP designs that can cut and seal off-center pipe takes time. Therefore, rigs are more vulnerable to a blowout for several reasons, including 1) inadequate assessment of the conditions when effective compression could be an issue during offshore operations; 2) incomplete or outdated well control procedures and training that do not include assessments of the shut-in conditions which may buckle the drillpipe in the BOP and the actions of the drill team and crews to prevent or address the situation. The critical need for incorporating human factors in safety management and hazard assessments is discussed further in Volume 3 (Section 5.4).

Existing US regulations do not require demonstration of barrier effectiveness for adequate MAE risk mitigation. In a dynamic work environment where the operational challenges and available technology are in flux, it can be difficult for a regulator to implement sufficient rules in real-time to sufficiently address the risks of each drilling operation. The US regulator employs a weakened offshore approach because it does not require industry 1) to reduce risk of MAEs to a target such as ALARP and 2) to demonstrate effective barrier safety management through continuous improvement based upon performance standards, assurance schemes and third-party verification, and gap closure for all SCEs. These and other attributes are explored in detail in Volume 3 (Sections 5.0 and 6.0)

Deficiencies identified during the failure analysis of the Deepwater Horizon BOP could still remain undetected in BOPs currently being deployed to wellheads. At the time of the incident, neither recommended industry practices nor US regulations required testing of the AMF/deadman system's functionality. Post-incident changes that call for function testing the AMF/deadman have not addressed this issue (Section 5.3.2).

8.0 Recommendations

Although the CSB raises several BOP functionality issues in this report, the Agency will not make recommendations for specific improvements to BOP design. The Deepwater Horizon BOP is just one of various BOP models available to owners and operators conducting drilling and completions activities both on and offshore. The CSB sees opportunities for greater safety impacts through improvements to regulatory-required management of safety critical elements (SCEs) rather than a strict focus on prescriptive changes that may improve only one SCE (the BOP) identical to the one used on the DWH. The regulatory gaps identified in the analysis of the BOP as a barrier yield opportunities for broad safety improvements. Therefore, the CSB recommends the following preventive measures.

CSB-2010-10-I-OS-R1

Bureau of Safety and Environmental Enforcement, United States Department of Interior

Augment 30 C.F.R § 250 Subpart S to require the responsible parties, including the lessee, operator, and drilling contractor, to effectively manage all safety critical elements (SCEs)—technical, operational, and organizational—thereby ensuring their effective operation and reducing major accident risk to As Low As Reasonably Practicable (ALARP). At a minimum, require the following improvements:

a. Written identification of all safety critical elements for offshore operations through hazard analysis. This list will be made available for audits and inspections performed by the responsible parties, external entities (e.g., independent competent parties, third-party auditors), and the regulator, and it will be shared among the lessee, operator, and drilling contractor. Identifying all safety critical elements shall ensure the establishment and maintenance of effective safety barriers to prevent major accidents;

b. Documented performance standards (as defined in Section 5.2 of the CSB Macondo Investigation Report Volume 2) describing the required performance of each SCE, including its functionality, availability, reliability, survivability, and interactions with other systems;

c. Augmentation of 30 C.F.R § 250.1916 to include requirements for all responsible parties, including contractors, to conduct monitoring for continuous active assurance of all identified SCEs through each SCE's lifecycle (as described in Section 5.0 of the CSB Macondo Investigation Report Volume 2);

d. Documented independent verification scheme for the identified SCEs reported to and subject to review by the regulator (as described in Section 5.5 of the CSB Macondo Investigation Report Volume 2), where:

    1. the independent party meets BSEE criteria that guarantee its competence and independence from the company or facility for which it is providing verification;

    2. the independent verification occurs prior to commencement of the offshore drilling or production activity and periodically, as defined by BSEE;

3. all resulting assessments of the independent verification activities will be tracked in a formal records management system; and
4. Corrective action shall be taken to address negative verification findings and non-compliance. Verified noncompliance shall be tracked by the responsible party as a process safety key performance indicator and be used to drive continuous improvement.

CSB-2010-10-I-OS-R2

Bureau of Safety, Environment and Enforcement, United States Department of Interior

Publish safety guidance to assist the responsible parties in fulfillment of regulatory obligations stipulated in R1 for the identification and effective management of safety critical elements (SCEs)—technical, operational, and organizational—with the goal of reducing major accident risk to As Low As Reasonably Practicable (ALARP), including but not limited to each of the identified minimum requirements (See R1, items a-d).

CSB-2010-10-I-OS-R3

American Petroleum Institute

Publish an offshore exploration and production safety standard for the identification and effective management of safety critical elements (SCEs)—technical, operational, and organizational—with the goal of reducing major accident risk to As Low As Reasonably Practicable (ALARP), including but not limited to:

a. development and implementation of an SCE management system that includes the minimum necessary "shall" requirements in the standard to establish and maintain effective safety barriers to prevent major accidents;
b. methodologies for (1) the identification of SCEs and (2) the development of performance standards of each SCE, including its functionality, availability, reliability, survivability, and interactions with other systems;
c. establishment of assurance schemes for continuous active monitoring of all identified SCEs throughout each SCE's lifecycle;
d. fulfillment of independent verification requirements and use of those verification activities to demonstrate robustness of the SCE management process;
e. development of process safety key performance indicators pertaining to the effective management of SCEs to drive continuous improvement.

CSB-2010-10-I-OS-R4

American Petroleum Institute

Revise *Blowout Preventer Equipment System for Drilling Wells* (API Standard-53, 4th edition) to establish additional testing or monitoring requirements that verify the reliability of those individual redundant blowout prevention systems that are separate from the integrated system tests currently recommended.

Appendix 2-A: Deepwater Horizon Blowout Preventer Failure Analysis

This appendix is a separate pdf file available on the CSB Macondo Investigation webpage: http://www.csb.gov/macondo-blowout-and-explosion/.

Appendix 2-B: Deepwater Horizon RBS 8D BOP MUX Control System Report

This appendix is a separate pdf file available on the CSB Macondo Investigation webpage: http://www.csb.gov/macondo-blowout-and-explosion/.

Appendix 2-C: Scenarios When Two BSRs Would Not be Optimal

	Scenario	Considerations
1	Well control actions result in a shut-in well with high drillpipe pressures leading to buckled drillpipe across the blind shear ram(s). Crew decides to manually shear drillpipe.	Activation of the first blind shear ram could trap the drillpipe on the side of the BOP, leading to off-center drillpipe in the second shear ram.[a]
2	Rig crew determines it should shear the drillpipe, but the control system fails.	Neither shear ram would initially activate. Secondary activation through remotely operated vehicle (ROV) intervention or other means would be necessary.[198]
3	The circumstances necessary to trigger the AMF/deadman system are established.	Volumetric accumulator constraints[b] may inhibit the AMF/deadman from closing two sets of blind shear rams.[b] For example, the DWH had two sets of shear rams (blind shear ram and a casing shear ram), but the AMF/deadman system was capable of closing only one of them due to accumulator limitations.
4	A pipe ram in a BOP is replaced with a blind shear ram. In a four-ram cavity BOP, this would result in two blind shear rams, but only two pipe rams.[b]	"Moored rigs without a riser margin[c] should assess the need for two shear rams."[199] For moored rigs with a riser margin, "The main function of a BOP is well control-i.e. returning a well to primary well control after a kick. Three pipe rams, backed up by at least one annular, provide the required flexibility, functionality and redundancy for this and avoid the last resort of shearing pipe…The workgroup concluded that this reduction in the number of pipe rams would result in risks in well operations not being ALARP."[200]

[a] Rotating two sets of blind shear rams 90 degrees from one another could lead to the drillpipe being positioned between the shearing blades of the second set of blind shear rams, thus enabling the second set to shear the drillpipe.

[b] During normal operations, pressurized hydraulic fluid for solenoids is supplied from the rig through the rigid conduit line, but in AMF/deadman operations, the fluid comes from pressurized storage bottles called accumulators located on the BOP.

[c] A "riser margin" is additional weight added to the mud column in the riser so that if a riser is lost, the weight of the mud in the well below the seafloor is sufficient to control well pressure. The walls of a deepwater well have a tendency to fracture, creating difficulties in keeping a riser margin. For shallow wells, a riser margin is not as difficult to achieve.

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U.S. CHEMICAL SAFETY AND HAZARD INVESTIGATION BOARD

INVESTIGATION REPORT
VOLUME 3

DRILLING RIG EXPLOSION AND FIRE AT THE MACONDO WELL

(11 Fatalities, 17 Injured, and Serious Environmental Damage)

DEEPWATER HORIZON RIG

MISSISSIPPI CANYON 252, GULF OF MEXICO

APRIL 20, 2010

KEY ISSUES:

- HUMAN FACTORS
- ORGANIZATIONAL LEARNING
- SAFETY PERFORMANCE INDICATORS
- RISK MANAGEMENT PRACTICES
- CORPORATE GOVERNANCE
- SAFETY CULTURE

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Acronyms and Abbreviations

ALARP	As Low As Reasonably Practicable
AMF	Automatic Mode Function
ANSI	American National Standards Institute
API	American Petroleum Institute
ASTM	American Society for Testing and Materials
BOEM	Bureau of Ocean Energy Management
BOEMRE	Bureau of Ocean Energy Management, Regulation, and Enforcement
BOP	Blowout Preventer
BSEE	Bureau of Safety and Environmental Enforcement
BSR	Blind Shear Ram
CCPS	Center for Chemical Process Safety
CEO	Chief Executive Officer
COS	Center for Offshore Safety
COSO	Committee of Sponsoring Organizations
CRM	Crew Resource Management
CSB	US Chemical Safety Board
DAFW	Days Away From Work
DAFWC	Days Away From Work Case
DAFWCF	Days Away From Work Case Frequency
DART	Days Away from Work, Restricted duty, and Transfer situations
DAWFC	Days Away from Work Case Frequency
DNV	Det Norske Veritas
DOI	Department of Interior
DWH	Deepwater Horizon
DWOP	Drilling and Wells Operation Practice
EDS	Emergency Disconnect System
EHS	Environmental Health and Safety
EPA	Environmental Protection Agency
ERM	Enterprise Risk Management

ETP	Engineering Technical Practices
FAA	Federal Aviation Administration
FRC	Financial Reporting Council
GDP	Group Defined Practice
GHSER	Getting HSE Right
GRI	Global Reporting Initiative
HAZID	Hazard Identification
HAZOP	Hazard and Operability Study
HIPO	High Potential Incident
HPDO	High Potential Dropped Objects
HRO	High Reliability Organization
HSE	Health Safety Executive
HSSE	Health, Safety, Security and Environment
HTO	Human, Technology and Organization
IADC	International Drilling Contractors Association
INPO	Institute of Nuclear Power Operations
IOGP	International Association of Oil & Gas Producers
ITL	Information to Lessee
LCM	Loss Circulation Material
LMRP	Lower Marine Riser Package
LOPA	Layers of Protection Analysis
LOPC	Loss of Primary Containment
LTA	Lost Time Accident
LTI	Lost Time Incident/Lost Time Incident rate
MAE	Mary Accident Event
MAHRA	Major Accident Hazard Risk Assessment
MHRA	Major Hazard Risk Assessment
MAP	Major Accident Prevention
MAR	Major Accident Risk
MBI	Marine Board of Investigation
MBO	Management by Objective

MGS	Mud-Gas Separator
MHRA	Major Hazard Risk Assessments
MIA	Major Incident Announcement
MMS	Minerals Management Service
MOC	Management of Change
MODU	Mobile Offshore Drilling Unit
MSHA	Mine Safety and Health Authority
NAE	National Academy of Engineering
NOPSA	National Offshore Petroleum Safety Authority
NOPSEMA	National Offshore Petroleum Safety and Environmental Management Authority
NPT	Negative Pressure Test
NRC	Nuclear Regulatory Commission
NSOAF	North Sea Offshore Authorities Forum
NTL	Notice to Lessee
NTS	Non-technical Skills
NTSB	National Transportation Safety Board
OCS	Outer Continental Shelf
ODE	Onshore Drilling Engineer
OECD	Organization for Economic Co-operation and Development
OIC	Operations Integrity Case
OIM	Offshore Installation Manager
OLF	Norwegian Oil Industry Association
OMS	Operating Management System
OOC	Offshore Operators Committee
OSH	Occupational Safety and Health
OSHA	Occupational Safety and Health Administration
PMAA	Performance Monitoring Audit and Assessment
PSA	Petroleum Safety Authority
PSM	Process Safety Management
QHSE	Quality, Health, Safety and Environment
RAT	Risk Assurance Tool

RIF	Recordable Injury Frequency
SASB	Sustainability Accounting Standards Board
SCE	Safety Critical Element
SCTA	Safety Critical Task Analysis
SEC	Securities and Exchange Commission
SEEAC	Safety, Ethics and Environment Assurance Committee
SEMS	Safety and Environmental Management System
SHAPE	Safety and Health in Amec Process & Energy
SHE	Safety, Health, and Environment
SIC	Serious Injury Case
SID	Standing Instructions to the Driller
SINTEF	Norwegian: Stiftelsen for industriell og teknisk forskning
SIS	Safety Instrumented Systems
SMS	Safety Management System
SOP	Standard Operating Procedure
SPE	Society of Petroleum Engineers
SPI	Safety Performance Indicator
SPU	Strategic Performance Unit
TPSR	Total Potential Severity Rate
TRIR	Total Recordable Injury Rate
TSTP	Task Specific THINK Procedure
UK	United Kingdom
US	United States
USCG	United States Coast Guard
WAD	Work as Done
WAI	Work as Imagined
WBM	Water Based Material
WCID	Well Construction Interface Document
WLCPF	Well Lifecycle Practices Forum
WSL	Well Site Leader

Volume 3

Human, Organizational, and Safety System Factors of the Macondo Blowout

Volume 3 – Introduction

Volume 3 Overview

Introduction

Chapter 1 – Human Factors

Chapter 2 – Organizational Learning from Incident Investigations

Chapter 3 – Safety Performance Indicators

Chapter 4 – Risk Management and the Multi-employer Work Environment

Chapter 5 – Corporate Governance and the Influence of Shareholders

Chapter 6 – Culture for Process Safety

Chapter 7 – Conclusion

Chapter 8 – Recommendations

In 1988, the offshore oil and gas industry experienced its deadliest accident when an explosion aboard the Piper Alpha oil production platform took the lives of 167 individuals. In its aftermath, a major incident investigation revealed a number of issues concerning the management of major accident risk offshore.[1] Twenty-five years later, the Piper Alpha disaster was described as "the lens through which we [the offshore industry] view our safety efforts."[2] The Macondo incident serves to check the focus of that lens, as the blowout illuminates the increasing complexity of offshore operations, technologies, and drilling environments. To that end, the CSB's investigation of the Macondo incident revisits some of Piper Alpha's lessons and introduces new ones related to human performance, organizational learning, safety performance indicators, risk management coordination, and corporate cultures that promote safety.

The risk management policies of both BP and Transocean promote an incident-free workplace. BP's 2008 major corporate safety Operating Management System (OMS) framework states, "Our goals are simply stated: no accidents, no harm to people, and no damage to the environment."[3] In Transocean's 2009 Health and Safety Policy statement, the company commits to operating in an "incident-free workplace—all the time, everywhere."[4] ExxonMobil,[5] Shell

[1] Department of Energy. *The Public Inquiry into the Piper Alpha Disaster; Presented to Parliament by the Secretary of State for Energy by Command of her Majesty*. November, 1990.

[2] Oil & Gas UK. *Health & Safety Report 2014;* 2014; p 1. http://oilandgasuk.co.uk/wp-content/uploads/2015/05/HS087.pdf (accessed December 20, 2015).

[3] Internal Company Document, BP. *The BP Operating Management System Framework, Part 1, An Overview of OMS*, Issue 2, November 3, 2008, p 24, BP-HZN-2179MDL0033320, see Exhibit 2352 http://www.mdl2179trialdocs.com/releases/release201302281700004/Lynch_Richard-Depo_Bundle.zip (accessed October 7, 2015).

[4] Internal Company Document, Transocean. *Health and Safety Policies and Procedures Manual*, Issue 03, Revision 07, HQS-HSE-PP-01, December 15, 2009, General, BP-HZN-2179MDL00132067, see Exhibit 4942 http://www.mdl2179trialdocs.com/releases/release201302281700004/Farr_Daniel-Depo_Bundle.zip (accessed October 7, 2015).

[5] ExxonMobil, Commitment to Safety, http://www.exxonmobile.com/USA-English/EMPCo/healthsafetyenvironment_safety.aspx (accessed December 8, 2014).

Global,[6] Total,[7] ConocoPhillips,[8] and Chevron[9] have similarly stated "zero incident" risk management goals, but zero incidents for a day, month, or even years do not preclude a company from an incident tomorrow. Preventing incidents requires a shift in focus from past successes to current risk reduction activities. Ultimately, risk reduction efforts must be continually accounting for inevitably changing circumstances (e.g., the drilling environment, technology, knowledge, and workforce).

While the Macondo blowout occurred under the direction of Transocean and BP, it affected the offshore industry worldwide,[10] demonstrating that risk management for preventing major accident events (MAEs) continues to challenge the offshore industry despite the numerous lessons from the Piper Alpha incident.[11] For example, almost five years after the Macondo blowout, audit findings from one of the offshore US regulators, Bureau of Safety and Environmental Enforcement (BSEE), suggest that some companies use their safety and environmental management system (SEMS) programs[12] to document regulatory compliance rather than to actually manage risks.[13] In fact, post-incident CSB analyses of Transocean and BP risk management policies at the time of the blowout reveal that many of the policies would have satisfied current SEMS requirements. Yet the companies did not effectively implement these policies to manage the major accident risks of the Macondo well, and the companies were not held accountable by the regulator to ensure that they managed safety as their company policies stipulated. Beyond BP and Transocean, the CSB found a lack of US offshore industry regulations and guidance for human factors, process safety indicators, and corporate governance. Volume 3 of the CSB Macondo investigation report addresses the insufficient focus on managing major hazard risk throughout the lifecycle of the Macondo well, beginning with the well's initial design, through execution of the project, which included several modifications, and finally during temporary abandonment planning and execution. The CSB's report:

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[6] Shell Global, Safety, http://www.shell.com/global/environment-society/safety.html (accessed December 8, 2014).

[7] Total, Industrial Safety: Our Objectives and Ambitions, http://www.total.com/en/society-environment/industrial-safety/our-objectives-and-ambitions (accessed December 8, 2014).

[8] ConocoPhillips, Our Safety Commitment, http://www.conocophillips.com/sustainable-development/safety-health/Pages/our-safety-commitment.aspx (accessed February 8, 2015).

[9] Chevron, Workforce Health and Safety, http://www.chevron.com/corporateresponsibility/approach/workforce/ (accessed December 8, 2014).

[10] E.g., Oil & Gas UK. *Guidelines on BOP Systems for Offshore Wells, Issue 2;* Oil & Gas UK: Great Britain, May, 2014; p 182.; House of Commons Energy and Climate Change Committee. *UK Deepwater Drilling-Implications of the Gulf of Mexico Oil Spill;* HC 450-1; The Stationery Office Limited: London, Great Britain, January 6, 2011.; International Association of Oil & Gas Producers. *Deepwater Wells: Global Industry Response Group Recommendations;* Report No. 463; May, 2011.

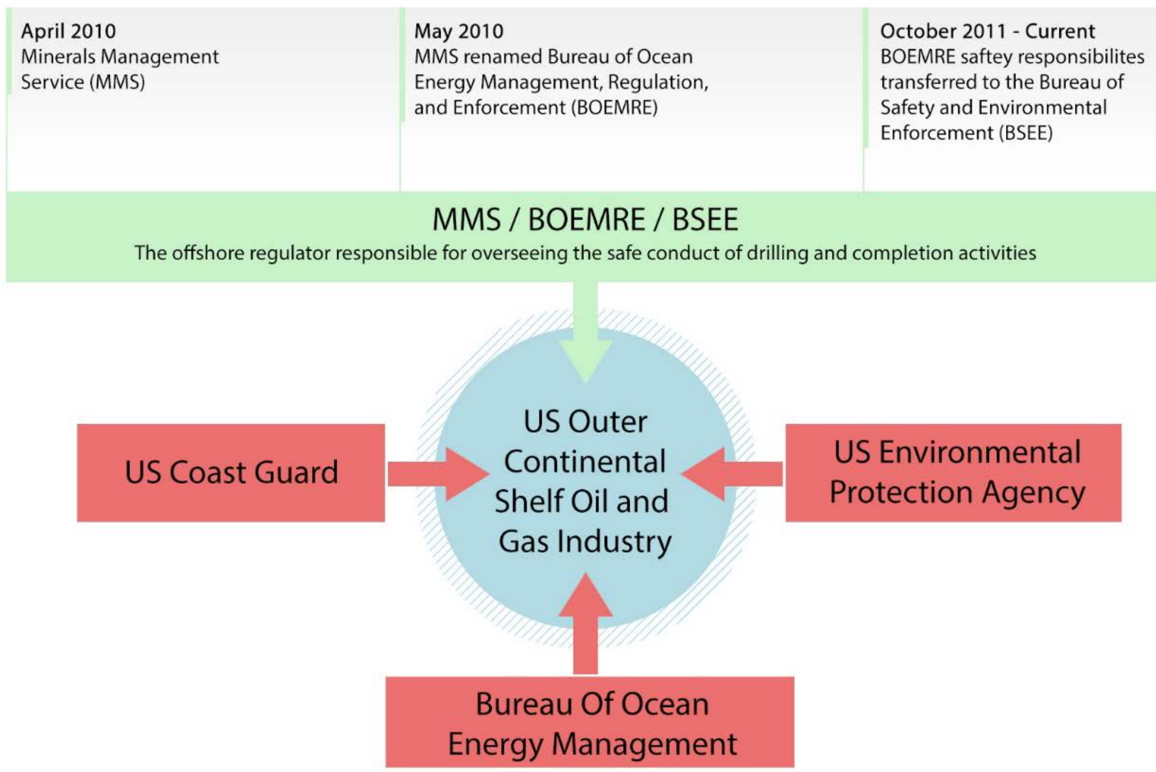
[11] E.g., Walker, S. *Review of the Cullen Recommendations - are they still relevant?*, Oil & Gas UK's Piper 25 Confernece, Aberdeen, Scotland, June, 2013.; Hackitt, J. *Piper Alpha – honouring the legacy and adapting for the future*, Oil & Gas UK's Piper 25 Confernece, Aberdeen, Scotland, June, 2013.; Fryan, R. *Piper Alpha 25*, Oil & Gas UK's Piper 25 Confernece, Aberdeen, Scotland, June, 2013.

[12] 30 C.F.R. §250.1900 Subpart S, Safety and Environmental Management Systems (2015).

[13] Bureau of Safety and Environmental Enforcement. *BSEE Priorities Regarding SEMS*, Offshore Technology Conference, Houston, TX, 2015; http://www.bsee.gov/uploadedFiles/BSEE/BSEE_Newsroom/Speeches/2015/OTC%202015%20Mtg%20SEMS%20Presentation.pdf (accessed December 19, 2015).

1. Identifies instances where crewmember's actions were relied upon for successful and safe well operations, but neither BP nor Transocean effectively defined performance expectations, nor did they support the crew with a rigorous human factors management system.
2. Demonstrates that both BP and Transocean possessed safety management system policies meant to manage major accident hazards, but they did not effectively implement these policies because of:
    a. Inadequate incorporation of human factors into safety management practices and hazard assessments;
    b. Ineffective organizational learning from previous incidents;
    c. Unclear roles and responsibilities, separately and jointly, for managing major accident risk; and
    d. Insufficient fulfillment of internal company requirements to reduce risk to as low as reasonably practicable (ALARP).
3. Advances the importance of actively monitoring the effectiveness of barrier and safety management systems.
4. Illuminates the influence of oversight from corporate board of directors and shareholders on risk management.
5. Illustrates the current gaps in US regulations and guidance that do not incorporate recognized process safety concepts, including human factors, ALARP, and effective management of safety critical elements.
6. Lays the necessary foundation for carefully examining the strong oversight and influence required of the regulator in pushing companies to effectively implement what they claim they are doing to manage major accident risk and in driving them toward continual risk reduction.

Throughout Volume 3, the CSB refers to "the regulator" or "offshore regulations" to indicate either MMS or BSEE and their respective safety regulations for drilling and completions activities on the outer continental shelf. As indicated in the figure below, MMS evolved into BSEE after the Macondo incident occurred. In reality, several regulatory bodies oversee the offshore oil and gas industry, including the US Coast Guard (USCG), the Bureau of Ocean Energy Management (BOEM), and the Environmental Protection Agency (EPA), but the CSB generally limits its discussion to MMS and BSEE due to its specific authority over the safe conduct of offshore drilling and completion operations.



Moving Beyond the Blowout Preventer

Volume 2 of the CSB Macondo investigation report introduces safety critical elements (SCEs), also called safety barriers, as equipment or tasks that provide the highest level of protection against MAEs, and, conversely, whose failure increases the risk of an MAE.[14] In that volume, the CSB uses the blowout preventer (BOP) as the vehicle to explore targeted risk reduction by describing the steps required for maintaining SCE effectiveness to ensure risk of an MAE is as low as reasonably practicable.[15]

Historically, safety barriers have been identified as physical in nature, intended to separate and protect people and the environment from hazards.[16, 17] Physical barriers, such as the downhole cement and BOP installed at the Macondo well, have been closely assessed post-incident for their contribution to the blowout.[18] But focusing on solutions to these technical failures cannot prevent future incidents without giving equal attention to failures of less visible, non-physical barriers and support systems.

The safety barrier concept must extend beyond physical safeguards. For example, a blowout preventer should establish a physical barrier to prevent the flow of hydrocarbons from the well to the drilling rig, yet the BOP can accomplish this only if the crew detects the kick soon after ingress and activates the appropriate BOP component in time for it to seal the well. Beyond the crew's actions, companies must appropriately manage several organizational factors to ensure the BOP will successfully function as a barrier, including:

- proper selection of a BOP with capabilities appropriate to control the well being drilled;
- maintenance and care to ensure the BOP can function as designed;
- a crew's capabilities in identifying the need to close the well;
- active monitoring of the BOP and its associated safety systems to ensure its effectiveness as a barrier when summoned; and
- company procedures and cultural practices that directly influence a crew's actions.

This brief dissection of the BOP as a physical barrier illustrates how its success depends upon a barrier system[19] that incorporates operational/human and organizational elements.

In the United States, Macondo precipitated numerous industry and government publications to address issues such as safe drilling operations, well containment and intervention capability, and oil spill response

[14] See CSB Macondo Investigation Report, Volume 2, Section 4.2.3.1, p 58.

[15] *Ibid*., Figure 5-1, p 63.

[16] Sklet, S. Safety Barriers: Definitions, Classification, and Performance. *J. Loss Prevent. Proc.* 2006, 19, 494.

[17] The weight of a column of fluid that fills the hole being drilled (wellbore) and the riser is the primary barrier used to control pore pressures and prevent kicks during drilling and completion activities; for more detail, see Volume 1 of the CSB Macondo Investigation Report, Section 4.2.3.1, p 19.

[18] CSB Macondo Investigation Report, Volume 2.

[19] "A barrier system describes how a barrier function is realized or executed…A barrier element is a component or a subsystem of a barrier system that by itself is not sufficient, to perform a barrier function..." Sklet, S. Safety Barriers: Definitions, Classification, and Performance. *J. Loss Prevent. Proc.* 2006, pp 19, 494.

capability.[20] The focus of these US regulations, standards, and guidance has primarily been on the reduction of physical threats and improvements in managing technical barriers such as those related to this incident. In contrast, new US regulations and guidance aimed at advancing our understanding and management of human performance—the operational barriers—have been limited. This volume explores opportunities in the US for further improvements.

Volume Overview

Because Deepwater drilling is highly dependent on the actions of the well operations crew, Volume 3 of the CSB Macondo investigation report begins by exploring four specific phases of activity by the crew leading up to the blowout and subsequent explosions. These phases provide a framework for analyzing the human and organizational factors contributing to the April 20, 2010, incident. From there, this volume reviews several human factors issues relevant to the incident (Chapter 1.0).

Volume 3 extends beyond human factors and safety system performance to organizational learning of offshore incident investigations (Chapter 2.0) and major challenges facing industry in this endeavor, as demonstrated by several well control incidents. Chapter 3.0 illuminates successful personal safety program initiatives that BP and Transocean have not adequately applied to process safety. Chapter 3.0 then describes advances in safety performance indicators and suggests offshore process safety indicators appropriate for rig, company, industry, and regulatory levels. Chapter 4.0 details how several of BP's and Transocean's MAE risk management policies could have made a positive impact on work completed at the Macondo well, but safety roles and responsibilities were unclear, and ultimately neither company applied their policies. Since BP's and Transocean's boards of directors did not have sufficient oversight for process safety issues and major accident prevention, Chapter 5.0 reviews corporate governance good practice, as well as the influence that shareholders, SEC reporting requirements, and the regulator might have on ensuring boards of directors remain focused on potential MAEs. Ultimately, the organizational behaviors and practices of BP and Transocean demonstrated a focus on personal safety without an equal attention to managing barriers and safety management systems meant to prevent MAEs, and both companies exhibited behaviors more akin to a minimal safety compliance approach (Chapter 0). With limited safety management regulatory provisions and oversight for the drilling operation, they did not abide—nor did any government authority require them to abide—by their own, more stringent corporate risk management policies. And in many respects, their documented policies still meet or exceed the current regulatory requirements for risk management.

In demonstrating that the deficiencies outlined in this volume continue to exist offshore in the Gulf of Mexico (GoM), the CSB identifies opportunities for further strengthening industry management of major accident hazards and the role of the regulator in this endeavor. The facts and findings described in Volume 3, as well as in Volumes 1 and 2, provide the bridge to Volume 4; this final volume illustrates how the regulatory changes since Macondo, while greatly significant, do not go far enough to put the onus on industry to effectively reduce risk, nor do they sufficiently provide the mechanisms for the regulator to proactively assure effective industry management and control of major hazards.

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[20] Joint Industry Task Force (JITF). *JITF Executive Summary;* March 13, 2013, p 1. http://www.api.org/~/media/files/oil-and-natural-gas/exploration/offshore/executive-summary-final-031312.pdf (accessed October 2015, 2015).

1.0 Human Factors

Chapter 1.0 Overview

This chapter provides an analysis of the human factors pertinent to the incident to shed light on the reasoning behind the decisions and actions of those immediately involved in the drilling and temporary abandonment process at Macondo. The chapter describes the current industry dependence on human actions to maintain safe operations and details a significant gap in effective management of human factors in offshore operations.

In the aftermath of a catastrophe, the individuals immediately involved in the activities that precipitated the event often receive much of the focus and subsequent blame, due largely to the ease of drawing causal lines between those activities and the negative outcomes. This holds true for Macondo, where much attention has been on the incorrect interpretation of the well data during the negative test[21] and well displacement, the delayed response to hydrocarbons entering the well, and the diversion of the well fluids to the mud gas separator instead of off the sides of the rig away from potential ignition sources and the people on board.[22] Beyond Macondo, human "errors" have also been linked to numerous major accidents from a wide variety of environments, including Chernobyl (nuclear), Herald of Free Enterprise (passenger ferry),[23] Clapham Junction (railroad),[24] Piper Alpha (offshore production facility),[25] and Texas City (onshore refinery).[26, 27]

Pointing to human failure "is hardly surprising…every operational, inspection and maintenance task is carried out by a skilled technician and the successful outcome relies on error-free performance."[28] But we should expect human performance variability, and in fact it is normal and necessary.[29] Humans are

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[21] The negative test is defined in Section 1.2.2 and discussed at length throughout Chapter 1. The negative test is also referred to as 'negative flow test' and 'negative pressure test,' depending upon which variable is measured/observed as part of the test procedure. The CSB will use the general 'negative test' for the remainder of this volume.

[22] The diverter system and mud gas separator are described in detail in Section 1.3.

[23] On March 6, 1987, a vehicle and passenger ferry capsized immediately after leaving its Belgian port when its bow door was left open, killing 193 people.

[24] Poor maintenance and human fatigue were deemed causal in this December 20, 1988, multi-train collision that resulted in 35 deaths and 500 injuries.

[25] On July 6, 1988, 167 individuals died from explosions and fire on this North Sea oil platform. A number of human factors issues were identified pertaining to procedures, the permit to work process, shift handover, communication, and training, among others.

[26] Several human factors were identified as contributory to the March 23, 2005 BP Texas City refinery explosions and fire leading to 15 deaths and 180 injuries. These included workload/staffing, distraction, fatigue, poor/inadequate instrumentation, and human-computer interface design of the unit control board.

[27] Energy Institute, Guidance on Human Factors Safety Critical Task Analysis, 1st ed., March 2011, p 1.

[28] Hamilton, I. Human Error: in the loop; *The Chemical Engineer,* 2012**,** *854,* p 40.

[29] Shorrock, S. Humanistic Systems; 'Human error': The handicap of human factors, safety and justice, http://humanisticsystems.com/2013/09/21/human-error-the-handicap-of-human-factors-safety-and-justice/ (accessed October 7, 2015).; Hollnagel, E. *Barriers and Accident Prevention;* Ashgate: 2004.

valuable because of their flexibility—their ability to adapt and troubleshoot within workplace conditions that can be "vague, shifting, and suboptimal."[30] For every catastrophic incident, humans have achieved countless other successful outcomes because of their variability and ingenuity in the face of unexpected situations. As such, humans remain a critical component of any high-hazard system and play a direct and indispensable role in preventing or mitigating a major accident event.

Human intervention is essential throughout the entire lifecycle of a drilling operation, where reliance on successful human performance begins with the initial hazard analysis to assess and design the well, and it continues through the plans and procedures developed and subsequently modified in response to the real-time well conditions. This reliance places a heavy dependence upon the decisions and actions of the well operations crew[31] which can 1) increase or decrease the risk of a well kick, and 2) compromise or strengthen the effectiveness of various technical barriers[32] intended to minimize the potential for a blowout.

Official inquiries into the Macondo incident concluded that the well operations crew and rig management made decisions and took actions that they should not have,[33] and some called for more technical competency training.[34] Yet improving human performance goes far beyond simply retraining individuals on the technical aspects of offshore operations. As Sidney Dekker expresses in his book *The Field Guide to Understanding Human Error*, "Accidents are seldom preceded by bizarre behavior … Mishaps are the result of everyday influences on everyday decision making, not isolated cases of erratic individuals

[30] Shorrock, S. Humanistic Systems; 'Human error': The handicap of human factors, safety and justice, http://humanisticsystems.com/2013/09/21/human-error-the-handicap-of-human-factors-safety-and-justice/ (accessed October 7, 2015).

[31] While the well operations crew members often get credit for making decisions and taking direct action to conduct the drilling activities, a number of management and engineering personnel play a role in the decision-making/action-taking process through various means, such as providing leadership instruction, guidance, and technical analysis of the well. The complexity of these relationships provides support for improved methods of non-technical skills development, which is covered in Section 1.7 of this chapter.

[32] Technical barriers are physical in nature, such as the BOP or drilling mud, either of which can be used to physically stop the flow of hydrocarbons from a well. The CSB Macondo Investigation Report, Volume 2, chapters 2 and 4 provide further details on physical, operational, and organizational barriers.

[33] BP. *Deepwater Horizon Accident Investigation Report;* September 8, 2010; p 10.; National Commission on the BP Deepwater Horizon Oil Spill and Offshore Drilling. *Deep Water The Gulf oil Disaster and the Future of Offshore Drilling;* 2011; pp 115, 120-122.; National Commission on the BP Deepwater Horizon Oil Spill and Offshore Drilling. *Chief Counsel's Report: The Gulf Oil Disaster;* Feburary 17, 2011; Sections 4.6 – 4.8.; US Coast Guard. *Report of the Investigation into the Circumstances Surrounding the Explosion, Fire, Sinking and Loss of Eleven Crew Memebers Aboard the MODU, Deepwater Horizon;* 2011; p 12.; National Academy of Engineering and National Research Council of the National Academies. *Macondo Well – Deepwater Horizon Blowout: Lessons for Improving Offshore Drilling Safety;* The National Academies Press: Washington, D.C., 2011; pp 3, 19.

[34] BP. *Deepwater Horizon Accident Investigation Report;* September 8, 2010; pp 183-184.; National Commission on the BP Deepwater Horizon Oil Spill and Offshore Drilling. *Chief Counsel's Report: The Gulf Oil Disaster;* Feburary 17, 2011; p 162.; Bureau of Ocean Energy Management, Regulation, and Enforcement. *Report Regarding the Causes of the April 20, 2010, Macondo Well Blowout;* 2011; pp 8, 210.

behaving unrepresentatively." [35, 36] Furthermore, human performance is often only deemed erroneous in the aftermath of a negative outcome. The CSB's investigative work frequently finds a history of *acceptable* performance leading up to an incident that was never considered erroneous or critiqued until catastrophe happened. (See Call-out Box.) Indeed, "There is almost no human action or decision that cannot be made to look flawed or less sensible in the misleading light of hindsight."[37] Overall, the performance failures identified post-incident do not point to worker competency per se, but to a variety of situational, contextual, and organizational variables that influence even a highly competent person's decision-making.

Performance Judged "Good" or "Bad" Depending on the Outcome

Error-free performance is unattainable, largely because the performance decision or action is subjectively judged erroneous or error-free based on the outcome. After an incident, the decisions and actions of those immediately involved in the event are invariably criticized. Personnel have broken rules, not followed procedures, and made "illogical" decisions. However, the CSB has frequently found that decisions and actions labeled as "poor" post-incident were previously accepted, and sometimes even rewarded.

The BP Texas City refinery explosion (2005)[†] is one such example. On the day of the incident, process parameters were exceeded during unit startup. In fact, process parameters were deviated in the 18 previous startups of that unit. Sometimes these startups led to a hydrocarbon release into the unit, but none resulted in explosions and fatalities. These deviations were not assessed, nor were steps taken to prevent future deviations. Up until the day of the incident, the deviations to procedures were considered acceptable to protect the unit equipment and achieve successful unit startup.

[†]US CSB, Refinery Explosion and Fire: BP Texas City, Section 3.1.1, http://www.csb.gov/bp-america-refinery-explosion/.

"As a discipline, human factors is concerned with understanding interactions between people and other elements of complex systems. Human factors applies scientific knowledge and principles as well as lessons learned from previous incidents and operational experience to optimize human wellbeing, overall

[35] As in any CSB incident investigation, unless evidence suggests intentional criminal acts, it is assumed that the crew members were evaluating the information at hand and responding without any malicious intent toward themselves, their coworkers, and the facility/organization.

[36] Dekker, S. *The Field Guide to Understanding Human Error;* Ashgate: 2006; p 18.; James Reason and others make similar statements, e.g., see Reason, J. *Human Error;* Cambridge University Press: 1990.

[37] Department of Transport. *Investigation into the Clapham Junction Railway Accident;* Her Majesty's Stationary Office: London, 1989, p 147.

system performance and reliability. The discipline contributes to the design and evaluation of organisations, tasks, jobs and equipment, environments, products and systems."[38]

Thus, drilling organizations—like any entity conducting high-hazard operations—must incorporate human factors into safety management practices. They must consider human strengths and limitations when designing a task and implement safety management systems to support the work activities of those conducting the hazardous operations.[39] They must explicitly identify the performance expectations of the human-dependent controls, and continually assess those controls to ensure they are sufficient and can be reliably maintained or executed.

This chapter provides specific evidence of the lack of effective integration of human factors into the design, planning, and execution of drilling and completions activities at the Macondo well, and it illustrates a demonstrable gap in US offshore regulation and guidance to incorporate more robust management of human factors. Specifically, this chapter shows:

- The organizational influence on human performance;
- The importance of human factors engineering considerations for safety critical system design and usage;
- The still unresolved risk of gas-in-riser situations that place unrealistic expectations on well operations crews;
- The need for development and use of non-technical skills,[40] including communication, teamwork, and decision-making, by the operator, drilling contractor, and other well services providers;
- The gap between work-as-imagined (WAI) by well designers, managers, or regulatory authorities and work-as-done (WAD) by the well operations crew; and
- The importance of assessment of safety critical tasks and identification of controls that could maximize the likelihood of successful human performance.

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[38] International Association of Oil & Gas Producers. *Human Factors Engineering in Projects, Report No. 454;* August 2011.

[39] Volume 3 offers multiple examples throughout of how multiple safety management system programs, including those for management of change, procedures, and incident investigations, can support successful human performance.

[40] Non-technical skills have been defined as "the cognitive, social and personal resource skills that complement technical skills, and contribute to safe and efficient task performance." [Flin, R.; O'Connor, P.; Crichton, M. *Safety at the Sharp End;* Ashgate Publishing: Hampshire, England, 2008; p 1.] Non-technical skills will be discussed more fully in Section 1.7 of this chapter.

1.1 Macondo Temporary Abandonment Personnel

To set the context of this analysis, Table 1-1 provides a review of the individuals immediately involved in the temporary abandonment activities.

Table 1-1. Well Control Personnel on Board the Deepwater Horizon Rig on April 20, 2010, that are discussed in this volume.*

Position	Employer	No. On Board/ No. on Duty at time of blowout	Detail
Well Site Leader (WSL)	BP	2 / 1	Considered the "Company Man," this person represents the operator/leaseholder; there was also a third WSL on board who was a trainee
Offshore Installation Manager (OIM)	Transocean	1	Manages all aspects of the rig, including well, crane, and marine operations
Senior Toolpusher	Transocean	1	Supervises well operations; conducts a variety of administrative tasks associated with the well operations; assists the OIM
Toolpusher	Transocean	2 / 1	Supervises well operations/rig floor; advises and assists the driller
Driller	Transocean	2 / 1	Operates drilling equipment; using visual observation of rig floor and down hole data, monitors and responds to well conditions
Assistant Driller	Transocean	4 / 2	Assists the driller in operating the drilling equipment and monitoring/responding to well conditions
Mud Engineer	M-I Swaco	2 / 1	Also called a drilling fluids specialist, this person is responsible for ensuring the drilling fluid (mud) meets design specifications necessary for the well operation
Mudlogger	Sperry-Sun	2 /1	Monitors well (down hole) conditions and video feed of flow on rig to assist the driller

There are a number of additional personnel with responsibilities associated with well operations, such as the Subsea Supervisor, Floorhands, Derrickhands, and Cementers. However, these positions do not play a prominent role in the analysis presented within this volume. There are also a number of personnel on shore that provide technical and managerial support, such as the Onshore Drilling Engineer, who is discussed in Section 1.7.2.

Besides these 16 individuals, 110 others representing 13 companies were on board the rig on April 20, 2010, most of whom (79) were Transocean personnel.[41] On official duty at the time of the blowout were 9 of the 16 well operations crewmembers identified in Table 1-1. The drillers operated drilling equipment and monitored the well from the driller's cabin (or shack) on the drill floor. The senior toolpusher supervised the toolpushers and the drillers' activities. The mudlogger was housed in the mudlogger's shack, a separate location one flight of stairs away from the drillers. Both the Offshore Installation Manager (OIM) and Well Site Leader (WSL) oversaw resources and operational performance.

1.2 Macondo Temporary Abandonment Activities: Four Phases

By April 20, 2010, the Macondo crew completed exploratory drilling activities at the well after discovering several potential oil and gas producing zones.[42] This success meant that the Macondo well would likely be converted from an exploratory well to a producing one at some future date, so the Deepwater Horizon (DWH) crew began the process to temporarily abandon the well.[43]

As part of this process, and before leaving the well site, the DWH crew pressure tested the well to ensure there were no leaks and the hydrocarbon bearing zones were sealed. After the crew successfully conducted a positive pressure test of the well,[44] BP's temporary abandonment plan called for a negative test[45] followed by displacement of the drilling mud from the riser with seawater. For the human factors analysis, this chapter divides this process into four phases:

- Presetting of the diverter system route;
- Displacement of the drilling mud from the drillpipe and upper wellbore;
- Monitoring of pressure in the underbalanced well; and
- Displacement of the riser.

Dividing the activities of the crew into these four phases provides an opportunity to explore the contextual framework in which the crew was operating, which changed with each phase. This chapter discusses the implications of this dynamic framework on the human factors that influenced the crew's collective understanding of the real-time conditions of the well.

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[41] Table 1-2 from Volume 1 of the CSB Macondo Investigation Report provides additional details on the personnel on board.

[42] The CSB Macondo Investigation Report, Volume 1 details Macondo exploratory drilling activities.

[43] A production facility would return later to extract the oil and gas from the well.

[44] See Volume 1, Section 2.2.1 for more details about pressure testing a well. During a positive pressure test, a well is pressured up and then held in this condition to see if the pressure is maintained, indicating no leaks in the casing. If a decrease in pressure is observed, regulations require that either the well be re-cemented, the casing repaired, or additional casing installed to ensure the well is sealed.

[45] See Volume 1, Section 2.2.1 for more details about pressure testing a well. A negative pressure text simulates the underbalanced condition of the well upon abandonment by displacing some of the heavy drilling mud from the well and closing the BOP to isolate the bottom of the well from the hydrostatic pressure exerted by fluids above the BOP.

1.2.1 Phase 1: Presetting of the Diverter System Route

The diverter system is one of the pieces of equipment on a drilling rig designed to limit oil and gas from inundating the rig floor during excessive flow[46] from the riser by routing the well fluids to a safer location. Using a control panel, the Deepwater Horizon crew could preset the route to one of two locations (Figure 1-1), either the mud gas separator (MGS, an atmospheric separating vessel), located on the rig, or overboard. The standard preset route was to the MGS; this was the route preset on April 20, 2010.[47] In this configuration, if the crew wanted to change the route before or during an emergency, they needed to complete a multi-step process to divert overboard (additional details in Section 1.3).

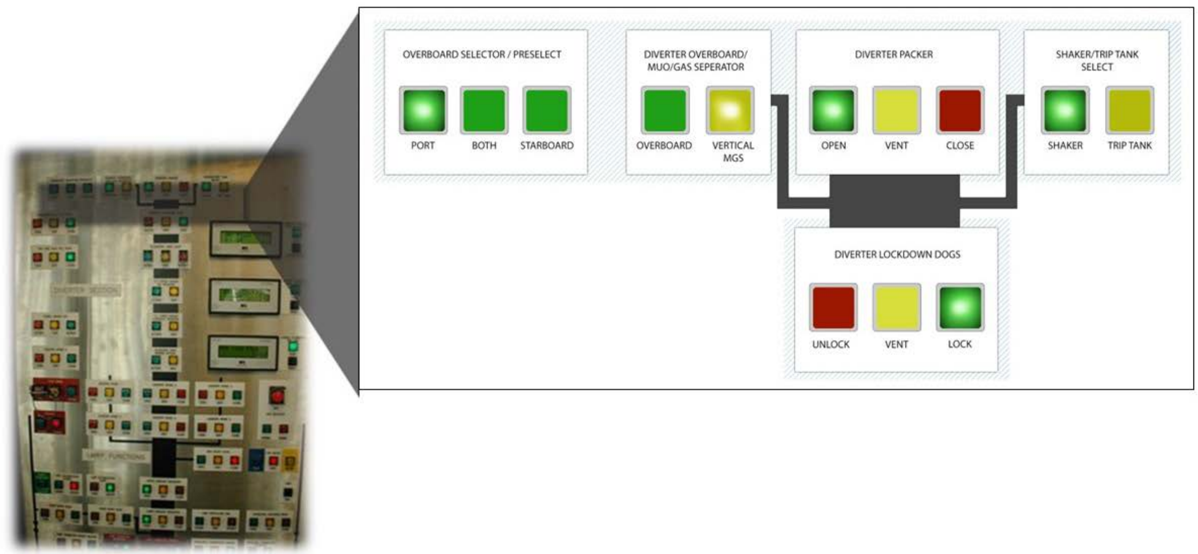

Figure 1-1. Control panel (left) and partial close-up of control panel on the Deepwater Horizon found in the driller's cabin[48] and on the bridge of the rig. These controls were used to preset the diverter.

1.2.2 Phase 2: Displacement of the Drilling Mud from the Drillpipe and Upper Wellbore

During a negative test, the crew purposely underbalances the well to simulate the condition that will exist once the well is abandoned. Generally, the primary barrier used to prevent the flow of hydrocarbons (oil and gas) from the reservoir is a column of heavy fluid that fills the wellbore and the riser and essentially

[46] Excessive flow could be the result of a blowout or, if the BOP is closed, a release of gas from the riser. Initially, the Macondo explosion was the latter because the BOP successfully sealed the well just prior to the explosion occurring with the well blowout evolving after the initial explosion. See CSB Macondo Investigation Report, Volume 2, Section 2.5, p. 30 and Appendix 2-A, p 23.

[47] Internal Company Documents, Transocean. Interview Final Memo, June 2, 3, 4, and 11, 2010, Interviews with Drillers, Assistant Drillers, OIM, TRN-INV-00000180, TRN-INV-00000698, TRN-INV-00002791, and TRN-INV-00003448, TRN-I NV-00004242. The driller's cabin, on the drill floor, contains the primary control panel. Hearing before the Deepwater Horizon Joint Investigation, May 26, 2010, p 19

[48] The driller's cabin, on the drill floor, contains the primary control panel. Hearing before the Deepwater Horizon Joint Investigation, May 26, 2010, p 19.

"pushes" back on the hydrocarbons. When a well is abandoned, some of the fluid column is replaced with lighter sea water, and the well may become underbalanced, meaning the weight of the fluid column may not be sufficient to keep hydrocarbons from entering the wellbore. If the hydrocarbon bearing zones in the well are sealed by additional barriers (e.g., cement), the well will not flow despite being underbalanced. By simulating the underbalanced condition and observing the pressure in the well, the crew is able to test the integrity of the well in a controlled manner before removing the fluid column barrier.

At Macondo, between 3:00 p.m. and 5:00 p.m., the crew displaced drilling mud from the drillpipe and upper wellbore by pumping a dense spacer[49] material (Figure 1-2, left) followed by seawater to push the drilling mud out of the drillpipe and the upper wellbore.[50] The intent was to move this mud and all of the spacer material until they were both above the BOP (Figure 1-2, right). Then they closed the BOP to isolate the well from the hydrostatic pressure[51] generated by the liquids above the BOP. Had the crew suspected any problems with the well at the end of this activity, they had the option to open the blowout preventer to reestablish the drilling mud barrier in the well.

[49] As defined by Schulmberger Oilfield Glossary (http://www.glossary.oilfield.slb.com/Terms/s/spacer_fluid.aspx), "Any liquid used to physically separate one special-purpose liquid from another. Special-purpose liquids are typically prone to contamination, so a spacer fluid compatible with each is used between the two…Spacers are used primarily when changing mud types and to separate mud from cement during cementing operations." Ultimately, cement could be negatively affected if it is contaminated by the synthetic based oil drilling mud.

[50] There was also a small amount of freshwater used during displacement that is not depicted in Figure 1-2. See footnote 36 in Appendix 2-A of the Macondo Investigation Report Volume 2 for more detail.

[51] Hydrostatic pressure is exerted by liquid at a given point as a result of the weight of the column of fluid above it. See Volume 1, Section 2.1 for more description.

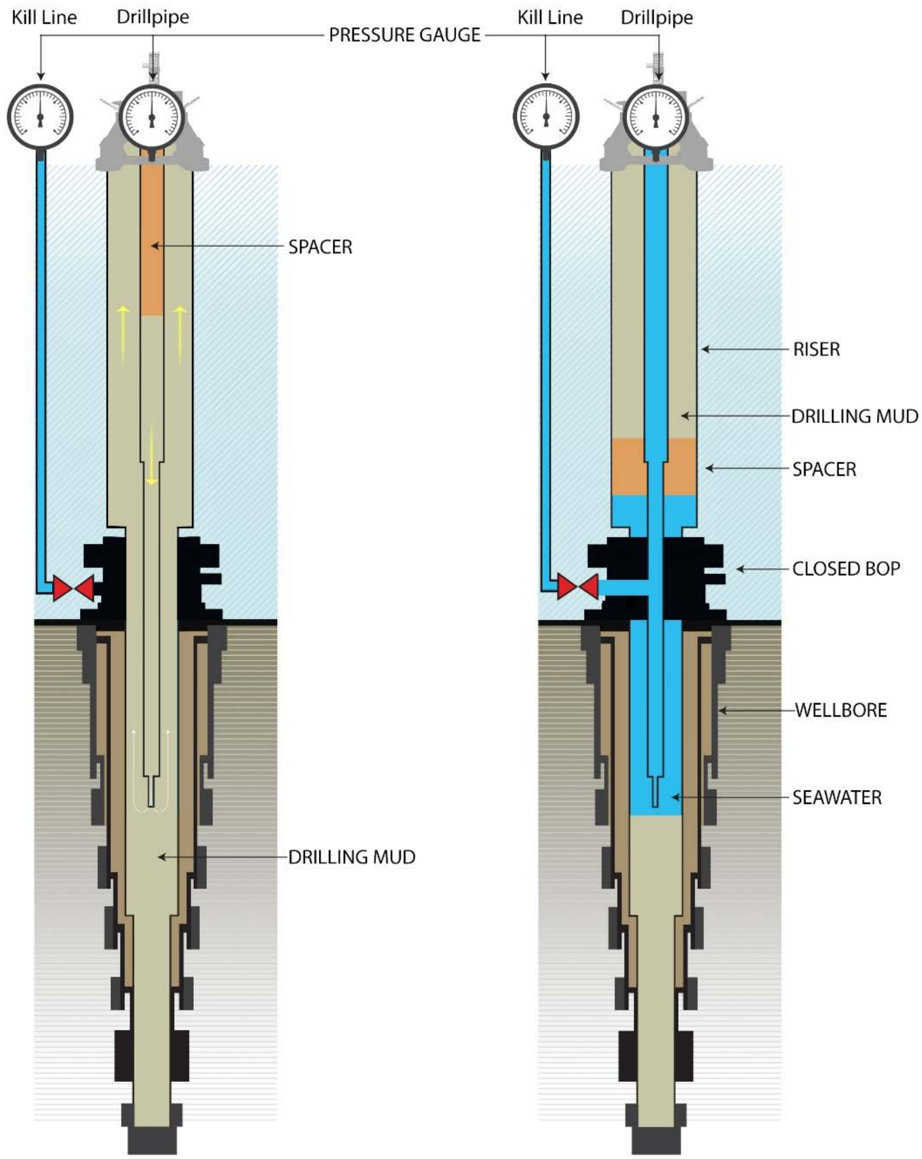

Figure 1-2. On the left, the well as spacer material is pumped into the well, beginning to push drilling mud out of the riser. On the right, the intended well configuration for the negative test.

After closing the BOP, the crew released a predictable amount of trapped pressure in the well by bleeding fluid (seawater) from the drillpipe.[52]

[52] The trapped pressure is commonly illustrated using a u-tube model. See more details in Section 1.4 and Appendix 2-A from Volume 2 of the CSB Macondo Investigation Report.

1.2.3 Phase 3: Monitoring Pressure in the Underbalanced Well

The crew declares a negative test successful, assuming the hydrocarbon bearing zone at the bottom of the well has been sealed, after crewmembers observe no flow or pressure increase from the underbalanced well upon releasing the initial trapped pressure. Various methods are possible to accomplish the negative test; indeed, at least six negative test procedures were used on the DWH between August 2007 and April 2010.[53] They generally fell into two main categories:

1. displacing the drillpipe with the pipe end no deeper than 500 feet below the sea floor (at Macondo the bottom of the drillpipe was approximately 3,000 feet below the seafloor);[54] and
2. displacing a choke/kill line, a pipe that runs from the BOP to the rig, with the blind shear rams of the BOP closed.

Initial BP temporary abandonment plans for the Macondo well proposed displacing the kill line (Figure 1-3, left).[55] Under this configuration, only the kill line could be used to conduct a negative test, but BP determined this approach did not create enough underbalance pressure to simulate the abandonment condition of the well.[56] Instead, BP determined that drillpipe needed to be lowered into the well to displace the upper wellbore with seawater to create the necessary underbalance conditions. Ultimately, the negative test procedure employed at Macondo actually displaced both the drillpipe and the kill line, enabling the crew to observe pressure from the underbalanced well from either the kill line or the drillpipe (Figure 1-3, right).

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[53] Internal Company Document, Transocean. *Memorandum: Investigation of the Negative Test and Riser Displacement Procedures (Preliminary Report)*, July 26, 2010, TRN-INV-00847616, see Exhibit 5007 http://www.mdl2179trialdocs.com/releases/release201302281700004/Roller_Perrin-Depo_Bundle.zip (accessed October 7, 2015).

[54] Internal Company Document, BP. *Form MMS - 124 Application for Permit to Modify*, April 16, 2010, Temporary Abandonment Procedure, BP-HZN-MBI00127909, http://www.mdl2179trialdocs.com/releases/release201304041200022/TREX-00570.pdf (accessed October 7, 2015).

[55] See Appendix 2-A, p 61, of CSB Macondo Investigation Report, Volume 2 for more details.

[56] BP intended to set a surface cement plug at 3,300 feet below the seafloor which increased the necessary negative test requirement. Displacing the kill line created only 1,844 psi pressure differential while displacing the upper wellbore would simulate an underbalance pressure of 2,371 psi, see Appendix 2-A, Section G, pp 61-62.

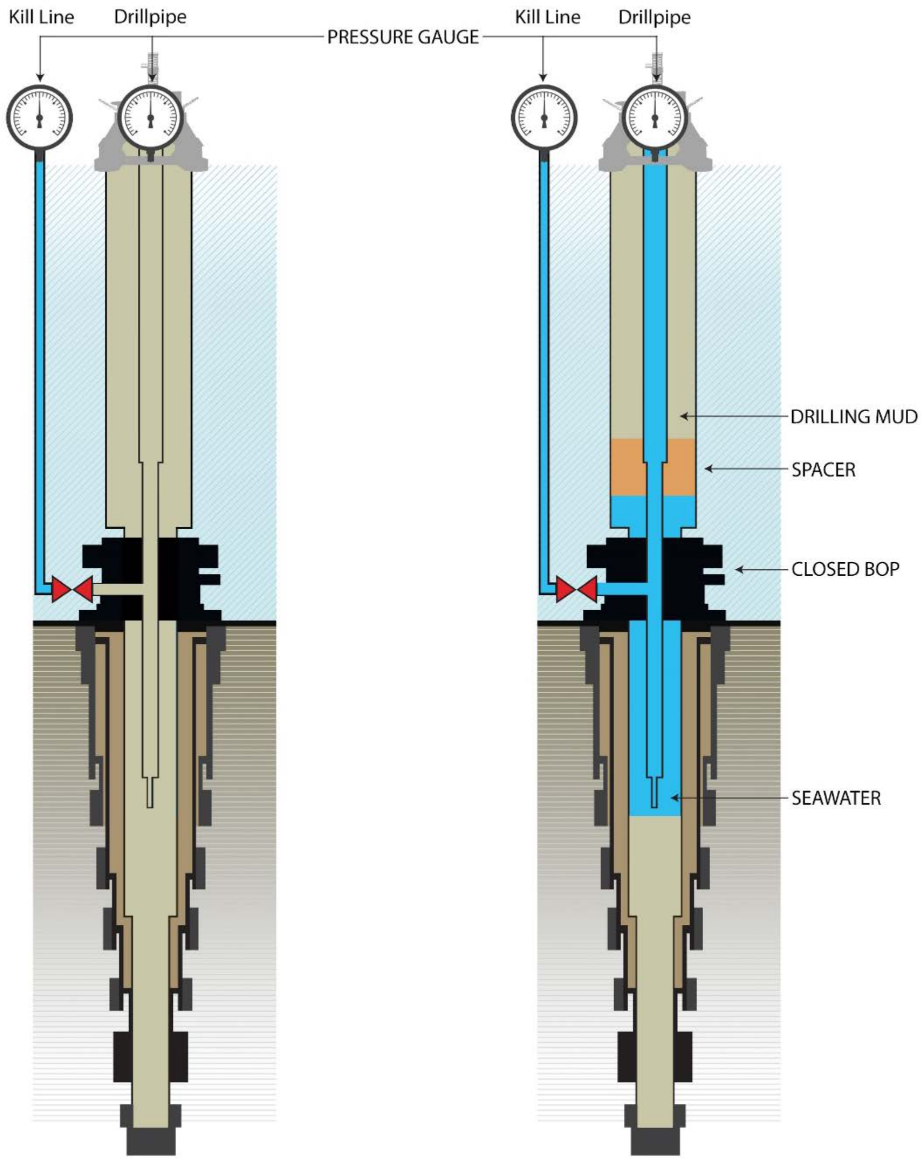

Figure 1-3. Initial negative test configuration for the Macondo well called for only displacing the kill line (left), but the final configuration had both the kill line and the drill pipe displaced with sea water.

However, the actual conditions of the well after displacement did not match the plans and expectations of the crew. The spacer material used during the displacement of the drillpipe and upper wellbore was not fully pushed above the BOP, reducing the pressure that would appear on the kill line. Also, some spacer was positioned across the kill line in the BOP, likely enabling the dense material to enter and plug the line (Figure 1-4). Section 1.4 explores the reasons for the under-displacement.

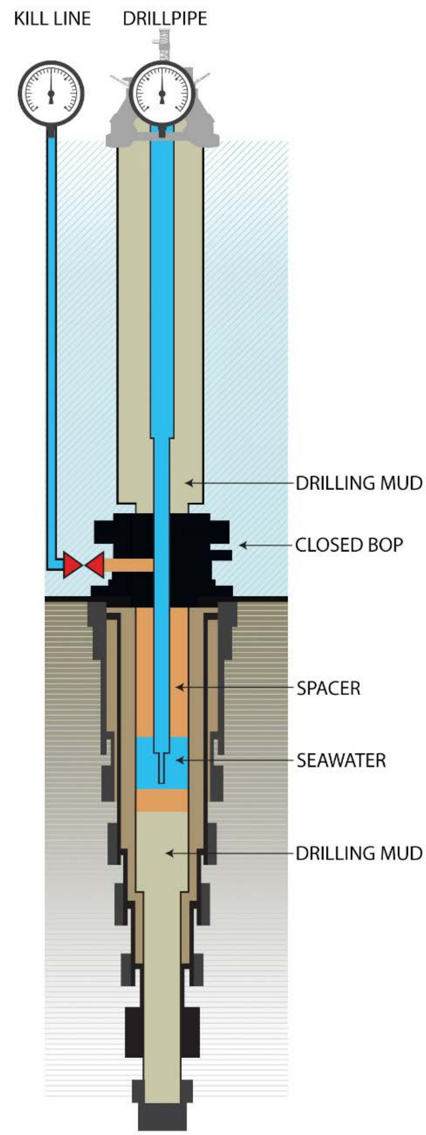

Figure 1-4. Actual well conditions, with spacer positioned across the BOP, which likely lead to plugging of the kill line.

During the 3 hours between when the crew first closed the BOP to begin the negative test and they deemed the test successful, indicating the well was sealed, they observed pressures or flow from the drillpipe and the kill line four times. Pressure on the drillpipe rose after each of the four observations,[57]

[57] CSB Macondo Investigation Report, Volume 2, Appendix 2-A; National Commission on the BP Deepwater Horizon Oil Spill and Offshore Drilling. *Chief Counsel's Report: The Gulf Oil Disaster;* Feburary 17, 2011; pp 147-159.

but flow from the kill line eventually ceased. The zero flow from the kill line and zero pressure continued for 30 minutes, so the crew considered this as evidence that the well was sealed.

1.2.4 Phase 4: Displacement of the Riser

Acceptance of the negative test as successful indicated the Deepwater Horizon crew believed the well had been sealed. The crew proceeded to open the BOP and displace the remaining drilling mud from the Macondo well in preparation of setting a surface cement plug.[58] With the drilling mud removed (Figure 1-5), the open blowout preventer was the only physical barrier against flow into the well (a kick). The ability of the blowout preventer to act as this barrier was contingent upon human detection of the kick and timely activation of the BOP.

During the process of displacing the riser, a mixture of seawater, drilling mud, and hydrocarbons erupted onto the drilling rig, which the crew immediately tried to divert to the mud gas separator (MGS). Within a minute after diverting, mud overwhelmed the MGS and erupted out of it and multiple other locations. From the time well fluids released onto the deck until the first explosion, the crew had 9 minutes to understand what was happening, determine the best well control responses, and implement them.[59]

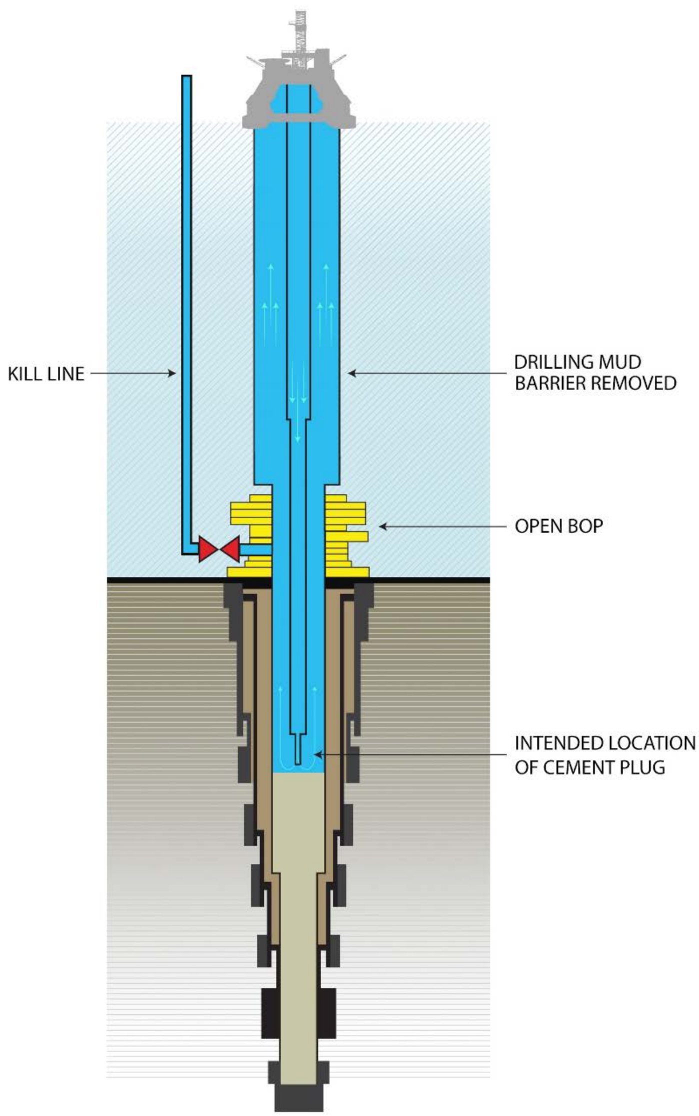

Figure 1-5. During the final displacement of the well, the remaining drill mud above the drillpipe is replaced with seawater.

[58] Cement plugs are portions of cement put into a wellbore to seal it. “Surface” is typically used to refer to the shallowest cement plug used in a well. See Volume 1, Section 2.0 for more details.

[59] CSB Macondo Investigation Report, Volume 2, pp 29-30 describes the sequence of well control actions completed by the crew.

1.2.5 Human Performance at Macondo

Within the four phases of temporary abandonment crew activity, this chapter analyzes a number of human performance actions (Table 1-2) to give context for the actions and decisions in the hours leading up to the incident and to explore potential mitigating approaches or controls.

Table 1-2. Identified human performance actions/decisions during the four phases of temporary abandonment leading up to the blowout.

PHASE OF CREW ACTIVITY	HUMAN PERFORMANCE ACTIONS AND DECISIONS OF INTEREST POST-INCIDENT
Phase 1: Preset of the Diverter System Route	The diverter system route was preset to flow out of the well to the Mud Gas Separator (MGS). Once well fluids erupted from the well onto the deck, the crew did not successfully complete the multi-step process necessary to reroute the well fluids overboard (Section 1.3).
Phase 2: Displacement of the Drilling Mud from the Drillpipe and Upper Wellbore	The crew did not achieve the intended well conditions during the displacement of the drillpipe and wellbore; some spacer material remained below the closed BOP. The under-displacement likely led to plugging of the kill line, impacting pressure readings used by the crew to assess well integrity (Section 1.4).
Phase 3: Monitoring Pressure in the Underbalanced Well	The crew incorrectly rationalized pressure and flow indicators observed from the kill line and the drillpipe during the negative test. Thus, they considered the well sealed (Section 1.5).
Phase 4: Displacement of the Riser	During completion of the displacement process, the well experienced an influx of reservoir fluid. For almost an hour, the crew did not detect hydrocarbons flowing into the well and eventually up the riser toward the rig (Section 1.6).

Doing What Made Sense at the Time

Some investigation reports described "significant" and "obvious" anomalies in the real-time data available to the crew during the hours leading up to the blowout with assertions or implications that the crew should have recognized and acted upon these anomalies.[†] *But how obvious were these indicators? Any declarations of what the control system data indicated about the Macondo well were constructed from extensive post-incident modeling of the well flow conditions and with hindsight as to the consequences of each decision or action taken by the crew. In the moment, no one person would have had the benefit of such comprehensive knowledge. These individuals were doing what made sense to them at the time. Each individual's understanding of the well conditions was shaped by a complex interplay between the various communication tools used to share information about the well (verbal communications, control board systems, procedures) and the individual's knowledge, experience, judgment, and biases.*

[†] BP. *Deepwater Horizon Accident Investigation Report;* September 8, 2010; pp 42; National Commission on the BP Deepwater Horizon Oil Spill and Offshore Drilling. *Deep Water: The Gulf Oil Disaster and the Future of Offshore Drilling;* 2011; pp 115, 177-179.

1.3 Phase 1 – Organizational Influence on Human Performance

During drilling and completion activities at a well, gas and oil can pass above a BOP before it is closed. This creates a gas-in-riser event that can progress to a "riser gas blowout," identified as such to indicate that the wellbore is sealed and the only source of gas is in the riser. This is a hazardous situation because riser gas migration toward the rig may be nearly undetectable and can rapidly change from a seemingly stable condition to an extremely high flow rate, releasing large amounts of gas on the drilling rig that can ignite and explode.[60]

For Macondo, the April 20, 2010, incident progressed from a gas-in-riser event ultimately to an uncontrolled blowout after the crew's well control actions and the physical well barriers (e.g., the BOP and diverter system) were unable to mitigate the hazardous conditions created once hydrocarbons entered the riser. The BOP as a barrier is analyzed in Volume 2. The diverter system, analyzed here, was activated by the crew as well fluids released out of the riser onto the rig. The system was preset to route well fluids to the mud gas separator, rather than overboard; it was quickly overwhelmed and hydrocarbons blew onto the rig floor. Post-Macondo, Transocean now requires well operations crews to preset the diverter system

[60] For example, see the MMS Zapata Lexington report, U.S. Department of the Interior/Minerals Management Service. Investigation of September 1984 Blowout and Fire Lease OCS-G 5893, Green Canyon Block 69 Gulf of Mexico, Off the Louisiana Coast; OCS Report 86-0101; Minerals Management Service: 1986; http://www.bsee.gov/Inspection-and-Enforcement/Accidents-and-Incidents/Panel-Investigation-Reports/86-0101-pdf/ (accessed October 7, 2015).

route overboard,[61] thus removing aspects of manual human intervention with an engineering control. However, the organizational decision to preset the diverter route to overboard increases the likelihood of discharges into the sea that might otherwise have been controlled through use of the MGS. Therein lies a risk to drift back to the original practice as, over time, the rig operator receives environmental penalties for discharges that, with hindsight, are determined to have been preventable. Furthermore, the decision to eliminate the manual intervention requirement does not fully resolve an underlying hazard for a diverter system to fail under high load even if it has been reset to direct well fluids overboard. Ultimately, as this section shows, there is a danger of inappropriately placing blame on human performance for a technical problem the offshore industry does not fully understand.

Through an examination of the diverter system design and the evolution of its purpose and use offshore, this section demonstrates that unrealistic expectations were placed on the crew to send well fluids overboard once they entered the riser. Furthermore, a review of the actions of the Deepwater Horizon crew illustrates the strong influence that organizational policies, historic operational practices, and technical design have on human performance, including:

- The economic and regulatory consequences for diversion of well fluids overboard;
- The operational decision to preset the diverter system route to send flow from the well to the MGS, which was standard practice for Transocean and occurred far before the temporary abandonment activities commenced;
- The design of the diverter system and the multi-step process to redirect well fluids overboard;
- The reliance by all involved parties on the subjective judgment of the well operations crew to determine whether the well flow would be too great for the MGS to handle; and
- The time available to the crew to respond in a chaotic and stressful situation.

1.3.1 Diverter Dual Role: Operational and Emergency Mitigation Device

During drilling and completion operations, drilling fluids returning from the well are routed to a variety of equipment so that they may be processed and recycled for future drilling. As part of that process, the diverter system can direct well fluids containing flammable gas to the MGS where the gas is segregated from the drilling mud and vented away from the drill floor (Figure 1-6).[62] This might occur, for instance, in response to a well kick that the BOP has contained. The influx is then circulated though the MGS, a standard practice acknowledged in both BP and Transocean well control manuals.[63] Less frequently, the

[61] Internal Company Document, Transocean. *Well Control Handbook*, Issue HQS-OPS-HB-01, Revision 00, July 22, 2011, Handling Gas in the Riser, Exhibit 5781, http://www.mdl2179trialdocs.com/releases/release201302281700004/Braniff_Barry-Depo_Bundle.zip (accessed October 7, 2015).

[62] Internal Company Document, Transocean. *Well Control Handbook*, Revision 01, HQS-OPS-HB-01, March 31, 2009, Well Control Equipment, BP-HZN-2179MDL0033106, http://www.mdl2179trialdocs.com/releases/release201303071500008/TREX-00596.pdf (accessed October 7, 2015).

[63] *Ibid*., BP-HZN-2179MDL00330980.; Internal Company Document, BP. *Well Control Manual: Volume 2 Fundamentals of Well Control*, Issue 3, BPA-D-002, 2000, Mud Gas Separator, pp 6-4-3, BP-HZN-2179MDL00336730. See Exhibit 2390 http://www.mdl2179trialdocs.com/releases/release201302281700004/Frazelle_Andrew-Depo_Bundle.zip (accessed October 7, 2015).

diverter system is also used as an emergency mitigation system meant to limit the amount of oil and gas inundating the rig floor from a riser gas event by directing the well flow overboard, thus minimizing the chance that flammable gases could find an ignition source on the rig.[64]

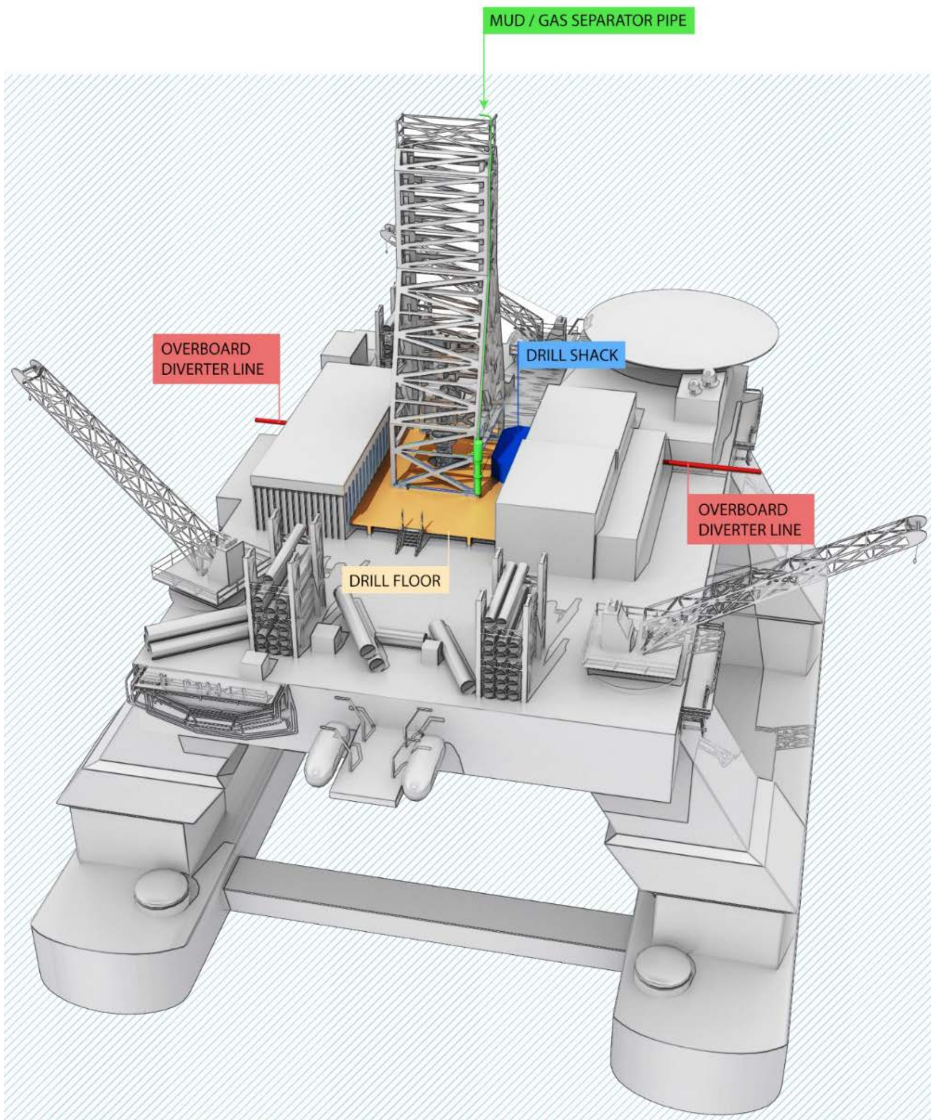

Figure 1-6. The diverter system on a rig can be routed to direct well fluids containing flammable gas to the mud gas separator (green) so that gas can be vented away from rig floor or drilling fluids can be directed routed overboard (red).

[64] Internal Company Document, BP. *Well Control Manual: Volume 2 Fundamentals of Well Control*, Issue 3, BPA-D-002, December 2000, Blowout Preventer Equipment, BP-HZN-2179MDL00336706, see Exhibit 2390 http://www.mdl2179trialdocs.com/releases/release201302281700004/Frazelle_Andrew-Depo_Bundle.zip.; Internal Company Document, Transocean. *Well Control Handbook*, Revision 01, HQS-OPS-HB-01, March 31, 2009, Equipment for Handling Gas in the Riser, BP- BP-HZN-2179MDL00330974, http://www.mdl2179trialdocs.com/releases/release201303071500008/TREX-00596.pdf (accessed October 7, 2015).

1.3.2 Organizational Policy and Practice Influence Human Performance

Transocean's Well Control Handbook (2009) at the time of the incident did not identify criteria for determining the diverter route during various well operations, and the handbook remained neutral on the preferred route.[65] Historically, Deepwater Horizon rig personnel reported that use of the diverter system to send well fluids overboard was rarely, if ever, needed because the MGS successfully handled previous well control situations,[66] and that the mud gas separator route was the standard arrangement on the Deepwater Horizon.[67]

Diverting overboard has a number of consequences. For one, drilling mud is expensive and on-site mud supplies may be limited, so use of the MGS allows salvaging the mud.[68] Also, discharging oil-based drilling mud overboard is legally restricted by both the EPA and BOEM, so sending material into the ocean can result in a citation for violating environmental regulations.[69] This well-known consequence was one that crewmembers knew to avoid where possible.[70] Such knowledge applies pressure on the well operations crew to default toward avoiding the higher probability environmental risk rather than the low probability, but high consequences of overwhelming the MGS.

MGSs are designed to handle the circulated fluids and gas contained by a BOP in response to a well kick, and the diverter is intended to redirect manageable influxes of well fluids, not a blowout. Alignment of a diverter is a matter of (a) rig configuration, which is inherent to the rig selected by the oil company operator for a particular campaign, and (b) a well's risk assessment, which the oil company operator

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[65] Transocean Well Control Handbook: "If the riser is flowing, divert the flow overboard. If so equipped, the flow can be diverted through a gas handling system or MGS," and "if the flow rate increases, be prepared to open up the diverter line to send the mud overboard." Internal Company Document, Transocean. *Well Control Handbook*, Revision 01, HQS-OPS-HB-01, March 31, 2009, BP-HZN-2179MDL00330975 and BP-HZN-2179MDL00330976, http://www.mdl2179trialdocs.com/releases/release201303071500008/TREX-00596.pdf (accessed October 7, 2015).

[66] CSB interview; National Commission on the BP Deepwater Horizon Oil Spill and Offshore Drilling interview.

[67] Internal Company Documents, Transocean. *Interview Final Memo*, June 2, 3,4, and 11, 2010, Interviews with Drillers, Assistant Drillers, OIM, TRN-INV-00000180, TRN-INV-00000698, TRN-INV-00002791, and TRN-INV-00003448, TRN-I NV-00004242.

[68] Internal Company Document, BP. *Well Control Manual: Volume 2 Fundamentals of Well Control*, Issue 3, BPA-D-002, December 2000, Mud Gas Separator, see Exhibit 2390, BP-HZN-2179MDL00336730, http://www.mdl2179trialdocs.com/releases/release201302281700004/Frazelle_Andrew-Depo_Bundle.zip.

[69] 30 C.F.R. 250.300 Pollution Prevention; 30 C.F.R. 122 EPA Administered Permit Programs: The National Pollutant Discharge Elimination System; see also Memorandum of Understanding Between the Environmental Protection Agency and the Department of the Interior Concerning the Coordination of NPDES Permit Issuance with the Outer Continental Shelf Oil and Gas Lease Program http://www.bsee.gov/uploadedFiles/BSEE/Newsroom/Publications_Library/001_1984-MOU.pdf (accessed Feburary 26, 2016).

[70] Internal Company Document, Transocean. *Interviewing Form: OIM*, October 13, 2010, TRN-INV-00001864, see Exhibit 3801 http://www.mdl2179trialdocs.com/releases/release201304041200022/Harrell_Jimmy-Depo_Bundle.zip (accessed October 7, 2015). National Commission on the BP Deepwater Horizon Oil Spill and Offshore Drilling interview.

develops to address a geotechnical risk assessment.[71] Well control procedures should address predicted exit flow rates from kick scenarios in the well's risk assessment to avoid overwhelming the MGS. Transocean's 2009 well control handbook indicates it is "essential to verify that the [mud gas separator] system is capable of handling the maximum amount of fluid and gas that could be produced by the well in the case of a severe kick. The relevant information of the well to be drilled should be obtained from the Operator and should be compared to the system capacity according to the Company [Transocean]."[72]

MGSs are not usually designed for the fluid and gas that occur from a riser gas event or blowout, largely because those rates can be impractically large. In reality, limited information is available to the crew to discern when a situation exceeds the MGS capabilities or how quickly the situation may progress. (See Section 1.3.4 for more detail.) The Transocean well control handbook in effect at the time of the Macondo blowout implied that the crewmembers should observe the riser flow and that they would have sufficient time to react to a potentially hazardous situation: "if the riser is flowing [as the result of a kick], divert the flow overboard. If so equipped, the flow can be diverted through a gas handling system or MGS … If the flow rate increases, be prepared to open up the diverter line to send the mud overboard."[73]

The dual purpose of the diverter system and internal Transocean diverter/MGS policy created a significant human factors dilemma for the Deepwater Horizon crew. They were placed into a position of deciding if a gas-in-riser event was controllable, if the MGS could safely separate flammable gas from the well fluids, if the situation exceeded the capabilities of the system, and if they needed to divert mud overboard.

Training strongly influences responses in emergency situations. The Transocean Well Control Handbook required each crew to conduct a diverter drill at the beginning of every tour to "improve the crew's reaction time and prove the operation of all diverter system equipment."[74] However, a senior Transocean toolpusher from the Deepwater Horizon stated he was unaware of any drills to simulate gas in the riser and the required decision-making response, including changing the diverter flow path.[75] As previously stated, testimony from DWH personnel suggests that training and typical practice emphasized well fluid diversion through the MGS. An Assistant Driller with Transocean for 6 years and with over 23 years offshore experience reported that he was taught to always divert to the MGS if mud came out of the riser before diverting overboard and to do this only if the MGS became overwhelmed.[76]

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[71] The Australian offshore regulator provides useful guidance on well risk assessments http://www.nopsema.gov.au/assets/Guidance-notes/GN1602-Well-operations-management-plan-content-and-level-of-detail-Rev-0-December-2015.pdf (accessed Feburary 26, 2016).

[72] Internal Company Document, Transocean. *Well Control Handbook*, Revision 01, HQS-OPS-HB-01, March 31, 2009, Well Control Equipment, BP-HZN-2179MDL00331068, http://www.mdl2179trialdocs.com/releases/release201303071500008/TREX-00596.pdf (accessed October 7, 2015).

[73] *Ibid*., Specific Environments, BP-HZN-2179MDL00330976.

[74] *Ibid*., Preparation and Prevention, BP-HZN-2179MDL00330825.

[75] Hearing before the U.S. District Court for the Eastern District of Louisiana under the Multi-District Litigation docket MDL No. 2179, March 5, 2013 pp 1894-95, http://www.mdl2179trialdocs.com/releases/release201303051200006/2013-03-05_BP_Trial_Day_6_PM-Final.pdf (accessed October 7, 2015).

[76] National Commission on the BP Deepwater Horizon Oil Spill and Offshore Drilling interview.

Yet gas-in-riser is a hazardous situation because riser gas migration toward the rig may be nearly undetectable in the early stages and can rapidly change from a seemingly stable condition to an extremely high flow rate, resulting in a release of large amounts of gas on the drilling rig that can ignite and explode.[77] BP's well control manual cautions:

> "Free gas in the riser represents one of the most dangerous situations on a rig from a standpoint of personnel safety… [A] small influx of free gas can expand as it approaches the surface to produce very significant gas volumes at surface. History has shown that this gas could unload violently as it approaches the surface…It is not out of the realm of possibilities that this slow migration of gas in the riser could go unnoticed as the other activities are taking place, and the gas will begin to unload before anyone notices it. These conditions are the most dangerous."[78]

The Macondo blowout demonstrates that such a situation can quickly evolve into a dire emergency because, while gas flowed into the well for almost an hour without detection, only minutes passed between when it entered the riser and drilling mud shot across and above the drill floor.[79] Add to that crisis the crew's scant experience in sending well fluids overboard due to the rarity of riser gas events,[80] as well as the trained habit and actual practice to initially send fluids and gas to the MGS.

[77] For example, see the MMS Zapata Lexington report, U.S. Department of the Interior/Minerals Management Service. Investigation of September 1984 Blowout and Fire Lease OCS-G 5893, Green Canyon Block 69 Gulf of Mexico, Off the Louisiana Coast; OCS Report 86-0101; Minerals Management Service: 1986; http://www.bsee.gov/Inspection-and-Enforcement/Accidents-and-Incidents/Panel-Investigation-Reports/86-0101-pdf/ (accessed October 7, 2015).

[78] Internal Company Document, BP. *Well Control Manual: Volume 2 Fundamentals of Well Control*, Issue 3, BPA-D-002, December 2000, Blowout Preventer Equipment, BP-HZN-2179MDL00336706, see Exhibit 2390 http://www.mdl2179trialdocs.com/releases/release201302281700004/Frazelle_Andrew-Depo_Bundle.zip.

[79] CSB Macondo Investigation Report, Volume 2, pp 29-30.

[80] CSB Interview: National Commission on the BP Deepwater Horizon Oil Spill and Offshore Drilling interviews.

Diverter Safety System Adapted for Operational Purposes – An Example of Organizational Drift

Use of the diverter as an operational tool for routing drilling fluids to the MGS was a secondary development to its original design purpose of diverting well fluids and gas overboard during shallow gas blowouts.

A recommendation in the early 1980s was to develop a dedicated additional device, now commonly called a "riser gas handler," for installation below the telescopic joint at the top end of the riser. This location was chosen to avoid subjecting surface equipment (e.g., slip joint seals, diverter seals) to pressures that would exceed their design capabilities.[a, b] *This device was not intended to divert a well blowout fueled by a formation in the well, but to safely handle gas that had gotten into the riser above a closed BOP. In this manner, the riser gas handler allows for the circulation of a gas-in-riser event to a mud pit on the rig rather than diverting the riser fluids overboard. However, the riser gas handler has had only limited acceptance, and has been installed on few rigs.*

Years later came the recognition that a system capable of circulating the well fluid/mud through the MGS to remove small amounts of gas would allow for salvaging of the expensive drilling mud and would reduce environmental releases. The diverter system was then adapted to achieve this purpose. A line was installed upstream from the diverter line outlet valve, permitting mud from the riser to circulate through the MGS to remove residual gas. The diverter system aboard the Deepwater Horizon matched this design.

Post-incident, the Norwegian Oil Industry Association (OLF) recommended eliminating the use of the diverter as a tool for routing drilling fluids to the MGS.[c] *To eliminate the possibility of overloading the MGS, OLF specifically recommended updating language of its relevant standard [Norsok D-001] to clarify that the diverter system's function is safety and that it is designed to handle gas in the riser above the BOP by routing all hydrocarbons overboard and, ideally, downwind. As such, OLF recommended that any connection between the diverter system and the MGS should be designed out of the system, except for possibly a connection from the downstream end of the choke manifold to the MGS. Others followed suit, resurrecting the riser gas handler approach.*[b]

[a] Hall, J. E.; Roche, J. R. Diverter for deepwater drilling risers permits kick control; *Oil & Gas Journal* 1985**,** pp 116-119.

[b] E.g., Kozicz, J. R. Development of a marine riser gas managment system; *Society of Petroleum Engineers* 2012**,** January.

[c] Norwegian Oil Industry Association (OLF). *Deepwater Horizon Lessons learned and follow-up;* May, 2012; Reccomentation no. 8, p 16.

1.3.3 Diverter System Design Required Multi-Step Process to Divert Fluids Overboard

With presetting the Deepwater Horizon diverter flow to the MGS, the system design required the crew to take a two-step action to send flow overboard.

The crew could use the diverter system from one of three locations: a Diverter Control Panel on the drill floor,[81] a Driller Control Panel in the driller's cabin,[82] and a duplicate of the Driller Control Panel, called the OIM Control Panel, on the bridge.[83] While the drill floor diverter control panel used toggle switches, the driller, who has primary responsibility for well control operations from the driller's cabin, [84] and the OIM control panels used pushbuttons. As indicated in Figure 1-7, at the top left of the panels were three sets of pushbuttons to select:

- the overboard flow path (starboard, portside, or both);
- the overboard or MGS flow path; and
- an open or closed position of the diverter.[85]

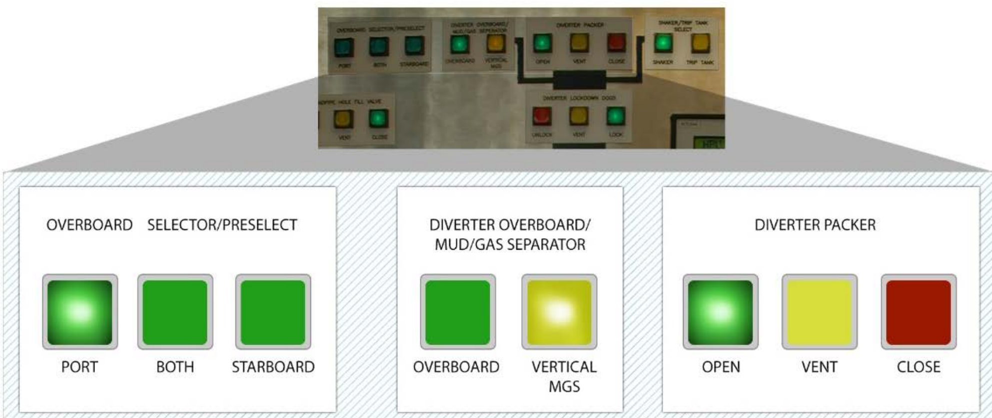

Figure 1-7. Control panel and partial close-up of control panel on the Deepwater Horizon found in the driller's cabin and on the bridge of the rig.

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[81] Cameron Controls, *Assembly, Diverter Control Panel*, Sheet 1 of 6, Drawing No. SK-122358-21-04, Rev D01, March 23, 2000.

[82] The driller's cabin, shack, or doghouse (as it is informally called) was located on the drill floor; this location was where the drillers and assistant drillers monitored and controlled well conditions through control system panels that they could manipulate to operate various drilling equipment, including the BOP and diverter. Information on the Driller Control Panel can be found here: Cameron Controls, *Assembly Drawing, Driller Control Panel*, Sheets 2 and 4 of 11, Drawing No. SK-122106-21-04, Rev F01, January 7, 2000.

[83] Cameron Controls, *Assembly Drawing, Toolpusher Remote Control Panel*, Sheets 2 and 4 of 11, Drawing No. SK-122107-21-04, Rev E01, May 16, 2000.

[84] Hearing before the Deepwater Horizon Joint Investigation, May 26, 2010, p 19.

[85] These buttons were actually hydraulic fluid switches, meaning they physically redirected the flow of hydraulic fluid to manipulate the position of the diverter. Pushing the 'VENT' button for the diverter packer seen in Figure 1-7 removes hydraulic pressure from the diverter packer.

When the diverter was closed, the system always maintained an open pathway, either overboard or to the MGS to not shut in the pressure from the well. This route was chosen by selecting either OVERBOARD or VERTICAL MGS (Figure 1-8).

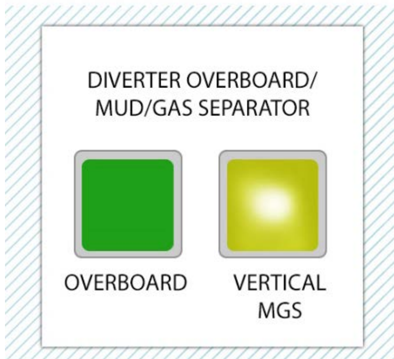

Figure 1-8. Control Panel Pushbuttons to preset route to MGS or overboard.

Regardless of which vent pathway was opened (overboard or vertical MGS), one of the OVERBOARD SELECTOR/PRESELECT pushbuttons would remain lit (Figure 1-9), as it indicated only the pre-selection of the overboard valves that would open if the OVERBOARD button were subsequently selected.

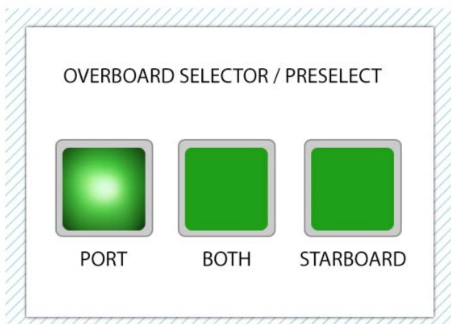

Figure 1-9. Control Panel Pushbuttons to preselect the overboard route.

Thus, pressing the OVERBOARD button would close the diverter and fluids would flow through either the portside, starboard, or both overboard lines as determined by the OVERBOARD SELECTOR/PRESELECT pushbuttons.

This design is not ideal from a human factors perspective, as a crewmember could hit the one button that closes the diverter but miss the second step of changing the diverter route from MGS to overboard. Sound human factors engineering design suggests that opportunities for omission (skipping of steps) be designed out of a system when possible.[86] Adding an automated feature to the diverter control system is one way to achieve this goal. At least one Deepwater Horizon Well Site Leader believed the diverter had an automated function that would divert flow overboard upon detection of increased pressure within the MGS,[87] a design used on other rigs in the Gulf of Mexico.[88] However, post-incident analysis revealed that the Deepwater Horizon diverter did not have such functionality.[89]

Because the individuals who activated the diverter system did not survive the incident, no one can sufficiently explore whether this design hindered performance of the well operations crew on the day of the Macondo blowout. A draft 2002 Transocean Deepwater Horizon procedure for using the diverter when gas is in the riser lists 10 steps in addition to activating the control system buttons to send flow overboard, including stipulations that the crew must fully shut in the well, determine wind direction,[90] and call the Bridge to verify wind direction and clear boats from the discharge location.[91] Whether this procedure was meant to be used on the day of the incident, the speed at which a gas-in-riser event can evolve makes following a 10-step procedure unrealistic.

From a human factors perspective, the question operators and drilling contractors need to ask is: how reliable is the human action to change the diverter location during reasonably anticipated emergency scenarios, such as a riser blowout? The speed at which a gas-in-riser event can evolve implies that crews may simply not have time to assess a situation before it is already out of control. Perhaps even more fundamental, consider Transocean's observation concerning diverting fluids from the Macondo blowout overboard: "it is impossible given the magnitude of the blowout to know if the diverter packer would have kept flow diverted overboard and if the gas ignition could have been prevented."[92] It is impossible to a large degree because no adequate engineering tools/software exist to model the complex gas migration and 2-phase flow of gas and liquids in a riser.[93] And various industry tests have given inconsistent results,

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[86] HSE. *Inspectors Toolkit: Human Factors in the Management of Major Accident Hazards;* October, 2005, p 14. http://www.hse.gov.uk/humanfactors/topics/toolkit.pdf (accessed January 15, 2016).

[87] National Commission on the BP Deepwater Horizon Oil Spill and Offshore Drilling interviews.

[88] CSB Interview; National Commission on the BP Deepwater Horizon Oil Spill and Offshore Drilling interview.

[89] Internal Company Document, Transocean. *Investigations: Mud Gas Separator Control*, Janurary 14, 2011, TRN-INV-03405410.

[90] If the decision was to divert overboard, the operator had to choose which side would be best to divert (based on wind direction), and then redirect the diverted flow away from the MGS and over the side chosen. However, with dynamically positioned (DP) rigs, such as the Deepwater Horizon, the side chosen is less of an issue, as the DP system maintains the rig's position so that it is headed into the wind. Thus, deciding which side to divert would be less of an issue; in fact, the preference would be to choose the both-sides option.

[91] Internal Company Document, Transocean. *Deepwater Horizon Dverter Procedure with Gas in Riser*, TRN-I NV-00697095 attachement to Email from Deepwater Horizon OIM, Transocean, to Deepwater Horizon Toolpusher, Transocean, Subject: Horizon Dovierter Procedure, June 3, 2002, TRN-I NV-00697094.

[92] Transocean. Macondo Well Incident: Transocean Investigation Report Volumes I; June, 2011, p 193.

[93] Sonnenmann, P. IADC workgroup conducting studies to better understand, manage gas-in-riser events. *Drilling It Safely*, July 9, 2015, http://www.drillingcontractor.org/iadc-workgroup-conducting-studies-to-better-understand-manage-gas-in-riser-events-35793 (accessed October 7, 2015).

highlighting the complexity of the phenomenon.[94] Safety or performance concerns of existing riser gas handling designs should be identified, corrected, and reconciled.

Ultimately, it would be unfair to cast blame on the Deepwater Horizon crew for diverting to the mud gas separator when the diverter system might have failed regardless. Post-Macondo, Transocean now requires well operations crews to preset the diverter system route overboard,[95] thus removing aspects of manual human intervention with an engineering control. Considering the design limitation of the diverter system, a solution such as this, meant to remove the 'choice' to divert overboard, may actually lead to a false sense of security when in fact that hazard remains. This problem highlights the need for a hazard analysis that correctly identifies the uncertainty of the gas in the riser scenario.

1.3.4 Needed Improvements in Detecting Gas Influx Prior to Reaching Riser

The decision to send flow overboard assumes the crew detects gas in the riser and recognizes when the gas volume will not exceed the rig's surface handling capability (e.g., diverter system, mud gas separator). Such predictions are a challenge, as evident by Macondo and other incidents discussed below. Generally, it is not possible to predict surface flow rates of a gas-in-riser event, a necessary parameter for determining when to unload overboard.[96] Any gas that enters into the riser can migrate toward the drilling rig, much as a bubble rises in water. The rate of migration depends on many factors and cannot be reliably predicted or even readily detected until the gas nears the surface. A gas bubble may disaggregate into a harmless foam, but it can also become unstable and rapidly erupt onto the rig floor. How severely depends on the size of the original bubble, or the amount of dissolved gas in the oil or oil-based mud. In a severe case, it may overload a closed surface diverter system. This tragically happened at Macondo, where the contents of the 5,000-foot riser (calculated to be initially 20-50% full of gas and oil, or more) erupted onto the rig floor only 2-3 minutes after the BOP was sealed.[97]

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[94] Hauge, E.; Godhavn, J. M.; Molde, D. O.; Cohen, J. H.; Stave, R. S.; Toftevaag, K. R. *Analysis of Field Trial Well Control Results with a Dual Gradient Drilling System,* Offshore Technology Conference 2015, Houston, TX, May 4-7, 2015; OTC-26056-MS.; Tarvin, J. A.; Hamilton, A. P.; Gaynord, P. J.; Lindsay, G. D. *Gas Rses Rapidly Through Drilling Mud*, IADC/SPE Drilling Conference, Dallas, TX, Fedbruary 15-18, 1994; IADC/SPE 27499.; Gonzalez, R.; Shaughnessy, J.; Grindle, W. Industry Leaders Shed Light on Drilling Riser Gas Effects; *Oil & Gas Journal* 2000**,** *July 17,* pp 42 - 46.; Johnson, A.; Rezmer-Cooper, I.; Bailey, T.; McCann, D. *Gas Migration: Fast, Slow, or Stopped*, SPE/IADC Drilling Conference, Amsterdam, February 26, 1995; SPE/IADC 29342.

[95] Internal Company Document, Transocean. *Well Control Handbook*, Issue HQS-OPS-HB-01, Revision 00, July 22, 2011, Handling Gas in the Riser, Exhibit 5781, http://www.mdl2179trialdocs.com/releases/release201302281700004/Braniff_Barry-Depo_Bundle.zip (accessed October 7, 2015).

[96] Sonnenmann, P. IADC workgroup conducting studies to better understand, manage gas-in-riser events. *Drilling It Safely*, July 9, 2015, http://www.drillingcontractor.org/iadc-workgroup-conducting-studies-to-better-understand-manage-gas-in-riser-events-35793 (accessed October 7, 2015).

[97] CSB Macondo Investigation Report, Volume 2, Appendix 2-A, pp 6, 21, 23.

Free Gas in the Riser Recognized by BP as "Most Dangerous" to Rig Personnel in the Gulf of Mexico

"As is intuitively obvious, the possibility of free gas getting into the riser in very deepwater locations is quite high and is probably the one event that is most dangerous to rig floor personnel. This is of particular concern in the Gulf of Mexico due to the preponderance of shallow geopressured formations."[†]

[†]Internal Company Document, BP. *Well Control ManualV of Well Control*, Issue 3, BPA-D-002, December 2000, Blowout Preventer Equipment, BP-HZN-2179MDL00336706, see Exhibit 2390 http://www.mdl2179trialdocs.com/releases/release201302281700004/Frazelle_Andrew-Depo_Bundle.zip/

In a separate riser unloading[98] event that occurred a little over a year before the Macondo incident on a Transocean semi-submersible off the coast of West Africa,[99] issues arose concerning the use of the diverter while gas was in the riser. Similar to Macondo, the crew did not detect the situation until mud and gas began releasing out of the riser onto the rig. However, in this instance, the crew was able to shut in the well and the gas vented and dispersed before it found an ignition source.

In December 2009, the Transocean-owned rig, Sedco 711, also experienced a riser blowout; well ingress went undetected by the crew until hydrocarbons were releasing onto the rig. However, similar to the West Africa incident, the crew was able to close the well and the released flammable material did not ignite.[100] (Chapter 2.0 discusses these incidents in more detail.) Transocean identified riser unloading events as "the biggest concern" when identifying areas for well control improvement.[101] And with wells being drilled in deeper water, the requisite riser length continues to increase, suggesting the increased potential for severe riser unloading if gas flows above the BOP. The well operations crew needs tools to understand well conditions before a riser unloading situation develops. Yet these incidents demonstrate the challenges to detecting hydrocarbon ingress into the well before the gas enters the riser.

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[98] The sudden and uncontrolled release of the riser contents (e.g., drilling mud, gas, etc.) onto the rig caused by expanding gas in the riser.

[99] Hearing before the U.S. District Court for the Eastern District of Louisiana under the Multi-District Litigation docket MDL No. 2179, March 19, 2013 p 4593, http://www.mdl2179trialdocs.com/releases/release201303191200014/2013-03-19_BP_Trial_Day_14_AM-Final.pdf (accessed October 7, 2015).; Internal Company Document, Transocean. *EAU Incident Investigation Report - M.G. Hulme, Jr. Well Control Incident - Riser Unloading*, OER-MGH-09-005, March 26, 2009, TRN-INV-01143039, http://www.mdl2179trialdocs.com/releases/release201303211200016/TREX-05650.pdf (accessed October 7, 2015).

[100] Internal Company Document, Transocean. *Operations Advisory*, NRS-OPS-ADV-008, April 14, 2010, TRN-MDL-02840790, see Exhibit 5749 http://www.mdl2179trialdocs.com/releases/release201304041200022/Hart_Derek-Depo_Bundle.zip (accessed October 7, 2015).

[101] Internal Company Document, Transocean. *Annual Report - 2009 Well Control Events & Statistics 2005 to 2009*, p 7, TRN-INV-00760060, http://www.mdl2179trialdocs.com/releases/release201303211200016/TREX-05649.pdf (accessed May 22, 2015).

Appendix 2-A of Volume 2 discusses the existence of two BOP pressure transducers on the Deepwater Horizon BOP that could have allowed the crew to cross-check the conflicting pressure readings between the drillpipe and the kill line. While it is not known if they were functional or used on the day of the incident, they were used during well control operations the previous month.[102] Neither the BP nor the Transocean well control manual referenced their use in operations and there were no signal processing or alarms associated with the sensor data.[103] If these sensors are incorporated into well monitoring activities, they (or similar other devices) may provide early indication of gas entering the riser.

Macondo and other delayed kick detection incidents support the need for improvements in kick detection capabilities and assessments of the reliability of those capabilities during emergency situations. Indeed, riser unloading events, while not common, are serious near-misses and can result in rig and environmental damage, as well as death.[104] As such, the CSB recommends industry further study riser gas unloading scenarios, testing, and modeling to improve understanding of this behavior and better manage the risk of large riser gas events.

1.4 Phase 2 – Seemingly Insignificant Decisions can have Great Impact in Complex Systems

In the previous section, examples from Macondo demonstrate the impact of organizational policies and practices on human performance. This section explores another characteristic of complex highly-interconnected systems—how minute indiscriminate decisions and behaviors of apparently no consequence when performed individually can coalesce into an unanticipated outcome.[105] Put another way, local decisions can have global impact.[106] At Macondo, introducing spacer material into the well and inadvertently placing it across the kill line of the BOP may have led to plugging of the kill line during the negative test, causing the zero pressure reading that the crew accepted as indication of a secure well.[107] In the moment, local decisions and actions taken by rig personnel and management pertaining to initial displacement may have seemed inconsequential, but they contributed to the positioning of the spacer across the kill line in the BOP:

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[102] Bureau of Ocean Energy Management, Regulation, and Enforcement. Report Regarding the Causes of the April 20, 2010, Macondo Well Blowout: Volume II Appendices; 2011; pp F-57 to F-61.

[103] CSB Macondo Investigation Report, Volume 2, Appendix 2-A, pp 5, 39-40.

[104] See Chapter 2 and U.S. Department of the Interior/Minerals Management Service. Investigation of September 1984 Blowout and Fire Lease OCS-G 5893, Green Canyon Block 69 Gulf of Mexico, Off the Louisiana Coast; OCS Report 86-0101; Minerals Management Service: 1986; http://www.bsee.gov/Inspection-and-Enforcement/Accidents-and-Incidents/Panel-Investigation-Reports/86-0101-pdf/ (accessed October 7, 2015).

[105] This phenomenon is a “routine byproduct of the characteristics of the complex system itself.” Dekker, S. *Drift into Failure: From Hunting Broken Components to Understanding Complex Systems;* Ashgate Publishing: Burlington, VT, 2011; pp 14 & 159.

[106] Dekker, S. Drift into Failure: From Hunting Broken Components to Understanding Complex Systems; Ashgate Publishing: Burlington, VT, 2011; pp 158-172.

[107] *BP Report*, Appendix Q, 3: concluded “Solids from the spacer could have plugged the kill line, or the viscosity or gel strength of the spacer could have been too high to allow pressure to be transmitted through the kill line.”

- Onshore BP personnel chose an unusual spacer type and used a large volume when displacing drilling mud from the riser to avoid hazardous waste management fees and environmental penalties.
- BP did not perform a risk assessment of the atypical spacer before its use; while conduct of risk assessment in itself does not guarantee that the risks will be managed, the act of conducting a risk assessment provides the opportunity for identification and control of those risks.
- The morning of the displacement, one of the BP Well Site Leaders on the rig and an onshore BP Drilling Engineer requested a well fluids specialist, a third-party contractor, to prepare the displacement procedure based upon previous displacements conducted on the rig. No others played a role in developing the procedure, no pressure and volume parameters were identified to gauge successful completion of the procedure, and no effective verification for accuracy of the procedure occurred before it was rolled out to the crew.
- As was customary, a drilling fluids specialist from M-I SWACO assumed the Horizon's pump efficiency was 96.1%, but the actual pump efficiency was closer to 90%, resulting in a smaller-than-planned volume of sea water to be pumped into the well.
- During troubleshooting efforts for the negative test, the Deepwater Horizon crew noticed that the riser was not full; a judgment was made that an annular preventer was leaking and the crew mitigated the perceived problem.

The independent local decisions regarding hazardous waste management, the informal and casual procedural development for the displacement process, and the judgment made concerning the riser fluid level seemed inconsequential to the successful completion of the temporary abandonment process, but with hindsight these decisions clearly had significant ramifications for the temporary abandonment.

BP chose to use Lost Circulation Materials (LCM)[108] as the spacer material between the drilling mud and the sea water to displace the mud from the well.[109] By doing so, BP was able to discharge the 450 barrels of leftover LCM overboard without environmental legal obligations and removed any need to pay for its disposal onshore.[110] The company never tested the LCM material for this application, had no operational reason for using it, and not assess the potential risks of using this spacer. Similar to routing the diverter line to the MGS, management was influenced by the potential risk of regulatory environmental penalties, which dictated the actions of the crew.

On the morning of April 20, 2010, a drilling fluids specialist from M-I SWACO[111] on the Deepwater Horizon received two different calls from a BP Well Site Leader and a BP Drilling Engineer to discuss

[108] Lost Circulation Material (LCM) is a class of drilling fluids designed to plug the fractured walls in the wellbore so that drilling mud is not lost into the formation.

[109] E.g., Volume 1, p 27; Transocean. *Macondo Well Incident: Transocean Investigation Report Volumes I and II;* June, 2011; p 28.; National Commission on the BP Deepwater Horizon Oil Spill and Offshore Drilling. *Chief Counsel's Report: The Gulf Oil Disaster;* Feburary 17, 2011; p 147.

[110] National Commission on the BP Deepwater Horizon Oil Spill and Offshore Drilling. *Chief Counsel's Report: The Gulf Oil Disaster;* Feburary 17, 2011; p 151, The *Chief Counsel's Report* noted that BP would avoid hazardous waste disposal obligations stipulated by the Resource Conversation and Recovery Act.; Hearing before the Deepwater Horizon Joint Investigation, July 19, 2010, pp 67, 79, 90.

[111] As a drilling fluids specialist, he was in charge of the properties of the drilling fluids, maintaining an inventory of what the rig had, and communicating what the rig would need. The drilling fluids specialist would also mix lost

the displacement procedures the crew had been using to conduct its negative tests.[112] The drilling engineer conveyed that they would be displacing the well more than normal, so the fluids specialist wrote a procedure that included the details he had been communicated (Table 1-3). At a 3:00 p.m. pre-job safety meeting (also referred to as a THINK drill),[113] the fluids specialist reviewed the procedure with the crew and reported no one raised any concerns.[114] The fluids specialist possessed only a general knowledge of conducting a negative test, and the procedure he provided to the crew addressed only the types and volumes of fluids that would be used during the displacement process. The procedure did not address the negative test other than to indicate that it would occur.[115]

Table 1-3. Selected steps from the M-I SWACO displacement procedure used at the Macondo well on April 20, 2010.[116]

	Macondo Displacement Procedure Steps (verbatim from M-I SWACO document)	***CSB Interpretation of the Procedure Steps and Explanatory Information***
1	Before displacing to seawater, conduct a THINK DRILL with all.	*Refers to Transocean's THINK planning and risk management process (see Section 1.8.3).*
2	Build 425 bbl WBM spacer in pit #5, and use Duo Vis to thicken up.	*"WBM Spacer" refers to the water-based material that was used to separate drilling mud from seawater during the displacement of the well. Leftover lost circulation material was used as a 16-pound-per-gallon (ppg) dense spacer at Macondo. Duo Vis is a thickening ingredient.*
3	Capacities: • Choke 100 bbls/794 strokes; • Kill 100 bbls/794 strokes; • Boost 73 bbls/579 strokes; • Drill pipe 196 bbls/1555 strokes; • Casing/Riser w/drill pipe annular 1817 bbls/14,420 stks. • Total displaced volume for hole and drill string, 2012 bbls/15,968 strokes	*'Stks' refers to the number of strokes on the pump pushing the material into the well. The displacement procedure assumed one pump stroke gave 0.126 bbls of fluid which is 96.1% volumetric efficiency of the theoretical value. This was the customary assumption for this rig.[117] However, analyses of subsequent real time data shows that the actual efficiency was less,*

circulation material like that used in the spacer material; Hearing before the Deepwater Horizon Joint Investigation, July 19, 2010, pp 39-41,

[112] Hearing before the Deepwater Horizon Joint Investigation, July 19, 2010, p 42.

[113] *Ibid*., pp 43, 55. See also Section 1.8.4 for more details concerning THINK Drills.

[114] Hearing before the Deepwater Horizon Joint Investigation, July 19, 2010 pp 43, 55.

[115] Section 1.8.3 details Transocean's polices concerning procedure development, including that for a negative test.

[116] Internal Company Document, MI SWACO. *BP/Deepater Horizon Rheliant Displacement Procedure "Macondo" OCS-G 32306*, BP-HZN-BLY00094818, see Exhibit 0052 http://www.mdl2179trialdocs.com/releases/release201302281700004/Lacy_Kevin-Depo_Bundle.zip.

[117] Transocean. Macondo Well Incident: Transocean Investigation Report:Volume II; June, 2011; Appendix G, pp 41, 57, 63.

	• Pump Output 0.126 bbls/stk	*about 89-91%.*[118] *As a consequence, less seawater was actually pumped than planned, leaving spacer in and below the BOP.*
4	Displace choke, kill, and boost lines, and close lower valves after each. Zero stroke counter.	
5	Pump 425 bbl WBM spacer from pit # 5 down drill pipe followed by seawater.	
6	Pump 775 bbls or 6150 stks. Spacer should be above the upper annular.	*This step does not indicate if a total of 775 bbls should be pumped or if an additional 775 bbls is intended. It becomes clear during a later step this is intended to be the cumulative total (spacer + seawater).* *This procedure and its 775 bbl. value erroneously do not include 30 bbl. of freshwater of pit wash that was reportedly planned and likely pumped just after the spacer. Analysis of real-time data indicates that the driller actually used 775+30 = 805 bbls for this step.*[119] *This additional 30 bbl. volume is necessary for the calculated volumes to place the spacer above the BOP.*
7	Close annular and conduct negative test. After successful negative test, open bag.	*"Bag" refers to the annular BOP.*
8	When WBM spacer returns at 15,968 stks…Compliance Engineer will take a sample for Static Sheen test…	*Sheen test: A sample of the returning well fluids is added to water and a visual determination is made if it causes a sheen, indicating synthetic oil based mud is still present and the returning fluids from the well cannot be disposed into the sea. An acceptable sheen test indicates that the displacement volumes were adequate, and such was the report to the driller.*[120]

Unknown to the crew, the volumetric efficiency of the rig's pump during the displacement was less than that assumed in the procedure, as noted in step 3. As a result, not enough seawater was pumped to

[118] CSB Macondo Investigation Report, Volume 2, Appendix 2-A, pp 5 & 12.; Transocean. *Macondo Well Incident: Transocean Investigation Report:Volume II;* June, 2011; Appendix G, pp 41, 57, 63.

[119] BP. *Deepwater Horizon Accident Investigation Report;* September 8, 2010; p 83. CSB Macondo Investigation Report, Volume 2, Appendix 2-A, pp 5, 12, 9 (footnote 36) and 14; Transocean. *Macondo Well Incident: Transocean Investigation Report:Volume II;* June, 2011; Appendix G, p 57.

[120] National Commission on the BP Deepwater Horizon Oil Spill and Offshore Drilling. *Chief Counsel's Report: The Gulf Oil Disaster;* Feburary 17, 2011; p 179.

displace all the spacer fluid above the BOP as intended. In hindsight, displacing all of the atypical spacer above the BOP was critical to minimize the possibility of plugging the kill line. Moving forward, a proactive measure may be to incorporate a safety factor on the target strokes to displace the spacer above the BOP.

At the end of the displacement (step 6), the drillpipe had 2,300 psi of trapped fluid pressure (see call-out box on page 53). If all of the spacer had been placed above the BOP as intended, the crew should have observed only ~1,600 psi of trapped pressure.[121] The high pressure reading could have warned the crew of the under-displacement, but the crew would have needed to be predisposed to look for this data and use it to deduce the conditions of the well, yet they weren't given that information and had no *a priori* reason for suspecting a problem.

Further, two pieces of evidence indicate that the well lost integrity during the initial displacement for the negative test. The loss of integrity would have further contributed to the under-displacement of spacer fluid, slowly taking fluid out of the well and reducing the displacement volume.[122] First, just after the crew closed an annular preventer[123] to isolate the well from the hydrostatic pressure of the riser, the real-time Deepwater Horizon data indicates the drillpipe pressure began to drop, implying a loss of well integrity.[124] Second, after closing the annular and initially attempting to bleed trapped pressure, the crew noticed that the riser was not full and assumed that the annular preventer was leaking riser fluid back into the well, causing drillpipe pressure to rise.[125] No witness testimony indicates the crew considered the possibility that well integrity had been compromised, and for at least two reasons the crew would have been predisposed to accept the leaking annular theory:

- The well had successfully passed a positive pressure test earlier in the day; and
- It is "not uncommon" to see an annular leak.[126]

Performing a visual check of the riser once the mud-displacing pumps were stopped, but before the annular preventer was closed for the negative test, could have provided a means to confirm if well integrity was secure or if remedial steps were necessary before proceeding with a negative test. However,

[121] CSB Macondo Investigation Report, Volume 2, Appendix 2-A, p 14.

[122] CSB Macondo Investigation Report, Volume 2, Appendix 2-A, p 10.

[123] Annular preventers are rubber components of a BOP that are designed to seal around virtually any object that passes through them as well as an open hole when no drillpipe is present. See Section 2.1 in Volume 2 for figures and further description.

[124] The leak possibilities were in either the casing or the wiper plug in the lower shoe. The CSB could find no evidence or technical reason why either of these should have leaked, but a leak assumption was necessary to model the real-time data. For the well data simulations found in Appendix 2A of the CSB Volume 2 Macondo report, it was assumed that the leakage occurred at the casing shoe, but leakage at the casing crossover (12,488 ft.) also provided a good data match. CSB Macondo Investigation Report, Volume 2, Appendix 2A, p 14.

[125] Witnesses at the Hearings before the Deepwater Horizon Joint Investigation Team gave contradictory recollections; Hearing before the Deepwater Horizon Joint Investigation, May 28, 2010 pp 115 & 133, "During the negative test they felt like they lost approximately 60 barrels of mud through the annular." A Transocean Subsea Supervisor also recalled that a BP well site leader spoke to a Transocean driller on shift who observed, "We didn't lose no mud through the annular. He say it U-tubed. Where it U-tubed to, I don't know;" Hearing before the Deepwater Horizon Joint Investigation, August 25, 2010 pp 271-272. August 25, 2010, pp 271-272.

[126] As a Transocean Senior Toolpusher and BP Wellsite Leader later described, I 2016.02.17 Day 2 Afternoon p 179, 2016.02.18 Day 3 Afternoon p 561.

witness testimony indicates such a visual check did not occur until after the crew began to troubleshoot the pressure increases in the well. Once the crew became aware of the drop in riser level, a decision was made to increase the annular closing pressure and fill the riser with more drilling mud; it stayed full, thus reinforcing the assumption of an annular leak.[127] A procedure providing the expected drill pipe pressure at the end of the initial displacement and a maximum acceptable value would have helped the crew detect the displacement shortfall.

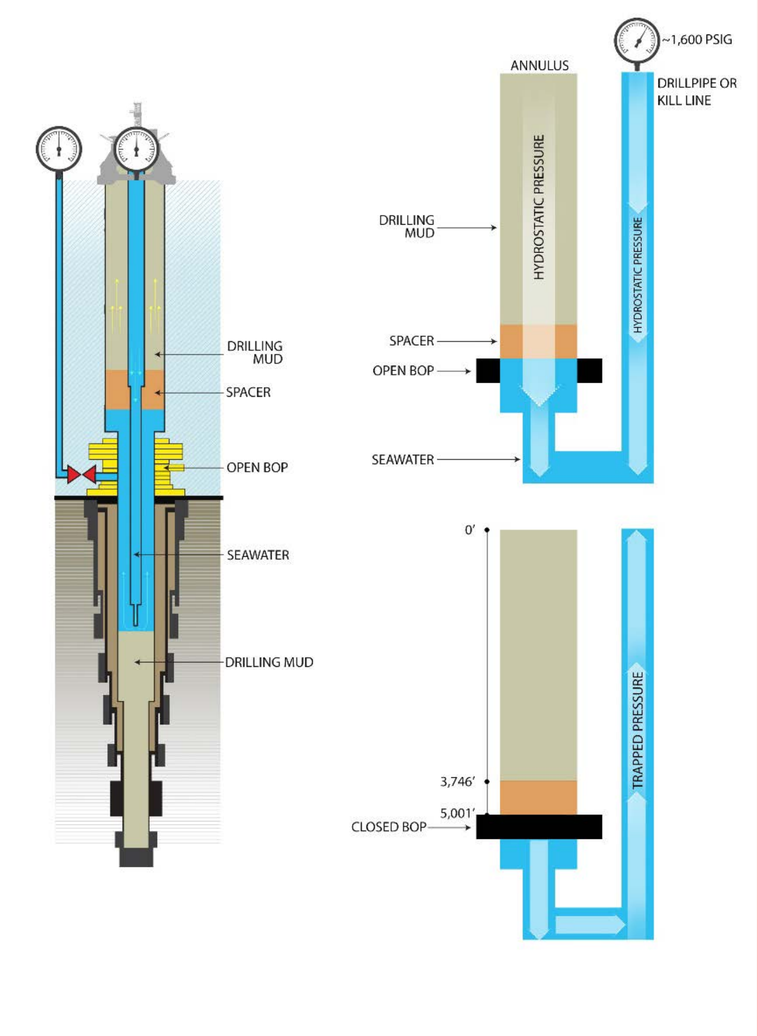
The issues covered in this section reveal numerous assumptions of the operator, drilling contractor, and other well service providers concerning the ability of the crew to accurately understand the conditions of the well throughout displacement. In reality, this status was inferred from the various indicators available and, as demonstrated here, incorrectly so. This evidence further supports the need for improved tools for accurate interpretation of well conditions, and this knowledge gap must be recognized when making decisions about well status throughout the drilling and temporary abandonment process.

[127] Hearings before the Deepwater Horizon Joint Investigation Team, May 28, 2010, pp 279 -280.

As described in Section 1.2.3, depending on the configuration of a negative test, the well pressure can be monitored from either the drillpipe, the kill line,[a] or in some instances both.

The pressure a crew observes after displacing drilling mud from a well can be illustrated by using the u-tube model seen here. The drillpipe, or the kill line, containing only relatively light seawater, is shown on one side of the u-tube.[b] On the other side, the annulus contains some seawater, but also much heavier drilling mud and spacer material. The heavier annulus material pushes down through the u-tube and up on the drillpipe seawater, increasing the drillpipe pressure, commonly called u-tube pressure, which can be predicted before fluid conditions in a well change.[c]

Similar to trapping gas in an inflated balloon, pressure will remain in a pipe if it is shut in. When the crew at Macondo closed the BOP, the u-tube pressure was trapped in the well until the crew intentionally released it from either the drillpipe or the kill line in preparation for the negative test.



[a] The kill line is a pipe that runs from the BOP to the rig.
[b] Hydrostatic pressure is height of the fluid column multiplied by the density of the fluid.
[c] The u-tube pressure is the hydrostatic pressure exerted by seawater in the drillpipe subtracted from the hydrostatic pressure generated in the annulus from the drilling mud and spacer material. Planned u-tube pressure at Macondo was ~1,600 psig.

Calculated hydrostatic pressures:
Drilling mud: 3,746 ft * 14.2 ppg * 0.052 = 2,766 psi
Spacer material: 1,255 ft * 16 ppg * 0.052 = 1,044 psi
Seawater: 5,001 ft * 8.55 ppg * 0.052 = 2,223 psi
where 0.052 is a units constant to convert feet-pounds per gallon (ppg) to pounds per cubic inch (lbs/in^3)

1.5 Phase 3 – Evidence of Confirmation Bias

After displacement of the drillpipe, the crew took steps to conduct the negative test by bleeding and observing pressure and flow from the well several times over three hours (striped portion of Figure 1-10). After closing the annular, (~5:00 pm) the crew bled trapped pressure from the drillpipe, but subsequently observed it rise. They then noticed the low riser level, increased closing pressure on the annular, refilled the riser, and bled pressure from the drillpipe again (~5:25 pm). Afterwards, the crew again observed drillpipe pressure rise.

Shift change was officially at 6:00 pm for the toolpushers and WSLs.[128] The night shift WSL came on duty. After discussions (addressed in more detail shortly) among the Transocean well operations crew and both BP well site leaders, the decision was made to change the procedure to test on the kill line stipulated in the drilling permit submitted to MMS.[129] The crew bled pressure from the kill line (5:50 p.m.) until the pressure was zero in the kill line. The crew next pumped seawater into the kill line to ensure it was full (6:35 p.m.) and then observed no flow on the kill line for 30 minutes.[130] Despite this, pressure on the drillpipe remained. As the timespan in solid green illustrates in Figure 1-10, about an hour and a half passed without further actions by the crew, as discussions of the pressure on the drillpipe ensued.

Purportedly, the night toolpusher[131] offered an interpretation of the drillpipe pressure that justified the observed pressure. Post-incident, this theory, termed the bladder effect, annular compression, and annular compaction,[132] could not be supported. While it is in dispute whether the entire on-duty well operations crew and both Well Site Leaders on the rig accepted this rationale,[133] ultimately, they proceeded with displacement. Continuation of the temporary abandonment process signified their acceptance of the negative test results and their belief that well integrity was secure.

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[128] The mud engineers also have shift change at this time, although they play a support role in the well operations. The drillers did not change out at this time; their shift change was at noon and midnight. (USA v. Robert Kaluza, Docket No. 12-CR-265, February 7, 2016, pp 153:5-154:3; USA v. Robert Kaluza, Docket No. 12-CR-265, February 18, 2016, p 304:`6-18.)

[129] Internal Company Document, BP. *Form MMS - 124 Application for Permit to Modify*, April 16, 2010, Temporary Abandonment Procedure, BP-HZN-MBI00127909, http://www.mdl2179trialdocs.com/releases/release201304041200022/TREX-00570.pdf (accessed October 7, 2015).; USA v. Robert Kaluza, Docket No. 12-CR-265, February 18, 2016, pp 320:20-21, 323:7-9, & 328:22-329:5.

[130] USA v. Robert Kaluza, Docket No. 12-CR-265, February 18, 2016, p 358:12-360:1

[131] The toolpusher plays a supervisory role within the drill crew, advising and assisting if the driller runs into a problem; Internal Company Document, Transocean. *Field Operations Policies & Procedures Manuel*, Issue 01, Revision 00, HQS-POP-PP-01, August 8, 2009; USA v. Robert Kaluza, Docket No. 12-CR-265, February 17, 2016, p 92:11-19.

[132] The bladder effect/annular compression theory is detailed in various places in the *Chief Counsel's Report*. The theory purported that the weight of the heavy drilling mud and spacer material pressed againt the annular preventer which in turned pressed against the fluids below the preventer, forcing them up the drillpipe; National Commission on the BP Deepwater Horizon Oil Spill and Offshore Drilling. *Chief Counsel's Report: The Gulf Oil Disaster;* Feburary 17, 2011; pp 157, 162, and 229-30 (amongst others). USA v. Robert Kaluza, Docket No. 12-CR-265, February 18, 2016, pp 326:1-17 & 366:2-17 & 550:6-553:15

[133] USA v. Robert Kaluza, Docket No. 12-CR-265, February 18, 2016, pp 366:8-11 & 439:23-440:11 & 472:9-15 & 554:1-8.

Why would the WSLs and well operations crew continue with the displacement despite the pressure reading on the drillpipe? Not all of these individuals survived to explain their rationale. Yet from those who did, along with the evidence available, it can be reasonably assumed that they would have not proceeded with the displacement had they believed a blowout to be a real possibility.[134] But they did proceed, removing the fluid barrier from the well.

Subsea supervisor testimony offered during the Joint Marine Board investigation provides insights into the general mindset of a crew during these final stages of drilling and abandoning a well:[†]

> *When you run that last string of casing and you have got it cemented, it's landed out and a test was done on it, then you say this job, we are at the end of it. Everything is going to be okay. Now I'm telling you this, not from a supervisor, not from the well-site leader's office, but from the working men that are out there, we have finished this well. You are thinking ahead to your next job. You're moving on.*

[†]Hearing before the Deepwater Horizon Joint Investigation, July 20, 2010, p 63.

[134] There exists a difference between real-time operational risk awareness by those conducting the work in the moment and risk awareness in the "back-office" sense by those removed from the actual operational setting. McLeod offers a useful discussion of the difference. [McLeod, R., 2015, *Designing for Human Reliability in the Oil, Gas and Process Industries,* Elsevier, Ltd.: Oxford, UK, pp 30-32.]

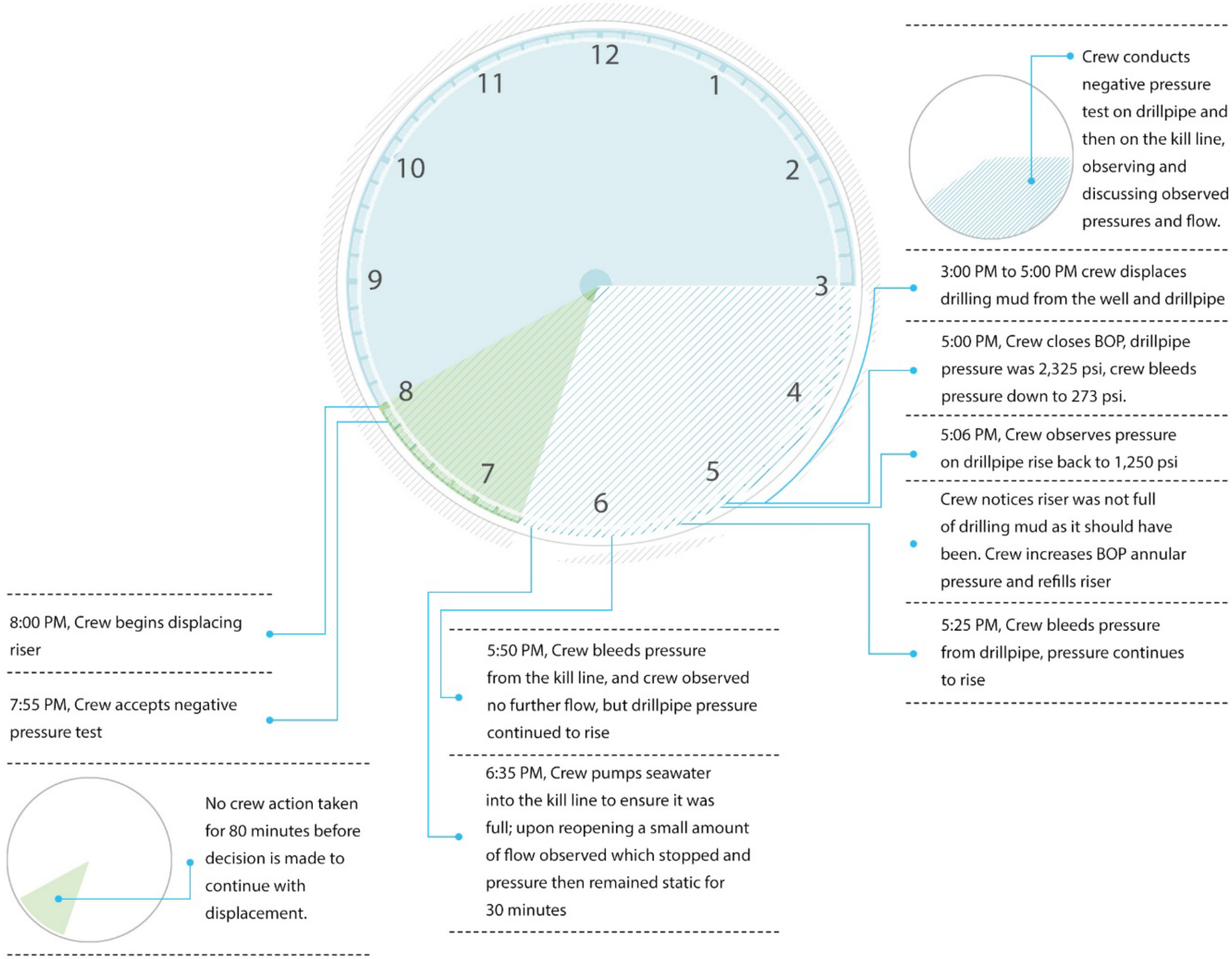

Figure 1-10. Crew Activities during Temporary Abandonment beginning at 3:00 p.m. on April 20, 2010.

Several facts, experiences, and rational justifications explain why the well operations crew proceeded:

- Up to the point of the blowout, challenges of the well throughout the drilling process were successfully overcome, including: 1) multiple losses of well control events throughout the drilling of the well in which the crew was able to regain control of the well[135] and 2) changes to the drilling plans to accommodate those challenges (e.g., drill depth, casing choice). The ability to regain control of the well numerous times prior could have reinforced a mentality that success was inevitable.
- The crew explained away or remediated several anomalies during the cementing process.[136]
- Various personnel deemed successful the bottom-hole cement job—the primary physical barrier set in the well to prevent loss of well control and the major operational task of temporary abandonment.[137]
- The positive pressure test conducted earlier in the day to verify casing integrity (i.e., no leaks from inside the well to the outside) was successful. While this test does not verify the integrity of the bottom hole cement job, it represents another successfully completed step in temporary abandonment.
- A rationale for the loss of riser fluid was provided.
- The well operations group purportedly discussed, and at least partially accepted, a rationale for the drillpipe pressure. The individual purported to have provided the rationale was considered highly competent in skills directly applicable to this situation—"[he] makes quality decisions on a consistent basis," "has always been a recognized leader on the Deepwater Horizon, and uses his experience to help others."[138] The professional respect for this individual, as well as the backing

[135] Numerous 'lost returns' events on February 17, March 2, 3, 21, 31, April 3, 4, and 9, 2010, well kicks on October 26, 2009 and March 8, 2010, and a ballooning event on March 25, 2010; National Commission on the BP Deepwater Horizon Oil Spill and Offshore Drilling. *Chief Counsel's Report: The Gulf Oil Disaster;* Feburary 17, 2011; Figure 4.2.8, p 59.

[136] These included issues with converting the float valve assembly, a device that allows cement to be pumped into a well and then to prevent flow back up the casing once pumping ceased. Ultimately, much higher pressure was required to convert the float valves. Additionally, the anticipated cement circulation pressure was lower than predicted, but the eventual conclusion was that the lower-than-expected pressure actually reflected a broken pressure gauge. National Commission on the BP Deepwater Horizon Oil Spill and Offshore Drilling. *Chief Counsel's Report: The Gulf Oil Disaster;* Feburary 17, 2011; Chapter 4.3, p 67.

[137] Email from Cementing Engineer, Halliburton, to Cementing Engineer, Halliburton, Subject: 9.875" x 7" Casing Post Job, "We have completed the job and it went well," April 20, 2010, HAL 0011208, see Exhibit 0708 http://www.mdl2179trialdocs.com/releases/release201302281700004/Stringfellow_William-Depo_Bundle.zip (accessed October 7, 2015).; Email from Drilling Engineer, BP, to Drilling Engineering Team Leader, Senior Drilling Engineer, Wells Team Leader, BP, Subject: Nitrogen Cement Team, "the Halliburton cement team … did a great job," April 20, 2010, BP-HZN-MBI00129141.; Foamed Casing Post Job Report from Macondo stated that the cement job was "pumped as planned" and that full returns were seen throughout the process; Internal Company Document, Halliburton. *9.875" x 7" Foamed Production Casing Post Job Report*, April 20, 2010, HAL_0011210, Exhibit 0708 http://www.mdl2179trialdocs.com/releases/release201302281700004/Stringfellow_William-Depo_Bundle.zip (accessed October 7, 2015).

[138] Internal Company Document, Transocean. *2009 Senior Supervisor Performance Appraisal - Performance Appraisal and Development Plan*, October 31, 2009, TRN-MDL-08076982, http://www.mdl2179trialdocs.com/releases/release201303071500008/TREX-52649.pdf (accessed October 7, 2015).

by others of the rationale as something plausible,[139] and even seen before,[140] gave the crew comfort that the theory was valid.

- The night shift WSL recalled participating in approximately 50 previous negative tests; to his knowledge, never had one failed.[141]
- They had conducted the negative test according to the drilling permit, seeing no flow for 30 minutes,[142] an indication of a successful negative test.[143]

It is reasonable to assume that these facts, experiential knowledge, and justifications convinced the crew that successful completion of the well was inevitable. This information strongly indicates that the well operations crew and WSLs were subject to confirmation bias,[144] a one-sided case-building process of unconscious selectivity in gathering and using evidence that supports one's beliefs.[145] Acceptance of an explanation or decision despite indications otherwise is more likely when a recognized leader supports the position, a lot is at stake, and an alternative scenario would be costly.[146] (See also Section 1.7.1.) Thus, the situation predisposed the crew to interpret the negative test as successful on April 20, 2010.

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[139] USA v. Robert Kaluza, Docket No. 12-CR-265, February 18, 2016, pp 326:7-17, 554:1-6; Hearing before the Deepwater Horizon Joint Investigation, July 20, 2010 pp 90-91, 153.

[140] Internal Company Document, BP. *Notes from Bob Kaluza Interview*, April 28, 2010, BP-HZN-MBI00021276, see Exhibit 0005 http://www.mdl2179trialdocs.com/releases/release201302281700004/Daigle_Keith-Depo_Bundle.zip (accessed October 7, 2015).

[141] USA v. Robert Kaluza, Docket No. 12-CR-265, February 18, 2016, pp 282:13-15, 294:2-6.

[142] USA v. Robert Kaluza, Docket No. 12-CR-265, February 18, 2016, p 358:12-360:1; Hearing before the U.S. District Court for the Eastern District of Louisiana under the Multi-District Litigation docket MDL No. 2179, March 5, 2013 p 1682:13-17, http://www.mdl2179trialdocs.com/releases/release201303051200006/2013-03-05_BP_Trial_Day_6_AM-Final.pdf (accessed October 7, 2015).

[143] USA v. Robert Kaluza, Docket No. 12-CR-265, February 18, 2016, pp 166:21-22, 358:12-360:1

[144] This analysis is in alignment with Hopkins, A. *Disastrous Decisions;* CCH Australia: Australia, 2012; p 40.

[145] Nickerson, R. S. Confirmation Bias: A Ubiquitous Phenomenon in Many Guises; *Review of General Psychology* 1998**,** *2* , pp 175-176.

[146] The logical extension of this argument would suggest that if integrity is lost but not acted upon, as was the case with Macondo, the result could be significantly costlier. However, research on confirmation bias demonstrates that people influenced generally weigh more heavily data that supports and affirms their beliefs. Nickerson, R. S. Confirmation Bias: A Ubiquitous Phenomenon in Many Guises; Review of General Psychology 1998, p 176.

Shift Change of Supervisory Personnel

Shift change for both the toolpushers and the WSLs was scheduled to occur at 6:00 p.m. on April 20, which coincided with the time the well operations crew were conducting and discussing the negative test.[a] Changing out were the toolpusher, identified as the rig floor supervisor of the drilling operations, and the WSL, the designated decision-maker for the well operations.[b] The day toolpusher reported that he left his shift approximately 20 minutes after his replacement arrived the evening of April 20;[c] if his time estimates are accurate, he would not have been in the drill shack for a significant portion of the discussion about the negative test that occurred during the day shift and the next steps for the night shift crew. There were also understanding gaps between the day and night WSLs, which were not realized until those conversations were deconstructed post-incident.[d] It can be argued that because the drill crew does not change out at the same time, the potential for communication gaps is lessened. But this situation reveals an opportunity to review shift change procedures and practices for all safety critical positions and to assess whether training in (non-technical) communication skills is warranted (see Section 1.7).

[a] Internal Company Document, BP. *Steve R. Notebook*, BP-HZN-MBI00021427, see Exhibit 4953 http://www.mdl2179trialdocs.com/releases/release201302281700004/Farr_Daniel-Depo_Bundle.zip (accessed October 7, 2015). The mud loggers also had shift change at this time, but they were in support roles more than supervisory. Testimony given in the U. S. Districk Court for the Eastern District of Louisiana under the Multi-District Litigation docket MDL No. 2179, March 5, 2013, pp 1676, http://www.mdl2179trialdocs.com/releases/release201303051200006/2013-03-05_BP_Trial_Day_6_AM-Final.pdf (accessed May 22, 2015).

[b] Internal Company Document, Transocean. *Interviewing Form: Toolpusher*, June 4, 2010, TRN-INV-00004994, http://www.mdl2179trialdocs.com/releases/release201304041200022/TREX-07532.pdf (accessed October 7, 2015).; USA v. Robert Kaluza, Docket No. 12-CR-265, February 18, 2016, pp 319:12-13, 348:17.

[c] Internal Company Document, Transocean. *Interviewing Form: Toolpusher*, June 4, 2010, TRN-INV-00004994, http://www.mdl2179trialdocs.com/releases/release201304041200022/TREX-07532.pdf (accessed October 7, 2015).; Testimony given in the U. S. Districk Court for the Eastern District of Louisiana under the Multi-District Litigation docket MDL No. 2179, March 5, 2013, pp 1676, http://www.mdl2179trialdocs.com/releases/release201303051200006/2013-03-05_BP_Trial_Day_6_AM-Final.pdf (accessed May 22, 2015).

[d] The night WSL asserted that he likely would have changed his decisions/actions on the night of April 20 if he had this information at the time. USA v. Robert Kaluza, Docket No. 12-CR-265, February 18, 2016, pp 371:21, 73:13.

1.5.1 Potential Influence of Distraction and Fatigue

A variety of performance shaping factors[147] contributed to the decisions and actions of the crew, some of which have already been discussed. Two additional factors have been prominently raised in review of the incident: fatigue and distraction of those carrying out temporary abandonment. While the CSB does not find conclusive evidence to assert that these factors played a causal role in the blowout, the agency cannot rule them out. Both are briefly covered here.

[147] Performance shaping factors, also called performance influencing factors, are the characteristics of the job (e.g., nature, workload, procedures, environment, etc.), individual (e.g., skills, attitude, personality, mental state, etc.) and organization (e.g., culture, leadership, resources) that influence human performance. (UK HSE, Performance Influencing Factors, http://www.hse.gov.uk/humanfactors/topics/pifs.pdf)

1.5.1.1 Fatigue

Fatigue can negatively affect workplace performance by increasing errors, delaying responses, and clouding decision-making.[148] Complex task decision-making that requires innovative and flexible thinking is also sensitive to fatigue.[149] "Fatigued people are less able to respond to unusual or emergency conditions effectively. They are also more likely to take risks."[150] The following facts are known about the Macondo blowout:

- Transocean implemented 21-day hitches (called "3 and 3") across all North American Division rigs in October 2009; prior to that time, both 14- and 21-day hitches were used. The analyses conducted, and rationale given, by Transocean to switch its Gulf regional fleet from a 14-day hitch to a 21-day hitch expressly focused on schedule predictability, interchangeability of crews from rig to rig, more time for crew training, and financial savings.[151] Missing from the analysis is consideration of sleep science.
- Limited research exists on performance impacts resulting from offshore 21-day hitch durations in comparison two 14-day hitches;[152] however, general sleep science shows detrimental performance effects increase as periods of consecutive shift work increase,[153] and most North Sea operations[154] in both UK and Norwegian waters implement 14-day hitches followed by 14 - 28 days of onshore rest.[155]

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[148] Rogers, A.S., Spencer, M.B., and Stone, B.M., 1999. Report 245/Validation and Development of a Method for Assessing the Risks Arising from Mental Fatigue, prepared by the Defence Evaluation and Research Agency Center for Human Services, for the HSE, U.K; Lerman, S. et al., Fatigue Risk Management in the Workplace, ACOEM Presidential Task Force on Fatigue Risk Management, Journal of Occupational and Environmental Medicine, 54(2), February 2012, p 1; and UK HSE, Human Factors, Specific Topic 2: Managing Fatigue Risks, http://www.hse.gov.uk/humanfactors/topics/specific2.pdf, p 1, accessed March 21, 2016.

[149] Rogers, A.S., Spencer, M.B., and Stone, B.M., 1999. Report 245/Validation and Development of a Method for Assessing the Risks Arising from Mental Fatigue, prepared by the Defence Evaluation and Research Agency Center for Human Services, for the HSE, U.K. Rosekind, M., Gander, P., et al., 1996. "Managing Fatigue in Operational Settings I: Physiological Considerations and Countermeasures," Behavioral Medicine, Vol. 21, pp 157-165.

[150] Energy Institute, *Improving Alertness through Effective Fatigue Management*, 2006, p 1; this document has been superseded by *Managing Fatigue using a Fatigue Risk Management Plan*, 1st ed., 2014, https://www.energyinst.org/technical/human-and-organisational-factors/human-factors-fatigue (accessed March 26, 2016).

[151] April 20, 2011, response by Transocean to CSB subpoena requests for records and information on Transocean's 21-day on/off work schedule.

[152] HSE, *Offshore Working Time in Relation to Performance, Health and Safety: A review of Current Practice and Evidence, RR772,* 2010, p 23 & 51.

[153] Rosekind, M., Managing work schedules: an alertness and safety perspective, in *Principles and Practice of Sleep Medicine,* eds. By Kryger, M, Roth, T., & Dement, W. Philadelphia, PA, 2004, pp 682 & 686.

[154] The exceptions most commonly include those working in remote UK waters, e.g., West of Shetland.

[155] Parkes, K., Shift schedules on North Sea oil/gas installations: a systematic review of their impact on performance, safety and health, *Safety Science, (50)*, 2012, pp 1638.

- Historical accident and injury data from the North Sea suggest that the ratio of fatalities and severe injuries to less severe injuries was markedly higher for hitches longer than 14 days in comparison to those of lesser quantity.[156]
- Research shows that schedules rotating 'backwards' from night to day shifts (as opposed to rotating 'forward' from day to night shifts),[157] and that make this switch in the middle of the hitch,[158] are more likely to negatively impact performance by causing fatigue as the body readjusts to a new sleep-wake schedule.
- Workers reported in a Lloyds Register culture/climate review that the 21-day hitch was causing fatigue, particularly during the final week.[159]
- The driller and one assistant driller working the evening of April 20 were on shift 20 of their 21-day hitch; the second assistant driller was on shift 19 of 21; each shift was 12 hours, not including any overage worked to conduct shift turnover.
- The day shift toolpusher was on day 20 of his hitch; his shifts were also 12 hours.
- The toolpusher on the evening of April 20 was only on day 6 of his hitch, but he was scheduled to leave the Deepwater Horizon the next day for another offshore facility; he would not be returning to the Horizon, where he spent approximately half his life for almost the last decade.[160]
- The BP Well Site Leaders were on a 14-day hitch; they were scheduled to have their swing-shift rotation at 2:00 a.m. on April 21.

To determine causality, investigators require sufficient evidence that identifiable fatigue factors[161] were present at the time of the incident and that fatigue-related performance loss contributed to or caused the

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[156] Parkes, K. (University of Oxford). *Psychosocial Aspects of Work and Health in the North Sea Oil and Gas Industry, 1996 – 2001*, Sudbury: Health and Safety Executive, 2002, p 38.

[157] HSE, *Offshore Working Time in Relation to Performance, Health and Safety: A review of Current Practice and Evidence, RR772*, 2010, pp 33-35; Rosa, R. and M. Colligan. *Plain Language about Shift Work*, Cincinnati: US Department of Health and Human Services (Centers for Disease Control and Prevention, National Institute for Occupational Safety and Health), July 1997, p 9.

[158] Parkes, K. (University of Oxford). *Psychosocial Aspects of Work and Health in the North Sea Oil and Gas Industry, 1996 – 2001*, Sudbury: Health and Safety Executive, 2002, pp 7, 37-38; HSE, *Offshore Working Time in Relation to Performance, Health and Safety: A review of Current Practice and Evidence, RR772*, 2010, pp 32-33; Parkes, K., Shift schedules on North Sea oil/gas installations: a systematic review of their impact on performance, safety and health, *Safety Science, (50)*, 2012, p 1647.

[159] "On their last week, they seem like they are in another world," and "On the last week, you are so tired that you feel like a robot" were two quoted responses. TREX-04261, *Lloyd's Register Safety Management Systems and Safety Culture/Climate Reviews: Deepwater Horizon* closing meeting on March 16, 2010, TRN-INV-00016761 and *Lloyd's Register EMEA Aberdeen Energy, Safety Management and Safety Culture/Climate – Deepwater Horizon*, May 11, 2010, p.16. TRN-HCEC-00090589.

[160] US District Court, Eastern District of Louisiana, MDL-2179, March 5, 2013, Day 6 morning session, p 1737.

[161] Fatigue factors are physiological aspects of an individual's sleep/wake cycle that underlie fatigue. Rosekind, M., Gregory, K., et al., 1993. "Analysis of crew fatigue factors in AIA Guantanamo Bay aviation accident, Appendix E," to Aircraft Accident Report: Uncontrolled Collision with Terrain, NTSB/AAR-94/04, Washington, D.C.: NTSB.

accident.[162] Fatigue factors include acute sleep loss and cumulative sleep debt,[163] continuous hours of wakefulness, circadian rhythm disruptions, and potential medical sleep conditions.

This analysis cannot go further due to the lack of specific information pertaining to the sleep and wake cycles of the individuals involved, many of whom suffered fatal injuries as a result of the incident or were not made available to the CSB for interviews. Without such information, the CSB cannot draw strong connections between fatigued mental states and explicit performance detriments demonstrated by the individuals. The CSB does not know how the well operations crew spent their off time in the days leading up to the blowout, what portion of that time they spent sleeping, and whether their sleep was of high quality. Yet the CSB does know that the night shift toolpusher and WSL were more likely to be fatigued due to their 6:00 p.m. – 6:00 a.m. schedules. The CSB can surmise that leaving the MODU after almost a decade would take an emotional toll on the toolpusher, which may amplify the effects of fatigue;[164] however, the evidence available does not provide sufficient information to make that claim.

Overall, sufficient information is not available for a causal connection to the blowout. Yet, the facts outlined here raise sufficient concern for the offshore industry to address fatigue as a safety issue. Testimony from Steve Newman, then the Transocean CEO, confirmed Transocean also implemented 28-day hitches.[165] Some offshore workers may prefer extended hitches for the equivalent-in-length non-work periods. But management has the responsibility to effectively manage the risks inherent in the work, and working hours, shift patterns, and hitch length are within its span of control. Reasons for implementing long hitches include limitations on the number of personnel that can be accommodated on the offshore facility and reductions in the number of shift changes, which minimize opportunities for error that could arise from more frequent staff change-outs.[166] An additional benefit is reduced helicopter traffic, which has also been recognized as a major offshore risk. Thus, a safety management system is necessary to assess the risk of fatigue and to establish and maintain policies and practices to effectively reduce those risks. API Recommended Practice 755 is voluntary US onshore guidance for developing and

[162] This two-step methodology was employed by the NASA Fatigue Countermeasures Program and the National Transportation Safety Board (NTSB) to assess operator fatigue in accidents, and it has been used in NTSB investigations of pipeline and transportation incidents. As the tasks of the well operations crew, pilots, board operators, and drivers parallel each other in that they all deal with issues of critical decision-making, attending to/monitoring technological systems, reacting quickly to abnormal conditions, and rectifying deviations from normal conditions, the methodology is appropriate and applicable to offshore well operations events.

[163] Acute sleep loss is the amount of sleep lost from an individual's normal sleep requirements in a 24-hour period. Cumulative sleep debt is the total amount of lost sleep over several 24-hour periods. If a person who normally needs 8 hours of sleep a night to feel refreshed gets only 6 hours of sleep for five straight days, this person has a sleep debt of 10 hours.

[164] "…combinations of stressors may act additively or combine to produce multiplicative effects on health and safety outcomes." HSE, *Offshore Working Time in Relation to Performance, Health and Safety: A review of Current Practice and Evidence, RR772*, 2010, pp 9-10.

[165] Hearing before the U.S. District Court for the Eastern District of Louisiana under the Multi-District Litigation docket MDL No. 2179, March 19, 2013 p 4666, http://www.mdl2179trialdocs.com/releases/release201303191200014/2013-03-19_BP_Trial_Day_14_AM-Final.pdf (accessed October 7, 2015).

[166] UK HSE, Guidance for Managing Shiftwork and Fatigue Offshore, Information Sheet No. 7/2008, http://www.hse.gov.uk/offshore/infosheets/is7-2008.htm (accessed February 14, 2011).

implementing a fatigue risk management system, but its scope is expressly applicable to shift workers commuting daily to the worksite.[167]

1.5.1.1 Distraction

Testimonies from witnesses suggest that the executive tour was only in the drill shack (and thus capable of interrupting/distracting those involved in the well operations) for about 5 minutes. The OIM and senior toolpusher, who were on the tour, were asked to stay within the drill shack to help the drill crew, and they did so for about 15 minutes more. The senior toolpusher stated that he did not play a role in the decision-making occurring with the shack concerning the negative tests and that he actually stepped out of the shack to discuss some next steps in temporary abandonment with the assistant driller.[168] The drill crew and WSLs continued to discuss the negative test and well data for some time after the tour group left, suggesting that they were focused on the work and not distracted by the executive group. However, without more detailed evidence of what was said, by whom, in what manner, and to what extent within that drill shack, the CSB cannot determine with any level of certainty how the tour might have impacted the flow of communication and the analysis of the well data/negative tests.

1.6 Phase 4 – Troubleshooting, Multiple Activities, and Communication Gaps Obscure Well Conditions

After accepting the negative test results at 7:55 p.m. (Figure 1-11), the crew continued with displacement of the riser. The crew engaged in multiple activities during this time, including a sheen test, several mud and well fluid transfers into and out of various locations, and displacement pump shutdowns and restarts (Figure 1-11). Unbeknownst to the people on the Deepwater Horizon, at ~8:50 pm, reservoir fluids began to flow into the well. Between 8:50 p.m. and 9:08 p.m., when the crew stopped displacing the riser to conduct the sheen test, the influx rate into the well was approximately 9 bpm (barrels/minute), and the pit gain on the rig was about 60 barrels over 16 minutes.[169] The crew did not detect this influx. Post-incident, the senior toolpusher noted that the number of pre-calculated strokes (step 8, Table 1-3) on the pump used

[167] API, Recommended Practice 755: Fatigue Risk Management Systems for Personnel in the Petroleum and Petrochemical Industries, 2007, p.1. The CSB notes that it has identified a number of ways this recommended practice could be further improved. See http://www.csb.gov/assets/1/7/Fatigue_Evaluation_for_Public_Comment_3_11_20131.pdf.

[168] USA v. Robert Kaluza, Docket No. 12-CR-265, February 17, 2016, pp 162:25, 163:12.

[169] The computer simulation found in Appendix 2-A indicates that by 9:09 p.m. about 9 bpm were flowing into the well, and the pit gain on the rig was about 60 barrels over 16 minutes. These conditions should have been sufficient to be observable on the rig, but the crew was not predisposed to look for them.

to displace the riser correlated with the visual sheen test results, indicating that the drilling mud in the riser had been displaced and the spacer had reached the rig.[170, 171] In short, "everything looked good."[172]

As a backup to the well operations crew, the Sperry Sun[173] mudloggers aboard the rig were hired by BP to monitor surface instruments that provided drilling and well information and to raise concerns for any abnormalities.[174] Sperry Sun had installed its own flow meter on the rig to monitor returns from the well, but apart from this particular device, the mudlogger monitored the same data as the drillers.[175] Yet, prior to resuming the displacement, the mudlogger was not privy to all the discussions about whether to accept the negative test. He was not with the well operations crew in the drill shack; instead, he was in a separate windowless office approximately 15 feet from the perimeter of the rig floor.[176] He surmised that the negative test was successful only because displacement of the drillpipe was occurring.[177] While he did leave his monitoring post to go to the restroom in the hour before blowout, this purportedly occurred sometime between 8:50 p.m. and 9:15 p.m., when fluid transfer movements were either impacting or were perceived to be impacting the flow-out meter.[178]

If an organization is relying upon individuals to monitor and troubleshoot an operational process, it must make efforts to ensure they have enough information to do so. The mudlogger might have had the same raw data available to him as the driller, but the information was contextually incomplete—he was not a

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[170] Internal Company Document, Transocean. *Senior Toolpusher Interviewing Form*, May 28, 2010, TRN-MDL-00493745, http://www.mdl2179trialdocs.com/releases/release201304041200022/TREX-50296.pdf (accessed October 7, 2015).

[171] Subsequent analysis by both Transocean and the CSB indicates that the spacer had not yet reached the surface at 9:08 p.m. A possible explanation for the successful sheen test may be that spacer bypassed some of the drilling mud, giving a false displacement indication. If a sheen were detected, it would have been an indication of an incomplete displacement, that the actual pump efficiency was lower than assumed; *Macondo Well Incident: Transocean Investigation Report:Volume II;* June, 2011; Appendix G, Figure 44, p 103; CSB Macondo Investigation Report, Volume 2, Appendix A, Figure 9, p 20.

[172] Internal Company Document, Transocean. *Senior Toolpusher Interviewing Form*, May 28, 2010, TRN-MDL-00493745, http://www.mdl2179trialdocs.com/releases/release201304041200022/TREX-50296.pdf (accessed October 7, 2015).

[173] A subsidiary of Halliburton; see Volume 1, Section 1.1, for description of various well service providers contracted by BP.

[174] Hearing before the Deepwater Horizon Joint Investigation, December 8, 2010, p 267; Hearing before the Deepwater Horizon Joint Investigation, December 7, 2010, p 18.

[175] The mudlogger reported that Transocean had its own HiTech Profibus system, the data of which was shared with the mudloggers, but not necessarily communicated in the same format; Hearing before the Deepwater Horizon Joint Investigation, December 7, 2010, p 116. For a more detailed analysis, see Hopkins, A., February 2011, *A working paper prepared for the CSB: the failure of monitoring prior to blowout*, available at the Macondo investigation page of the CSB.gov website.

[176] Hearing before the U.S. District Court for the Eastern District of Louisiana under the Multi-District Litigation docket MDL No. 2179, March 13, 2013 p 3494, http://www.mdl2179trialdocs.com/releases/release201303131200011/2013-03-13_BP_Trial_Day_11_AM-Final.pdf (accessed October 7, 2015).

[177] Hearing before the Deepwater Horizon Joint Investigation, December 7, 2010, pp 28, 158.

[178] Starting around 9:08 p.m., when the overboard line was opened, the mudlogger's ability to see flow out of the well was impaired; Hearing before the Deepwater Horizon Joint Investigation, December 8, 2010, p 189.; Hearing before the Deepwater Horizon Joint Investigation, December 7, 2010, pp 212, 216.

part of the conversations concerning the negative test results and their implications for the well, nor was he fully abreast of the fluid transfers,[179] yet he was relied upon as the independent layer of protection for kick detection.[180] In actuality, during temporary abandonment, he was a dependent layer, able to interpret well conditions only from the data that was available to him.

Once the sheen test was accepted, the crew diverted overboard the fluids returning from the well, bypassing the pit volume monitoring system, which is the prime means for the crew to detect flow anomalies from the well. A pressure anomaly was observed at ~9:31 p.m., but instead of checking the well for flow—which would be the anticipated course of action if well influx was suspected—the crew shut down the displacement pumps and began troubleshooting valves and lines at the surface.[181] Within nine minutes of shutting down the pumps, oil and gas erupted a mixture of seawater, drilling mud, and hydrocarbons up onto the drilling rig floor.

The actions of the crew, summarized in Figure 1-11, depict a group that was neither idle nor complacent in the minutes leading up to the blowout at 9:40 p.m. Rather, the crew demonstrated that they knew something was amiss, and they were actively trying to understand the situation by examining surface valves and lines. The crew's performance of these surface checks suggests their perception of only minor problems, such as a valve leak, not a catastrophic gas-in-riser situation.

[179] The mudlogger reported calling the drill shack several times to understand the data he was seeing from his control station. Hearing before the U.S. District Court for the Eastern District of Louisiana under the Multi-District Litigation docket MDL No. 2179, March 13, 2013 pp 3603, 3605-2606, 3527-3828, http://www.mdl2179trialdocs.com/releases/release201303131200011/2013-03-13_BP_Trial_Day_11_AM-Final.pdf (accessed October 7, 2015).

[180] Internal Company Document, BP. *BP Incident Investigation Team - Notes of Interview with Mark Hafle*, July 8, 2010, BP-HZN-BLY00144213, http://www.mdl2179trialdocs.com/releases/release201304110900026/TREX-04447.pdf (accessed October 7, 2015).; Hearing before the Deepwater Horizon Joint Investigation, December 8, 2010, p 267; Hearing before the Deepwater Horizon Joint Investigation, December 7, 2010, p 18.

[181] CSB Macondo Investigation Report, Volume 2, Appendix 2-A, p 11.

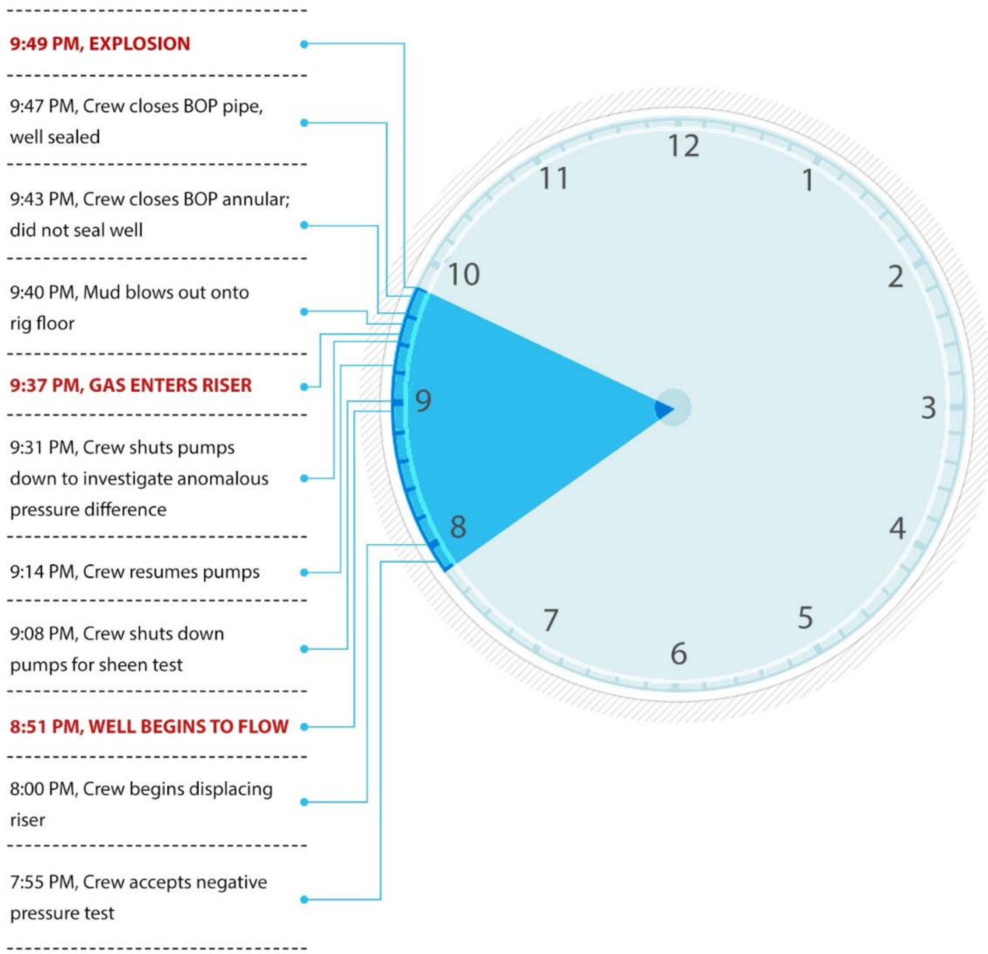

Figure 1-11. Crew activities and actions during final displacement of the riser.

The crew was predisposed to interpret the pressure anomaly as unrelated to cement integrity because of a perceived "successful" completion of the well. In summary, "as operations continue, the resulting anomalies remain undetected or are satisfactorily accounted for until matters evolve to a point where events demolish the reality inside which the crew is operating."[182]

1.7 Competency and Non-technical Skills

The human factors contributing to the Macondo incident almost automatically raise questions about competency of the personnel involved, and more fundamentally about the meaning of competency. More job-specific training is often the recommendation in the aftermath of a catastrophic incident, as was the

[182] Thorogood, J. *The Macondo Inflow Test Decision: Implications for Well Control and Non-technical Skills Training*, SPE/IADC Drilling Conference and Exhibition, London, March 17-19, 2015; SPE/IADC-173123-MS, p 8.

case in Macondo.[183] Traditional training typically consists of teaching crews to manage conditions based on plans (rules, procedures, policies). As such, post-incident investigations often focus on the need to improve those skills (i.e., knowledge of procedures and ability to execute them), and steps are taken to revise procedures and manuals so that individuals will be prepared for those specific unanticipated conditions when they arise.

This approach faces two challenges. First, task-specific or technical competency training does not guarantee error-free performance. A highly skilled, technically competent person can make glaring human errors.[184] For example, an expert surgeon may amputate a patient's right limb with technical precision only to realize later that the left one was to be removed.[185] Second, within complex systems, "rules, regulations, policy or procedures cannot be written to address all the situations that people may face,"[186] precisely because these systems can have emergent properties that are inherently unpredictable.[187] Consequently, "expertise is required to recognize when the unexpected is present or may arise."[188] Thus, technical competency is only one aspect of an individual's performance capabilities, and other non-technical skills (NTS) are necessary to prepare individuals to manage the natural variability inherent within the complex system. Non-technical skills are meant to enhance human performance reliability in high-demand and high-risk work environments (e.g., the hospital operating room, the nuclear plant control room), [189] where innovation and adaptation by people are needed to successfully operate within imperfect systems.[190]

Akin to crew resource management (CRM)[191] skills used in aviation, NTS are "the cognitive, social and personal resource skills that complement technical skills, and contribute to safe and efficient task

[183] National Commission on the BP Deepwater Horizon Oil Spill and Offshore Drilling. *Deep Water The Gulf oil Disaster and the Future of Offshore Drilling;* 2011; p 122.; National Commission on the BP Deepwater Horizon Oil Spill and Offshore Drilling. *Chief Counsel's Report: The Gulf Oil Disaster;* Feburary 17, 2011, pp 162, 185.

[184] Health and Safety Executive. *Reducing Error and Influencing Behaviour;* HSG48; 2009; pp 12-17. http://www.hseni.gov.uk/hsg_48_reducing_error_and_influencing_behaviour.pdf (accessed October 7, 2015).

[185] This scenario is based upon the example given in Flin, R.; O'Connor, P.; Crichton, M. *Safety at the Sharp End;* Ashgate Publishing: Hampshire, England, 2008; p 10.

[186] Pupulidy, I. Novices, Experts & Errors: Toward a Safer Fire Ground; *Wildfire* 2015**,** *24 (1),* p 33.

[187] Dekker, S. Drift into Failure: From Hunting Broken Components to Understanding Complex Systems; Ashgate Publishing: Burlington, VT, 2011; pp 155-160. Weick, K.; Sutcliffe, K. Managing the Unexpected: Resilient Performance in an Age of Uncertainty, 2nd ed.; John Wiley & Sons, Inc: San Francisco, CA, 2007.

[188] Pupulidy, I. Novices, Experts & Errors: Toward a Safer Fire Ground; *Wildfire* 2015**,** *24 (1),* p 33.

[189] Flin, R.; O'Connor, P.; Crichton, M. *Safety at the Sharp End;* Ashgate Publishing: Hampshire, England, 2008, p 1.

[190] Pupulidy, I. Novices, Experts & Errors: Toward a Safer Fire Ground; *Wildfire* 2015**,** *24 (1),* p 33.

[191] Crew Resource Management (CRM) is defined as "a management system which makes optimum use of all available resources—equipment, procedures and people—to promote safety and enhance the efficiency of … operations." The focus of CRM training is on cognitive and intrapersonal skills. (Civil Aviation Authority. *Crew Resource Management (CRM) Training, Guidance for Flight Crew, CRM Instructors and CRM Instructor Examiners;* CAP 737; Chapter 1, Sections 2.1 and 2.2.)

performance."[192] As defined in Table 1-4, they focus on situation awareness, decision-making, communication, teamwork, leadership, and stress and fatigue management.[193]

Table 1-4. Non-technical skill categories, definitions, and example behaviors associated with each.[194]

Skill Category	Definition	Types of Behaviors
Situation awareness	Developing and maintaining a dynamic awareness of the situation and the risks present during a wells operation, based on gathering information from multiple sources from the task environment, understanding what the information means, and using it to think ahead about what may happen next.	• Gathering information • Understanding information and risk status • Anticipating future developments
Decision-making	Diagnosing the situation and reaching a judgment to choose an appropriate course of action.	• Identifying and assessing options • Selecting and communicating an option • Implementing and reviewing decisions
Communication	Exchanging (transmission and reception) of information, ideas and feelings, by verbal (spoken, written) or non-verbal methods.	• Briefing and giving feedback • Listening • Asking questions • Communicating assertively
Teamwork	Working in a group, in any role, to ensure joint task completion, including coordination, cooperation and conflict resolution. A core concept of CRM training is not necessarily to strengthen any particular team but rather to make individuals more effective in whichever team they are working in.[195]	• Understanding own role with the team • Coordinating tasks with team members/other shift • Considering and helping others • Resolving conflicts
Leadership	Directing, managing, and supporting a team in order to accomplish tasks for set targets.	• Planning and directing • Maintaining standards • Supporting team members
Stress and Fatigue Management	Mitigating the effects of stress and fatigue.	• Identifying signs of stress and fatigue • Coping with effects of stress and fatigue

[192] Flin, R.; O'Connor, P.; Crichton, M. *Safety at the Sharp End;* Ashgate Publishing: Hampshire, England, 2008, p 1.

[193] *Ibid*. ; IOGP. *Crew Resource Management for Well Operations;* 501; April, 2014; p 12. http://www.ogp.org.uk/pubs/501.pdf (accessed October 7, 2015).

[194] Except where specifically footnoted, this information is extracted and compiled from IOGP *Crew Resource Management for Well Operations;* 501; April, 2014; pp 12-15. http://www.ogp.org.uk/pubs/501.pdf (accessed October 7, 2015).

[195] Flin, R.; O'Connor, P.; Crichton, M. *Safety at the Sharp End;* Ashgate Publishing: Hampshire, England, 2008; p 93.

Aviation provides perhaps the most notable example of focused effort to develop individuals' non-technical skills, where this effort came to fruition after recognition that aviation accidents were not primarily the result of technical problems or lack of technical knowledge of the crew, but due to the crew's inability to understand their situation and respond appropriately.[196] The Tenerife runway collision that killed 538 individuals in 1977 is one of the more well-known examples. The black box recordings of the two cockpits and air traffic control communications provide unique insight into non-technical aspects of their interactions that might have contributed to the event. The transcript of these communications reveals usage of vague and nonstandard language, hesitation by lower ranked individuals to assertively question higher ranked personnel, unclear communication of decisions among teams, and an insufficient verification of understanding verbal messages.[197] United Airlines also experienced a significant accident in 1978, in which similar interpersonal behaviors were identified as contributory, and in 1979 the National Transportation Safety Board issued a recommendation requiring flight crew training in resource management skills.[198] Two years later, United initiated the first US crew resource management program.[199]

The offshore oil and gas industry does not have the benefit of black box recorders to examine critical interactions between its well control personnel for both assessment and further improvements. Yet Macondo provides a unique set of data to explore potential non-technical skill gaps—the behavior and actions of the both on and offshore crew and management in the hours leading up to the gas release onto the rig underscore the importance of non-technical skills development in offshore high-risk operations.

Three specific examples from the activities leading up to the blowout are (1) the 80 minutes when the toolpusher, driller, well site leader, and others discussed pressure discrepancies between the drillpipe and kill line, (2) when the well site leader mentioned those discrepancies to the onshore drilling engineer, and (3) the interactions of the mudlogger with others from the well operations crew in monitoring the well. An analysis of these situations is presented here to demonstrate that systematic application of various NTS could have altered the interactions between rig personnel for the better.

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[196] Civil Aviation Authority. Crew Resource Management (CRM) Training, Guidance for Flight Crew, CRM Instructors and CRM Instructor Examiners; CAP 737; Chapter 1, Section 1.1 and 2.2.

[197] An annotated transcript of these communications is available here: http://www.pbs.org/wgbh/nova/space/final-eight-minutes.html (accessed December 7, 2015).

[198] NTSB, Aircraft Accident Report: United Airlines, Inc., Douglas DC-8-54, N8082U, Portland, Oregon, December 28, 1978 (NTSB-AAR-79-7), 1979, Washington, DC.; Helmreich, R. L.; Merritt, A. C.; Wilhelm, J. A. The evolution of crew resource management training in commercial aviation; *International Journal of Aviation Psychology* 1999, 9(1), p 19.

[199] Helmreich, R. L.; Merritt, A. C.; Wilhelm, J. A. The evolution of crew resource management training in commercial aviation; *International Journal of Aviation Psychology* 1999**,** *9(1),* p 19.

1.7.1 Case Study for NTS: Pressure Discrepancies between Drillpipe and Kill Line

Despite its limitations,[200] the evidence and testimony from surviving witnesses provides sufficient information to perform a simple assessment of when the toolpusher, driller, well site leader and others discussed the pressure discrepancies between the drillpipe and kill line. (See the solid green shaded portion of Figure 1-10.) The well operations crew, less the mudlogger, spent 80 minutes discussing the negative test results and their implications. This discussion suggests that the crew did, in fact, recognize that the well data they were examining were atypical enough to warrant further observations and consideration. Yet, the survivors' testimonies reveal a lack of discussion about the possibility of well integrity loss—as if the crew could not conceive this possibility. Why? What can be done to help crews recognize when they are falling into such a mental trap? Table 1-5 highlights evidence suggesting the well operations crew exhibited ineffective use of non-technical skills.

Table 1-5. Multiple Interpersonal Behaviors and Interactions amongst Well Operations Personnel Demonstrate Need for Non-technical Skills.

Testimony Illustrating Interpersonal Behaviors of the Well Operations Crew	Relevant Non-technical Skills (using options listed in **Table 1-4**)
An experienced and highly-esteemed toolpusher explained the negative test results as something that "happens all the time," [201] and the driller confirmed that he had seen these results before.[202]	• Situation awareness (gathering information, understanding information and risk status, anticipating future state/developments); • Decision making (identifying and assessing options); • Implementing and reviewing decisions
Other crewmembers questioned the bladder effect explanation but ultimately agreed with the rationale.[203]	• Teamwork (resolving disparate opinions/conflict);

[200] There is limited testimony pertaining to the negative tests, and even where testimony exists, witnesses tend to contradict each other. The individuals most involved in the negative test discussion either refrained from giving testimony to the CSB and other post-incident civil and criminal hearings, or they did not survive the incident.

[201] The Toolpusher, who had significant on-the-job experience and received noteworthy remarks in his performance review as "extremely competent" and someone who "does all within his level of authority to prevent exposure to potentially compromising situations." Internal Company Document, Transocean. *2009 Senior Supervisor Performance Appraisal - Performance Appraisal and Development Plan*, October 31, 2009, TRN-MDL-08076982, http://www.mdl2179trialdocs.com/releases/release201303071500008/TREX-52649.pdf (accessed October 7, 2015).

[202] Internal Company Document, BP. *Notes from Bob Kaluza Interview*, April 28, 2010, BP-HZN-MBI00021276, see Exhibit 0005 http://www.mdl2179trialdocs.com/releases/release201302281700004/Daigle_Keith-Depo_Bundle.zip (accessed October 7, 2015).

[203] Hearing before the Deepwater Horizon Joint Investigation, July 20, 2010 pp 90-91; Internal Company Document, BP. *Notes from Don Vidrine Interview*, April 27, 2010, BP-HZN-MBI00021424, see Exhibit 0006 http://www.mdl2179trialdocs.com/releases/release201302281700004/Pleasant_Christopher-Depo_Bundle.zip (accessed October 7, 2015).

	• Communication (asking questions; being assertive); • Situation awareness (understanding information and risk status)
The day shift WSL deferred to the toolpusher, saying "if you have seen this so many times before, it must be true."[204]	• Situation awareness (understanding information and risk status); • Decision-making (identifying and assessing options; • Implementing and reviewing decisions); • Communication (asking questions)
The night shift WSL coming on duty during the middle of the negative test process was teased for questioning the annular compression rationale.[205]	• Teamwork (resolving disparate opinions/conflict, understanding role within team); • Communication (asking questions; being assertive); • Situation awareness (understanding information and risk status); • Leadership (planning and directing)
The same WSL focused on performing the negative test as stated in the permit submitted to the regulator. When the test on the kill line was conducted, as stipulated in the permit, there was no flow for 30 minutes which he took as confirmation that the well was secure.	• Situation awareness (understanding information and risk status); • Decision-making (identifying and assessing options; • Implementing and reviewing decisions); • Communication (asking questions)
The night shift WSL reported looking for changes in the pressure readings rather than the absolute pressure in the well. As a result, although 1400 psi was indicated on the drillpipe, it remained stable, which he stated indicated to him that no gas was coming up the well.[206]	• Situation awareness (understanding information and risk status); • Decision-making (identifying and assessing options, implementing and reviewing decisions); • Communication (asking questions)
There was a lack of explicit coordination with the mudlogger and a need for the well operations crew and mudlogger to articulate their expectations for the mudlogger's monitoring	• Situation awareness (gathering information; understanding information and risk status); • Decision-making (identifying and assessing options; communicating the options chosen);

[204] Internal Company Document, BP. *Notes from Bob Kaluza Interview*, April 28, 2010, BP-HZN-MBI00021277, see Exhibit 0005 http://www.mdl2179trialdocs.com/releases/release201302281700004/Daigle_Keith-Depo_Bundle.zip (accessed October 7, 2015).

[205] Internal Company Document, BP. *Notes from Don Vidrine Interview*, April 27, 2010, BP-HZN-MBI00021424, see Exhibit 0006 http://www.mdl2179trialdocs.com/releases/release201302281700004/Pleasant_Christopher-Depo_Bundle.zip (accessed October 7, 2015).

[206] *Ibid*., BP-HZN-MBI00021424,

role throughout the displacement stages.[207] (See also Sections 1.6 and 1.7.1.1.)	• Communication (giving feedback; asking questions; being assertive); • Teamwork (understanding role within team; coordinating tasks with team members)

Decision-making is a two-stage cognitive process: (1) what is the problem (situation assessment) and (2) what shall I do?[208] The situation assessment of the negative test was inaccurate. “If the situation assessment is incorrect, then it is likely that the resulting decision and selected course of action that is taken in response will not be suitable.”[209] This can occur when “conditions change so insidiously that the operators do not update their situation assessments often enough”, and when “the current situation has altered to some extent from the expected situation and that remedial actions are required to return to the planned path.”[210] “Sources of failure in team decision-making, according to Orasanu and Salas (1993), include poor communication, logical errors, inadequate situation assessment and pressure to conform.”[211]

The evidence described in Table 1-5 suggests that improvements in non-technical skills of personnel involved in offshore well operations decision-making and implementation would benefit major accident prevention.[212]

1.7.1.1 Role of Mudlogger

During displacement of the riser, communication was inadequate. The mudlogger was identified post-incident as a perceived independent layer of protection, yet he was not privy to all pertinent information to fulfill this protective role. Indeed, there was not a shared situation awareness of the well, in part because the mudlogger was separate from the well operations crew and unaware of the rig activities that impacted his understanding of the data he was meant to monitor.

Communication in offshore operations, like any high-hazard work environment, is vital for successful completion. Figure 1-12 shows the various communication channels expected to be effectively functioning during drilling and completion activities.

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[207] Both explicit coordination and articulated expectations are characteristics of highly effective teams. See Flin, R.; O'Connor, P.; Crichton, M. *Safety at the Sharp End;* Ashgate Publishing: Hampshire, England, 2008, p 109.

[208] *Ibid*., p 45.

[209] *Ibid*., p 46.

[210] *Ibid*.

[211] *Ibid*., p 113. IOGP. *Crew Resource Management for Well Operations;* 501, April 2014, p, 12. http://www.ogp.org.uk/pubs/501.pdf (accessed October 7, 2015).

[212] Others have analyzed the effectiveness of non-technical skills usage at Macondo. For example, Roberts, Flin and Cleland examined the well operation crew’s situational awareness via content analysis of eight official investigation reports of the event as well as eight transcripts from two court hearings. See Roberts, Flin & Cleland. Everything was fine: An analysis of the drill crew’s situation awareness on Deepwater Horizon. *Journal of Loss Prevention in the Process Industries (38),* 2015, pp 87-100.

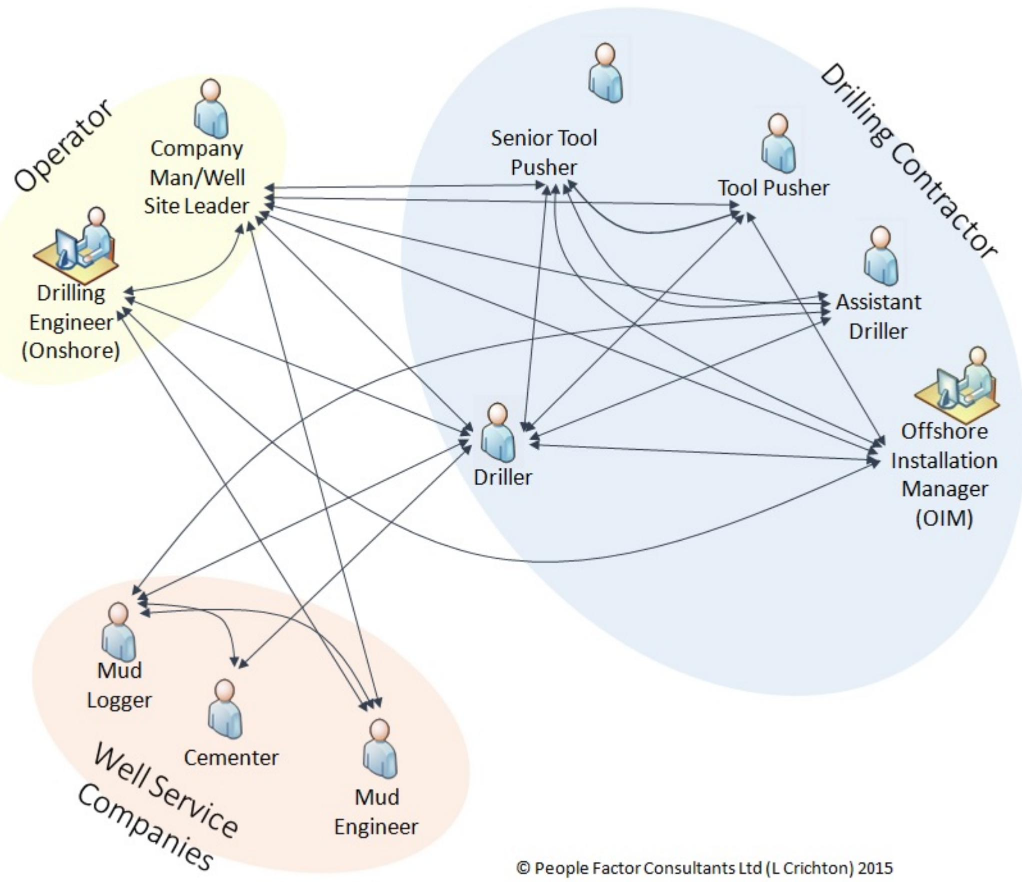

Figure 1-12. Intricate Communication Routes of Well Operations Personnel.

Both mudloggers gave testimony post-Macondo that they were uncomfortable with the multiple fluid movements and transfers between pits and off the rig.[213] While the day mudlogger voiced concerns, the transfers continued.[214] The night shift mudlogger confirmed that he did not speak up about this discomfort.[215] Considering the hierarchical organizational structure of the rig, the well service provider, as a client of the operator (i.e., BP), is perceived to be below that of the driller and assistant driller who are primary members of well control operations crew. A hesitation to be assertive with concerns by "lower" ranking individuals was a critical interpersonal behavior that CRM was meant to counter in the aviation industry.

[213] Hearing before the Deepwater Horizon Joint Investigation, December 7, 2010, pp 31-32; Internal Company Documents, BP. *Interview with Service Data Mudlogger*, May 26, BP-HZN–BLY00161924.

[214] Internal Company Documents, BP.

[215] Hearing before the Deepwater Horizon Joint Investigation, December 7, 2010, pp 31, 181.

Four transfers occurred between 9:10 p.m. and 9:35 p.m., and the displacement went to two pits. The night shift mudlogger attributed these fluid transfers to some of the data he was seeing.[216] There is some conflicting testimony by the mudlogger regarding if and how often he communicated with others from the well operations crew (e.g., the assistant driller, a mud engineer) concerning the rig activities and well data in the hours leading up to the release of mud onto the rig (Table 1-6). However, various purported exchanges between him and other well operations crew evinces a need for improved communications, including adequate feedback that the verbal messages and their implications were understood, as well as sufficiently shared situation awareness of the well and rig conditions among the entire well operations crew.

The testimony highlighted in Table 1-6 illustrates the challenges faced by the mudlogger. Communication is more difficult when the parties are not co-located. The mudlogger was only a short distance from the driller's cabin, but he was not privy to the same visual[217] and verbal information, nor to the context of that information.

Good practice guidance created post-Macondo identifies the mudlogger as "top priority" support personnel within the wells operations team (along with the roughneck and derrickman). As such, mudloggers should receive NTS training along with the driller, assistant driller, toolpusher, company man (i.e., WSL), drilling supervisor, rig manager, superintendent, and well services supervisor.[218] Improvements in team communication, both in training and in everyday application of this non-technical skill, between the various wells operations personnel would be beneficial. If the mudlogger had the requisite NTS, the limited access to well information that hindered his ability to act as an independent layer of protection might have been overcome.

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[216] Hearing before the Deepwater Horizon Joint Investigation, December 7, 2010, pp 218-219.

[217] Hearing before the Deepwater Horizon Joint Investigation, December 7, 2010, p 122.

[218] IOGP. *Crew Resource Management for Well Operations;* 501; April, 2014; Table 1, p 6. http://www.ogp.org.uk/pubs/501.pdf (accessed October 7, 2015).

Table 1-6. Summary of communications between Mudlogger and Other Well Operations Crewmembers the evening of April 20, 2010.

Date and Source of Testimony	Transcript excerpts and information concerning the Mudlogger's communication with others from the well operations crew
December 7, 2010 Joint United States Coast Guard/Bureau of Ocean Energy Management Investigation	When he noticed that the mud pumps were being brought online in a "staggering" manner during the final displacement and called an assistant driller to find out why, the assistant driller said, "That's the way we're going to do it this time."[219] He also spoke with the mud engineer when he noticed a gain in one of the active pits, although he could not recall the time. The mud engineer informed him that "they were moving mud out of some sand traps."[220] No other communications with the well operations crew during his shift were identified.[221]
March 13, 2013 United States District Court, Eastern District of Louisiana, Civil Action no. 10-MD-2179 "J"	Based upon examination of the data post-incident, at around 9:13 p.m. he noticed that the mud pumps were being brought online in a "staggering" manner.[222] He called an assistant driller to find out why, and the assistant driller "said, we're just doing it like that. He abruptly hung up."[223] Within minutes, he noted a spike in the standpipe pressure.[224] He called again to inquire, and was told that the crew, "had a valve lined up wrong, and we blew a pop-off, and we're sending a crew down there."[225] No other information was provided to him regarding the matter.[226] Earlier in his shift, around 8:30 p.m., the mudlogger called the mud engineer regarding a slow gain he was detecting in the active pit, and the engineer said that "they were flushing out one of the sand traps into the active pit."[227] Prior to that time, no one informed the mudlogger that this activity was to be undertaken.[228] Overall, he was not informed about the fluid movements occurring onboard the rig the evening of April 20.[229]

219 Hearing before the Deepwater Horizon Joint Investigation, December 7, 2010, pp 177 and 216.

220 *Ibid*, pp 178-179.

221 *Ibid*, pp 177-178.

222 Hearing before the U.S. District Court for the Eastern District of Louisiana under the Multi-District Litigation docket MDL No. 2179, March 13, 2013, pp 3605- 3606, http://www.mdl2179trialdocs.com/releases/release201303131200011/2013-03-13_BP_Trial_Day_11_AM-Final.pdf (accessed October 7, 2015).

223 *Ibid*.

224 *Ibid.*, pp 3606-3607.

225 *Ibid.*, pp 3605-3606.

226 *Ibid.*, p 3606.

227 *Ibid.*, p 3527-3528.

228 *Ibid.*, p 3528.

229 *Ibid.*, p 3603.

1.7.2 Case Study for NTS: Conversation between Well Site Leader and Onshore Engineer

This section dissects the purported phone conversation between the on-rig Well Site Leader (WSL) and the onshore Drilling Engineer (for simplicity, in this section referred to as ODE). Much focus was given to this conversation in the aftermath of the incident, as it was deemed a critical opportunity when the crew could have identified loss of well control and taken actions to secure the well.

The conversation was noted in interview summary write-ups conducted shortly after the incident,[230] before many of the facts of the incident were known (Table 1-7). In the months after Macondo, both individuals took legal positions that protected them from giving sworn testimony at various civil and criminal legal proceedings. The CSB was unable to interview either individual directly, thus must restrict its analysis to the one existing trial deposition[231] and the summaries of others. Nevertheless, the CSB identifies opportunities for NTS improvement by examining the description of the phone conversation from the perspective of both individuals.

Examining the conversation between the WSL and the ODE from each perspective gives clues as to the individuals' situation awareness of the well conditions and the perceived purpose of the call. The WSL appears to be focused on the cement plug and the method for setting it.[232] When the ODE suggests something may not be right with the negative test results, the WSL seems to dismiss conversation about the negative test, trying to refocus the ODE on the cement plug. The WSL reiterates that the negative test was redone and the results were good. There is ambiguity about whether the pressure difference between the drillpipe and kill line was a problem only initially or with all negative tests. The WSL was seeking one-way communication (seeking info on setting the surface plug), not seeking feedback and advice on the negative test.[233] The purpose of the phone calls and the respective roles of the WSL and ODE are ambiguous and varied—sometimes to inform and other times to obtain information, advice, or instruction.

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[230] BP Well Site Leader was interviewed by the BP Investigation Team on April 23 and 27, 2010, May 7 and 12, 2010; Internal Company Documents, BP. *Interview of Donald Vidrine, Well Site Leader on the Horizon Rig*, April 23, 2010, TRN-MDL-00265598, see Exhibit 3572 http://www.mdl2179trialdocs.com/releases/release201304041200022/Kaluza_Robert-Depo_Bundle.zip (accessed October 7, 2015) and *Notes from Don Vidrine Interview*, BP-HZN-MBI00021424, 21427, 21429, see Exhibit 0006 http://www.mdl2179trialdocs.com/releases/release201302281700004/Pleasant_Christopher-Depo_Bundle.zip (accessed October 7, 2015). BP Senior Drilling Engineer was interviewed by the BP Investigation Team on May 2, 2010 and July 8, 2010; Internal Company Documents, BP. *Interview of Mark Hafle - Sr. Drilling Engineer*, May 2, 2010, see Exhibit 0300, http://www.mdl2179trialdocs.com/releases/release201302281700004/Martin_Brian-Depo_Bundle.zip (accessed October 7, 2015) and *BP Incident Investigation Team - Notes of Interview with Mark Hafle*, July 8, 2010, BP-HZN-BLY00103037, see Exhibit 0296 http://www.mdl2179trialdocs.com/releases/release201302281700004/Cowie_James-Depo_Bundle.zip (accessed October 7, 2015).

[231] USA v. Robert Kaluza, Docket No. 12-CR-265, February 18, 2016.

[232] In his February 18, 2016, testimony, the WSL states that he does not recall why he called the ODE, but he knows it was not to discuss the negative test. USA v. Robert Kaluza, Docket No. 12-CR-265, February 18, 2016, pp 470:17-471:6.

[233] The WSL confirms the purpose of the call as informational in his February 18, 2016 testimony. USA v. Robert Kaluza, Docket No. 12-CR-265, February 18, 2016, pp 471:7-472:24, 511:12-19.

Table 1-7. Interview statements concerning conversation between the on-rig Well Site Leader (WSL) and the onshore drilling engineer (ODE); names have been replaced with title abbreviations.

Interview	Excerpts from Interview Notes/Summaries	Assessment of the Interpersonal Behaviors being described and the Identified Potential Non-technical Skills Failures
WSL Interview April 27, 2010	Called ODE to discuss surface plug. [Later in the testimony] ODE called back while displacing @ +/- 9 p – not sure why he called – curious about how things going.[234]	Reveals uncertainty about the purpose of the call – communication (briefing, asking questions); – teamwork (understanding role, coordinating tasks)
WSL statements as summarized by various interviewers (same interview)	Called ODE to discuss surface plug, said still watching stripping tank, dripping had stopped and everything looked fine.[235]	Purpose of call appears to be for the WSL to inform only, not seek counsel. – teamwork (understanding roles)
	ODE calls to check. He tells ODE negative test was squirrelly. Told ODE no problems.[236] The 1400 psi was the difference between the mud in the riser. This was annular compression – they (toolpusher, etc) said it does that all the time. If we have 1400 psi on the drill pipe we should see it on the kill line? Let's bleed it off and see—the kill line was bled then stopped.	Problem noted ("squirrelly" results), but not explored fully by either party – situation awareness (gathering information, understanding information and risk status, anticipating future states) – communication (briefing and giving feedback, listening, asking questions, being assertive [on the part of the ODE]) – leadership (planning, directing, supporting)
	I then went to call ODE. When I came back they were still watching the stripping tank and the dripping had stopped. Everything looked fine. [Later in the testimony] I talked to ODE about the 1400—said that if there had been a kick in the well we would have seen it.[237]	Information is shared between the WSL and ODE implies that the possibility of a kick is not absent from their mindsets ("if there had been a kick in the well, we would have seen it"), but further discussion on this point is absent by either party.

[234] Internal Company Document, BP. *Steve R. Notebook*, BP-HZN-MBI00021407, see Exhibit 4953 http://www.mdl2179trialdocs.com/releases/release201302281700004/Farr_Daniel-Depo_Bundle.zip (accessed October 7, 2015).

[235] Internal Company Document, BP. *Interview Notes Don Vidrine*, BP-HZN-MBI00021424, see Exhibit 4953 http://www.mdl2179trialdocs.com/releases/release201302281700004/Farr_Daniel-Depo_Bundle.zip (accessed October 7, 2015).

[236] Internal Company Document, BP. *Interview Notes Don Vidrine (Kent C. handwritten notes)*, April 27, 2010, BP-HZN-MBI00021415, see Exhibit 4953 http://www.mdl2179trialdocs.com/releases/release201302281700004/Farr_Daniel-Depo_Bundle.zip (accessed October 7, 2015).

[237] There are several sets of notes from the various interviews conducted by BP post incident; according to testimony given in the Multi-District Litigation hearing, the following document is a compilation of all interviewers' notes from the April 27, 2010 interview: Internal Company Documents, BP. See Exhibit 0303, http://www.mdl2179trialdocs.com/releases/release201302281700004/Martin_Brian-Depo_Bundle.zip (accessed October 7, 2015); Testimony given in the U. S. District Court for the Eastern District of Louisiana under the Multi-District Litigation docket MDL No. 2179, February 21, 2011 pp 34-35, see Martin Designations, http://www.mdl2179trialdocs.com/releases/release201302281700004/Martin_Brian-Depo_Bundle.zip (accessed May 22, 2015); Internal

		– situation awareness (gathering information, understanding information and risk status, anticipating future states) – communication (briefing and giving feedback, listening, asking questions, being assertive [on the part of the ODE]) – leadership (planning, directing, supporting)
ODE Interview May 2, 2010 ODE statement as summarized and compiled by various interviewers	While watching monitors of rig activity while he worked he received a call at 8:52 pm from WSL. Loss the phone connection—he called WSL back. WSL asked if they were going to test the plug? ODE asked WSL, "What's going on?" WSL said the day crew screwed up the inflow test and he had to go up and run another test. ODE asked WSL if everything was OK? WSL replied that nothing came out of the kill line. ODE said good night and hung up the phone.	Problem with negative test raised as a tangential item to the main purpose of the call, to ask the ODE about the surface plug. The WSL was not calling to seek counsel on the negative test, but shared info when prompted by ODE. Based on limited information shared and the manner of the exchanges, it appears the WSL provides answers to ODE's questions to inform. When the ODE asks about the test problem, The WSL shares very little information, and the ODE does not probe for additional information. The ODE does not request a follow-up. – situation awareness (gathering information, understanding information and risk status, anticipating future states) – communication (briefing and giving feedback, listening, asking questions, being assertive) – teamwork (understanding role); – leadership (planning, directing, supporting)
ODE Interview July 8, 2010 ODE statement as summarized and compiled by various interviewers	Later, on April 20, 2010, WSL called ODE at 8:52 p.m. to talk about how to test the surface plug and whether they should apply a pressure test or a weight test. ODE noted that WSL also talked to him about the negative tests. WSL told ODE that the crew had zero pressure on the kill line, but that they still had pressure on the drillpipe. ODE said he told WSL that you can't have pressure on the drillpipe and zero pressure on the kill line in a test that's lined up properly. ODE said that he told WSL he might consider whether he had trapped pressure in the line or perhaps he didn't have a valve properly lined up. WSL told ODE that he was fully satisfied that the rig crew had performed a successful negative test. ODE said he didn't have the full context for what had transpired during the tests and it wasn't clear to him whether WSL was talking	Purpose of the call was to discuss the surface plug; discussion of negative test was tangential to that purpose. When sharing the observed pressure data from the negative test, the ODE identifies a problem ("you can't have pressure on the drill pipe and zero pressure on the kill line in a test that is properly lined up"), and identifies a potential solution. Yet the WSL rejects the suggestion of a problem ("fully satisfied"). ODE accepts judgment of WSL, assuming lack of context. He was at an onshore location separate from the crew, not part of the immediate team

Company Document, BP. *Interview Notes Don Vidrine (Kent C. handwritten notes)*, April 27, 2010, BP-HZN-MBI00021419-00021420, see Exhibit 4953 http://www.mdl2179trialdocs.com/releases/release201302281700004/Farr_Daniel-Depo_Bundle.zip (accessed October 7, 2015).

	about the first or second negative tests. WSL told him he watched the kill line for 30 minutes and didn't see a drip come out of it, so ODE assumed that WSL had concluded that it was not a problem.[238]	conducting the work. ODE admits to lack of clarity but did not explore the issue further. WSL provides ODE with evidence (lack of flow for 30 minutes on kill line) to further support is judgment. – situation awareness (gathering information, understanding information and risk status, anticipating future states) – communication (briefing and giving feedback, listening, asking questions, being assertive [on the part of the ODE]) – teamwork (understanding role—was ODE meant to verify well data/decisions or only provide counsel when requested?) – leadership (planning, directing; supporting)

[238] Internal Company Document, BP. *BP Incident Investigation Team - Notes of Interview with Mark Hafle*, July 8, 2010, BP-HZN-BLY00103032, http://www.mdl2179trialdocs.com/releases/release201303071500008/TREX-00296.pdf (accessed October 7, 2015).; Testimony given in the U. S. Districk Court for the Eastern District of Louisiana under the Multi-District Litigation docket MDL No. 2179, April 9, 2013, pp 16-23, http://www.mdl2179trialdocs.com/releases/release201304090900024/2013-04-09_BP_Trial_Day_24_PM-Final.pdf (accessed May 22, 2015).

The WSL and ODE faced a number of challenges to effective communication the night of April 20, 2010. The offshore-onshore arrangement for this work team hinders its ability to have a shared understanding of the contextual aspects of the work environment and engenders a lack of awareness of each other's roles and responsibilities.[239] While the ODE had access to rig-based data on the well, it is not clear to what extent the ODE perceived, comprehended, or analyzed that data. In theory, such shared computer systems are meant to improve communication and understanding, but research shows that "information exchange is often less complete and the discussion more biased."[240]

Interestingly, post-incident the ODE stated that he couldn't determine if the well was flowing from the data at his disposal because he didn't know what was occurring on the rig, and he criticized the mudlogger company for less-than-desirable well monitoring performance. Yet the ODE had the same Sperry Sun software and rig data available to monitor as the mudlogger.[241] Along the same lines as the drilling engineer, the mudlogger was not fully abreast of what was occurring on the rig during the time he was expected to monitor the well for flow. Additionally, when returns were routed overboard, the volume of fluids leaving the well could not be monitored. [242]

Other seemingly ancillary factors may also have influenced the conversation between the WSL and ODE. For example, whether the individuals were relative strangers or long-time acquaintances could influence the tone and style of the discussion, as well as unspoken agreements about the purposes of such calls. A less formal, more casual informational conversation would be more typical of the latter, even when organizational hierarchies may suggest otherwise. In this case, however, the organizational hierarchy within BP was such that the ODE did not have direct line management accountability over the WSL.[243] He was not meant to instruct or give orders but to counsel, and it appears that this counsel could be freely given or solicited; thus, neither party expected the ODE to explicitly probe or verify the decisions of the WSL. As far as they were both concerned, the point of the call was to discuss the next steps in the temporary abandonment process, and the discussion of the negative test was incidental to the call.

This organizational arrangement may not be atypical for industry. The onshore drilling engineer, while identified as part of the larger group of well operations team, is not included in the top 17 wells roles

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[239] Flin, R.; O'Connor, P.; Crichton, M. *Safety at the Sharp End;* Ashgate Publishing: Hampshire, England, 2008, p 77.

[240] *Ibid*.

[241] Internal Company Document, BP. *BP Incident Investigation Team - Notes of Interview with Mark Hafle*, July 8, 2010, BP-HZN-BLY00103037, see Exhibit 0296 http://www.mdl2179trialdocs.com/releases/release201302281700004/Cowie_James-Depo_Bundle.zip (accessed October 7, 2015), and Hearing before the U.S. District Court for the Eastern District of Louisiana under the Multi-District Litigation docket MDL No. 2179, February 10, 2011, see Corser designations Vol 1, pp 83-84, http://www.mdl2179trialdocs.com/releases/release201302281700004/Corser_Kent-Depo_Bundle.zip (accessed October 7, 2015).

[242] The Senior Toolpusher noted: "There was no way to monitor the volume of what was dumped overboard;" Internal Company Document, Transocean. *Senior Toolpusher Interviewing Form*, May 28, 2010, TRN-MDL-00493744, http://www.mdl2179trialdocs.com/releases/release201304041200022/TREX-50296.pdf (accessed October 7, 2015).

[243] National Commission on the BP Deepwater Horizon Oil Spill and Offshore Drilling. *Chief Counsel's Report: The Gulf Oil Disaster;* Feburary 17, 2011, p 31.

examined for CRM applicability in the latest offshore guidance.[244] This suggests that the role of the ODE in such a situation had not been identified as a critical opportunity for decision-making input into well operations.

In the aftermath of Macondo, assertions have been made that this conversation should have led to a decision to shut-in the well. If communication between shore engineering support is to be designated a useful barrier for the mitigation of well influx, then roles and responsibilities for both parties must be explicitly defined. The development and incorporation of NTS into everyday practices within the work environment often includes improved protocols for communication, decision-making, and role clarity that would improve performance for a wide range of interpersonal relationships.

1.7.3 Integration of Non-technical Skills

To improve team interactions and counter situations such as in the examples above, the aviation industry (and other high-hazard industries, such as nuclear) introduced crew resource management into the everyday operational performance of flight crews. In 2006 the NTSB placed CRM improvements on its Most Wanted List, and five years later the Federal Aviation Administration (FAA) published the final rule to require CRM training for all crewmembers, including pilots and flight attendants.[245]

In the oil and gas industry, the concept of non-technical skills is not completely foreign. The UK offshore regulator, the Health Safety Executive (HSE), honed in on the importance of non-technical skills for line management personnel when it conducted a 2010 human and organizational factors inspection of four Transocean rigs in the North Sea. The HSE identified an absence of training for supervisors, including OIMs and senior/say toolpushers, in interpersonal leadership capabilities, finding that a number of these supervisors were put in managerial positions "with no skills or training to support them in this role."[246] The inspection noted that interviews with personnel revealed "there is no training once staff are promoted above driller level … This reinforces the view that training is focused on technical skills, rather than management or non-technical skills."[247] These inspection findings are relevant when considering that some of the primary decision-makers on the negative test results were the Transocean toolpushers and OIM, as well as the BP Wells Site Leaders.[248] Transocean and BP are not unique. Industry has acknowledged needed improvements in the non-technical skills of offshore facility personnel. In its report on the lessons learned from the Deepwater Horizon, OLF suggested CRM be considered for well activities on the Norwegian Continental Shelf.[249] And various international industry associations have

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[244] IOGP. *Crew Resource Management for Well Operations;* 501; April, 2014, Table 1, p 6. http://www.ogp.org.uk/pubs/501.pdf (accessed October 7, 2015).

[245] NTSB, We are safer, http://www.ntsb.gov/safety/mwl/Pages/was2.aspx, (accessed October 9, 2015)

[246] HSE, Specialist Inspection Report, Offshore Division Human and Organizational Factors Team. *Transocean-Human & Organizational Factors Intervention;* July - October, 2009, p 4.

[247] *Ibid*., pp 23-25, 27.

[248] National Commission on the BP Deepwater Horizon Oil Spill and Offshore Drilling. *Deep Water The Gulf oil Disaster and the Future of Offshore Drilling;* 2011, pp 107-109.

[249] Norwegian Oil Industry Association (OLF). *Deepwater Horizon: Lessons learned and follow-up;* May, 2012; Section 2.3.9, pp 29-30, recommendation No. 29.

since developed non-technical skills training guidance,[250] while some companies are exploring methods of incorporating such skill development into the curriculum of their offshore personnel. Yet, at this time, no US regulatory requirements or guidance for such training have been established.

It has been suggested that an organization that embodies the characteristics of an HRO (high reliability organization) encourages and continually develops the non-technical skills expertise of its personnel.[251] Training, practice, and assessment of people's NTS must be an integral part of everyday activity. "[T]he level of transfer will depend on the prevailing organizational culture at the worksites …. The training instructions have to be reinforced at the worksite, where observation and constructive feedback on well crewmembers' non-technical skills should become part of the normal way of operating at the worksite. The language of CRM should become part of everyday worksite discussions."[252] Furthermore, "the course content should be informed by an ongoing human factors analysis of task performance during well operations, especially in relation to the detection and management of control problems."[253] Finally, communication training should be an inherent component of each module of CRM training, and standard communication terminology and phraseology should be embedded within technical training so that good communication practices are intimately associated with the technical aspects of the work.[254]

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[250] IOGP produced two guidance documents, *Crew Resource Management for Well Operations;* Report No. 501, April, 2014. http://www.ogp.org.uk/pubs/501.pdf (accessed October 7, 2015) and *Guidelines for Implementing Well Operations Crew Resource Management training*, Report No. 502, December 2014; http://www.iogp.org/pubs/502.pdf (accessed October 7, 2015); Oil & Gas UK published *Guidelines on Competency for Wells Personnel, Issue 1* (January 2012); the Energy Institute developed *Guidance on Crew Resource Management (CRM) and Non-technical Skills Training Programmes, 1st ed.,* 2014. Also, the International Association of Drilling Contractors offers a resource database of both technical and non-technical competencies for a wide array of offshore job positions, see http://www.iadc.org/knowledge-skill-and-ability/.

[251] Thorogood, J. L.; Crichton, M. T. Threat-and-error management: the connection between process safety and practical action at the worksite; *SPE Drilling & Completion* 2014**,** *December,* pp 465-471.

[252] IOGP. *Crew Resource Management for Well Operations;* 501, April, 2014, p 19. http://www.ogp.org.uk/pubs/501.pdf (accessed October 7, 2015).

[253] *Ibid*.

[254] *Ibid*.

Non-technical Skills and Organizational Culture

In the post-Macondo world, increasing personnel proficiency in NTS is critical for those working in the dynamic and high-hazard offshore work environment. However, training on NTS is not enough. Like so many other safety system components, inculcating non-technical skills will be successful only if the organization itself places importance on it. Evolving to high levels of operational discipline will promote NTS usage in everyday activity. [†]

[†] Thorogood, J. L.; Crichton, M. T. Threat-and-error management: the connection between process safety and practical action at the worksite; *SPE Drilling & Completion* 2014**,** *December*, pp 465-471.

Drilling is increasing in complexity as wells are drilled at greater and greater depths with high degrees of coordination between various companies (operators, drilling contractors, multiple well service providers) with specialized expertise. Such complexity impairs predictability of all potential safety challenges; thus, risk assessments of such operations will likely not identify all of the possible scenarios. Variability is inevitable, and NTS or CRM training will help prepare personnel and management to be resilient to that variability.

1.8 Work-as-Imagined Versus Work-as-Done: The Operator/Drilling Contractor Gap

Offshore drilling and well completion involves the complex interaction of multiple employers, including the leaseholder/operator (e.g., BP) and drilling contractor (e.g., Transocean), and other essential service providers (e.g., Sperry Sun[255]). In offshore drilling operations, the drilling contractor brings the infrastructure (drilling rig), supplies the majority of the workforce, and has more direct control over the primary operations (drilling) and emergency response (well control). The operator, though, is responsible for the well's design and drilling program, which form the basis for establishing safe drilling operations, and should account for site-specific conditions that could increase the risk or complexity of the contractor's various drilling and well control operations.

Successful execution of a drilling program requires that the operator and the drilling contractor actively work to bridge the gap between work-as-imagined (WAI) in the drilling program and work-as-done (WAD) by the well operations crew. [256] In essence, WAI describes what well designers and managers expect will or should happen at the well, while WAD is what the well operations crew actually does. There is a natural gap between WAI and WAD because it is not possible to write a drilling program that

[255] See Volume 1, p 9 for a description of other well service providers hired by BP to help drill the Macondo well.

[256] Dekker, S., Chronicling the Emergence of Confused Consensus: Work as Imagined versus Work as Actually Done, chapter 7, pp 86-90, within Hollnagel, E., Woods, D.D., and Leveson, N., eds., *Resilience Engineering: Concepts and Precepts*, Ashgate Publishing: Hampshire, England, 2006.

foresees all circumstances and covers every detail, or that crewmembers can follow exactly as written.[257] Reality and necessity require that well operations crews continually adjust to accommodate current work conditions in order to achieve the desired work goals.

To minimize that gap between WAI and WAD in offshore drilling, the operator and drilling contractor generally rely upon the knowledge and experience of their well site leaders and well operations crew, but they should also focus on building a resilient process that can "adjust its functioning prior to, during or following changes and disturbances so that it can sustain required operations under both expected and unexpected conditions."[258] Ideally, the safety management systems of the operator and drilling contractor will reinforce one another (and sometimes overlap) to continually develop a workforce adept in technical and non-technical skills, evaluate various well and rig specific scenarios, create rig/well specific procedures, and identify risk reduction measures. If done effectively, this process would help maximize drilling contractor or operator practices that lead to a more resilient process which can adapt to and successfully manage the evolving risk of a drilling operation.

Numerous Macondo investigation reports commented on the minimal detail provided to the Deepwater Horizon crew for the negative test and temporary abandonment procedures, [259] but it is important to review the operational structures in both companies that permitted the situation to evolve as it did. To deconstruct the gap between WAI and WAD that occurred at the Macondo well, this section explores BP's development and communication of the temporary abandonment plan, the Deepwater Horizon's displacement and negative test procedures, and both companies' management of change programs. By exploring these topics, the CSB demonstrates how to minimize the WAI and WAD gap.

This analysis highlights the following key findings:

- BP's development of the Macondo Temporary Abandonment (TA)[260] plan occurred without a formal process, creating conditions for a TA design that lacked assessment of decisions, including review of internal policies and standards for quality control;

[257] Dekker, S., Chronicling the Emergence of Confused Consensus: Work as Imagined versus Work as Actually Done, chapter 7, p 86, within Hollnagel, E., Woods, D.D., and Leveson, N., eds., *Resilience Engineering: Concepts and Precepts*, Ashgate Publishing: Hampshire, England, 2006.

[258] Hollnagel, E. Prologue: The Scope of Resilience Engineering. In *Resilience Engineering in Practice: A Guidebook;* Hollnagel, E., Paries, J., Woods, D. D., Wreathall, J., eds.; Ashgate: Surrey, UK, 2011, p xxxvi.

[259] National Academy of Engineering and National Research Council of the National Academies. *Macondo Well – Deepwater Horizon Blowout: Lessons for Improving Offshore Drilling Safety;* The National Academies Press: Washington, D.C., 2011, p 32.; BP. *Deepwater Horizon Accident Investigation Report;* September 8, 2010; pp 85.; Transocean. *Macondo Well Incident: Transocean Investigation Report Volumes I and II;* June, 2011; pp 85-86.; USCSB, 2014. *Explosion and Fire at the Macondo Well, Gulf of Mexico, April 20, 2010,* Report No. 2010-10-I-OS, Appendix 2-A, p 42, http://www.csb.gov/assets/1/19/Appendix_2_A__Deepwater_Horizon_Blowout_Preventer_Failure_Analysis1.pdf (accessed October 7, 2015), June 2014.

[260] While the Macondo TA plan included choices on the production casing design (e.g., long string vs. liner, Sizes/grades of pipe, etc.) and other abandonment features (e.g., BOP/riser retrieval, rig clean-up, surface cement plug etc.), for purposes of the CSB analysis in this Volume, the TA plan discussion will be limited to the negative test and displacement of the well. The CSB previously discussed the placement of the surface cement plug; Volume 1, pp 18, 25.

- BP sent a final written "Forward Plan" to the Transocean well operations crew concerning the TA plan on April 16, 2010, and those instructions lacked any mention of the negative test. Ultimately, a drilling fluids specialist from M-I SWACO provided written negative test instructions to the well operations crew on the afternoon of April 20.[261]
- Post-incident, BP described the negative test procedure as "broad, operational guidelines" and that it expected the Deepwater Horizon rig crew to use "the method consistent with their regular practice on prior wells."[262] The broad nature of the procedure implies that the Transocean drilling team and BP well site leaders would deal with any problems occurring during the TA plan by employing their knowledge, experience and skills. Missing from the process were tools that could have minimized the gap between WAI and WAD, such as written work plans or safety critical procedures.
- Transocean did not enforce its own policy to utilize written Standing Instructions to the Driller, which a previous Transocean incident investigation noted should "raise awareness and […] highlight" underbalanced conditions in a well when a single barrier is present.[263]
- The lack of safety critical task identification or incorporation of hazard controls in the TA procedures provided to the Deepwater Horizon crew did little to emphasize or optimize crew performance;
- Transocean did not follow its corporate policies to meaningfully engage the workforce in managing risks posed by an activity through identifying effective barriers. (1) Transocean did not develop written safety critical procedures for negative tests and displacement of a riser, even though internal Transocean policies required them for the Macondo well. (2) Generic Deepwater Horizon safety critical procedures for displacement and negative tests did not identify potential major accident events like loss of well control or a blowout. Most of the identified hazards focused on personal safety or relatively minor spills of drilling mud on the rig and overboard. (3) Transocean was unable to identify an operational safety critical procedure that addressed the lineup of the diverter system for either normal or non-normal (i.e., emergency) operating conditions.

1.8.1 BP's Development and Communication of the Temporary Abandonment Plan

BP manages the development and delivery of a well through a five stage-gate process that incorporates peer review by sub-surface specialists (geologists and geoscientists) as well as engineering and

[261] See discussion in Section 1.4 and summary of instruction in Table 1-3 for more details.

[262] BP. *Deepwater Horizon Accident Investigation Report*; September 8, 2010, p 85.

[263] Internal Company Document, Transocean. *Operations Advisory*, NRS-OPS-ADV-008, April 14, 2010, Exhibit 5749, TRN-MDL-02840797, http://www.mdl2179trialdocs.com/releases/release201304041200022/Hart_Derek-Depo_Bundle.zip (accessed October 7, 2015).

operational specialists from the Drilling and Completions (D&C) business unit.[264,265] Approval to move through the various stages is a formal process supported by documented risk assessments and assurances. BP policies and standards in the *Drilling and Wells Operation Practice* (DWOP)[266] and related Engineering Technical Practices (ETPs)[267] define the process. The DWOP and ETPs outline practices for drilling and well operations intended to minimize harm to people and the environment as well as to prevent accidents that could have a high negative impact either financially or to the company's reputation. It follows that compliance to these policies and standards should reduce the risk of a drilling operation to levels that BP management deems acceptable.

The risks of a well can be broadly divided into two categories: those created or controlled through design and those created or controlled through execution of the design plan (referred to here as operational risk). Major design risks that could affect the safety and well-delivery schedule generally emerge early in the well-planning process. For example, drilling is easier and safer if the well design can avoid hazards such as natural pockets of gas or seafloor faults.[268,269] For hazards that cannot be designed out of the well, mitigation measures affecting operational practices at the well can be adopted.[270] For instance, design engineers of the Macondo well indicated that traditional kick tolerances were not practicable in deepwater wells like Macondo. As a result, they requested a dispensation from BP's accepted kick tolerance[271] as

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[264] BP operations are divided into business units like the Gulf of Mexico Drilling & Completions or the Gulf of Mexico Exploration & Appraisal units. Individual business unit leaders oversee operations and performance of the units.

[265] Internal Company Document, BP. *Gulf of Mexico SPU: Drilling Engineering BtB Stage Gate Process (Well Level)*, Revision 1, November 30, 2009, Introduction, BP-HZN-2179MDL00284917, see Exhibit 1515 http://www.mdl2179trialdocs.com/releases/release201302281700004/Cocales_Brett-Depo_Bundle.zip (accessed October 7, 2015).

[266] The DWOP is "a summary of the key elements of the DC&W [Drilling Completion & Wells] Engineering Technical Practices. It also encompasses a number of standard practices that are not the subject of the ETPs. Where any potential conflict or lack of detail exists, the ETP has primacy. It is important to note that the ETPs may contain important requirements over and above those summarised in this document and therefore conformance solely with this document does not ensure conformance with the ETPs or STPs [Site Technical Practicies] derived from those ETPs;" Internal Company Document, BP. *GP 10-00 Drilling and Well Operations Practice*, Issue 1, October 2008, BP-HZN-BLY000332264, http://www.mdl2179trialdocs.com/releases/release201304110900026/TREX-06121.pdf (accessed May 26, 2015).

[267] BP developed written ETPs to ensure wells are designed, drilled, completed and maintained to consistent standards.

[268] As defined by *The Free Dictionary* (http://www.thefreedictionary.com/geological+fault), a fault is "a crack in the earth's crust resulting from the displacement of one side with respect to the other."

[269] CSB interviews.

[270] For example, there can be a pre-spud exercise known as "drilling the well on paper" to inform the crew of the well-specific hazards; e.g., Hearing before the Deepwater Horizon Joint Investigation, August 24, 2010 p 16.

[271] BP defines kick tolerance as the maximum volume of a kick influx that can be safely shut in and circulated out of the well without breaking down the formation at the open hole weak point;" Internal Company Document, BP. *GP 10-00 Drilling and Well Operations Practice*, Issue 1, October 2008, "This document contains the practices that have been agreed by BP management as current and relevant for drilling and well operations.", BP-HZN-BLY00034543, http://www.mdl2179trialdocs.com/releases/release201304110900026/TREX-06121.pdf (accessed May 26, 2015).

defined in the DWOP, and they indicated that the drilling contractor's well control operations at Macondo would instead rely on upon other emerging technologies.[272]

For development wells,[273] where the geology is known with a high degree of confidence, the subsequent completion or temporary abandonment program may be developed, reviewed and approved either as part of the main program itself or as a separate document. However, for exploration and appraisal wells, as in Macondo, the outcome is not known a priori and the well may require production flow testing[274] before either temporary or permanent abandonment. Under these circumstances, detailed planning is postponed to avoid wasted effort until the outcome is known.[275] Being exploratory in nature, the Macondo well was drilled to collect data about the geology and quality of the oil and gas at its location.[276] BP's permit to drill highlighted the need to wait for an evaluation of the geology to determine final plans for the well, including whether it would ultimately be abandoned or converted to a production well.[277] Consequently, BP did not develop a temporary abandonment plan for the well during the initial five stage-gate process.

[272] The request indicated, "Slow pump rates have previously been proven successful in circulating out influxes [kicks]. If unable to circulate out influx at reduced rates, bullhead techniques may be required;" Internal Company Document, BP. DCMOC-09-0048, Kick Tolerance less than 25 bbls with a 1.0 ppg kick intensity, July 10, 2009, BP-HZN-CSB00175983. The engineers completing the request cited BP's own well control manual which states, "Traditional kick tolerance calculation is based on circulating the kick out. Deepwater drilling is subject to particular complications due to tight mud weight/fracture margins and high chokeline friction pressures which would render some wells non-drillable in compliance with policy. In such event, a different approach can be adopted based on keeping the problem downhole and utilising bullhead techniques or other emerging technologies." The well control manual does not specify the "emerging technologies" it is referring to.; Internal Company Document, BP. *Well Control Manual: Volume 1 Procedures and Guidelines*, Issue 3, BPA-D-002, December 2000, Deepwater Drilling Considerations, 1-5-10, BP-HZN-2179MDL00336023, see Exhibit 2389 http://www.mdl2179trialdocs.com/releases/release201302281700004/Farr_Daniel-Depo_Bundle.zip (accessed October 7, 2015).

[273] Wells drilled in a previously explored area where the geology of the field has been documented and has been shown to be suitable for production of oil and gas.

[274] Well testing helps determine the how much and how fast a well will produce; Dyke, K. V. In *Fundamentals of Petroleum;* 4th ed.. The University of Texas at Austin, p 161.

[275] Hearing before the U.S. District Court for the Eastern District of Louisiana under the Multi-District Litigation docket MDL No. 2179, June 30, 2011; see Little designations Vol 3, p 35, http://www.mdl2179trialdocs.com/releases/release201302281700004/Little_Ian-Depo_Bundle.zip (accessed October 7, 2015).

[276] USCSB, 2014. *Explosion and Fire at the Macondo Well, Gulf of Mexico, April 20, 2010,* Report No. 2010-10-I-OS, Volume 1, p 13 http://www.csb.gov/file.aspx?DocumentId=679 (accessed October 7, 2015).

[277] BP's Application for Permit to Drill a New Well stated, "A decision on the way forward will be made following evaluation of the [12-1/4" x 14"] open hole interval. The well will either be P&A'd or temporarily abandoned for future completion. Once the final evaluation program is complete, a decision will be made as to whether to sidetrack, TA well, or PA the well." If the well proved commercially viable, data concerning the well's geology and hydrocarbon properties would be collected and used to create a production plan; alternatively, if the well was not viable, the data would be gathered to determine why the commercial predictions failed; Internal Company Document, BP. Form MMS 123A/123S Application for Revised New Well, October 29, 2009, 11; see Exhibit 1336 http://www.mdl2179trialdocs.com/releases/release201302281700004/Paine_Kate-Depo_Bundle.zip (accessed October 7, 2015).

As completion of the well neared, BP personnel developed a temporary abandonment program (Table 1-8) in a process that generally aligned with the common company process. They:[278]

- completed a high level risk assessment for the well;
- delayed the TA program preparation until the well was reasonably well configured;
- followed the general process of TA program preparation, working out options and preparing, discussing, and finalizing a draft program;
- created a well design that conformed with policies described in the DWOP and ETPs, but the DWOP and ETPs did not address all temporary abandonment issues such as location of a surface cement plug[279] or negative test;
- expected teams to deal with unforeseen operational risks that materialized by employing their knowledge, experience, and skills.

Herein though lay an operational gap in BP's well development process of the Macondo well. The Temporary Abandonment program was not reviewed through the stage-gate process, and it was not normal practice to do so.[280]After the initial draft of the TA program, changes to the negative test and final well design, including the location of the surface cement plug,[281] were addressed through the Management of Change process (see Section 1.9), while others were addressed by "Ops Notes." There was no formal process for approving Ops Notes, which could consist simply of short emails. (See Table 1-8.)[282] As a result, the development of the Macondo TA plan occurred without a formal process that included a structured document complete with revision history and a signature page. This created conditions for an incomplete and unauditable development of the TA design that lacked formal

[278] Internal Company Document, BP. *Gulf of Mexico SPU: Drilling Engineering BtB Stage Gate Process (Well Level)*, Revision 1, 2200-T2-DO-RP-0003, November 30, 2009, Introduction, BP-HZN-2179MDL00284914, see Exhibit 1515 http://www.mdl2179trialdocs.com/releases/release201302281700004/Cocales_Brett-Depo_Bundle.zip (accessed October 7, 2015).

[279] Cement plugs are portions of cement put into a wellbore to seal it. "Surface" is typically used to refer to the shallowest cement plug used in a well.

[280] Hearing before the U.S. District Court for the Eastern District of Louisiana under the Multi-District Litigation docket MDL No. 2179, June 30, 2011; see Little designations Vol 3, pp 35-39, http://www.mdl2179trialdocs.com/releases/release201302281700004/Little_Ian-Depo_Bundle.zip (accessed October 7, 2015).

[281] BP stated that the surface cement plug was designed "in accordance with common industry practice," but BP did not address surface cement plugs in either the DWOP or ETPs; BP. *Deepwater Horizon Accident Investigation Report;* September 8, 2010, p 92. See Volume 1, pp 18 and 25 for additional information on surface cement plugs.

[282] Internal Company Document, BP. *Horizon - Onshore/Offshore Communication Process*, BP-HZN-BLY00096591, see Exhibit 7312 http://www.mdl2179trialdocs.com/releases/release201302281700004/Cowie_James-Depo_Bundle.zip (accessed October 7, 2015); Hearing before the U.S. District Court for the Eastern District of Louisiana under the Multi-District Litigation docket MDL No. 2179, June 30, 2011; see Little designations Vol 3, pp 35-39, 44, http://www.mdl2179trialdocs.com/releases/release201302281700004/Little_Ian-Depo_Bundle.zip (accessed October 7, 2015); Hearing before the U.S. District Court for the Eastern District of Louisiana under the Multi-District Litigation docket MDL No. 2179, March 22, 201; see Sprague designations Vol 2, p 71, http://www.mdl2179trialdocs.com/releases/release201302281700004/Sprague_John-Depo_Bundle.zip (accessed October 7, 2015).

documentation or assessment of decisions, including review of internal policies and standards to provide quality control.

Table 1-8. Description of the development and communication of the Macondo TA program.

Communication date	Email Subject (If Applicable)	Sender	Recipient	CSB Characterization of Communication
4/14[283]	Forward Ops	BP Drilling Engineer	BP Well Site Leader	Brainstorming session for the temporary abandonment plan.
4/15[284]	Updated Procedure	BP Drilling Engineer	BP Well Site Leaders and trainee Wells Team Leader Senior Drilling Engineer Operations Engineer Drilling Engineering Team Leader M-I SWACO Drilling Fluids Specialist	*Macondo Drilling Production Interval* for the final section of the well; a 21-page document describing the temporary abandonment program.
4/15[285]	N/A	BP Senior Drilling Engineer	BP Drilling Engineering Team Leader Drilling & Completions Operations Manager Engineering Manager	Management of Change for the production casing at Macondo that also mentions the final cement job, but not the negative test
4/16[286]	N/A	BP Regulatory Representative	Minerals Management Service (MMS)[a]	Application for Permit to Modify: BP's submittal of its Temporary Abandonment plan to MMS. The plan is described on a single page in 8 steps.

[283] Email from Drilling Engineer, BP, to Well Site Leader, BP, Subject: Forward Ops, April 14, 2010, BP-HZN-MBI 00126982, http://www.mdl2179trialdocs.com/releases/release201303141200012/TREX-00537.pdf (accessed October 7, 2015).

[284] Email from Drilling Engineer, BP, to Various, BP, Subject: Updated Procedure, April 16, 2010, Attachment: GoM Exploration Wells MC 252 #1ST00BP01 - Macondo Prospect - 7 x 9-7/8 Interval, BP-HZN-2179MDL00249965, http://www.mdl2179trialdocs.com/releases/release201303141200012/TREX-00545.pdf (accessed October 7, 2015).

[285] Internal Company Document, BP, *Production Casing for Macondo*, DCMOC-10-0069, April 14, 2010, BP-HZN-MBI00143259. http://www.mdl2179trialdocs.com/releases/release201304110900026/TREX-02659.pdf (accessed January 28, 2015).

[286] Internal Company Document, BP. *Form MMS - 124 Application for Permit to Modify*, April 16, 2010, Temporary Abandonment Procedure, BP-HZN-MBI00127909, http://www.mdl2179trialdocs.com/releases/release201304041200022/TREX-00570.pdf (accessed October 7, 2015).

4/16[287]	none	BP Well Site Leader	Numerous Transocean Personnel including the well operations crew and the OIM	A one-page summary of the *Macondo Drilling Production Interval*; it is missing any reference to the negative test.
4/18 ~11AM[288]	Negative Test	BP Drilling Engineer	BP Wells Team Leader	Brainstorming session of negative test options, as stated in the email, "The way we currently have it set up is the standard we have been using, but this one is slightly different because the plug is so deep…"
4/18 5PM[289]	RE: Negative Test	BP Drilling Engineer	BP Wells Team Leader	Agreement to displace drillpipe with seawater to the wellhead and conduct the negative test
4/20 ~7:30AM[290]	N/A	BP Drilling Engineer and BP Well Site Leader	M-I SWACO Drilling Fluids Specialist	Phone calls from BP personnel to inquire about standard DWH displacement procedure and to provide details about the temporary abandonment plan to the M-I SWACO Drilling Fluids Specialist.
4/20 10AM[291]	Ops Note	BP Drilling Engineer	BP Well Site Leaders Well Site Leader trainee Wells Team Leader Senior Drilling Engineer Operations Engineer Drilling Engineering Team Leader	Modifications of temporary abandonment plan.
4/20 3PM[292]	N/A	M-I SWACO drilling fluids specialist	The well operations crew	BP/Deepwater Horizon displacement procedures used on the day of incident Added a large volume of 16 ppg spacer (significant change). See Section 1.9.1 for details.

[a] US offshore safety regulator at the time of the Macondo accident until June 18, 2011.

[287] Internal Company Document, BP. *Forward Plan*, April 16, 2010, BP-HZN-2179MDL00002043, see Exhibit 2337 http://www.mdl2179trialdocs.com/releases/release201304041200022/Taylor_Carl-Depo_Bundle.zip (accessed October 7, 2015).

[288] Email from Drilling Engineer, BP, to Wells Team Leader, BP, Subject: Negative Test, April 18, 2010, BP-HZN-BLY00070087, http://www.mdl2179trialdocs.com/releases/release201305171200030/TREX-001816.pdf (accessed October 7, 2015).

[289] *Ibid*.

[290] Hearing before the Deepwater Horizon Joint Investigation, July 19, 2010, pp 271-272.

[291] Email from Drilling Engineer, BP, to Numerous, BP, Subject: Ops Note, April 20, 2010, BP-HZN-2179MDL00060995, http://www.mdl2179trialdocs.com/releases/release201303141200012/TREX-00097.pdf (accessed October 7, 2015).

[292] BP. *Deepwater Horizon Accident Investigation Report;* September 8, 2010; Appendix P: BP/Deepwater Horizon Rheliant Displacement Procedure "Macondo" OSC-G 32306.

1.8.2 Gap between 'Work as Imagined' and 'Work as Done' at the Macondo Well

At the Macondo well, the gap between the work-as-imagined (WAI) by the planners and the work-as-done (WAD) at the rig site needed to be bridged by the BP operations engineers onshore and the knowledge and experience of the BP WSLs and Transocean well operations crew on the rig. Post-incident, BP described the final temporary abandonment plan as "broad, operational guidelines" and that it expected the Deepwater Horizon rig crew to use "the method consistent with their regular practice on prior wells."[293] In effect, the well operations crew would deal with any problems that occurred during the TA plan employing their knowledge, experience and skills. Missing from the process though were tools that could have minimized the gap between WAI by BP and WAD by Transocean, such as written work plans or safety critical procedures.

As indicated in Table 1-8, BP did not include Transocean in the discussions to develop the temporary abandonment plan, and while BP provided the crew with a written displacement procedure, it did not give them negative test instructions. (See Section 1.4.) The practice on the Deepwater Horizon was for BP to provide the OIM and well operations crew a "Forward Plan" that described upcoming critical operations.[294] On April 16, 2010, BP sent a Forward Plan describing the temporary abandonment activities, [295] but it was missing any reference to the negative test. The OIM bridged what was possibly a simple documentation oversight,[296] a potential gap in WAI versus WAD at Macondo, which he described post-incident: "I told [the BP Well Site Leader] it was my policy to do a negative test before displacing with seawater."[297] Worth noting is that the OIM indicated it was "his" policy and did not refer back to a corporate Transocean policy.[298] It is unknown if a different OIM would have had the same "personal" policy.

[293] BP. *Deepwater Horizon Accident Investigation Report*; September 8, 2010; p 85.

[294] Hearing before the U.S. District Court for the Eastern District of Louisiana under the Multi-District Litigation docket MDL No. 2179, July 14, 2011; see Taylor designations p 65, http://www.mdl2179trialdocs.com/releases/release201304041200022/Taylor_Carl-Depo_Bundle.zip (accessed October 7, 2015).

[295] Internal Company Document, BP. *Forward Plan*, April 16, 2010, BP-HZN-2179MDL00002043, see Exhibit 2337 http://www.mdl2179trialdocs.com/releases/release201304041200022/Taylor_Carl-Depo_Bundle.zip (accessed October 7, 2015).

[296] Concerning the omission, the DWH OIM stated "[they] didn't have no problem [with performing a negative test]. They just left it out of the [forward] plan;" Hearing before the Deepwater Horizon Joint Investigation, May 27, 2010, p 116.

[297] Hearing before the Deepwater Horizon Joint Investigation, May 27, 2010 p 26.

[298] The Transocean Well Control Handbook in place at the time of the incident did not address negative tests; Internal Company Document, Transocean. *Well Control Handbook*, Revision 01, HQS-OPS-HB-01, March 31, 2009, BP-HZN-2179MDL00330768, http://www.mdl2179trialdocs.com/releases/release201303071500008/TREX-00596.pdf (accessed October 7, 2015). After the incident, Transocean updated its handbook which now states "prior to displacing kill weight fluid from the wellbore/riser, a negative/inflow test must be performed. This test must expose all barrier components to a pressure equal to or lower than the pressure it will be exposed to during or after the displacement is complete;" Internal Company Document, Transocean. *Well Control Handbook*, Issue HQS-OPS-HB-01, Revision 00, July 22, 2011, Well Planning Considerations, see Exhibit 5781

A corrected Forward Plan was not sent; consequently, the April 16, 2010, communication is the last documented daily instruction the rig received (see Table 1-8). A BP Well Site Leader trainee on the Deepwater Horizon commented post-incident that the issuance of daily instructions depended upon the Well Site Leader and that the DWH Well Site Leader likely relied on verbal discussions in daily meetings to communicate information.[299]

Transocean described written Standing Instructions to the Driller (SID) as a key communication tool with the customer (in this case BP), and that the SID should be developed with the customer representative and communicated to the drillers at the beginning of each shift.[300] The SID is supposed to include well hazard descriptions, focusing on the next 12 hours of well operations. In a company advisory issued just weeks before the Macondo blowout, Transocean noted that a SID should "raise awareness and […] highlight" underbalanced conditions in a well when a single barrier is present.[301] Despite Transocean's SID requirements and the recent advisory, there is no evidence that SIDs were used on the Deepwater Horizon as envisioned in corporate policies. This underscores a missed opportunity to bridge gaps between the operator and the drilling contractor.

While SIDs could support communications between the operator and the drilling contractor, they do not replace the need for safety critical procedures. The consistent development and appropriate use of written operating procedures are key to managing the risk of a hazardous operation. Procedures are not safety barriers on their own, and using them does not guarantee that work-as-done will be completed as imagined. But procedures facilitate reliable and informed human performance from one individual to another or even by the same individual by documenting the intended steps of a task.[302]

http://www.mdl2179trialdocs.com/releases/release201302281700004/Braniff_Barry-Depo_Bundle.zip (accessed October 7, 2015).

[299] Internal Company Document, BP. *Interview of Lee Lambert*, April 29, 2010, see Exhibit 2157, http://www.mdl2179trialdocs.com/releases/release201304041200022/Harrell_Jimmy-Depo_Bundle.zip (accessed October 7, 2015).

[300] Internal Company Document, Transocean. *Field Operations Policies & Procedures Manuel*, Issue 01, Revision 00, HQS-POP-PP-01, August 8, 2009, Performance Management: Rig and Well Operation Management, TRN-CSB-0002380.

[301] More specifically, advisory sites a 'mechanical barrier,' but the circumstances of the incident were such that the crew was relying on a tested barrier, lowering their risk perception of the operation. Internal Company Document, Transocean. *Operations Advisory*, NRS-OPS-ADV-008, April 14, 2010, Exhibit 5749, TRN-MDL-02840797, http://www.mdl2179trialdocs.com/releases/release201304041200022/Hart_Derek-Depo_Bundle.zip (accessed October 7, 2015). See also Chapter 2.0 describing this incident (also referred to as Sedco 711) and other previous incident investigations.

[302] Center For Chemical Process Safety. *Guidelines for Risk Based Process Safety;* John Wiley & Sons: Hoboken, NJ, 2007, p 246.

1.8.3 Transocean Procedural Development Policies

Transocean requires rig supervisors and managers to work with the lease holders to assess rig-specific and site-specific conditions that could increase the risk or complexity of various drilling operations.[303, 304] Transocean asserts that the planning has both commercial and safety purposes. From a commercial standpoint, the planning enables Transocean and the lessees to identify critical milestones for a well and potential impact that planned Transocean activities might have on well delivery. Planning improves the safety of well operations by:[305]

- identifying risk reducing controls by elevating various well and rig-specific scenarios;
- eliminating assumptions that could negatively impact safety during operations;
- encouraging a multidisciplinary team approach to ensure best industry practices; and
- considering lessons learned from previous wells or other installations.

These interactions are intended to contribute to the development of procedures for safety critical tasks.[306]

Transocean has a formal method, the THINK Planning Process, for well operations crews to develop, communicate, and monitor tasks. [307] THINK is a planning and risk management tool that begins with task

[303] Internal Company Document, Transocean, *Performance and Operations Policies and Procedures Manual-Level L1A*, Issue #1, Revision # 00, April 19, 2010, Section 2 (Planning and Reporting), Subsection 1 (Well Construction Planning), TRN-MDL-00607022. http://www.mdl2179trialdocs.com/releases/release201302281700004/Rose_Adrian-Depo_Bundle.zip Exhibit 1474 (accessed January 28, 2015). Despite the late revision date on this document, testimony given by several individuals in the U.S. District Court for the Eastern District of Louisiana under the Multi-District Litigation docket MDL No. 2179 indicated that the policies described in this document were in effect at Macondo. For example, see Hearing before the U.S. District Court for the Eastern District of Louisiana under the Multi-District Litigation docket MDL No. 2179, April 26, 2011; see Rose Designations Vol 2, pp. 25, 28-29, http://www.mdl2179trialdocs.com/releases/release201302281700004/Rose_Adrian-Depo_Bundle.zip (accessed January 28, 2015).

[304] Internal Company Document, Transocean. *Field Operations Policies & Procedures Manuel*, Issue 01, Revision 00, HQS-POP-PP-01, August 8, 2009, Performance Management: Rig and Well Operation Management, TRN-CSB-0002274 – TRN-CSB-0002320.

[305] Internal Company Document, Transocean, *Performance and Operations Policies and Procedures Manual-Level L1A*, Issue #1, Revision # 00, April 19, 2010, Section 2 (Planning and Reporting), Subsection 1 (Well Construction Planning), TRN-MDL-00607018, see Exhibit 1474 http://www.mdl2179trialdocs.com/releases/release201302281700004/Rose_Adrian-Depo_Bundle.zip (accessed January 28, 2015).

[306] Internal Company Document, Transocean, *Health and Safety Policies and Procedures Manual-Level L1*, Issue #3, Revision # 7, December, 15, 2009, Section 4 (Safety Policies, Procedures and Documentation), Subsection 6.3 (Evaluating and Improving), TRN-MDL-00046866, see Exhibit 1449 http://www.mdl2179trialdocs.com/releases/release201302281700004/Rose_Adrian-Depo_Bundle.zip, Exhibit (accessed October 8, 2014).

[307] THINK is a five step process that involves planning, inspecting, identifying, communicating, and controlling risk; Hearing before the U.S. District Court for the Eastern District of Louisiana under the Multi-District Litigation docket MDL No. 2179, April 25, 2011; see Rose Designations Vol 1, p 32, http://www.mdl2179trialdocs.com/releases/release201302281700004/Rose_Adrian-Depo_Bundle.zip (accessed January 28, 2015); Internal Company Document, Transocean. *Health and Safety Policies and Procedures Manual*, Issue 03, Revision 07, HQS-HSE-PP-01, December 15, 2009, Preface, BP-HZN-2179MDL00132055, see Exhibit

development and identification of associated task hazards. The THINK process requires users to communicate hazards they identify to other crewmembers and to establish controls to mitigate them. The complexity of a task determines the depth of assessment and formality of the THINK plan.[308] According to company policy, for a low risk job, THINK can be a mental process by an individual or a verbal conversation between multiple people, while a more complex or higher risk job requires a written THINK plan that supervisors must assess for completeness and quality. However, THINK does not define how to determine the complexity of the task or the severity of the risks, it implies a subjective determination by the employee. Thus, if crewmembers perceive the task to be well understood or minimally risky, the potential is significant for individuals not to perform the necessary task analysis, risk assessment, and procedural development for safety critical activities.

When a planned activity involves safety critical tasks, Transocean requires a written Task Specific THINK Procedure (TSTP). [309] Transocean identified 106 key operations that require a written TSTP prior to the Macondo blowout,[310] including temporary abandonment activities and negative tests like those that occurred at Macondo at the time of the incident.[311] All crewmembers involved in a critical task or potentially affected by it are supposed to participate in developing the Task Specific THINK Procedure, which requires individuals or groups to:[312]

- review and discuss the Task Specific THINK Procedures prior to commencing the task;
- confirm the control measures for all task steps within the procedure;
- ensure personnel understand their responsibilities to carry out the steps;
- understand the hazards and the consequences of those hazards; and

4942 http://www.mdl2179trialdocs.com/releases/release201302281700004/Farr_Daniel-Depo_Bundle.zip (accessed October 7, 2015).

[308] Internal Company Document, Transocean. *Health and Safety Policies and Procedures Manual*, Issue 03, Revision 07, HQS-HSE-PP-01, December 15, 2009, Section 4 (Safety Policies, Procedures and Documentation), Subsection 2.1 (THINK Planning Process), BP-HZN-2179MDL00132217, see Exhibit 4942 http://www.mdl2179trialdocs.com/releases/release201302281700004/Farr_Daniel-Depo_Bundle.zip (accessed October 7, 2015).

[309] *Ibid*., BP-HZN-2179MDL00132224.

[310] Internal Company Document, Transocean, *Transocean HSE Review*, April 10, 2008, TRN-INV-00705442; Email from Deepwater Horizon Offshore Installation Manager, Transocean, to Deepwater Horizon Toolpusher, Transocean, Subject: FW: List of Critical TSTPs and Maintenance Tasks; Basic 106 TSTPs, June 5, 2007, TRN-INV-02063839; Internal Company Document, Transocean, *List of TSTPs and Critical Maintenance Activities*, TRN-INV-02063841.

[311] Internal Company Document, Transocean, *Performance and Operations Policies and Procedures Manual-Level L1A*, Issue #1, Revision # 00, April 19, 2010, Section 3 (OPS—Drilling Related), Subsections 5 and 6 (Simultaneous Drilling and Production Operations, Well Testing/DST), TRN-MDL-00607137 and TRN-MDL-00607142, see Exhibit 1474 http://www.mdl2179trialdocs.com/releases/release201302281700004/Rose_Adrian-Depo_Bundle.zip (accessed October 8, 2014).

[312] Internal Company Document, Transocean, *Health and Safety Policies and Procedures Manual*, Issue 03, Revision 07, HQS-HSE-PP-01, December 15, 2009, Section 4 (Safety Policies, Procedures and Documentation), Subsection 2.1 (Risk Management), TRN-MDL-00046636, see Exhibit 1449 http://www.mdl2179trialdocs.com/releases/release201302281700004/Rose_Adrian-Depo_Bundle.zip, (accessed October 8, 2014).

- ensure the expected results are understood prior to commencing the activity.

Transocean also requires a Task Risk Assessment for all critical task steps in a TSTP to ensure that risks related to specific task steps are as low as reasonably practicable.[313] The Task Risk Assessment is intended to provide a greater level of risk assessment and to clearly identify potential consequences for each step so that crewmembers and/or management can verify control measures to prevent or mitigate an undesired event.

In practice, the Deepwater Horizon well operations crew had access to a company database of TSTPs, but Transocean standards require the Rig Manager[314] to review the TSTP and any risk analyses, including Task Risk Assessments or those conducted by a customer, such as an Operator like BP, to ensure they remain relevant for the proposed operation at a specific well.[315] The Vice President of Quality, Health, Safety and Environment described the use of the TSTP database:[316]

> "… we have a database with [TSTPs] … we call it the THINK database … They are rig specific, because every rig is a little different … people can go into that database and they can see the task specific THINK procedure for another rig doing the same job and they might want to compare it with that.
>
> But we do warn that every time we do a job, the conditions are changed. The weather conditions may be different. The experience of the crew may be different. You have to take into account that every time you do it, it may not be exactly the same as the last time."

1.8.4 Lack of Written Transocean Procedures and Work Instructions at Macondo

An expert hired by BP post-incident to review the negative test activities at Macondo commented, "The rig crew does not have to be told how to run a negative test. This should be a routine operation that fits within their training."[317] This sentiment does not address the fact that procedures are more than a set of instructions; they are tools for competent, motivated individuals to plan, coordinate, verify, and assure

[313] *Ibid*., TRN-MDL-00046637.

[314] The Rig Manager is a shore-based position with responsibilities for the personnel, training, and operational performance of the offshore facility/rig; the Offshore Installation Manager has direct line accountability to the Rig Manager. (Hearing before the Deepwater Horizon Joint Investigation, August 23, 2010, pp 5-6.)

[315] Internal Company Document, Transocean, *Performance and Operations Policies and Procedures Manual-Level L1A*, Issue #1, Revision # 00, April 19, 2010, Section 3 (OPS—Drilling Related), Section 3 (OPS—Drilling Related), Subsection 6 (Well Testing/DST), TRN-MDL-00607142, see Exhibit 1474 http://www.mdl2179trialdocs.com/releases/release201302281700004/Rose_Adrian-Depo_Bundle.zip (accessed October 8, 2014).

[316] Hearing before the Deepwater Horizon Joint Investigation, May 26, 2010, pp 219-220.

[317] Bourgoyne, A. T. *Expert Report - In RE: Oil Spill by the Oil Rig "Deepwater Horizon" in the Gulf of Mexico, on April 20, 2010;* United States District Court Eastern District of Louisiana MDL No. 2179, Section J Judge Barbier; Magistrate Shushan: October 7, 2011; p 52. http://www.mdl2179trialdocs.com/releases/release201304080900023/TREX-08173.pdf (accessed October 7, 2015).

performance will achieve the intended results.[318] Minimizing the difference between WAI and WAD requires the participation of the individuals actually performing the work.

Companies and their workforce may employ various methods and parameters for conducting a negative test and, as the Macondo incident demonstrates, both individual variations and the interpretation of the data can be critical. Good practice guidance asserts that safety critical tasks demand an error assessment process because of their potential to cause or mitigate a major accident event.[319] It is not about the competency of the individual performing the task, as even the best employees will not be able to achieve positive performance outcomes all of the time.[320]

On the morning of the incident, there was a safety meeting to hold a THINK drill before displacing drilling mud from the well. THINK drills are an opportunity to discuss the proposed job, including the TSTP, assign crewmembers tasks, and discuss potential hazards.[321] Witnesses described the THINK drill on April 20, 2010 as covering the basic steps to be completed that day,[322] as described in the M-I SWACO displacement procedure (Table 1-3), and only generally addressing the types and volumes of fluids that were to be used.[323] In practice, a TSTP is to be used as a basis for a THINK drill, but the M-I SWACO procedure was not a TSTP. Instead, there was a presumptive role the M-I SWACO procedure would play in managing the risks associated with displacement and the negative pressure, even though it did not include a hazard analysis of the proposed steps. A TSTP, or in this case a procedure, that fails to identify the well-specific hazards and controls for a given operation yields a weak THINK drill, which does not adequately inform the crew about the hazards associated with their tasks.

The DWH crew completed numerous negative test procedures between August 2007 and April 2010, and each should have triggered development and use of a TSTP that reflected the real-time conditions of the well.[324] However, the CSB could identify only one TSTP for a negative test (Figure 1-13), which

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[318] Health and Safety Executive. *Reducing Error and Influencing Behaviour;* HSG48; 2009; p 10. http://www.hseni.gov.uk/hsg_48_reducing_error_and_influencing_behaviour.pdf (accessed October 7, 2015).

[319] Energy Institute 1st ed., Guidance on Human Factors Safety Critical Task Analysis, March 2011, p 1.

[320] Health and Safety Executive. *Reducing Error and Influencing Behaviour;* HSG48; 2009; p 10. http://www.hseni.gov.uk/hsg_48_reducing_error_and_influencing_behaviour.pdf (accessed October 7, 2015).

[321] Hearing before the U.S. District Court for the Eastern District of Louisiana under the Multi-District Litigation docket MDL No. 2179, March 5, 2013 p 1972, http://www.mdl2179trialdocs.com/releases/release201303051200006/2013-03-05_BP_Trial_Day_6_PM-Final.pdf (accessed October 7, 2015).

[322] Hearing before the U.S. District Court for the Eastern District of Louisiana under the Multi-District Litigation docket MDL No. 2179, April 10, 2013, p 8274, http://www.mdl2179trialdocs.com/releases/release201304101200025/2013-04-10_BP_Trial_Day_25_PM-Final.pdf (accessed October 7, 2015); Hearing before the U.S. District Court for the Eastern District of Louisiana under the Multi-District Litigation docket MDL No. 2179, March 5, 2013 p 1946, http://www.mdl2179trialdocs.com/releases/release201303051200006/2013-03-05_BP_Trial_Day_6_PM-Final.pdf (accessed October 7, 2015).

[323] Internal Company Document, MI SWACO. *BP/Deepater Horizon Rheliant Displacement Procedure "Macondo" OCS-G 32306*, BP-HZN-BLY00094818, see Exhibit 0052 http://www.mdl2179trialdocs.com/releases/release201302281700004/Lacy_Kevin-Depo_Bundle.zip.

[324] Internal Company Document, Transocean. *Memorandum: Investigation of the Negative Test and Riser Displacement Procedures (Preliminary Report)*, July 26, 2010, TRN-INV-00847616, see Exhibit 5007

Transocean refers to as a “negative flow test.” This TSTP fails to describe or prompt users of the TSTP to identify the location of the drillpipe in the well, the displacement of the drillpipe, or the use of spacer material. Consequently, while this generic document represents a starting point from which a procedure could be developed in the manner described in Section 1.8.3, it is insufficient for a negative test like that conducted at Macondo on April 20, 2010.

http://www.mdl2179trialdocs.com/releases/release201302281700004/Roller_Perrin-Depo_Bundle.zip (accessed October 7, 2015).

Transocean SedcoForex

DEEPWATER HORIZON

START TO BE ACCOUNTABLE

PLAN	INSPECT	IDENTIFY	COMMUNICATE	CONTROL
List the step-by-step operational procedure for completing the task. State WHAT will be done - Do Not define HOW at this point. Be as general as possible and use specifics only when they are critical to the operation (e.g. weight, time, location, equipment, etc.). If it is impossible to list all of the essential steps of the operation here, use a second worksheet or break the operation into two or more sub-operations.	List WHAT equipment, materials and areas are to be inspected for each step of the operation. Be sure to include personal protective equipment. If the same equipment is used in more than one step, there is no need to repeat.	Brainstorm the potential hazards and risks associated with each operational step, piece of equipment, work area and all materials.	WHAT information needs to be communicated to WHOM? Ensure that all personnel performing the task understand how to perform the task safely, the hazards, risks, and controls required. Anyone else who might be affected by or might affect the task must clearly understand their role.	WHAT precautions should be taken to avoid risk of injury, environmental damage or property damage? How will the task be conducted to reduce the risk to an acceptable level as low as reasonably practical?

TASK SPECIFIC THINK PROCEDURE

Brief Description of Task: Negative flow test using choke and kill lines

PLAN	INSPECT	IDENTIFY HAZARDS	COMMUNICATE	CONTROL
1. Perform negative flow test.	• Choke manifold for proper alignment	Well fluids going to wrong place	• Driller and drill crew toolpusher	• A.D.s double check each other
2. displace choke and kill lines with sea water close in on fail safe valves line up to mini trip tank	• choke manifold for proper alignment	Wrong fluid going down hole. Valves closed and blow relief valves	• Driller, A.D.s, drill crew, derrick man, sub sea tool pusher	• Derrick man and assistant cross check line in pit room and ad. Cross check
3. Space out close lower annular or the appropriate rams.	• Sub sea ensure right gallon count	Wrong space out damage rams	• Driller A.D.s,drill crew tool pusher,sub sea	• Sub sea controls and monitors gallon count
4. open well to surface open choke and kill line fail safe valves and remote choke to mini trip tank	• ensure flow path to poor boy and it is open and clear	Closed flow path will give false indication of no flow	• Driller,A.D. drill crew tool pusher and sub sea ,	• A.D.s cross check each other
5. check for flow	• ensure flow path is open	Same as above	• Driller AD.s drill crew toolpusher and sub sea.	• A.d.s cross check each other

Figure 1-13. Deepwater Horizon negative test Task Specific THINK Plan.[325]

[325] Internal Company Document, Transocean. *Deepwater Horizon Task Specific THINK Procedure: Negative flow test using choke and kill lines*, TRN-MDL-01995569,

A generic Deepwater Horizon TSTP for displacing the riser with seawater appears in Figure 1-14; this activity was being conducted at the time of the Macondo blowout. The hazards in the TSTP focus on minor spills of synthetic-based drilling mud onto the rig floor (and their becoming a personal safety slip hazard) or on going overboard. The TSTP does not address major accident hazards, such as the number or robustness of the barriers to prevent a kick or blowout while one of the primary barriers, the drilling mud, is being removed. It is also generic enough to be used in several circumstances and does not mention the importance of assessing cement integrity or the potential for kicks if the well is placed into an underbalanced state. Instead, the TSTP implies implicit trust that the casing/bottom hole cement barrier is good, so no additional barriers will be required. Despite multiple examples of tested barriers subsequently failing on Transocean rigs (see Section 2.0), there are no controls indicated in the TSTP, such as the prohibition of bypassing pressure, flow, or volume monitoring systems that could indicate a subsequent barrier failure any time the well is being circulated. Furthermore, Transocean was unable to identify an operational TSTP that included the line-up of the diverter system for either normal or abnormal (i.e., emergency) operating conditions.[326]

http://www.mdl2179trialdocs.com/releases/release201304041200022/TREX-04640.pdf (accessed October 7, 2015).

[326] Internal Company Document, Transocean. *Investigations - Daily Summary*, September 9, 2010, TRN-INV-01816603.

Transocean

START TO BE ACCOUNTABLE

TASK SPECIFIC THINK PROCEDURE

Brief Description of Task: Displace Riser With Sea H20

PLAN	INSPECT	IDENTIFY HAZARDS	ENVIRONMENTAL	COMMUNICATE	CONTROL
1. Hold pre-task meeting and task specific with all crewmembers and company reps involved.	• Area of meeting is free of disturbances and general rig traffic. ppe	• None	• None	• Lists roles and responsibilities during the meeting. Insure all members involved in the operation understand their roles accordingly. Issue out hand radios to persons involved after meeting.	• Meeting area to be controlled ie: if not involved in task then no need to be there.
2. Line-Up to take returns directly to mud pits bypassing the shakers via the Shaker man.	• Work areas, walkways, proper valve alignment, flow line cameras, proper operating hand radios and all personal protective equipment used during this task. ppe	• Improper communication between Driller and Shaker man, slipping on surfaces and or walkways, improper valve alignment, to many people entering in and out of shaker house during operation causing a distraction, improper valve alignment or spilling of mud in walkway causing a slip hazard.	• Improper valve alignment causing a spill overboard, hydraulically driven equipment malfunctioning at time of displacement on rig floor. Synthetic base mud being spilled in floor or walkways.	• Driller to shaker hand by use of audio box and hand held radios.	• Make sure the channel on the radios are being used and is not being interfered with by another source of activity.
3. Take returns into equalized mud pits 6-10 with returns starting in pit 6 first. Isolate #1 mud pump charging pump from synthetic base mud and line up on sea chest valve via derrick man.	• Valves being used and any unused valves are isolated. Sea chest lines, and phone communication between rig floor and mud pit room/mud pump room. All dump valves and master dump valves for pits. ppe	• Improper communication between driller and derrick man. Improper valve alignment causing trapped pressure.	• Same	• Driller to derrick man by way of telephone. Derrick man to double check all valves alignments with pump hand.	• Keep distractions in the pit room and the pump room to a minimum to maintain good communication between derrick man and pump man.
4. Lineup to displace choke line with seawater with #1 mud pump on #2 standpipe.	• Rig floor valves, standpipe valves, mud pump valves, sea chest valves, mud pump and personal protective equipment.	• Improper communication between driller, assistant drillers, floor hands and derrick man. Improper valve alignment causing trapped pressure or blown pop offs.	• Same	• Driller to assistant drillers, derrick man, floor hands and double-check all valve alignments.	• Keep distractions in the DWS to a minimum while the driller assigns duties.
5. Test choke, kill and boost lines 1000 psi over circulating rate.	• Same as above. • Ensure there is enough room in slugging pit in case pop off blows.	• High pressure testing on rig floor, moonpool and pump room. • Rupture in line. • Same as above.	• SOBM spill overboard from rupture in line. •	• Announcement of high pressure testing over PA system.	• Work permit in place. • Barriers in place to prevent people from entering area. • Good communication between derrickman and rig driller.
PLAN List the step-by-step operational procedure for completing the task. State WHAT will be done – Do Not define HOW at this point. Be as general as possible and use specifics only when they are critical to the operation (e.g. weight, time, location, equipment, etc.). If it is impossible to list all of the essential steps of the operation here, use a second worksheet or break the operation into two or more sub-operations.	**INSPECT** List WHAT equipment, materials, areas are to be inspected for each step of the operation, be sure to include personal protective equipment. If the same equipment is used in more than one step, there is no need to repeat.	**IDENTIFY** Brainstorm the potential hazards and risks associated with each operational step, piece of equipment, materials and work area.	**ENVIRONMENTAL IMPACT** Brainstorm the potential for environmental hazards and risks associated with each operational step, piece of equipment, materials and work area.	**COMMUNICATE** WHAT information needs to be communicated to WHO? Ensure that all personnel performing the task understand how to perform the task safely, the hazards, risks, and controls required. Anyone else who might be affected by or might affect the task must clearly understand his or her role.	**CONTROL** WHAT precautions should be taken to avoid personal, property or environmental damage? How will the task be conducted to reduce the risk to an acceptable level as low as reasonably practical?

Figure 1-14. Transocean Task Specific THINK Procedure addressing displacing a riser with seawater.

Managing safety critical task procedures through Transocean's TSTP process could provide Transocean the opportunity to assess more thoroughly the human performance expectations for the tasks at hand. For example, with the removal of physical well barriers, a question should arise concerning what tools and mechanisms are in place for crewmembers to quickly recognize and a gas in the riser situation. Such a process would benefit from the participation of individuals with expertise in assessing human performance and potential organizational influences. A human factors safety critical assessment of the diverter system design would include recognizing situational conflicts and identifying meaningful actions to resolve them. The Transocean well control handbook was updated post-Macondo to instruct the crew to preset the route overboard.[327] While using an engineering control eliminates the manual intervention

[327] Internal Company Document, Transocean. Well Control Handbook, Issue HQS-OPS-HB-01, Revision 00, July 22, 2011, Handling Gas in the Riser, Exhibit 5781,

previously required of the crew to change the diverter route if gas in the riser exceeds MGS capacity, this organizational decision to preset the diverter route to overboard may ultimately cause other problems. It increases the likelihood of discharges into the sea that might otherwise have been controlled through use of the MGS. Thus, there is a risk of organizational drift back to the original practice as, over time, the rig operator receives environmental penalties for discharges that, with hindsight, a regulator determines to have been preventable.[328] These tradeoffs and the potential influences they may have on decision-making are examples of what must be recognized as part of a human factors safety critical task assessment process (discussed in more detail in Section 1.10.2).

Lack of Assessment of Human Factors in Previous Transocean Incidents

The UK offshore regulator, the Health and Safety Executive (HSE) found a lack of a structured and systematic consideration of the human contribution to safety during in 2009 a multi-rig Human & Organizational Factors inspection. The HSE noted, "human failures and the range of factors that may influence human performance have not been adequately addressed in risk assessment or within incident investigations,"[a] and this was "particularly with respect to major hazard risk assessment."[b] In its 2003 Major Accident Hazard Risk Assessment (MAHRA), Transocean identified that a failure of the diverter system could result in a rig floor blowout with multiple injuries, fatalities, or loss of the rig.[c] The MAHRA listed prevention controls focused on the diverter equipment (testing, inspections, and maintenance), but did not address any vulnerabilities of manual activation of the diverter.

[a] HSE, Specialist Inspection Report, Offshore Division Human and Organizational Factors Team. *Transocean-Human & Organizational Factors Intervention;* July - October, 2009, p 3.

[b] HSE, Specialist Inspection Report, Offshore Division Human and Organizational Factors Team. *Transocean-Human & Organizational Factors Intervention;* July - October, 2009, p 6.

[c] Internal Company Document, Transocean. *Major Accident Hazard Risk Assessment Deepwater Horizon*, Revision 01, August 29, 2004, TRN-MDL-01184777, http://www.mdl2179trialdocs.com/releases/release201303141200012/TREX-02188.pdf (accessed October 7, 2015).

The CSB could not identify Macondo-specific TSTPs or formal Task Risk Assessments for any safety critical tasks, and Transocean did not conduct a qualitative risk assessment with rig management approval as part of developing temporary abandonment procedures. Despite all of its internal company policies, post-incident Transocean claimed that it was BP's responsibility to conduct a hazard analysis and develop

http://www.mdl2179trialdocs.com/releases/release201302281700004/Braniff_Barry-Depo_Bundle.zip (accessed October 7, 2015).

[328] This also implies a powerful influence by a regulator on the organizational behaviors it intentionally (and sometimes unintentionally) encourages through its regulations. The role of a regulator in driving safety change is discussed in Volume 4 of the CSB Macondo Investigation Report.

the written negative test and temporary abandonment procedures used at the Macondo well.[329] Thus, at Macondo, the operator and drilling contractor each presumed the other was responsible for a proper negative test procedure. The crew was left to put together something to get the work done.

Nancy Leveson frames major accident causation and prevention in terms of a problem of control of a complex system.[330] When examining well engineering and operations from that perspective, two conclusions can be drawn. First, in an industry dominated by engineers, the design and planning aspects of preparing an operation are addressed in the management systems of the majority of organizations and reinforced by regulatory requirements. Second, by contrast, once the drilling program is signed off, there is a notable lack of guidance either within the industry at large or within operator organizations as to exactly how to execute the program at the rig site—in other words, how the plan will be translated into action.

This lack of control over bridging the gap between work-as-imagined and work-as-done, or absence of objective control mechanisms, extends beyond the simple requirement for operational, or procedural, discipline to the whole framework of communication command and control. Thorogood and Crichton addressed this question by suggesting that a company evaluate its organizational and workforce capabilities to conduct safe and efficient operations through documented management, training, and monitoring of eight elements:[331]

1. preparation of programs
2. generation of written work instructions
3. operations monitoring procedures
4. handling changes and deviations
5. decision-making protocols
6. operational discipline
7. mission rules
8. competency

1.9 Management of Change (MOC)

Experience shows that changes in the operating environment, systems, procedures, equipment, organization, and management personnel and practices represent some of the biggest challenges to effectively managing major hazard risks. Poorly managed change frequently results in serious failures, many of which are precursors to major accidents (or higher costs as well). A vital component of change management is an assessment of how those technical changes may influence human performance.

In the offshore drilling industry, these change management responsibilities do not reside with only one company. Due to the various specialties and coordination required to drill a well, all parties involved in a drilling operation should share them—leaseholder, drilling contractor, and other well service providers

[329] Transocean. Macondo Well Incident: Transocean Investigation Report Volumes I and II; June, 2011, p 78.

[330] Leveson, N. G. *Engineering a Safer World;* Massachusetts Institute of Technology: Cambridge, MA, 2011.

[331] Thorogood, J.; Crichton, M. T. Operational Control and Managing Change: The Integration of Non-technical Skills With Workplace Procedures; *SPE Drilling and Completion* 2013**,** *28,* pp 203-211.

(third-party contractors).[332] The lease holder of a well is responsible for designing the well plan, but changes to a plan potentially have health, safety, and environmental consequences that could impact the drilling contractor's rig, crew, and others involved in the operation. Conversely, changes to the drilling rig, equipment, materials, and personnel by the drilling contractor or well service providers may introduce new challenges to the safe execution of the well plan.

At Macondo, both BP and Transocean initiated or instituted multiple changes to the temporary abandonment activities that negatively affected the effectiveness of the safety critical barriers meant to prevent blowouts, and they did this without first assessing the hazards introduced by those changes, including human performance impacts.[333] As a result, they missed opportunities, often simple and relatively low cost, to implement effective human performance controls to prevent or mitigate unwanted consequences.

This section shows that BP and Transocean did not effectively manage changes with the temporary abandonment process, further supporting the conclusion that the companies did not identify safety critical steps in the temporary abandonment process as safety critical, nor did they recognize the impact of those changes on human performance. Ultimately, this section discusses how regulatory oversight was absent or ineffective in ensuring either BP or Transocean upheld internal management of change policies or that company policies effectively controlled for major accident hazards. (Section 3.5.2 describes indicators that owners and operators can use for internal company oversight.)

1.9.1 Management of Change: A Missed Opportunity

Table 1-9 identifies several changes to the Macondo temporary abandonment plan, highlighting the potential hazards introduced by the changes, and the actual human performance impacts of those changes.

At the time of the Macondo incident, BP had internal MOC guidelines for the Gulf of Mexico and Drilling and Completions (D&C) Organization that covered administrative, organizational, and technical changes, as well as dispensations from BP's Drilling and Wells Operation Practice (DWOP) and BP-owned rig equipment.[334] Contractors, like Transocean, were to utilize their own MOC systems, which should include BP "as appropriate," and which BP reserved the right to audit.

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[332] Drilling a well requires third-party contracted support like cementing and well monitoring support services. See Volume 1, Section 1.1 of the CSB's Macondo report for more detail.

[333] National Commission on the BP Deepwater Horizon Oil Spill and Offshore Drilling. *Chief Counsel's Report: The Gulf Oil Disaster;* Feburary 17, 2011, p 107. http://permanent.access.gpo.gov/gpo4390/C21462-407CCRforPrint0.pdf (accessed October 7, 2015).; BP. *Deepwater Horizon Accident Investigation Report;* September 8, 2010, p 36.; Transocean. *Macondo Well Incident: Transocean Investigation Report Volumes I;* June, 2011, p 10.

[334] Internal Company Document, BP. *GoM Drilling and Completions D&C Recommended Practice for Management of Change*, Revision 0, 2200-T2-PM-PR-0001-0, March 31, 2009, see Exhibit 6291 http://www.mdl2179trialdocs.com/releases/release201302281700004/Daigle_Keith-Depo_Bundle.zip (accessed October 7, 2015).

Table 1-9. BP and Transocean instituted multiple changes to the temporary abandonment activities that had the potential to negatively affect well barriers without first assessing the hazards of those changes.

Scope of Change	Potential Hazard	Human Performance Implications at Macondo
Leftover circulation material was used as a spacer in the Macondo cement job design.	The lost circulation material (LCM) was never tested as a spacer, and its viscous, gelling nature made it susceptible to plugging lines used for the negative test. Also, its high density added complexity to the correct interpretation of the test pressures.	The LCM was under-displaced, leaving part of the spacer below the BOP and adversely affecting the test interpretation (Section 1.4).
Foamed cement[335] design for cement placed at the bottom of the well in an oil-base mud to seal the hydrocarbon bearing zone.	The design was both complex and challenging, increasing the risk of poor cement quality once installed at the bottom of the well.	The cement barrier failed to seal the well (Section 1.9.1). This was the primary barrier relied upon during displacement of the riser, but the crew was not made aware of the increased risk of a poor cement job.
Cement from a previous well was used for the foamed cement job at the Macondo well.	The cement had a defoaming additive that might have negatively affected foaming efforts for the Macondo well cement design, increasing the risk of poor cement quality once installed at the bottom of the well.	Cement barrier failed to seal the well (Section 1.9.1). This was the primary barrier relied upon during displacement of the riser, but the crew was not made aware of the increased risk of a poor cement job.

BP's MOC guidelines required a justification statement to describe the rationale for a proposed change, such as the potential to improve safety, increase efficiency, or reduce costs. The scope of the change, including necessary resources, potential impacts, and interfaces, was also to be described. Assigned reviewers of an MOC were supposed to work as a team to ensure a "thorough technical evaluation and impact assessment."[336] Typical reviewers would be managers who were accountable for the overall impact of the proposed change. If a requested change was an exception to approved BP practices,[337] a

[335] Foamed cement is a mixture of cement slurry (cement, water, and other dry or liquid additives), foaming agent, and a gas that physically resembles a lightweight shaving cream.

[336] *Ibid*., p BP-HZN-2179MDL00339810.

[337] BP's used Engineering Technical Practices (ETPs), Site Technical Practice (STPs), and Group Practices to define minimum engineering and operations corporate standards.

dispensation to the DWOP, [338] or a change in well design, then an Engineering Authority (EA)[339] would also have to act as an approver for the change.[340]

Section 1.8.1 treats the lack of a hazard analysis on the temporary abandonment process as a flawed design process, but a secondary opportunity to complete a hazard analysis presented itself in a BP MOC that cited the bottom hole cement job. [341] Senior BP managers reviewed and approved the MOC, which listed risks such as fracturing the wellbore during cementing operations and noted the possible need to seek MMS approvals for resulting mitigation strategies if that risk materialized. The MOC did not discuss the inherent challenges of using foamed cement, including impacts it might have on well integrity and the need for increased vigilance by the rig crew for barrier failure.[342]

While industry guidelines address general cementing practices,[343] each cement job is dictated by specific well characteristics that vary throughout the drilling operation. Consequently, cement job designs are adjusted to accommodate real-time well conditions. Internal BP guidance for cementing complex wells states, "Due to unknown or unforeseen well conditions, the properties of the foam cement in the annulus[344] could end up being significantly different from the original design. The *sensitivity* of the design and the *associated risk* to the well should be *evaluated on a case-by-case basis* [italics original]."[345] The guidance lists several possible risks and specifically indicates that loss of well control or well kicks could result from circumstances leading to poor cement quality.[346] Post-incident BP noted that the foamed cement design for Macondo was complex and that improved MOC could have raised awareness of the challenges to achieving a successful cement job.[347]

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[338] The DWOP is a document that BP management agrees contains current and relevant practices for drilling and well operations. These practices are intended to minimize harm to people and the environment as well as to prevent accidents that could have a high negative impact either financially or to the company's reputation.

[339] The EA is the top ranking decision-maker for engineering decisions in a business unit.

[340] Hearing before the U.S. District Court for the Eastern District of Louisiana under the Multi-District Litigation docket MDL No. 2179, May 4, 2011; see Grounds designations p 99, http://www.mdl2179trialdocs.com/releases/release201302281700004/Grounds_Cheryl-Depo_Bundle.zip (accessed October 7, 2015).

[341] Internal Company Document, BP. *Production Casing for Macondo, DCMOC-10-0069*, April 14, 2010, BP-HZN-MBI00143259, http://www.mdl2179trialdocs.com/releases/release201304110900026/TREX-02659.pdf (accessed October 7, 2015).

[342] *Ibid*.

[343] API Standard 65, 2nd ed., Isolating Potential Flow Zones During Well Contruction-Part 2, December 2010.

[344] The annulus is the space between the drillpipe and wellbore. See Deepwater Drilling and Temporary Abandonment of the Macondo Well in Volume 1, p 20 of the CSB Macondo report for more details and diagrams.

[345] Internal Company Document, BP. Cementing in hostile environments: Guidelines for obtaining isolation in demanding wells, December 200263 BP-HZN-BLY00175616.

[346] The guidance lists cement channeling, low foam quality, and unstable foam—all possibilities BP listed in its investigation report as potential sources of cement failure at Macondo; BP. *Deepwater Horizon Accident Investigation Report;* September 8, 2010; p 36.; Transocean. *Macondo Well Incident: Transocean Investigation Report Volumes I;* June, 2011, pp 34, 55.

[347] BP, *Deepwater Horizon Accident Investigation Report*; September 8, 2010, p 36.

Beyond the foamed cement design, three substitutions or replacements occurred during the cementing process at Macondo. Leftover cement from a previous well was used and leftover lost circulation material was substituted as a spacer in the cement job design.[348] These changes were treated as "replacement in kinds"[349] without assessing whether they fulfilled necessary specifications or whether they could perform as anticipated. The substituted cement was designed for a non-foamed cement job and was being converted to a foamed design for Macondo,[350] but neither the crew nor management evaluated the conversion.[351] The lost circulation material was never tested as a spacer, and its viscous, gelling nature made it susceptible to plugging lines used for the negative test.[352]

Concerning other aspects of the TA program (e.g., the negative test, underbalancing the well), the BP Wells Team Leader responsible for initiating an MOC stated that he did not feel the changes were significant and that the team was experienced at conducting negative tests, so an MOC was not prepared.[353] Personnel experience is only one of many potential factors to consider in assessing and managing risk because wells can offer unique circumstances that even experienced crewmembers have not previously addressed. Furthermore, experience and competency do not preclude human error, so considerations of potential error must be part of the MOC process.

Transocean criticized BP for not preparing MOC documents to address the risks of the temporary abandonment operations,[354] but in its own investigation report Transocean failed to address the Deepwater Horizon's noncompliance with Transocean Corporate requirements. Transocean identified numerous scenarios for conducting formal MOC plans, including:[355]

- Change in people;
- Change in installation/facility specific procedures;
- Changes to safety systems or critical operating equipment;
- Changes to software and hardware;
- Equipment and structural changes, including non-original equipment replacement, upgrades or modifications; and

[348] To avoid mixing the foamed cement and the synthetic-oil-based-mud, a spacer fluid is used in between the two fluids.

[349] A replacement in kind is a replacement component or procedure with the same specifications or effects as the original.

[350] The leftover cement contained a defoaming additive which could negate efforts to create a foamed cement.

[351] BP. *Deepwater Horizon Accident Investigation Report*; September 8, 2010, p 60.

[352] CSB, 2014, *Explosion and Fires at the Macondo Well, Gulf of Mexico,* April 20, 2010, Report No. 2010-10-I-OS, June 2014, Appendix 2-A, p 17.

[353] Internal Company Document, BP. *BP Incident Investigation Team - Notes of Interview with John Guide*, July 1, 2010, p BP-HZN-BLY00124225, see Exhibit 0153 http://www.mdl2179trialdocs.com/releases/release201302281700004/Paine_Kate-Depo_Bundle.zip (accessed October 7, 2015).

[354] Transocean. Macondo Well Incident: Transocean Investigation Report Volumes I; June, 2011, p 10-11.

[355] Internal Company Document, Transocean. *Company Management System*, Issue 04, Revision 05, HQS-CMS-GOV, November 30, 2009, Corporate Policies and Procedures, Level 1, TRN-MDL-00032841, see Exhibit 0925 http://www.mdl2179trialdocs.com/releases/release201302281700004/Rose_Adrian-Depo_Bundle.zip (accessed October 7, 2015).

- Mobile Offshore Drilling Unit (MODU)[356] design and/or operating criteria.

Changes to installation/facility specific procedures included the negative test and temporary abandonment plans. The THINK Planning Process (Section 1.8.3)—the backbone of Transocean's MOC program—dictates how a plan for a task is developed. The plan should then be observed and monitored while it is executed using Transocean's START Observation and Monitoring Process. START (See, Think, Act, Reinforce, Track) is a tool to reinforce safe behavior, correct unsafe behavior, and ensure controls or barriers remain in place during implementation of a plan. Despite these requirements, Transocean did not generate MOCs (or TSTPs) while drilling the Macondo well. Chapter 4.0 further explores the lack of clarity concerning safety roles and responsibilities between the operator and drilling contractor, as influenced by US regulations, for safety critical activities.

1.9.2 MOC Regulatory Requirements and Good Practice Guidance

Management of Change is recognized as one of several vital components of an effective safety management system for hazardous operations.[357] While voluntary guidance recommended that leaseholders/operators develop and use an MOC process,[358] companies operating in the Gulf of Mexico at the time of the Macondo event were not required to have a formal MOC process as part of a larger major accident prevention program, nor did regulations require that these parties effectively coordinate their management of change activities.

1.9.2.1 Regulatory Requirements for an MOC Safety Management System

Offshore safety guidance in effect in the US at the time of the Macondo blowout, *Recommended Practice for the Development of a Safety and Environmental Management Program for Offshore* (API RP 75), recommended that MOC programs include the development of a written MOC procedure that contains design basis for the change; analysis of safety, health and environmental considerations for the proposed changes; revisions to operating procedures, work practices, and training; communication of the changes; and required authorizations to implement the change.

[356] As defined by US Code 2101 15(a), a MODU is "a vessel capable of engaging in drilling operations for the exploration or exploitation of subsea resources."

[357] Center For Chemical Process Safety. *Guidelines for Risk Based Process Safety;* John Wiley & Sons: Hoboken, NJ, 2007; Chapter 15.; International Association of Drilling Contractors, *Health, Safety and Environment Case Guidelines for Mobile Offshore Drilling Units*, Issue 3.6, January 2015, p 13.

While the CCPS guidelines were not expressly written for offshore operations, they have recently been effectively implemented in drilling and well operations. [Chajai, H.; Smith, C. *Defining and Improving Process Safety for Drilling and Well Services Operations*, IADC/(SPE) Drilling and Completion (SPE) Drilling Conference and Exhibition, 4-6 March 2014, Fort Worth, TX]. As such, they complement the IADC guidelines for assessing BP and Transocean policies in place at the time of the incident and BSEE's current MOC program requirements.

[358] API Recommended Practice, 75, 3rd (2004, reaffirmed 2008) ed., Recommended Practice for Development of a Safety and Environmental Management Program for Offshore Operations and Facilities, pp 9-10.

While API RP 75 was voluntary, both companies' MOC policies had requirements that incorporated or went beyond the recommendations contained within the RP. However, such MOC analyses were not performed for a number of changes at the Macondo well. (See previous section.) After the incident, the regulator codified industry good practices for MOC already stipulated within the corporate policies of BP and Transocean (Table 1-10).

Table 1-10. A comparison of best practice elements of an MOC program, current BSEE MOC requirements, and BP and Transocean's MOC programs in place at the time of the Macondo incident.

MOC Program Elements	Required by Regulator at Time of Incident	Included in BP MOC Policies	Included in Transocean MOC Policies	Required by Regulator Post Macondo ††
Write MOC procedures for changes to equipment, procedures, personnel, materials, and operating conditions		x	x	x
Review changes		x	x	x
Include technical basis in review		x	x	x
Include impact on safety, health, and the environment in review		x	x	x
Include time period for change in review		x	x	x
Approve procedure		x	x	x
Communicate change and train appropriately		x	x	x
Document changes to operating procedures		x	x	x
Identify, track, and implement changes through management system. Activities should be audited and used to improve dependability of MOC process.				x
Drive risk to as low as reasonably practicable through MOC process		implied†	x	

†BP's MOC guidelines do not explicitly state ALARP, but they do reference BP's OMS Exploration and Production Drilling and Well Operations Practice (DWOP), which states "all risks shall be managed to a level which is as low as reasonably practical" or ALARP; Internal Company Document, BP. *GP 10-00 Drilling and Well Operations Practice*, Issue 1, October 2008, pp A-9, BP-HZN-BLY00034504, http://www.mdl2179trialdocs.com/releases/release201304110900026/TREX-06121.pdf (accessed May 26, 2015).

††Specific requirements for an MOC program are addressed in 30 C.F.R. § 250.1912 (2015), while management's general responsibilities, which includes the improvement of the safety and environmental management system (SEMS) program, are addressed at 30 C.F.R. § 250.1909 (2015).

BSEE now requires leaseholders[359] to identify their MOC approval procedures and give both the technical basis for the change as well as an evaluation of the potential impacts on safety and health.[360] Companies now are required to communicate changes and document MOCs that result in procedural changes.[361] While BSEE requires companies to establish MOC program goals, there are no requirements to align risk tolerance expectations between BSEE and the companies its regulations cover, such as driving risk to as low as reasonably practicable (ALARP).[362]

1.9.2.2 Multi-party MOCs are an International Concern

At the time of the incident, no voluntary US industry guidance recommended how drilling contractors might provide critical reviews of their clients' designs or programs for the well to assure that the design/program did not put their equipment and personnel at an unacceptable level of risk. The multiparty environment of offshore oil and gas operations supports the need to coordinate any changes initiated by the various parties that have the potential to impact the safety of the crew, rig, equipment, and environment.

On a global level, after the Macondo blowout, there was a surge of industry recognition and appreciation for the interplay between leaseholder, drilling contractor, and well service providers. A 2013 multinational audit of offshore operators and drilling contractors in the North Sea raised as a primary concern the crucial need for improvements in the coordination and interface between client and driller, noting a "lack of clarity in the various levels of bridging and interfacing documentation/processes" as well as a "lack of effective gap analysis in the client and drilling contractor systems/documentation."[363]

In the US, the API published new voluntary guidance in November 2013 to address the need to develop a Well Construction Interface Document (WCID) that bridges safety and environmental management systems among the lease holder, drilling contractor, and other third-party contractors.[364] API's guidance specifically calls for the WCID to address MOC systems and risk assessment processes. Thus, while each company should have its own system for managing risk, the changes should be coordinated and communicated between all the potentially affected parties.[365] (The CSB further discusses the important role of bridging documents in effectively managing safety in Section 4.4.5.)

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[359] However, as discussed in Volume 4, Section 3.3 of the CSB Macondo Investigation Report, the key federal offshore safety management regulations that address MOC programs (the Safety and Environmental Management Systems Rule) issued in the wake of the Macondo incident do not directly cover contractors.

[360] 30 C.F.R. § 250.1912 (d) (1-2, 4) (2012).

[361] 30 C.F.R. § 250.1912 (a) (2) (2012).

[362] See Section 4.1 in this Volume and Section 3.1 in Volume 4 for further discussion on ALARP.

[363] North Sea Offshore Authorities Forum (NSOAF). *Multi-National Audit Human and Organisational Factors in Well Control 2012-2013*, pp 3-4; http://www.hse.gov.uk/offshore/nsoaf.pdf (accessed May 2016, 2015).

[364] American Petroleum Institute, Bulletin 97, 1st ed., *Well Construction Interface Document Guidelines*, November 2013, p 1.

[365] *Ibid*., pp 7-8.

1.10 Inadequate Requirements for Incorporating Human Factors in US Offshore Operations

Before the Macondo incident, a company conducting US offshore drilling and completion operations was not required to maintain and implement a documented safety management program.[366] Thus, there were no requirements to incorporate human factors into such a program.[367] Also missing were any requirements for the safe management of critical tasks, operating procedures, and changes to the operational plan, process or the people conducting the work. US offshore lacked requirements for industry to incorporate good practice process safety principles, such as using the hierarchy of controls when deciding on the technical, operational and organizational barriers needed to prevent a major accident.

Despite this regulatory shortfall, the importance of human factors offshore did not go unrecognized by industry and regulators.[368] The following conclusion was noted at an April 2002 seminar to discuss human factors integration into oil and gas offshore operations: "Ignoring human factors will result in an increase not a decrease in incidents, lower safety performance and increased costs. Human factors are paramount to all aspects of offshore operations and essential in reducing human performance-related risks."[369] Participants of this event included the US and UK offshore regulators (MMS and HSE, respectively), and major companies in industry, such as BP, Shell, and Exxon.

Several years later, in 2006, API published *Human Factors Tool for Existing Operations* to assist industry members in "incorporating human factors considerations into existing equipment and tasks."[370] According to the guidance document, this tool is meant for use by those conducting the actual work—the rig crew or process unit operators and mechanics.[371] It provides a methodology for identifying both (1) latent human error conditions and (2) potential human errors immediately prior to commencing hazardous

[366] The SEMS Rule was promulgated in October 2010.

[367] Related the safe operation of a ship and pollution prevention, the US Coast Guard has had regulations since 1998 that require certain vessels, including self-propelled MODUs, to comply the International Management Code for the Safe Operation of Ships and for Pollution Prevention (ISM Code). As a result, vessels must "have on board valid documentation showing that the vessel's company has a safety management system which was audited and assessed, consistent with the International Safety Management Code of IMO Resolution A.741(18);" 33 U.S.C. § 96.370 (a) (1) (2016). See also International Management Code for the Safe Operation of Ships and for Pollution Prevention (International Safety Management (ISM) Code), 62 Fed. Reg. 67492 (December 24, 1997).

[368] The USCG acknowledged the role of human factors in major accidents when introducing regulations requiring the ISM Code, "Recent casualty studies concluded that in excess of 80 percent of all high consequence marine casualties may be directly or indirectly attributable to the ''human element.'' […] The ISM Code offers a systematic approach to mariners with the policy and procedures needed to understand their duties and address the human element issues and risks that can prevent casualties from occurring."; International Management Code for the Safe Operation of Ships and for Pollution Prevention (International Safety Management (ISM) Code), 62 Fed. Reg. 67492 (December 24, 1997)

[369] Demystifying Human Factors: Practical solutions to reduce incidents and improve safety quality and reliability, 2nd International Workshop on Human Factors in Offshore Operations, Houston, TX, April 8-10, 2002.

[370] API, *Human Factors Tool for Existing Operations*, API Human Factors Task Force, Regulatory Analysis & Scientific Affairs Department, February 2006, p 1.

[371] *Ibid*., p 2.

work.[372] The expectation is to use the information compiled through this process to identify needed safeguards, to determine the risks most likely to result in consequences, and to develop recommendations for the reduction or elimination of the hazards.[373] While the document suggests the tool requires little or no training, [374] a certain level of human factors expertise and authority to examine management system failures and cultural influences are likely needed to identify and accurately risk-rank the latent conditions that can contribute to human error scenarios. Furthermore, it does not emphasize the importance of considering human factors in the designing and planning phases of a hazardous operation/equipment lifecycle, and it fails to indicate where technical and operational barriers may be identified and implemented. And since the document is merely guidance, its use offshore is optional.

The emerging lessons of Macondo demonstrate the criticality of the human component within safe offshore operations. Yet, there remains a dearth of US regulatory requirements or national industry guidance aimed at improving human performance during safety critical offshore operations. In the aftermath of the blowout, the regulator and industry hastened numerous US task force initiatives to address issues such as safe drilling operations, well containment and intervention capability, and oil spill response capability,[375] but focused these initiatives on physical threats and technical barriers and controls. In comparison, at the time of the incident, international offshore regions with developed regulatory regimes provided both regulatory requirements and guidance on human factors, and made further advancements in managing human factors offshore. This section makes some global comparisons and identifies opportunities to further incorporate human factors into safety management practices within the US offshore.

1.10.1 After Macondo, Limited US Offshore Regulatory Requirements Remain for Including Human Factors

In the US, companies operating offshore are not required to demonstrate to the regulator that they are effectively managing safety critical tasks, nor must they incorporate human factors into the management of those tasks to reduce risk. The post-Macondo safety management regulation, *Safety and Environmental Management Systems* regulations (SEMS Rule [30 C.F.R. 250 Subpart S]), very minimally addresses human factors. It requires that "The factors (human or other) that contributed to the initiation of the incident and its escalation/control" be addressed in incident investigations [250.1919(a)(2)], yet that requirement is limiting and reactive, seeking only to assess human performance for its immediate causal ties to a given incident.

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[372] *Ibid*., pp 2-3.

[373] *Ibid*., p 3.

[374] *Ibid*, p 1.

[375] Four Joint Industry Task Forces (JITFs) comprising of members from various industry associations were created post-Macondo to address critical offshore activities: operating procedures, equipment, subsea well control and containment, and oil spill preparedness and response. The aim of the JITFs was to further improve existing API standards and make recommendations to the regulator. [Joint Industry Task Force (JITF). *JITF Executive Summary ;* March 13, 2013; p 1. http://www.api.org/~/media/files/oil-and-natural-gas/exploration/offshore/executive-summary-final-031312.pdf (accessed October 15, 2015).]

The American Petroleum Institute's *Recommend Practice for Development of a Safety and Environmental Management Program for Offshore Operations and Facilities* (API RP 75), which has been incorporated into the SEMS Rule by reference, suggests that human factors be "considered" in the following aspects of safety management: the design and implementation of the company's SEMS program; the design of new facilities or major modifications to those facilities; the development of operating procedures and safe work practices; the facility hazard analysis; and in regards to equipment accessibility for operation, maintenance and testing.[376] But *considered* is a weak requirement that does not suggest any action to incorporate human factors principles and best practice. A company could consider human factors issues, do nothing, and still meet the requirements outlined in the regulation. API RP 75 does not provide instruction on how to identify and assess human performance or implement controls for those potential performance failures that may impact safety critical task completion.

Furthermore, only one human factors standard, ASTM F1166-95,[377] is a related reference in API 75. The ASTM standard focuses on maritime facilities and equipment design, particularly on ergonomic design criteria and anthropometric considerations.[378] While this ASTM voluntary standard does provide guidance on a number of human performance principles,[379] it is not required of industry.

Application of the API tool remains voluntary. It has not been revised or amended since its creation, nor has it been incorporated by reference into the SEMS Rule or listed as a normative reference within API 75.

1.10.2 Good Practice Techniques and Guidance on Human Factors

Human factors technical standards and guidance applicable to the oil and gas industry exists, some of which have been referenced in this volume.[380] In addition to that guidance, a variety of tools and methods have been developed over the years to assess the human contribution to safety and operational success, ranging in name and complexity including, among others: [381]

- Human Factors Risk Assessment

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[376] API Recommended Practice, 75, 3rd ed. (2004, reaffirmed 2008 and 2013), Recommended Practice for Development of a Safety and Environmental Management Program for Offshore Operations and Facilities, Sections 1.2.2, 2.3.5, 5.1, 6.1, 8.1 and 3.1.

[377] American Society for Testing and Materials (ASTM) F1166-95, Standard Practice for Human Engineering Design for Marine Systems, Equipment, and Facilities, 1995.

[378] ASTM F1166-95 (3.1.10) defines anthropometrics as the (1) study of the physical size, strength, and range of motion of the human body and the application of that data to the design of systems, equipment, workspaces, and tools to maximize human performance and safety in a work setting; and (2) measurement of human variability of body dimensions and strength as a function of gender, race, and regional origin.

[379] ASTM FM6611-95 Section 4.2.

[380] Further, McLeod provides a succinct summary of the most widely used guides pertaining to human factors engineering. See, McLeod, R., *Designing for Human Reliability: Human Factors Engineering in the Oil, Gas and Process Industries*, Elsevier, 2015, pp 348 – 356.

[381] E.g., HSE, Human Factors Assessment of Safety Critical Tasks, OTO 1999, Report 095; Energy Institute, Guidance on Human Factors Safety Critical Task Analysis, March 2011; HSE, Inspector's Human Factors Toolkit, Identifying Human Failures, Core Topic 3. http://www.hse.gov.uk/research/otopdf/1999/oto99092.pdf (accessed March 26, 2016).

- Human Reliability Assessment
- Human HAZOP
- Hierarchical Task Analysis
- Predictive Human Error Analysis
- Safety Critical Task Analysis (SCTA)

The SCTA is a proactive safety management activity of identifying human performance expectations, potential hindrances to those expectations, and controls to mitigate or eliminate those hindrances before safety-critical work commences.[382] Potential severe consequences of a blowout or gas in the riser scenario are the very hazards identified as particularly in need of more in-depth hazard assessment. An HSE technical report suggests that "only hazards with implications for kick and blow-out scenarios [be] considered [for safety critical task assessment], since these are considered to be the greatest sources of risk in well operations."[383] SCTAs are meant to assess failure mechanisms that extend beyond the span of control of the crew, into areas such as equipment design and mechanical integrity, as well as organizational factors that could influence decision-making, including production or time pressures. As such, these assessments often require the involvement of shore-based personnel as well as the crew.

The hierarchy of controls is one approach to test the sufficiency of the barriers for a safety critical task; in fact, it is considered a step in the human performance assessment process.[384] A foundational argument of the hierarchy of controls principle is that the most effective control minimizes or removes the hazard. If that is not possible, then one of the other progressive inherent safety strategies listed in Figure 1-15 may be used to manage those hazards and reduce risks associated with the operation.

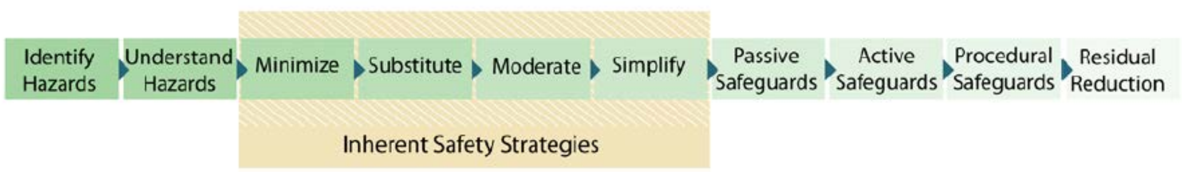

Figure 1-15. Illustration of the Hierarchy of Controls, including inherent safety strategies, for minimizing and eliminating hazards.

[382] Energy Institute, Guidance on Human Factors Safety Critical Task Analysis, March 2011, p 1.

[383] HSE. Human Factors Assessment of Safety Critical Tasks, Offshore Technical Report - OTO 1999 092; July, 2000; p 14. http://www.hse.gov.uk/research/otopdf/1999/oto99092.pdf (accessed March 26, 2016).

[384] HSE, Inspector's Human Factors Toolkit, Identifying Human Failures, Core Topic 3. http://www.hse.gov.uk/humanfactors/topics/toolkit.pdf (accessed March 26, 2016).

Using the Hierarchy of Controls to Assess Human Performance Aspects of Safety Critical Tasks †

- *Minimize: Can the consequences of the human failure be prevented (or mitigated), e.g., by additional barriers in the system?*
- *Substitute: Can the human contribution be removed, e.g., by a more reliable automated system?*
- *Moderate: Can human performance be assured by mechanical or electrical means? For example, the correct order of valve operation can be assured through physical key interlock systems or the sequential operation of switches on a control panel can be assured through programmable logic controllers. Actions of individuals alone should not be relied upon to control a major hazard.*
- *Simplify: Can the PIFs [Performance Influencing Factors] be optimised, (e.g., improve access to equipment, increase lighting, provide more time available for the task, improve supervision, revise procedures or address training needs)?*

†Energy Institute, *Guidance on Human Factors Safety Critical Task Analysis*: London. March 2011, p 16.

1.10.3 International Offshore Regulatory Requirements and Guidance

The UK HSE requires consideration of human factors and offers guidance to its duty holders on the principles to which the regulator will assess the treatment of human factors.[385, 386] These principles include clearly describing the defined role of the human element in a hazardous operation/facility and demonstrating its reliability to perform the desired tasks; analyzing safety critical tasks and demonstrating (drawing upon recognized human factors good practice) that task performance can be delivered as expected; accounting for occupational factors, such as workload and shiftwork schedules; and analyzing human performance issues, such as work task feasibility, procedure design, training, and human-technology interfaces.[387] Furthermore, companies operating in the UK waters of the North Sea are expected to conduct qualitative analyses of human performance and demonstrate to the regulator they have identified potential performance consequences and the measures to counteract or mediate those consequences.[388] The UK HSE provides publicly-available guidance for its regulatory inspectors to both

385 UK Health Safety Executive, Assessment Principles for Offshore Safety Cases (APOSC), March 2006, Forward. http://www.hse.gov.uk/offshore/aposc190306.pdf (accessed March 26, 2016).

386 HSE, Safety report assessment guide: Human factors and HSE, Assessment principles for offshore safety cases (APOSC) http://www.hse.gov.uk/offshore/aposc190306.pdf (accessed March 26, 2016).; HSE, Human Factors Assessment of Safety Critical Tasks, Offshore Technical Report – OTO 1999 092 (July 2000), Section 3.2.1, p 32. http://www.hse.gov.uk/research/otopdf/1999/oto99092.pdf (accessed March 26, 2016).

387 UK Health Safety Executive, Assessment Principles for Offshore Safety Cases (APOSC), March 2006, Principle 8, items 43 – 48. http://www.hse.gov.uk/offshore/aposc190306.pdf (accessed March 26, 2016).

388 HSE, Inspector's Human Factors Toolkit, Identifying Human Failures, Core Topic 3. http://www.hse.gov.uk/humanfactors/topics/toolkit.pdf (accessed March 26, 2016).

understand how to effectively analyze safety critical task performance and to audit companies' efforts at considering human performance variability and potential negative outcomes.[389]

In Australia, the regulator, NOPSEMA, asserts that the use of strategies that identify and optimize human factors will help industry reduce risk of a major accident, and using such strategies will help companies meet their obligations under the applicable Act and associated Regulations.[390] NOPSEMA stresses the importance of the hierarchy of controls, stating "The nature, number and scale of the controls should be such that they are robust, not easily defeated and the level of control is effective for the risks they are intended to manage, prevent or mitigate. A hierarchy of controls should be established, with those that eliminate or prevent MAEs given priority over those that reduce or mitigate the outcomes."[391]

The Norwegian offshore regulator, the Petroleum Safety Authority (PSA), asserts that the interaction among human, technology and organization—HTO—is central for accident prevention and the basic element in its petroleum industry Health, Safety and Environment regulations.[392] Section 13, *Work processes*, specifically states, "The interaction between human, technological and organisational factors shall be safeguarded in the work process."[393] As such, PSA emphasizes, among other human factors issues, the importance of the psychosocial and organizational factors, as well as HTO in safety critical systems.[394]

"Drilling and wells are examples of areas with great challenges in the interaction between people, technology and organisation. For example, the driller must maintain control of the well, lead the work on the drill floor and deal with technically advanced, screen-based solutions in the drilling cabin. It may thus be challenging to understand, operate and maintain an overview of all the incoming data – and simultaneously maintain control and overview of what is physically taking place on the drill floor."

Petroleum Safety Authority, HSE Management: HTO/Human factors, August 28, 2013, http://www.psa.no/hto-human-factors/category965.html (accessed January 23, 2016).

389 HSE, Safety report assessment guide: Human factors and HSE, Assessment principles for offshore safety cases (APOSC); HSE, Human Factors Assessment of Safety Critical Tasks, Offshore Technical Report – OTO 1999 092 (July 2000).

390 The Offshore Petroleum and Greenhouse Gas Storage Action (2006) and the Offshore Petroleum and Greenhouse Gas Storage (Safety) Regulations. National Offshore Petroleum Safety and Environmental Management Authority (NOPSEMA), Resources: Human Factors, http://www.nopsema.gov.au/resources/human-factors/ (accessed July 31, 2015).

391 NOPSEMA, Guidance Note N-04300-GN0060, The Safety Case in Context: An Overview of the Safety Case Regime, rev. 6, June 2013. http://www.nopsema.gov.au/assets/Guidance-notes/N-04300-GN0060-The-Safety-Case-in-Context-An-Overview-of-the-Safety-Case-Regime-Rev-6-June-2013.pdf (accessed March 26, 2016).

392 Petroleum Safety Authority, HSE Management: HTO/Human factors, August 28, 2013, http://www.psa.no/hto-human-factors/category965.html (accessed January 23, 2016).

393 Regulations Relating to Management and the Duty to Provide Information in the Petroleum Activities and at Certain Onshore Facilities (The Management Regulations), Last amended December 18, 2015, http://www.ptil.no/management/category401.html#_Toc280619401 (accessed January 24, 2016).

394 Petroleum Safety Authority, HSE Management: HTO/Human factors, August 28, 2013, http://www.psa.no/hto-human-factors/category965.html. (accessed January 23, 2016).

The International Association of Drilling Contractors (IADC) is a global industry association, of which Transocean is a member. The organization publishes the Health Safety and Environmental Case Guidelines (HSE Case Guidelines) for Mobile Offshore Drilling Units, such as the Deepwater Horizon, providing guidance for a harmonized global framework and methodology for the management of safety. Ten countries require use of the guidelines by force of regulation, and it is recognized as best practice in ten additional countries, some of which have regulations pending to require adoption of the guidelines.[395] The document, however, is only a voluntary standard in the US. Part 2 of the guidance contains HSE management objectives related to "procedural (human factors) controls."[396] The HSE Case Guidelines recommend that drilling contractors verify HSE critical activities and tasks, as well as the more typical physical safety critical equipment, stipulating, "Identification of Critical Activities or Tasks is essential to effectively manage major hazards or high risk hazards."[397] Part 4 of the Guidelines states, "A recognized best practice for risk optimization is to address each risk systematically according to a strategic hierarchy [of control]."[398] The HSE Case Guidelines also explicitly focus on the drilling contractor's management system, stating that it "needs to ensure that personnel policies, training, competencies, attentiveness and alertness, and other human factors allow individuals to perform their Critical Activities or Tasks effectively and efficiently,"[399] and that such factors be monitored periodically.[400]Onshore Regulatory Requirements and Industry Guidance

A number of US onshore regulations and standards address various aspects of human factors in downstream oil and gas operations, which are more robust than current offshore requirements. The federal onshore safety regulations applicable to oil and gas operations, *Process Safety Management of Highly Hazardous Chemicals (PSM)*, stipulates that the required initial hazard analysis must address human factors.[401] Contra Costa County, California, goes beyond this PSM requirement; refineries within its jurisdiction must abide by the County Safety Ordinance, which has provisions that each refinery develop and implement a human factors program for its process hazard analysis, operating and maintenance procedures, and incident investigation management systems.[402] The Ordinance also stipulates that the human factors program include staffing and shiftwork considerations, as well as the management of

[395] Countries requiring use of the guidelines by force of regulation include Australia, Cuba, Denmark, Faeroe Islands, Germany, Ireland, the Netherlands, New Zealand, Norway, and the United Kingdom. Angola, Canada, Brazil, India, Malaysia, Oman, Qatar, Senegal, South Africa, and Trinidad & Tobago recognize the guidelines as best practice. See http://www.iadc.org/iadc-hse-case-guidelines/.

[396] IADC, HSE Case Guidelines for MODU, Issue 3.4, November 2011, section 2.0.4 Demonstrating Assurance of HSE Management Objectives.

[397] *Ibid*., section 4.7 Risk Treatment.

[398] *Ibid.*, section 4.7 Risk Treatment.

[399] *Ibid.*, section 4.7 Risk Treatment.

[400] *Ibid.*, section 6.3 Periodic Monitoring.

[401] OSHA, Process Safety Management of Highly Hazardous Chemicals, 1910.119(e)(3)(vi).

[402] County Ordinance Chapter 450-8, Risk Management, 450-8.016(b)(1)(a, b, d, and e), Stationary source safety requirements, Human factors program, http://cchealth.org/hazmat/iso/ (accessed January 22, 2016).

organizational changes that affect staffing, and employee training on human factors principles and the human factors program itself.[403]

The State of California OSH proposed *Process Safety Regulation for Petroleum Refineries*, 5189.1, goes even further, requiring the written human factors program to examine issues including but not limited to workload, staffing, shiftwork arrangements, procedural clarity, and job task conditions as they influence human performance.[404] The proposed regulation also would require a human factors analysis of process controls (such as automated functions), as part of the larger process hazard analysis, for any major design changes to a process, and all incident investigations and organizational changes.[405]

Both the Contra Costa County Ordinance and the proposed State of California process safety regulation include requirements for employee and employee representative participation in developing the human factors program,[406] and that the regulated party document this program within its "safety plan."[407]

API Publication 770, *A Manager's Guide to Reducing Human Errors: Improving Human Performance in the Process Industries,*[408] provides guidance for onshore petrochemical processes on the topic of human factors engineering, a subset of larger human factors field, as well as on one specific human factors assessment method, human reliability assessment. The guidance illustrates the inherent and critical role of the human in successful completion of a hazardous operation throughout the lifecycle of operation (e.g., research and design, construction, installation, operation and maintenance), as well as throughout the various organizational levels within an organization (e.g., actions of the unit operator all the way to decisions by the corporate office).[409] This guidance has not been extended to offshore.

1.11 Conclusion

When a company does not complete a hazard assessment that accounts for well-specific conditions for safety critical procedures, does not identify vulnerability to human error in a structured and effective way, and does not identify appropriate controls to mitigate risk, it is relying on the workers' varied knowledge and experience to effectively perform drilling tasks. In other words, the operational barrier for activities

[403] *Ibid*., 450-8.016(b)(1)(c and f) and 450-8.016(b)(3).

[404] State of California, Division of Occupational Safety and Health, *Proposed GISO §5189.1, Process Safety Management for Petroleum Refineries,* Version 4.5, May 26, 2015, §5189.1(s)(2), p.26-27.

[405] *Ibid*., §5189.1(s)(3) & (t), pp 26-27.

[406] County Ordinance Chapter 450-8, Risk Management, 450-8.016(b)(2), Stationary source safety requirements, Human factors program, http://cchealth.org/hazmat/iso/ (accessed January 22, 2016).

[407] County Ordinance Chapter 450-8, Risk Management, 450-8.016(b)(4), Stationary source safety requirements, Human factors program, http://cchealth.org/hazmat/iso/ (accessed January 22, 2016) and State of California, Division of Occupational Safety and Health, *Proposed GISO §5189.1, Process Safety Management for Petroleum Refineries,* Version 4.5, May 26, 2015, §5189.1(s)(7), p.27 and §5189.1(q), p.24. The 'safety plan' is submitted by the regulated party to the regulator as a record of asserted compliance with the provisions of the regulation and description of the manner of that compliance. County Ordinance Chapter 450-8, Risk Management, 450-8.016, http://cchealth.org/hazmat/iso/ (accessed January 22, 2016).

[408] API Publication 770, A Manager's Guide to Reducing Human Errors: Improving Human Performance in the Process Industries, March 2001.

[409] See table 1 on page 2 of the referenced document for a useful example.

such as displacement of a well and completion of a negative test is one hundred percent error-free performance by the workers. Thus, a question emerges from Macondo: If the workers' knowledge and experience do not match the particular details of a negative test and the human decisions regarding the test are in error, what barriers are left to ensure a safe outcome?

If the critical layer of protection is the crew, then assessment of their capabilities and interactions with each other, the equipment, and the work environment must be comprehensive, and it must acknowledge human nature, variability, capabilities and limitations. Performance expectations and standards need to be realistic and appropriate in light of this fact.

Macondo provides numerous examples of not addressing human factors considerations in planning and executing temporary abandonment, factors that contributed to the well operations crew's decisions and actions on the day of the incident. The multiple human factors issues explored in this chapter illustrate the need for incorporating human factors in process safety management for offshore oil and gas exploration and development activities. The full consequences of Macondo suggest a strong need for companies and regulators to assess how to strengthen the complex interactions among the human, technological, and organizational elements of a system. Yet, from the major reports published on the Macondo incident,[410] only NAE recommended incorporating human factors in safety management,[411] as part of two very broad recommendations aimed at improving offshore drilling safety and fostering an effective safety culture. Ultimately, the NAE recommendations make the same suggestions of the current SEMS Rule, to "consider" human factors principles for improving human performance and reliability, yet neither advocates for mandated action to ensure incorporation of human factors into MAE safety management. "Consider" is not enough, and as Volume 4 addresses more explicitly, it can lead to a check-the-box activity.[412] Consequently, a more rigorous incorporation of human factors and safety strategies for managing human performance into US safety management requirements and practices is necessary for preventing major accidents.

[410] National Academy of Engineering and National Research Council of the National Academies. *Macondo Well – Deepwater Horizon Blowout: Lessons for Improving Offshore Drilling Safety;* The National Academies Press: Washington, D.C., 2011; BP. *Deepwater Horizon Accident Investigation Report;* September 8, 2010; Transocean. *Macondo Well Incident: Transocean Investigation Report Volumes I and II;* June, 2011; National Commission on the BP Deepwater Horizon Oil Spill and Offshore Drilling. *Chief Counsel's Report: The Gulf Oil Disaster;* Feburary 17, 2011; Transportation Research Board of the National Academies. *Evaluating the Effectiveness of Offshore Safety and Environmental Management Systems;* Special Report 309; National Academy of Sciences: Washington DC, 2012.

[411] NAE made the following recommendations: Industry should greatly expand R&D efforts focused on improving the overall safety of offshore drilling in the areas of design, testing, modeling, risk assessment, safety culture, and systems integration. Such efforts should encompass well design, drilling and marine equipment, human factors, and management systems. These endeavors should be conducted to benefit the efforts of industry and government to instill a culture of safety; and (2) Industry, BSEE, and other regulators should foster an effective safety culture through consistent training, adherence to principles of human factors, system safety, and continued measurement through leading indicators.

[412] Volume 4, Chapters 2 and 3.

2.0 Organizational Learning from Incident Investigations

Chapter 2.0

This chapter explores incident investigations from a variety of perspectives, including the operator/drilling contractor interface, different geographical regions of an international organization, and a regulatory regime that does not explicitly require root cause investigations to address safety management systems. It also highlights numerous challenges that inhibit effective communication of lessons learned across the international offshore industry.

In the months and years leading up to the Macondo blowout, multiple well control incidents occurred on Transocean rigs active around the world under various operators.[413] Several of these events call attention to aspects of offshore incident investigations that are addressed in this chapter, including the operator/drilling contractor interface and challenges to disseminating lessons learned in a global company and across an industry. The quality of the responsive risk reduction corrective actions implemented as a result of lessons learned will be affected by the nature of information gathered on the incident. Thus, this chapter concludes with a look at the US regulatory requirements for incident investigation during Macondo and currently for opportunities to overcome the challenges.

Investigations provide companies with an opportunity to formally review, report, track, and learn from undesirable events.[414] An effective incident investigation program identifies hazards and system causal deficiencies and takes corrective actions to reduce risk before further similar accidents occur.[415] By reviewing previous Transocean incidents that involved various operators, the CSB reiterates that not only a company, but in fact the industry, "suffers from repeated failures and incidents because less formal feedback mechanisms are not sufficient to identify effective recommendations."[416]

2.1 Joint Incident Investigations and Challenges to Disseminating Lessons Learned Between Companies

Work-as-imagined and work-as-done discrepancies, described in Section 1.8, are not unique to the Macondo incident or BP and Transocean.[417] For example, on February 20, 2009, Transocean experienced

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[413] Internal Company Document, Transocean. *Transocean Annual Report - 2010 Well Control Events & Statistics 2005 to 2010*, TRN-MDL-01858257, http://www.mdl2179trialdocs.com/releases/release201305171200030/TREX-036071.pdf (accessed October 7, 2015).

[414] Center For Chemical Process Safety. *Guidelines for Risk Based Process Safety;* John Wiley & Sons: Hoboken, NJ, 2007; pp 552, 556.

[415] American National Standards Institute/American Industrial Hygiene Association (ANSI/AIHA) Z10-2012, *Occupational Health and Safety Managment Systems*, 2012, p 25.

[416] Center For Chemical Process Safety. *Guidelines for Risk Based Process Safety;* John Wiley & Sons: Hoboken, NJ, 2007, p 556.

[417] In almost every investigation conducted by the CSB, the agency has found significant disparities between company policies and actual practice at the worksite. The reasons for the disparity are often multi-faceted.

a well control event that resulted in the riser unloading aboard the M.G. Hulme, Jr. while drilling for t Eni[418] off the coast of West Africa. The crew did not detect a kick until gas passed above the BOP when gas and drilling mud released onto the rig. The investigation concluded that the gas zone was reached earlier than predicted and the crew did not detect an influx that occurred when pumps had been shut down to investigate a problem.[419] Phrases found in Transocean's investigation report are indicators of inadequate bridging between work-as-imagined versus work-as-done (Table 2-1).

Table 2-1. Excerpts from the M.G. Hulme, Jr well control incident report that reflect WAI versus WAD conflicts.[420]

Excerpts from the Transocean M. G. Hulme, Jr. investigation report†	**CSB observations**
"the well program made no mention …" "the use of the […]† system is a significant change from conventional drilling …" "Did not challenge [the operator] on the quality of the pre-spud meeting or the adequacy of the well planning material." "the TSTP did not adequately quantify the hazards, nor did it discuss the preventative or mitigating controls" "due to the use of the E-CD† equipment the Driller did not understand that he could …" "Did not recognize the importance of…" "Assigned driller with limited […] experience" "the driller was in a new position …"	• Lack of, or minimal, detail provided by the operator in written work plans places a heavy reliance on the skills, knowledge, and experience of the drilling contractor which may not be sufficient for the task. • More than a set of instructions, procedures are tools for competent, motivated individuals to plan, coordinate, verify, and assure performance will achieve the intended results.

† Eni Circulation Device (E-CD), "permits the continuous circulation of mud in the well, which maintains a constant down hole pressure over the entire drilling process…," http://www.eni.com/en_IT/innovation-technology/technological-focus/safe-drilling/safe-drilling.shtml.

The need to identify lessons from incidents like the Macondo blowout or the M. G. Hulme, Jr. well control event transcends individual companies because the operators and drilling contractors have

[418] http://www.eni.com/en_IT/home.html (accessed October 7, 2015).

[419] Internal Company Document, Transocean. *EAU Incident Investigation Report - M.G. Hulme, Jr. Well Control Incident - Riser Unloading*, OER-MGH-09-005, March 26, 2009, TRN-INV-01143039, http://www.mdl2179trialdocs.com/releases/release201303211200016/TREX-05650.pdf (accessed October 7, 2015).

[420] *Ibid*.

different roles, expertise, and safety management systems that influence the design and operational risk of drilling a well. As a result, efforts to minimize the gap between WAI and WAD would be most effective if operators and drilling contractors alike work together to investigate incidents and identify corrective opportunities.

2.2 Challenges to Disseminating Lessons Globally

Four months before the Macondo incident, on December 23, 2009, a Transocean-owned rig, Sedco 711, experienced a significant well control event in the North Sea.[421] Delayed detection of a well kick resulted in gas and drilling mud from the riser unloading onto the rig with some being lost to the sea. Unlike the situation at the Macondo well, the flammable material that reached the rig did not ignite, and the BOP was able to seal the well and limit the release to what had already traveled above the BOP before it was closed.

The Sedco 711 incident occurred when a mechanical barrier that successfully passed a positive inflow test subsequently failed while the well was being underbalanced.[422] The crew did not detect the kick, in part, because the mud returns were being routed to reserve pits, which prevented the crew from monitoring the returns on the active pit system.[423,424] Other data were not interpreted as indicators of loss of well control based on the crew's faith in the successful well barrier test. Transocean identified three immediate technical and operational causes, including failure of the tested downhole barrier, failure to monitor and identify the influx, and failure to close in the well prior to the influx reaching the BOP.[425] Shell, the well

[421] Internal Company Document, Transocean. *Operations Advisory*, NRS-OPS-ADV-008, April 14, 2010, TRN-MDL-02840795, http://www.mdl2179trialdocs.com/releases/release201304041200022/Hart_Derek-Depo_Bundle.zip, Exhibit 5749, (accessed October 7, 2015); Hearing before the U.S. District Court for the Eastern District of Louisiana under the Multi-District Litigation docket MDL No. 2179, June 13, 2011 pp 22-26, http://www.mdl2179trialdocs.com/releases/release201302281700004/Cameron_David-Depo_Bundle.zip (accessed October 7, 2015).; Internal Company Document, Transocean. *711 Well Control Incident Power Point*, TRN-MDL-00870381, http://www.mdl2179trialdocs.com/releases/release201303211200016/TREX-01760.pdf (accessed October 7, 2015).; Internal Company Document, Shell. Incident Investigation Report Bardolino Well Control Incident, Report: EP201002315140, January 26, 2010, p 4, TRN-INV-01823569.

[422] Internal Company Document, Transocean. *711 Well Control Incident Power Point*, p 4, TRN-MDL-00870381, http://www.mdl2179trialdocs.com/releases/release201303211200016/TREX-01760.pdf (accessed October, 7 2015, October).

[423] Internal Company Document, Transocean. *Operations Advisory*, NRS-OPS-ADV-008, April 14, 2010, TRN-MDL-02840795, http://www.mdl2179trialdocs.com/releases/release201304041200022/Hart_Derek-Depo_Bundle.zip, Exhibit 5749, (accessed October 7, 2015).

[424] An important kick indicator is an increase in fluids coming from the well compared to the volume of fluids pumped into the well. As described by the National Commission on the BP Deepwater Horizon Oil Spill and Offshore Drilling (Commission). *Chief Counsel's Report: The Gulf Oil Disaster*, February 17, 2011, p 165, "The active pit system refers to a computer setting that allows the driller (and others) to select several pits and aggregate their volumes into one "active pit volume" reading. Even though there are several different pits involved, the rig's computer system displays them as a single pit for volume monitoring purposes."

[425] Internal Company Document, Transocean. *Operations Advisory*, NRS-OPS-ADV-008, April 14, 2010, TRN-MDL-02840796, see Exhibit 5749. http://www.mdl2179trialdocs.com/releases/release201304041200022/Hart_Derek-Depo_Bundle.zip (accessed October 7, 2015).

operator, reported both onshore and offshore personnel believed that once the crew successfully performed the inflow test, the barrier would not fail, which "led to a blinkered approach" by the crew regarding the true well conditions.[426] The report states, "This belief is highlighted by the fact that there were clear indications of the operation not going to plan, but the thoughts were tailored in looking for surface reasons for the anomalies." [427] Ultimately, the crew rationalized the well control indicators to support the conclusion that the well barrier was intact.

A Transocean operations advisory noted a lack of clear well control procedures and a weak risk assessment for planning and executing the well plan.[428] As at Macondo, procedures were missing critical process parameters, "The well planning did not highlight that the well would be under balance during the […] operation. There were no hydrostatic step up/down charts to show the expected pressures in the well at the different stages of the well clean up, and specifically when the well went under balance."[429] As a result of the Sedco 711 event, Transocean and Shell, separately identified corrective actions. Shell's proposed actions focused on written tools that Section 1.8 previously noted were important for closing the WAI and WAD gap:

- Inclusion of loss of well barrier risks on TSTPs (see Section 1.8.3 for TSTP discussion);[430]
- Increased communication of Standing Instructions to the Driller (SID) with clear roles, accountability, and responsibilities listed (see Section 1.8.2 for SID discussion); [431]
- Development and use of written work instructions for well control operations that include guidance information on overbalance and underbalance operations and on conducting inflow tests, and that document the risk assessment and mitigation actions.[432]
- Revisions to the Well Control Handbook pertaining to conducting fluid displacements under controlled conditions and calculating hydrostatic pressure;[433]
- Review of the Transocean (contractor) and Shell (operator) bridging document to clarify accountabilities and standardize the well control process into defined phases that identify when decision-making requires management or technical onshore support (see Section 4.4.5 for Macondo bridging documents discussion);[434] and

[426] Internal Company Document, Shell. *Incident Investigation Report Bardolino Well Control Incident*, Report: EP201002315140, January 26, 2010, p 12, TRN-INV-01823569.

[427] *Ibid*.

[428] Internal Company Document, Transocean. *Operations Advisory*, NRS-OPS-ADV-008, April 14, 2010, TRN-MDL-02840796, see Exhibit 5749 http://www.mdl2179trialdocs.com/releases/release201304041200022/Hart_Derek-Depo_Bundle.zip (accessed October 7, 2015).

[429] *Ibid*., TRN-MDL-02840797.

[430] Internal Company Document, Shell. *Incident Investigation Report Bardolino Well Control Incident*, Report: EP201002315140, January 26, 2010, p 41, TRN-INV-01823569.

[431] *Ibid*., p 20, TRN-INV-01823569.

[432] *Ibid*., pp 4, 14, TRN-INV-01823569.

[433] *Ibid*., p 15, TRN-INV-01823569.

[434] *Ibid*., p 16, TRN-INV-01823569.

- Corrective actions for Schlumberger (third-party contractor) related to including relevant parties in hazard assessment activities[435] and to incorporating a lateral learning process for capturing lessons learned from operational incidents (to Schlumberger)[436] and risk assessment changes and management (to Shell).[437]

As part of its investigation, Transocean noted two “missed opportunities” related to the mudlogger. One was that the mudlogger reported an increase in well fluids, but the driller did not act upon it, attributing the increase instead to reasons other than loss of well integrity. A second was that the mudlogger did not inform the client supervisor, toolpusher, or the driller again when the flow of well fluids continued to rise.[438] These lines of communication match what is presented in Figure 1-12. Despite observing that the well kick indicator was reported by the mudlogger and that increased communication might have helped, neither Transocean’s nor Shell’s corrective actions addressed communication skills or gaps. Instead, their corrective actions focused more generally on increasing awareness among crew members by reviewing the incident, reiterating the need for early kick detection, and ensuring well programs noted when underbalanced conditions were to exist in a well. Third-party mudlogger services like those provided by Schlumberger during this project are contracted by the operator, indicating that the operator is likely best positioned to cause bridging between the drilling contractor and other third-party contractors. Beyond the mudlogger missed opportunities, Transocean was also concerned with updating its well control manual as a result of Shell’s recommendation.[439]

Four months later, Transocean’s Well Operations Manager in the Gulf of Mexico sent an email to colleagues in the North Sea, stating, “I’m still on the fence as to whether an advisory [on Sedco 711] is required or not.”[440] He was concerned that the well control manual sufficiently addressed underbalanced well conditions. The response he received from his North Sea counterparts was, “Expectation from Shell is an update in the [well control] manual—hence request for advisory until update issued. If not done then we will require to issue an [North Sea] advisory but I know Shell will ask what the Shell rigs are doing elsewhere in the world…”[441] Subsequently, an advisory for the Gulf of Mexico was developed that suggested additional text be included in the well control manual, including the statement, “Do not be complacent because the reservoir has been isolated and inflow tested. Remain focused on well control and maintain good well control procedures.”

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[435] *Ibid.*, p 15, TRN-INV-01823569.

[436] *Ibid.*, p 15, TRN-INV-01823569.

[437] *Ibid.*, p 17, TRN-INV-01823569.

[438] Internal Company Documents, Transocean. *Operations Advisory*, NRS-OPS-ADV-008, April 14, 2010, TRN-MDL-02840796, see Exhibit 5749 http://www.mdl2179trialdocs.com/releases/release201304041200022/Hart_Derek-Depo_Bundle.zip, (accessed October 7, 2015).

[439] Email from Aberdeen Operations Manager, Transocean, to Well Operations Manager, Transocean, Subject: potential advisory from 711 event, March 31, 2010, TRN-INV-03407526.

[440] *Ibid*.

[441] *Ibid*.

The DWH crew never received the US advisory describing the text changes that would be made to the well control manual. [442] Post-incident, Transocean's General Manager of North America who was responsible for forwarding the information to the GoM rigs stated that the email containing the advisory came in while he was on vacation and that he never saw it.[443] Another person covered the general manager's duties while he was on vacation, but upon review of both email accounts, neither person forwarded the advisory to employees working in the Gulf of Mexico. The advisory was posted on Transocean's internal electronic document system at the same time it was sent to the General Manager,[444] but unless employees subscribed for notifications of newly added documents, they would not have be made aware of its submission.[445]

Without auditable follow-up actions, and a person responsible for tracking them, such an unintended oversight is more likely to occur. Databases require users to initiate searches, and emails can languish in an inbox. Consequently, industry needs to consider how to most effectively communicate the various database resources (including those with email notifications) and how to absorb lessons into the organization's safety management systems. Inundating people with too much information leads to their overlooking critical information for immediate action. Changing this mindset will require industry and regulators to distinguish such critical information from learnings that could be reviewed on a less frequent basis.

The Well Operations Group Advisory developed for the Gulf of Mexico was also markedly different from the North Sea Operations Advisory concerning Sedco 711.[446,447] Where the GoM advisory described the

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[442] Hearing before the U.S. District Court for the Eastern District of Louisiana under the Multi-District Litigation docket MDL No. 2179, March 28, 2011; see Johnson Designations Vol 1, pp 91-93, http://www.mdl2179trialdocs.com/releases/release201302281700004/Johnson_Paul-Depo_Bundle.zip (accessed October 7, 2015).; Hearing before the U.S. District Court for the Eastern District of Louisiana under the Multi-District Litigation docket MDL No. 2179, October 27, 2011; see Braniff Designations Vol 1, p 27, http://www.mdl2179trialdocs.com/releases/release201302281700004/Braniff_Barry-Depo_Bundle.zip (accessed October 7, 2015).; Hearing before the U.S. District Court for the Eastern District of Louisiana under the Multi-District Litigation docket MDL No. 2179, March 24, 2011; see Canducci Designations Vol 2, pp 141-142, http://www.mdl2179trialdocs.com/releases/release201302281700004/Canducci_Gerald-Depo_Bundle.zip (accessed October 7, 2015).

[443] Hearing before the U.S. District Court for the Eastern District of Louisiana under the Multi-District Litigation docket MDL No. 2179, July 27, 2011; see Sannan Designations Vol 1, p 75, http://www.mdl2179trialdocs.com/releases/release201302281700004/Sannan_Stuart-Depo_Bundle.zip (accessed October 7, 2015).

[444] *Ibid.*, 1, p 81.

[445] Hearing before the U.S. District Court for the Eastern District of Louisiana under the Multi-District Litigation docket MDL No. 2179, April 25, 2011; see Rose Designations Vol 1, p 113, http://www.mdl2179trialdocs.com/releases/release201302281700004/Rose_Adrian-Depo_Bundle.zip (accessed October 7, 2015).

[446] Hearing before the U.S. District Court for the Eastern District of Louisiana under the Multi-District Litigation docket MDL No. 2179, March 28, 2011; see Johnson Designations Vol 1, pp 104-106, http://www.mdl2179trialdocs.com/releases/release201302281700004/Johnson_Paul-Depo_Bundle.zip (accessed October 7, 2015).

[447] Internal Company Documents, Transocean. *Operations Advisory*, NRS-OPS-ADV-008, April 14, 2010, and *Well Operations Group* Advisory, HQS-OPS-ADV-09, April 5, 2010, TRN-MDL-02840793 and TRN-MDL-

event simply as a "well control event," the North Sea included a description of the consequences such as 11 days of lost time, cost of approximately 5.2 million Euros (~6.5 million US dollars), and significant loss to Transocean's reputation. While the US advisory only addressed the well control manual text changes, the North Sea advisory provided details concerning:

- misplaced faith in a tested barrier;
- secondary activities that obscure the ability to monitor the pit levels;
- rationalizing rig data;
- no clear procedures in underbalanced conditions;
- weak risk assessments;

Despite the suggestion of several inherent human performance issues, the advisory corrective actions focused on reminding the drill crew of the importance of kick detection and their responsibilities, as well as the need to provide written warnings in the daily instructions when a single mechanical barrier is in effect.[448] Missing was an attempt to understand the psychological and cognitive reasons the crew placed faith in the barrier or rationalized the data. (For example, perhaps control board design or inadequate instrumentation contributed to their situational awareness of the well. This would be unknown unless examined as part of the investigation.) Also absent were identified steps the company might take to provide procedural clarity, conduct more useful risk assessments, or ensure secondary activities do not eclipse safety critical activities in future projects. Furthermore, the mudlogger communication issues mentioned earlier were not addressed.[449] Both the North Sea advisory and the more limited US version do not address these important underlying factors in order to resolve the human factors issues revealed in the investigation.

Large corporations like Transocean often consist of a series of business units which act as freestanding commercial organizations. So, while Transocean's North Sea and Gulf of Mexico business units work from the same corporate policies, implementation of those polices is determined separately by the independent business unit leaders. This can be described as centralized direction with decentralized implementation. As the Sedco 711 incident exemplifies, this approach can lead to different results among business units in the same company. The CSB and others previously noted the role a decentralized organizational structure can play in a major accident,[450] leading to systemic and cultural differences across business units rather than a consistent approach to managing major accident risk.

02840795, see Exhibit 5749 http://www.mdl2179trialdocs.com/releases/release201304041200022/Hart_Derek-Depo_Bundle.zip, (accessed October 7, 2015).

[448] Internal Company Documents, Transocean. *Operations Advisory*, NRS-OPS-ADV-008, April 14, 2010, and *Well Operations Group* Advisory, HQS-OPS-ADV-09, April 5, 2010, TRN-MDL-02840793 and TRN-MDL-02840795, see Exhibit 5749 http://www.mdl2179trialdocs.com/releases/release201304041200022/Hart_Derek-Depo_Bundle.zip, (accessed October 7, 2015).

[449] See Section 1.7.1.1.

[450] CSB, 2007. *Refinery Explosion and Fire, Texas City, TX, March 23, 2005,* Report No. 2005-04-I-TX, March 2007.; Hopkins, A. *Disastrous Decisions;* CCH Australia: Australia, 2012; pp 97 - 110.; The Baker Panel. *The Report of the BP US Refineries Independent Safety Review Panel;* January, 2007; p 94. http://www.csb.gov/assets/1/19/Baker_panel_report1.pdf (accessed October 7, 2015).; UK Health and Safety Executive and Scottish Environment Protection Agency. *Major Incident Investigation Report BP Grangemouth Scotland;* August 18, 2003; p 62.

2.3 Expanding Beyond Immediate Causes and Implementing Change

The broadest learning impact can be achieved when investigations extend beyond the immediate technical causes of an incident. Addressing deficient safety management systems and inadequate organizational practices can result in findings that go beyond the immediate chain events that preceded any one incident. As examples in this chapter show, while the immediate causes of a well control incident might vary, the safety management systems and organizational findings can be similar. Ultimately, BSEE has the opportunity to mandate such a focus and then facilitate the dissemination of lessons across the operator/drilling contractor boundary and geographical regions.

There is the danger of concentrating on the exact mechanism of the previous incident rather than identifying broad lessons. Regulatory requirements may exacerbate this narrow focus for investigating major accidents and near-misses. In the US, the SEMS Rule excludes drilling contractors and require only operators to complete incident investigations. Additionally, the SEMS Rule requires that the investigations identify contributing factors but do not explicitly require investigations to extend beyond the immediate causes to deficient safety management systems on the rig and inadequate organizational practices by either the operator or the drilling contractor.[451] In Europe, a recently adopted directive strives "to facilitate the exchange of information and to prevent future accidents of a similar nature," but then focuses on information of "technical interest" when describing information to be reported on near-misses.[452]

The global nature of drilling and the overlap that occurs when drilling contractors like Transocean work for multiple operators presents the opportunity for expediting industrywide learning with each well control event. Similarly, international operators could expose each other to learnings as a part of their joint ventures. Well incident databases from before[453] and after[454] the Macondo incident collect safety incident information that can be analyzed and shared across the industry to increase lessons learned. While industry develops and maintains these incident databases, regulators can also influence incident reporting and the sharing and implementing of lessons learned.

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[451] 30 C.F.R. § 250.1919 (2015).

[452] Directive 2012/18/EU of the European Parliament and the Council of 4 July 2012 on the Control of Major-Accident Hazards Involving Dangerous Substances, Amending and Subsequently Repealing Council Directive 96/82/EC.

[453] For example, Step Change in Safety supported Safety Alert Database and Information Exchange (SADIE) (now known as the Incident Alerts Database) https://www.stepchangeinsafety.net/safety-conversations/intro; (accessed October 7, 2015), SINTEF Offshore Blowout Database http://www.sintef.no/en/projects/sintef-offshore-blowout-database/ (accessed October 7, 2015), and the Norwegian Oil and Gas' Drilling Managers Forum initiative, Sharing to be Better, https://www.norskoljeoggass.no/en/Activities/HSE-and-operation/Sharing-to-be-better/.

[454] For example, in the UK the Oil & Gas Producers Wells Expert Group started a well control incident database http://www.iogp.org/Newsroom/News/PostId/71/well-control-incidents-database-submissions-a-benefit-to-industry (accessed October 7, 2015); in the US the Center for Offshore Safety initiated a Learning from Incidents program http://www.centerforoffshoresafety.org/COS%202013%20Annual%20Performance%20Report.pdf (accessed October 7, 2015).

Additional Roadblocks to Organizational Learning

Beyond the challenges discussed in this chapter, there are additional roadblocks that cannot be ignored.

Legal challenges to sharing information from internal investigations threaten maximum learning. At the Expert Forum on the Use of Performance-Based Regulatory Models in the US Oil and Gas Industry, Offshore and Onshore,[a] *a staff consultant from the Center for Chemical Process Safety commented, "too often when it's post-incident, lawyers get involved and it's very, very difficult to share information."*[b] *The speaker also described how companies fear that lessons learned will result in a punitive response from the regulator, so they start to protect documents under attorney-client privilege. He commented, "So, the more punitive the lawyers become concerned, the more closely they hold information. And really we need to go the other direction."*[c]

The timeliness of information is also of concern. The legalities surrounding incidents can affect when, if ever, information concerning an incident is released. For example, some technical findings related to the Macondo blowout were released within a year of the incident,[d] *but information that provided insight to the organizational and operational issues (including human performance) was not released until almost three years later when the US District Court for the Eastern District of Louisiana posted documents and depositions online that had been submitted as part of the criminal hearings.*

These two critical challenges must be overcome to further advance learning.

[a] Expert Forum on the Use of Performance-Based Regulatory Models in, 77 Fed. Reg. 50172 (August 20, 2012) https://www.osha.gov/pls/oshaweb/owadisp.show_document?p_table=FEDERAL_REGISTER&p_id=23267 (accessed October 7, 2015).

[b] Stakeholder meeting transcript for the Expert Forum on the Use of Performance-Based Regulatory Models in the U.S. Oil and Gas Industry, Offshore and Onshore, OSHA-2012-0033-0022, September 21, 2012, p 17.

[c] Stakeholder Meeting Transcript for the Expert Forum on the Use of Performance-Based Regulatory Models in the U.S. Oil and Gas Industry, Offshore and Onshore, OSHA-2012-0033-0022, September 21, 2012, p 36.

[d] Bureau of Ocean Energy Management Regulation and Enforcement (BOEMRE). *Forensic Examination of Deepwater Horizon Blowout Preventer;* Report No. EP030842; March 11, 2011.

2.4 Effectiveness of post-Macondo SEMS Requirements for Incident Investigation

At the time of the Macondo blowout, BSEE's predecessor MMS published investigations of selected serious incidents,[455] but US offshore regulations did not require companies to investigate their own incidents. With BSEE's promulgation of the SEMS Rule, operators now must develop investigation procedures for "all incidents with serious safety or environmental consequences."[456] For situations that

[455] See BSEE's Panel Investigation Reports at http://www.bsee.gov/Inspection-and-Enforcement/Accidents-and-Incidents/Panel-Investigation-Reports/Panel-Investigation-Reports/ (accessed October 7, 2015).

[456] 30 C.F.R. § 250.1919 (2014).

have the "potential" for serious consequences, facility management or the regulator may determine that an investigation is necessary. Factors that contributed to the incident and recommended changes must be addressed, and a corrective action program must be established where the conclusions are distributed to "similar facilities and appropriate personnel within their organization."[457] The requirements do not explicitly stipulate that safety management systems, the interface between the operator and contractors, or lessons learned from either international incidents or other companies be addressed. A March 8, 2010, well kick at Macondo exemplifies how an investigation lacking in these characteristics can result in missed opportunities to prevent similar consequences.

While drilling the Macondo well at a depth of approximately 13,250 feet, a well kick occurred.[458] The crew noted an increasing gain in pit volume,[459] prompting them to shut in the well for evaluation. Rig data indicates the well flowed undetected for approximately 30 minutes and resulted in a gain of 35 barrels before the situation was brought under control.[460] The larger the ingress, the greater the potential hazard, and Transocean documented that the majority of well kicks are detected in under 20 barrels, and noted that "failure to limit a kick to less than 20 barrels is less than ideal."[461] Thus, the March 8 and previously described Sedco 711 and M.G. Hulme, Jr., incidents proved to be crucial missed opportunities for Transocean to examine crew kick response time, share the subsequent lessons learned, and incorporate changes in their safety management systems to support improvements. Ultimately, while Sedco 711 and M.G. Hulme identified systemic deficiencies, none appeared in the official investigation of the March 8 incident by either company, nor were corrective actions taken to remedy such failures.

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[457] 30 C.F.R. § 250.1919(b)(3).

[458] Hearing before the U.S. District Court for the Eastern District of Louisiana under the Multi-District Litigation docket MDL No. 2179, May 11, 2011; See Sepulvado Designations Vol 1, pp 29-32, http://www.mdl2179trialdocs.com/releases/release201304041200022/Sepulvado_Murry-Depo_Bundle.zip (accessed October 7, 2015).; Internal Company Document, Transocean. IADC Daily Drilling Report, Deepwater Horizon, Report No. 37 (March 8, 2010), http://www.mdl2179trialdocs.com/releases/release201303071500008/TREX-00657.pdf (accessed October 7, 2015).

[459] See footnote 424 for definition.

[460] Hearing before the U.S. District Court for the Eastern District of Louisiana under the Multi-District Litigation docket MDL No. 2179, May 11, 2011; See Sepulvado Designations Vol 1, pp 29-32, http://www.mdl2179trialdocs.com/releases/release201304041200022/Sepulvado_Murry-Depo_Bundle.zip (accessed October 7, 2015).; Internal Company Document, Transocean. IADC Daily Drilling Report, Deepwater Horizon, Report No. 37 (March 8, 2010).; Hearing before the U.S. District Court for the Eastern District of Louisiana under the Multi-District Litigation docket MDL No. 2179, April 20, 2011; see Burgess Designations pp 31 - 38, http://www.mdl2179trialdocs.com/releases/release201302281700004/Burgess_Mark-Depo_Bundle.zip (accessed October 7, 2015).; Internal Company Document, BP. *File Note: Information regarding kick taken on Deepwater Horizon on March 8th 2010*, Exhibit 676, BP-HZN-BLY00096442, http://www.mdl2179trialdocs.com/releases/release201302281700004/Lee_Philip-Depo_Bundle.zip (accessed October 7, 2015).

[461] In 2009, Transocean recorded that 84% of kicks were detected in under 20 barrels, and 14% of kicks ranged from 20 to 60 barrels. Internal Company Document, Transocean. *Well Control Events & Statistics 2005 to 2009*, p 6, TRN-INV-00760054, http://www.mdl2179trialdocs.com/releases/release201303211200016/TREX-05649.pdf (accessed June 24, 2015).

BP requires well control incidents be reported in its official corporate incident reporting system, Tr@ction.[462] However, no Tr@ction report was created for the March 8 event.[463] The Wells Team Leader for the DWH "did not know that reporting this type of an incident was a requirement."[464] BP did, however, conduct a technical examination of the kick, which looked at the variables such as the geological conditions of the well and pore pressure detection analytics.[465] BP's Tiger Team[466] shared additional lessons learned through emails among the team.[467] Mainly, the lessons were technical, but one concerned better lines of communication among BP rig personnel and the "Houston office." It was noted that the mudlogger and wellsite pore pressure/fracture gradient[468] personnel should openly communicate with the wellsite geologist, who should then communicate with the BP well site leader.[469] However, this document did not address the potential human factors related to the well operations crew's kick response capabilities, nor how to improve that response through more effective technologies, barrier management, and safety system performance.

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462 Internal Company Document, BP. *GP 10-00 Drilling and Well Operations Practice*, Issue 1, October 2008, Section 15.2.12, BP-HZN-BLY00034504, http://www.mdl2179trialdocs.com/releases/release201304110900026/TREX-06121.pdf (accessed May 26, 2015).

463 Internal Company Document, BP. *BP Incident Investigation Team - Notes of Interview with John Guide*, July 1, 2010, BP-HZN-BLY00124228, see Exhibit 0153 http://www.mdl2179trialdocs.com/releases/release201302281700004/Paine_Kate-Depo_Bundle.zip (accessed October 7, 2015).; Internal Company Document, BP. *BP Incident Investigation Team - Notes of Interview with Mark Hafle*, July 8, 2010, BP-HZN-BLY00144214, http://www.mdl2179trialdocs.com/releases/release201304110900026/TREX-04447.pdf (accessed October 7, 2015).

464 Internal Company Document, BP. *BP Incident Investigation Team - Notes of Interview with John Guide*, July 1, 2010, BP-HZN-BLY00124228, see Exhibit 0153 http://www.mdl2179trialdocs.com/releases/release201302281700004/Paine_Kate-Depo_Bundle.zip (accessed October 7, 2015).

465 Internal Company Document, BP. *Macondo LL*, March 18, 2010, Powerpoint presentation prepared by the BP Macondo well onshore engineering team, BP-HZN-2179MDL00340813, http://www.mdl2179trialdocs.com/releases/release201305171200030/TREX-000051.pdf (accessed October 7, 2015).; Internal Company Document, BP. *File Note: Information regarding kick taken on Deepwater Horizon on March 8th 2010*, BP-HZN-BLY00306271, see Exhibit 7321 http://www.mdl2179trialdocs.com/releases/release201302281700004/Cowie_James-Depo_Bundle.zip (accessed October 7, 2015).

466 The Tiger Team is a group of experts (e.g., in shallow hazard assessment, pore pressure prediction, operations geology, etc.) that provides onshore sub-surface support for the planning and execution of deepwater exploration wells.

467 Email from Tiger Team Members, BP, Subject: RE: Lesson learned - Plan forward: Macondo, March 18, 2010, BP-HZN-2179MDL00015694, http://www.mdl2179trialdocs.com/releases/release201304041200022/TREX-00214.pdf (accessed October 7, 2015).

468 See Volume 1, Section 2.1 for description of pore pressure and fracture gradient.

469 Email from Tiger Team Members, BP, Subject: RE: Lesson learned - Plan forward: Macondo, March 18, 2010, BP-HZN-2179MDL00015697, http://www.mdl2179trialdocs.com/releases/release201304041200022/TREX-00214.pdf (accessed October 7, 2015).

At the time of the incident, Transocean required a Well Control Event Report whenever the rig experienced a well kick.[470] The Well Control Event Report recorded the conditions in the well at the time of the kick (e.g., mud weight, shut in drillpipe pressure, size of influx), and it required a root cause analysis of the event. In response to the March 8 kick, Transocean created an operation event report for the March 8 kick, attributing the event to "drill[ing] into abnormal pressure," but provided minimal information about the event and identified no corrective actions.[471] In emails with the BP Wells Team Leader, the Transocean Rig Manager identified the need to improve hazard recognition among the crew.[472] However, neither BP nor Transocean connected similarities of the March 8 kick with previous Transocean incidents, nor reviewed previously identified safety management system or communication deficiencies that might also have occurred at the Macondo well.

Ultimately, the March 8 incident was not investigated for its safety implications. It is worth reemphasizing that BP did not identify the delayed response on March 8 as a safety concern in its formal investigation of the incident, but it did acknowledge it post-Macondo.[473]

While current US offshore regulations require companies to address contributing factors in incident investigations, the regulations do not explicitly require investigations to extend beyond the immediate causes to deficient safety management systems and inadequate organizational practices. The Macondo blowout and other incidents discussed in this chapter point toward a need for an investigation to cover the operator/ contractors interactions, but the SEMS Rule excludes contractor compliance.[474] And while the SEMS Rule requires that "The factors (human or other) that contributed to the initiation of the incident and its escalation/control" be addressed in incident investigations [250.1919(a)(2)], it does not provide guidance on human and organizational analyses and joint operator/drilling contractor investigations.

Companies may comply only minimally with regulations that require the conduct of an activity (in this case, investigation of an incident) but do not explicitly stipulate the outcome to be achieved (i.e., major

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[470] Internal Company Document, Transocean. *Well Control Handbook*, Revision 01, HQS-OPS-HB-01, March 31, 2009, Well Control Procedures and Responsibilities and Appendix, BP-HZN-2179MDL0033078 AND BP-HZN-2179MDL00331106, http://www.mdl2179trialdocs.com/releases/release201303071500008/TREX-00596.pdf (accessed October 7, 2015).

[471] Internal Company Document, Transocean. *Well Control Event Report*, OER-DWH-10-023, March 8, 2010, TRN-MDL-00287183, see Exhibit 0688 http://www.mdl2179trialdocs.com/releases/release201302281700004/Johnson_Paul-Depo_Bundle.zip (accessed October 7, 2015).

[472] Email from Macondo Rig Manager, Transocean, to Wells Team Leader, BP, Subject: Hazard Recognition, 18 March, 2010, BP-HZN-2179MDL00289217, http://www.mdl2179trialdocs.com/releases/release201305171200030/TREX-000684.pdf (accessed October 7, 2015).

[473] In the aftermath of Macondo, the response time of the crew to the March 8 kick was criticized. The BP Wells Team Leader indicated that the well operations crew's response to the kick as "very poor," and that the Transocean Rig Manager believed the crew "had screwed up;" Internal Company Document, BP. *BP Incident Investigation Team - Notes of Interview with John Guide*, July 1, 2010, BP-HZN-BLY00124228, see Exhibit 0153 http://www.mdl2179trialdocs.com/releases/release201302281700004/Paine_Kate-Depo_Bundle.zip (accessed October 7, 2015).

[474] See Volume 4, Section 3.2 for details.

accident prevention through demonstrated risk reduction).[475] This reality exists even when internal company policies stipulate more stringent practices (Section 4.1). The SEMS Rule does not require that corrective actions from investigation findings demonstrably reduce risk to an identified goal. Volume 2 of the CSB's Macondo investigation report highlights pitfalls of not requiring companies to mitigate risk to targeted risk levels.[476] In summary, the potential exists for a company to satisfy regulatory requirements even though they may not adequately or effectively reduce the hazards of major accidents. The SEMS Rule requirements need to move beyond an activity-based focus, require in-depth assessment of organizational contributions, and encourage sharing of lessons learned across the offshore global community within and between companies.

2.5 Conclusion

Several of the issues raised in Chapter 1 concerning system and organizational deficiencies were not unique to the work conducted at the Macondo well—latent kick detection was not a Deepwater Horizon crew problem, but a challenge that Transocean faced internationally several times before. International investigation reports reviewed in this chapter identified improvements in tools that help minimize the gap between WAI and WAD, as well as those to help raise a crew's hazard awareness, but they were not implemented in the Gulf of Mexico.

Offshore regulations provide the minimal safety expectations a company must meet. Accordingly, if US regulations do not establish goals for incident investigations that require not just immediate technical findings, but also lessons from international incidents, then companies have the opportunity to limit what they do in response to incidents and near-misses. The M G. Hulme Jr., Sedco 711, and Deepwater Horizon March 8 well control event and April 20 blowout all indicate that incidents and near-misses need to be viewed beyond an individual rig level and within the larger context of a safety performance indicators program (addressed in detail in the next chapter). But, an indicators program can be only as good as the data upon which it is based, and it will be ineffective if the findings resulting from an investigation or indicator program are not actually acted upon to continually improve safety.

[475] See Volume 4, Section 2.5 for details.

[476] Volume 2, Section 6.1.1.1

3.0 Safety Performance Indicators

Chapter 3.0 Overview

This chapter begins with a more detailed description of efforts to advance understanding of effective safety performance indicators and a review of why indicators reflected in company policies, practices, audits, rewards, and reports become the foundational elements of a company's approach to risk management. The chapter then illustrates that BP and Transocean inadequately collected and used process safety indicator data. Finally, a review of the guidance available to industry calls for further improvements in developing, collecting, and using safety performance indicators.

Companies involved in offshore drilling and production—and even trade associations and regulators—can develop and use organizational and managerial measures, also called indicators, to monitor safety performance, compare or benchmark that safety performance, and set goals for continual improvement.

In the oil and gas industry, safety performance can be separated into two categories: personal safety (also called occupational safety) and process safety, which addresses efforts to reduce the potential for a major accident event.[477] The distinction is important because the indicators to monitor and the approaches to manage the two categories are different. For example, good personal safety is indicated by low individual worker injury rates which, for some tasks, could be achieved by simply using appropriate personal protective gear. In contrast, an offshore process safety indicator might be a well operations crew's well kick response time which, as Chapter 0 indicates, could require a variety of approaches to improve including safety critical task analysis and better communication between the operator and contractors.

History has repeatedly proven that good personal safety statistics have, in fact, often preceded major accident events, yet industry and regulators still rely on personal safety metrics to indicate good process safety performance. After the Macondo blowout when, then-CEO, Tony Hayward commented on BP's safety record:

> Before this tragic incident, our safety record was improving, with the key metrics such as recordable injury frequency (RIF),[478] days away from work case frequency (DAFWC)[479] and on-site fatalities all on a downward trend. This accident has been a terrible exception to that trend and we must learn the lessons from it.[480]

[477] A process safety incident is the unexpected releases of toxic, reactive, or flammable liquids and gases in processes involving highly hazardous chemicals—*Process Safety Management*, OSHA 3132, 2000 (reprinted).

[478] Recordable injuries as those that result in death, days away from work, restricted work or transfer to another job, medical treatment beyond first aid, or loss of consciousness, § 1904.7

[479] An industry benchmark defined as injuries that result in an employee being away from work for at least one calendar day after the injury.

[480] Email from BP's Employee Communications, to BP Employees, Subject: Gulf of Mexico update from Tony Hayward, July 9, 2010, BP-HZN-2179MDL01617349, see Exhibit 6059, http://www.mdl2179trialdocs.com/releases/release201302281700004/Hayward_Anthony-Depo_Bundle.zip (accessed October 7, 2015).

Unfortunately, good personal safety indicators can produce a false sense of security concerning process safety performance. RIF and DAFWC trends are the wrong ones to monitor the robustness of safety critical barriers and safety management systems intended to prevent and mitigate major accident events.

This chapter begins by distinguishing personal and process safety indicators, providing several demonstrable examples when good personal safety statistics did not equate to good process safety, and then delves into BP's and Transocean's indicator programs. At the time of the Macondo incident, both BP and Transocean measured and rewarded personal safety metrics, many of which require reporting to the regulator; correspondingly, both companies achieved low personal worker injury rates. Conversely, process safety did not receive the same attention from either company.

The chapter then describes advances in safety performance indicators since Macondo. After describing the general characteristics of effective process safety indicators, the chapter presents a selection of process safety indicators from various industry viewpoints. As the timescale of various indicators is diverse, this chapter discusses slow-moving metrics and real-time metrics that can be used to improve daily operational activities. Finally, the CSB proposes several indicators that could have made a positive impact on risk management at the Macondo well.

Both industry and the regulator must collect and assess valuable industrywide process safety indicators across the offshore community. Because companies may use various approaches to reduce risk and manage their major accident hazards, they also need to develop their process safety indicators for their specific barriers and actively monitor that data to maximize the benefits of their indicator programs. Industrywide good practice guidance on such indicators is relatively general at this time, so companies, regulators, and industry trade associations have an opportunity to propel it toward more detailed and practical proposed indicators.

3.1 Process Safety Performance Indicators for High-hazard Work Environments

Personal safety incidents can have serious consequences for individual workers, and are statistically far more common than major process safety incidents. As such, companies and regulators have taken steps to minimize them with some success. Yet process safety expert and chemical engineer Trevor Kletz (1922-2013) noted that relying on good personal safety performance results, such as recordable injury rates, as a barometer for process safety can introduce "a feeling of complacency, a feeling that safety was well managed."[481] Numerous findings from major chemical and petrochemical accidents in the United States, including several the CSB investigated, demonstrate that personal safety statistics are not good indicators for the health of barriers and safety management systems intended to prevent major accidents:

- In 1989, a Phillips chemical plant experienced a catastrophic series of explosions and fires that killed 23 workers, yet the company operated for several million work hours without a lost time incident.[482] Post-incident findings indicated that no hazard analysis was utilized at the plant to

[481] Kletz, T. *An Engineer's View of Human Error,* 3rd ed.; Institution of Chemical Engineers: Warwickshire, UK, 2001.

[482] A Lost Time Incident (LTI) is an injury that makes so a worker is unable to perform his or her regular duties, needs to take time off for recovery, or has to be assigned modified job activities.

identify process hazards, a permit to work system was not enforced at the plant, and personnel and critical control equipment were not separated from process units in accordance with accepted good engineering principles.[483]

- In 2004, the BP Texas City refinery was lauded by the BP Group CEO for the refinery's "best year ever" in terms of safety performance due to low recordable injury statistics—despite the documented failure to correct major process safety and management system deficiencies identified that same year in audits, mechanical integrity reviews and incident investigations. The following year, OSHA injury data noted the refinery was off to such a good start that its 2005 safety performance record "may be the best ever," a characterization which was turned on its head when a March 2005 refinery explosion killed 15 workers and injured 180 others.[484]
- In 2007, the Valero McKee Refinery in Sunray, Texas suffered a process safety incident that seriously burned 4 workers and forced an unexpected plant shutdown, despite low OSHA recordable injury rates and a fine personal safety record. Post incident findings noted a lack of management of change reviews before the incident,[485] a process hazard analysis that did not effectively identify hazards posed by fire exposure to neighboring equipment, and lack of engineering controls to stop the flow of high pressure flammable material.[486]
- In 2008, the Bayer CropScience facility in Institute, West Virginia, suffered a serious process safety incident that killed 2 workers and injured 8 others, among other documented process safety incidents, despite low OSHA recordable injury rates.[487] Post-incident findings indicated that a pre-startup safety review was not applied and personnel had been inadequately trained to operate new equipment involved in the accident.
- In 2010, CITGO's Corpus Christi refinery received national industry recognition[488] for safety performance in 2010 based on the refinery's low recordable injury rates in the previous year as

[483] US Department of Labor Occupational Safety and Health Aministration. *The Phillips 66 Company Houston Chemical Complex Explosion and Fire*; 1990.

[484] USCSB, 2007. Refinery Explosion and Fire, Texas City, TX, March 23, 2005, Report No. 2005-04-I-TX, March 2007, pp 168 and 175, http://www.csb.gov/assets/1/19/csbfinalreportbp.pdf (accessed October 7, 2015).

[485] Management of Change is a systematic method for reviewing the safety implications of modifications to process technology, facilities, equipment, chemicals, organizations, policies, and standard operating practices and procedures.

[486] USCSB, 2008. *LPG Fire Valero - McKee, Sunray, TX, Feburary 16, 2007,* Report No. 2007-05-I-TX, July 2008, http://www.csb.gov/assets/1/19/CSBFinalReportValeroSunray.pdf (accessed October 7, 2015).

[487] USCSB, 2011. *Pesticide Chemical Runaway Reaction and Pressure Vessel Explosion, Bayer Crop Science, Institute, West Virginia, August 28, 2008,* Report No. 2008-08-I-WV, January 2011, http://www.csb.gov/assets/1/19/Bayer_Report_Final.pdf (accessed October 7, 2015).

[488] This CITGO site received the National Petrochemical and Refiner's Association (now called the American Fuel & Petrochemical Manufacturers, or AFPM) annual award for the previous year's safety performance. Through the latter portion of the last decade, NPRA/AFPM relied exclusively on records maintained for employee injuries, illnesses, or death as recorded on the required OSHA 300 Form, though according to AFPM's website, current award qualification criteria is now based on both the "OSHA 300A Summary and API 754 Process Safety Collection." See www.afpm.org/Safety-Programs/ (accessed October 7, 2015).

reported to OSHA, notwithstanding that in 2009 the company suffered a major fire and release of dangerous hydrofluoric acid in its alkylation unit.[489]

- In 2010, the Tesoro Refinery in Anacortes, Washington, only a few weeks after winning the same national safety award as CITGO, suffered a devastating explosion and fire that took seven workers' lives when a nearly 40-year-old heat exchanger catastrophically failed during a maintenance operation to switch a process stream between two parallel banks of exchangers.[490] Post-incident findings indicated that safeguards were not evaluated, hazardous leaks at the refinery were normalized, process hazard analyses repeatedly failed to control the hazards presented by the leaks, and Tesoro did not monitor the actual operating conditions of the equipment that failed.
- At the time of the Macondo incident, a visiting team of executives focused on personal safety issues, touring the Deepwater Horizon rig to help celebrate the rig's excellent total recordable injury rate and to share lessons learned from a personal injury incident on another rig.[491]

Risk management approaches and measures to monitor for and manage the process safety hazards noted above are different than those for personal safety. Table 3-1 highlights some of significant differences.

"Industry has a long history of measuring safety performance based on lost time accident (LTA) rates … Safety is taken very seriously by most organizations and senior management takes an active interest in reducing LTA rates, providing leadership and resources aimed at improving performance … Unfortunately, LTAs do not show senior managers how well the low frequency/high consequence accidents are being managed. Incidents involving the failure of process safety can be devastating with the potential for multiple fatalities, offsite impacts and large scale environmental damage. Managers often fall into the trap of believing that a low and reducing LTA rate means that corporate safety is under control. History shows us that this is often not the case."

Christopher J. Beale, *Process Safety Performance Indicators – Experience Gained from Designing and Implementing a System of PSPIs for Different Chemical Manufacturing Operations*, ICheme Loss Prevention Bulletin 212 (April 2010), p 23.

[489] CSB Public Hearing: Safety Performance Indicators, Houston, TX, July 23-24, 2012; pp 13 – 14, http://www.csb.gov/assets/1/19/CSB_20Public_20Hearing.pdf (accessed October 7, 2015).

[490] USCSB, 2014. *Catashtrophic Rupture of Heat Exchanger*, *Anacortes*, *WA*, *April 2*, *2010,* Report No. 2010-08-I-WA, May 2014, http://www.csb.gov/assets/1/7/Tesoro_Anacortes_2014-May-01.pdf (accessed October 7, 2015).

[491] CSB interviews.

Table 3-1. Distinctions between Process and Personal Safety.[492, 493, 494]

	Process Safety	Personal Safety
Examples of Safety indicators	Hydrocarbon releases, inspection frequency, number of well kicks, well kick response time, PSM/SEMS audit action item closure	Recordable injury rate, days away from work frequency, number of behavior observations
Scope	Complex technical and organizational systems and/or operations and barriers	Individuals, individual behaviors/actions
Risk	Incidents with catastrophic potential (low frequency, high consequence)	Slips, trips, falls, dropped objects, etc. (high frequency, low consequence in terms of number injured)
Consequences of a single event	Release of dangerous materials or energy (e.g., fires, explosions) with the potential for multiple fatalities, major destruction of property/equipment, and environmental damage, all of which could extend beyond the confines of the workplace, as well as commercial and reputational damage	Most often results in individual workplace injury/fatality and/or minor facility/equipment damage.

Yet, many companies, as well as industry groups, and even the Occupational Safety and Health Administration (OSHA)[495] and the Mineral Management Service (MMS, now BSEE), as onshore and offshore safety regulators, respectively, have tended to rely on personal safety performance indicators as the preeminent measures of a company's overall status of "safety."[496] This leaves a critical gap in process safety performance monitoring that needs to be filled to prevent the next Macondo.

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[492] Holmstrom, D. *US Performance Indicators to Drive Improvement: CSB Overview*, CSB Safety Performance Indicator Public Hearing, Houston, TX, July 23, 2012, slide 4. http://www.csb.gov/UserFiles/file/Holmstrom%20%28CSB%29%20PowerPoint.pdf (accessed October 7, 2015).

[493] The Baker Panel. *The Report of the BP US Refineries Independent Safety Review Panel;* January, 2007; p 21. http://www.csb.gov/assets/1/19/Baker_panel_report1.pdf (accessed October 7, 2015).

[494] Hopkins, A. *Thinking About Process Safety Indicators;* Working Paper 53; National Research Centre for OSH Regulation: May, 2007, p 3.

[495] While OSHA injury and illness collected data do not focus on process safety, it can reflect critical occupational health and safety indicators that extend beyond "personal" safety matters. For example, the data may establish patterns of illness or injury that affect worker populations.

[496] See Volume 4, Section 4.2 for discussion on MMS/BSEE's use of indicators. An industry example includes the International Association of Drilling Contractors (IADC) which tracks work-related recordable injuries as part of its Incident Statistics Program (ISP) that recognizes companies for their "outstanding safety performance," http://www.iadc.org/isp/ (accessed October 7, 2015).

3.2 BP's Selection and Use of Performance Indicators

Through a review of key corporate documents, corporate-wide communications, and programs, this section shows that BP primarily used lagging, infrequent, and personal safety performance indicators as a means of assessing, measuring, and managing process safety.

3.2.1 BP Corporate Policies Reflect a Focus on Production, Personal Safety, and Lagging Indicators

BP's overall approach to using performance indicators in the Gulf of Mexico at the time of the Macondo incident is described in the *BP Gulf of Mexico Drilling and Completions Operating Plan and Local OMS Manual*.[497] In the document, BP committed that its management system was part of a continual improvement process that would establish clear plans and controls to achieve and maintain goals. This process was to be monitored by establishing key performance indicators to track progress using different safety, environmental, and regulatory metrics, which became for GoM business unit leaders the content of a report, commonly referred to as the Maroon Book (see Table 3-4).[498,499]

[497] Internal Company Document, BP, *GoM Drilling and Completions; GoM D&C Operating Plan/Local OMS Manual*, 2200-T2-DM-MA-0001, November 1, 2009, p 19, BP-HZN-MBI00193448, http://www.mdl2179trialdocs.com/releases/release201302281700004/TREX-06065.pdf (accessed October 7, 2015).

[498] BP operations are divided into business units like the Gulf of Mexico Drilling & Completions or the Gulf of Mexico Exploration & Appraisal units. Individual business unit leaders oversee operations and performance of the units.

[499] Hearing before the Hearing before the U.S. District Court for the Eastern District of Louisiana under the Multi-District Litigation docket MDL No. 2179, April 10, 2013, pp 8109 – 8110, http://www.mdl2179trialdocs.com/releases/release201304101200025/2013-04-10_BP_Trial_Day_25_AM-Final.pdf (accessed October 7, 2015).; Hearing before the U.S. District Court for the Eastern District of Louisiana under the Multi-District Litigation docket MDL No. 2179, June 17, 2011, see Dupree Designations Vol 2 p 176, http://www.mdl2179trialdocs.com/releases/release201302281700004/Dupree_James-Depo_Bundle.zip (accessed October 7, 2015); Internal Company Document, BP. *Gulf of Mexico SPU Operating Plan (OMS Handbook)*, December 3, 2008, BP-HZN-2179MDL00333175, http://www.mdl2179trialdocs.com/releases/release201305171200030/TREX-002908.pdf (accessed October 7, 2015).

Table 3-2. Indicator data collected for the Gulf of Mexico as reported in BP's Maroon Book for 2009.[500]

Gulf of Mexico (GoM)	BP's Classification/Description	Reported Number for 2009
Major Incidents and HIPOs		
Major Incident Announcements (MIAs)	Lagging	0
High Potential Incidents (HIPOs)	Lagging	11 total (only 1 process safety related)
MIA & HIPO Lessons Learned Reports Issued	Leading	9
Health and Safety		
Workforce Fatalities	Lagging, mature industry standard metric	0
Days Away from Work Case Frequency (DAFWCF)†	Lagging, mature industry standard metric	0 BP/0.1 Contractors
Recordable Injury Frequency (RIF)	Lagging, mature industry standard metric	0.9 BP/0.54 Contractor
Recordable Occupational Illness Frequency	Lagging, aim is improved reporting	0.09 BP/0 Contractor
Operations Integrity		
Process Safety Incident Index*	Lagging metric	21 BP/ Contractor not reported
Fires & Explosions	Lagging, industry standard	-
Loss of Primary Containment (LOPC)	Lagging, emerging industry standard	26 BP/ 2 Contractor
Flammable Gas Releases	Lagging, based on LOPC	11 BP/ 0 Contractor
Number of Oil Spills	Lagging, mature industry standard metric	8 BP/1 Contractor
Volume of Oil Spills	Lagging, mature industry standard metric	All spills less than 100 barrels
Overdue Plant Inspections & Tests	Leading	No reported numbers
Major Accident Risk (MAR) Assessments Completed	Leading	No reported numbers
MAR Action Closures	Leading	No reported numbers
Compliance, Audit and Action Closure		
Safety & Operations (S&O) Audit Delinquent Actions	Number overdue	0
Number of Approved Changes	Change to content/Due Date/Responsibility for S&O Audit Action	0
Incident Investigation - Action Closure	Actions from HIPO & MIA Investigations	100%

†An industry benchmark defined as injuries that result in an employee being away from work for at least one calendar day after the injury (see definition in API 754). API 754 classifies DAWFC as process safety events only if they are the result of an actual loss of containment due to weaknesses in barriers. BP did not distinguish between personal and process safety DAWFC in its metrics.

*The Process Safety Index considers four outcomes: (1) hazard severity of LOPC, (2) severity of fires and explosions, (3) injuries sustained, and (4) environmental impact.

[500] Internal Company Document, BP. *GoM Maroon Book*, http://www.mdl2179trialdocs.com/releases/release201305171200030/TREX-045257.xls (accessed June 16, 2015).

As BP indicated, no reported data for the leading indicators was listed in Table 3-2, and the rest of the indicators were lagging, many of them typical metrics used across industry and collected by the regulator.[501] Notably missing from Table 3-2 are process safety indicators to address safety management systems, safety critical barriers, or even well kicks, several of which BP-contracted Transocean rigs experienced.[502] Nor is there any indication of threats (e.g., weather, ship traffic, or active work permits) that could provide feedback to original risk assessment assumptions.[503] As evident in Table 3-2, contractor data is incorporated into the Maroon Book statistics.

BP also published an Orange Book quarterly that was shared with senior BP executives and the Board, [504] and included metrics used to generate the Maroon Book, but it addressed the entire international upstream segment.[505,506] Although BP executives and management could have used the Orange Book data for action planning or other more strategic initiatives related to process safety or major accident prevention (MAP), the indicators did not provide insight for BP's safety management systems, safety critical barriers, or threats. Furthermore, lacking from the Orange Book were stated goals, objectives, or other desired outcomes (e.g., reduction targets), set forth as expectations against which to compare, measure, and improve actual safety performance. BP did not state in advance how it would use the data to drive continual improvement, and it did not discuss variance in the level of safety attained versus the level of safety expected.

3.2.2 Individual Performance Plans Lacked Process Safety Metrics

Performance indicators can be used to drive individual performance safety goals when management uses them to steer the organization toward specific safety goals. In this way, the workforce can be influenced to approach "safety" as the company defines it. A review of performance contracts for BP employees connected to the Macondo well at various levels and job positions (Figure 3-1) indicates that personal

[501] Oil and Gas and Sulphur Operations in the Outer Continental Shelf - Incident Reporting Requirements, 71 Fed. Reg. 19,640 (April 17, 2006).

[502] Internal Company Document, Transocean. *Annual Report - 2009 Well Control Events & Statistics 2005 to 2009*, p 7, TRN-INV-00760087, http://www.mdl2179trialdocs.com/releases/release201303211200016/TREX-05649.pdf (accessed May 22, 2015).

[503] Section 3.4 provides more examples of potential indicators.

[504] Hearing before the U.S. District Court for the Eastern District of Louisiana under the Multi-District Litigation docket MDL No. 2179, Feburary 28, 2013 pp 1156-1157, http://www.mdl2179trialdocs.com/releases/release201302281700004/2013-02-28_Barbier_Day_04_PM-Final.pdf and June 29, 201, see Mogford Designation Vol 2,1 p 49, http://www.mdl2179trialdocs.com/releases/release201302281700004/Mogford_John-Depo_Bundle.zip (accessed October 7, 2015).

[505] BP's upstream segment encompasses exploration, development and production activities.

[506] Internal Company Document, BP.

safety metrics such as Total Recordable Incident Rate (TRIR)[507] and DAFWC trends were included in individual performance goals, but several indicators tracked in the Maroon and Orange Books were not.[508] Instead, many of the indicators listed on BP performance plans were compliance-based metrics that lacked continual performance process safety goals (e.g., adherence to regulations, completed training, adherence to BP policies). During CSB interviews, BP drilling and well completion managers and engineers alike stated that BP's safety focus in audits, reviews, and safety score cards primarily addressed personal safety, which was also reported to be the sole focus in relevant team meetings and company reports, and during benchmarking activities.

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[507] TRIR = (the number of medical treatment cases other than first aid + the number of restricted Work/Transfer Cases + the number of Lost Time Incidents + the number of fatalities) multiplied by 200,000 then divided by the Total Hours Worked. See IADC definitions at http://www.iadc.org/wp-content/uploads/2014/01/2015-ISP-Reporting-Guidelines.pdf (accessed October 7, 2015).

[508] BP provided numerous Annual Individual Performance Assessments to the CSB. Two examples that have been made public for the Macondo Well Site Leader and a Gulf of Mexico Engineering Manager are, Exhibit 3555 found at http://www.mdl2179trialdocs.com/releases/release201304041200022/Kaluza_Robert-Depo_Bundle.zip and Exhibit 0755 found at http://www.mdl2179trialdocs.com/releases/release201302281700004/Sprague_John-Depo_Bundle.zip (accessed October 7, 2015).

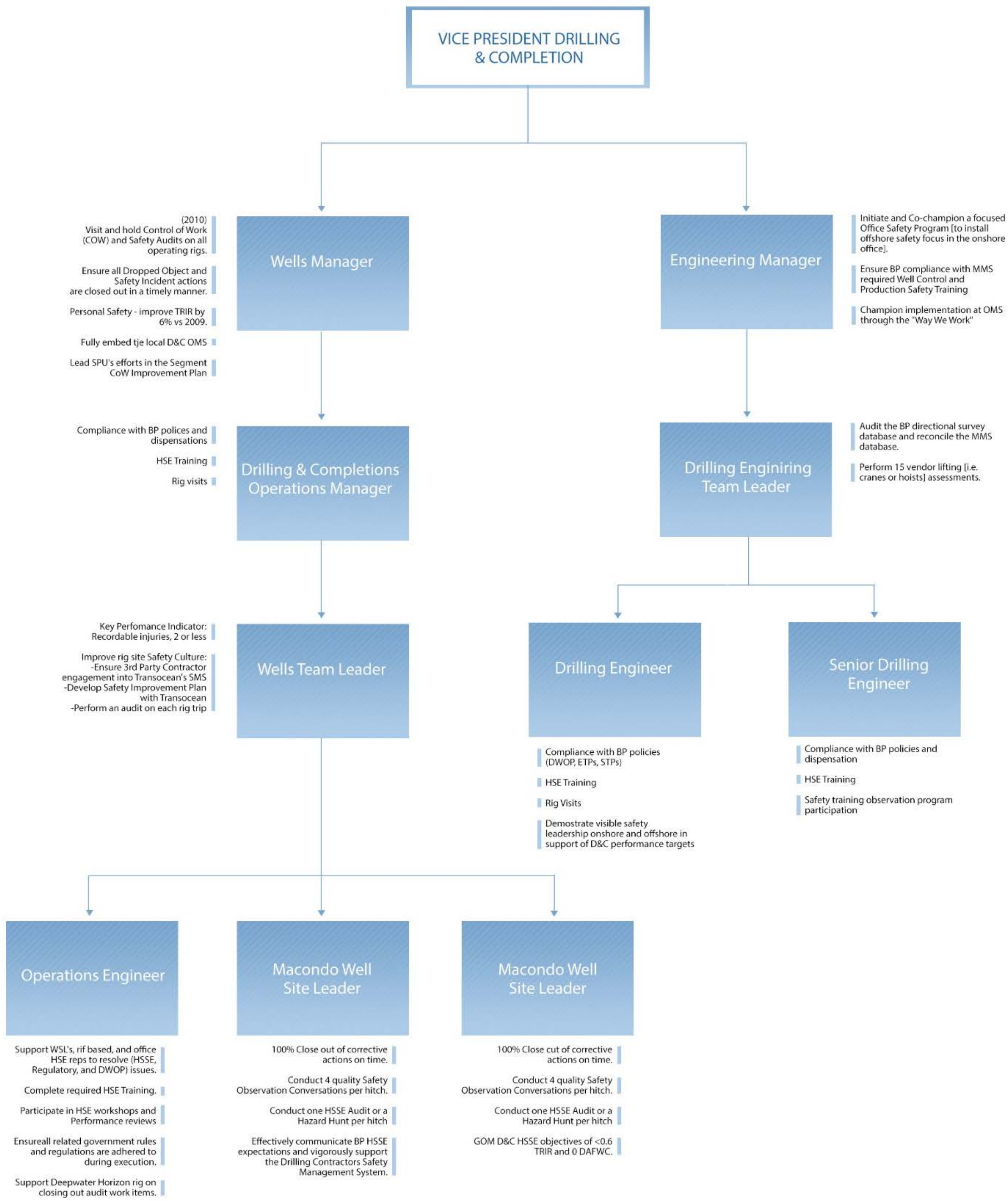

Figure 3-1. Safety performance goals for BP employees that were a part of the Deepwater Horizon's organizational structure.

Without an explicit focus on process safety, employee performance expectations can be overshadowed by intense cost performance expectations. For example, a former BP vice president of drilling and completion indicated an "incredible pressure with respect to cost reduction in 2008 and 2009," while at the same time production targets in his own individual performance contract were "significantly" raised.[509] The net result was that in pursuit of his duties, this vice president "slashed hundreds of millions of costs and increased production" from BP's offshore drilling operations.[510] BP's vice president of drilling and completions at the time of the Macondo incident also noted that his own individual performance contract had a number of cost containment goals, particularly in 2008 and 2009, due in part to a then-recent drop in oil prices.[511] These goals were informed by benchmarking information from industry sources relating to metrics of drilling progress, primarily in terms of cost and time,[512] along with "a lot of emphasis on cost," driven by specific targets for cost reduction during the calendar year before Macondo, all of which shaved approximately 10 percent off the 2009 operating budget.[513] However, this came without an accompanying set of goals for process safety in his performance contract.[514]

Even when there are safety indicators, such as those for personal safety, the former vice president of drilling and completion indicated to the CSB that he made conscious efforts to ensure leaders "were not putting pressure on the [well site leaders] and confusing the value of safety with priorities on cost or time." He observed, "it was a bit of a new thing for [leaders/well site leaders] to talk about how to have safety and performance in the same conversation."[515] Production focus is not unique to companies operating in the Gulf of Mexico. A 2012/2013 multinational audit in the North Sea observed that benchmarking key performance indicators (KPIs) often focused on drilling progress and efficiency with little to no mention of well control. The auditors noted:

> There is the potential for such performance orientated KPIs to conflict with safety performance, as it was common practice to have penalties in place for underperformance (e.g., in relation to the downtime rate of drilling progress) but how this was being managed from a human factors perspective was not clear. In other words, there was a lack of attention as to how penalties for underperformance could influence the performance of the driller in relation to safety-related decision-making and behaviour at the front-line.[516]

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[509] Hearing before the U.S. District Court for the Eastern District of Louisiana under the Multi-District Litigation docket MDL No. 2179, June 1, 2011, see Lacy Deposition, pp 792-804, http://www.mdl2179trialdocs.com/releases/release201303071500008/TREX-25002.pdf (accessed October 7, 2015).

[510] *Ibid*, p 804.

[511] While this individual discussed his performance plan with the CSB during an interview, BP did not provide the actual performance plan to the CSB.

[512] CSB interview.

[513] CSB interview.

[514] CSB interview.

[515] CSB interview.

[516] North Sea Offshore Authorities Forum (NSOAF). *Multi-National Audit Human and Organisational Factors in Well Control 2012-2013*, p 13. http://www.hse.gov.uk/offshore/nsoaf.pdf (accessed May 2016, 2015).

3.3 Transocean's Selection and Use of Performance Indicators

Transocean identified two "key tools" for safety management in both its contract with BP and in its Health and Safety Policies and Procedures Manual: (1) a risk assessment policy, which asked the workforce to identify hazards immediately before conducting a task, and (2) a safety observation program to identify positive and negative actions by the crew. [517] These two programs, the THINK Planning Process (described in Section 1.8.3) and the START Observation and Monitoring Process, and the data derived from them ultimately resulted in a direct company focus on personal/occupational safety and individual behavioral-based safety improvements and inattention to control major accident hazards. [518]

The aims of programs such as THINK and START are to reinforce safe behavior and correct unsafe acts or conditions.[519] These programs rely upon the employees to observe and recognize unsafe situations or activities. Thus, the types of safety issues likely to be documented are those that are readily observable, such as breaches to occupational safety rules and policies (e.g., missing personal protective equipment, poor housekeeping). However, process safety hazards and the active and passive safeguards meant to control, reduce, or mitigate them are not always readily observable. Thus, the THINK and START programs emphasized worker focus on personal safety observations and easily identifiable deviations from safety rules and company practices.[520]

Transocean required all personnel to monitor work practices and workplace conditions. All Transocean rig personnel were required to participate by each submitting a START observation card daily where they

[517] Internal Company Document, BP. *Amendment No. 38 to Drilling Contract No. 980249*, September 28, 2009, BP-HZN-CEC041519, see Exhibit 1488, http://www.mdl2179trialdocs.com/releases/release201302281700004/Hayward_Anthony-Depo_Bundle.zip (accessed October 7, 2015).; Internal Company Document, Transocean. *Health and Safety Policies and Procedures Manual*, Issue 03, Revision 07, HQS-HSE-PP-01, December 15, 2009, Preface, BP-HZN-2179MDL00132055, see Exhibit 4942, http://www.mdl2179trialdocs.com/releases/release201302281700004/Farr_Daniel-Depo_Bundle.zip (accessed October 7, 2015).

[518] Internal Company Document, Transocean. *Health and Safety Policies and Procedures Manual*, Issue 03, Revision 07, HQS-HSE-PP-01, December 15, 2009, Safety Policies, Procedures and Documentation, BP-HZN-2179MDL00132454, see Exhibit 4942, http://www.mdl2179trialdocs.com/releases/release201302281700004/Farr_Daniel-Depo_Bundle.zip (accessed October 7, 2015).; Internal Company Document, Transocean. *Asset Managment Handbook*, Issue 01, Revision 00, HQS-OPS-HB-06, April 22, 2008, Physical Asset Management Implementation, TRN-INV-00160105, This document established key performance indicators (KPIs) "to evaluate performance against an agreed benchmark" in specified areas in order to "achieve compliance or realize performance improvement." The first two categories of KPI's focused on protecting assets, as well as improving performance. The third category focused on HSE matters, with a heavy emphasis on personal safety and related lagging indicators (some of which were termed leading indicators), and none of which were focused on process safety or major hazards.

[519] *Ibid*., BP-HZN-2179MDL00132055.

[520] In CSB interviews, one Transocean crew member from the Deepwater Horizon conveyed that another crew member wrote a START observation on him when he entered a particular location on the rig without wearing safety glasses. Crew members also provided positive examples of "good" START observations, such as being properly tied off or having all the correct safety gear for a job.

describe observed positive or negative work practices.[521] Such reporting requirements are susceptible to underreporting due to the perceived negative potential consequences of candid self-reporting. This was true on the Deepwater Horizon, where some individuals reported hesitation about writing START observations.[522] Crewmembers stated they did this out of a fear of discipline or reprisal for being observed breaking a safety rule and that completing the START cards according to the "one a day" rule resulted in unnecessary observations, which in turn diluted the efficacy of actual worker concerns.[523] Crewmembers also reported that discussions in rig safety meetings focused on the quantity of cards, not the quality of the content.[524] Ultimately, management undermined the value of START card observations as indicators for risk management success by not addressing crew concerns and actively working to change the crew's perceptions.

[521] In interviews, Transocean crew members conveyed to the CSB that they were given 15 minutes on each shift to fill out a START observation card; this requirement was also reflected in some of the publicly available interview notes, e.g., Internal Company Document, Transocean. *Interviewing Form*, June 24, 2010, p 5, TRN-INV-00000300, see Exhibit 3339 http://www.mdl2179trialdocs.com/releases/release201304041200022/Bertone_Stephen-Depo_Bundle.zip (accessed October 7, 2015).

[522] As Transocean workers conveyed in CSB interviews, "I've seen guys get fired for someone [writing] a bad START card about them, … I've seen the people get fired for it;" "they wrote [a START card] on me and turned it in, and I was called into the office the next day and chewed up one side and down the other," and "people [tried] not to rat people out so to speak, you know like you wanted to be helpful, […] whereas some of the higher-ups in the office, they kind of wanted to weed out problems …"

[523] Internal Company Document, Transocean. *Lloyd's Register Safety Management Systems and Safety Culture/Climate Reviews: Deepwater Horizon*, March 16, 2010, Closing Meeting, slide 5, TRN-INV-00016752, http://www.mdl2179trialdocs.com/releases/release201302281700004/TREX-04261.pdf (accessed October 7, 2015).; Internal Company Document, Transocean. *Safety Management and Safety Culture/Climate: North America Division Summary Report*, July 2, 2010, TRN-HCEC-00090580, see Exhibit 0929 http://www.mdl2179trialdocs.com/releases/release201304041200022/Bertone_Stephen-Depo_Bundle.zip (accessed October 7, 2015).

[524] Internal Company Document, Transocean. *Safety Management and Safety Culture/Climate: North America Division Summary Report*, July 2, 2010, TRN-HCEC-00090663, see Exhibit 0929 http://www.mdl2179trialdocs.com/releases/release201304041200022/Bertone_Stephen-Depo_Bundle.zip (accessed October 7, 2015).; Internal Company Document, Transocean. *Lloyd's Register Safety Management Systems and Safety Culture/Climate Reviews: Deepwater Horizon*, March 16, 2010, Closing Meeting, slide 5, TRN-INV-00016752, http://www.mdl2179trialdocs.com/releases/release201302281700004/TREX-04261.pdf (accessed October 7, 2015).

At the time of the Macondo incident, Transocean also identified key leading and lagging health, safety, environmental, and operational performance indicators (KPIs), which it used to set goals and targets for itself:[525]

- Leading
  - Potential Severity Rate
  - START Observations
  - HSE Training Compliance
- Lagging
  - Actual Severity Rate
  - TRIR
  - Serious Injury Case (SIC) [526]
  - Safety statistics (for categories of incidents, such as dropped objects[527])

For safety, the potential and actual severity rates listed are based upon a classification system for personal injuries (e.g., first aid, restricted work, extended time off of work, etc.). There were also severity rate classification systems for environmental and operational indicators based on releases (e.g., to the rig, atmosphere, or overboard and the extent of cleanup efforts) and loss of revenue or cost to repair.[528] Transocean's health, safety, and environmental 2009 goals and targets appear in Table 3-3.[529]

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[525] Internal Company Document, Transocean. *Performance Monitoring Audit and Assessment Procedures*, Issue 03, Revision 00, HQS-CMS-PR-02, December 31, 2008, Performance Monitoring Audit and Assessment Plan, TRN-MDL-00039491, see Exhibit 0927 http://www.mdl2179trialdocs.com/releases/release201302281700004/Rose_Adrian-Depo_Bundle.zip (accessed October 7, 2015).

[526] As defined by Transocean, "any injury resulting from a work-related incident that prevents the injured person from continuing on his next shift," Internal Company Document, Transocean. *Health and Safety Policies and Procedures Manual*, Issue 03, Revision 07, HQS-HSE-PP-01, December 15, 2009, Annex, Definitions, p TRN-HCEC-00005205, the publicly available version of the Transocean Health and Safety Policeis and Procedures Manaul does not include the annex of defitions, so a version provided to the CSB that does is beign cited here.

[527] Dropped objects are a concern on rigs because they can result not only in injury, but also death if the mass and/or height from which the object is dropped is sufficient. In the oil and gas industry, dropped objects are among the top 10 causes of fatality and serious injury. See information provided by DROPS, an industrywide initiative focused on preventing dropped objects, http://www.dropsonline.org/assets/DROPS%20Intro.pdf (accessed December 20, 2015).

[528] Internal Company Document, Transocean. *Field Operations Policies & Procedures Manuel*, Issue 01, Revision 00, HQS-POP-PP-01, August 8, 2009, Performance Management: Rig and Well Operation Management, TRN-CSB-00016311.

[529] This was completed under the auspices of the QHSE Steering Committee which met at least twice a year to review and set HSE goals and performance. Internal Company Document, Transocean. *Health and Safety Policies and Procedures Manual*, Issue 03, Revision 07, HQS-HSE-PP-01, December 15, 2009, QHSE Steering Committees, see Exhibit 4942, BP-HZN-2179MDL00132097, http://www.mdl2179trialdocs.com/releases/release201302281700004/Farr_Daniel-Depo_Bundle.zip (accessed October 7, 2015).

Table 3-3. Corporate Quality, Health, Safety and Environment (QHSE) Strategy and Target Goals Status as reported by Transocean.[530]

Safety Target	Goal	Year to Date (October 2009)
Fatalities	0	4
TRIR	≤ 0.82	0.85
SIC Rate	≤ 0.29	0.39
Potential Severity Rate	≤ 30.00	45.31
Number of High Potential Dropped Objects	≤ 129	137
Environmental Target	**Goal**	**Year to Date (October 2009)**
Loss of Containment Major Reports	≤ 25	18

3.3.1 Transocean Recognized Need for Process Safety Performance Indicators

Transocean senior leadership voiced dissatisfaction with the company's development and use of leading indicators. In response to an email string between BP and Transocean senior leadership approximately eight months before the Macondo blowout, Transocean President Steven Newman forwarded his observations about Transocean's use of leading indicators to several senior Transocean managers:

> I am not convinced at all that we have the right leading indicators. The leading indicators we report today are all just different incident metrics—they have nothing to do with actually preventing accidents. What if we asked our OIMs to report the number of tasks that proceeded without a think plan discussion? Their first response would obviously be zero—which would then be the start of an interesting conversation (how do you KNOW that?). This is by no means a scientifically measured leading indicator, but the nature of the discussion would get the OIMs thinking about the culture on the decks—and the only way they could really meaningfully answer the questions would be to get out on the decks.[531]

[530] Internal Company Document, Transocean. *QHSE Steering Committee Meeting Minutes*, October 19, 2009, TRN-MDL-00039081, see Exhibit 0934 http://www.mdl2179trialdocs.com/releases/release201302281700004/Rose_Adrian-Depo_Bundle.zip (accessed October 7, 2015).

[531] Email from President, Transocean, Subject: FW: Prellmlnary thoughts and supplementary lnfo, September 25, 2009, TRN-MDL-03999532, http://www.mdl2179trialdocs.com/releases/release201303211200016/TREX-26032.pdf (accessed October 7, 2015).

Newman's comment echoes earlier sentiments expressed in this chapter, that "incident metrics" do not address the barriers and safety management systems meant to prevent or mitigate process safety events. His comment also recognizes the need to triangulate indicators information to meaningfully manage risk. For example, ensuring the rig crew completes a THINK plan discussion does not guarantee effective risk management. To fully assess whether THINK plans are driving an understanding of hazards and control measures connected to the task at hand, periodic walkthroughs to engage with the workforce directly or reviews of THINK plans might be necessary to determine exactly how the plans are used. This is particularly important, as THINK plans have been associated with numerous serious incidents and near-misses (see Section 3.5.2.2).

One opportunity for such a review occurred when Transocean completed its Performance Monitoring Audit and Assessment (PMAA) of the Deepwater Horizon.[532] The PMAA audit was intended to "evaluate performance of people in achieving the expectations and requirements described in the Company Management System."[533] Transocean's expectations were to analyze at a minimum of every 30 months each component of the company, from the facilities, installations, and offices, up through business units, sectors, divisions, and the corporate level.[534] However, during the Deepwater Horizon's last PMAA, THINK plans that addressed safety critical tasks were not assessed beyond an indication that they should mention the company's management system more.[535] As indicated previously (Section 1.8.4), several Deepwater Horizon TSTPs were vague and lacked well-specific hazards.

Transocean PMAA procedures indicate that key performance indicators should be evaluated so that the PMAA team can determine if performance improvement is occurring.[536] The health and safety indicators noted during the Deepwater Horizon PMAA were TRIR and SIC,[537] reflecting corporate focus and

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[532] Internal Company Document, Transocean. *Performance Monitoring Audit and Assessment Procedures*, Issue 03, Revision 00, HQS-CMS-PR-02, December 31, 2008, PMAA Policy and Procedure, TRN-MDL-00039467, see Exhibit 0927 http://www.mdl2179trialdocs.com/releases/release201302281700004/Rose_Adrian-Depo_Bundle.zip (accessed October 7, 2015).; Internal Company Document, Transocean. *Company Management System*, Issue 04, Revision 05, HQS-CMS-GOV, November 30, 2009, Corporate Policies and Procedures, Level 1, TRN-MDL-00032866, see Exhibit 0925 http://www.mdl2179trialdocs.com/releases/release201302281700004/Rose_Adrian-Depo_Bundle.zip (accessed October 7, 2015).

[533] Internal Company Document, Transocean. *Performance Monitoring Audit and Assessment Procedures*, Issue 03, Revision 00, HQS-CMS-PR-02, December 31, 2008, PMAA Policy and Procedure, TRN-MDL-00039467, see Exhibit 0927 http://www.mdl2179trialdocs.com/releases/release201302281700004/Rose_Adrian-Depo_Bundle.zip (accessed October 7, 2015).

[534] *Ibid*., TRN-MDL-00039468 - TRN-MDL-00039476.

[535] Internal Company Document, Transocean. *Management Summary of Corrective and Improvement Opportunities: Deepwater Horizon*, July 2, 2009, Performance Monitoring, Audit and Assessment Management Principles, TRN-MDL-01007259, see Exhibit 5766 http://www.mdl2179trialdocs.com/releases/release201304041200022/Hart_Derek-Depo_Bundle.zip (accessed October 7, 2015).

[536] Internal Company Document, Transocean. *Performance Monitoring Audit and Assessment Procedures*, Issue 03, Revision 00, HQS-CMS-PR-02, December 31, 2008, PMAA Policy and Procedure, TRN-MDL-90 see Exhibit 0927 http://www.mdl2179trialdocs.com/releases/release201302281700004/Rose_Adrian-Depo_Bundle.zip (accessed October 7, 2015).;

[537] Internal Company Document, Transocean. *Management Summary of Corrective and Improvement Opportunities: Deepwater Horizon*, July 2, 2009, Performance Monitoring, Audit and Assessment Management Principles, TRN-

reinforcing the Transocean president's concerns that the indicators being tracked were "just different incident metrics."

3.3.2 Transocean Bonus Awards Insufficiently Focused on Performance Relating to Process Safety and MAP

In a 2009 Transocean "asset reliability" project, Lloyd's Register found that individual performance contracts were underutilized and represented an "opportunity for improvement," and that KPIs were "limited" as they focused on items like "downtime, overdue maintenance and money spent."[538] Transocean's approach to safety through the calculation and payment of performance bonuses at the time of the Macondo incident reinforced Lloyd's findings. [539] Transocean calculated upper management bonuses on three safety metrics: TRIR, the total potential severity rate (TPSR),[540] and high potential dropped objects (HPDO).[541] In Transocean's 2009 annual report to shareholders, safety performance was defined by a formula that relates to bonus calculations. Safety performance related to only 20 percent of any total bonus payment, while financial performance related to 70 percent, and "new builds" accounted for the final 10 percent.

The variables used in Transocean's bonus calculation formula do not distinguish between occupation/personal safety injuries and process safety injuries. Additionally, there is no mention of process safety, major hazards, or catastrophic risks. This type of bonus calculation formula did not provide for balanced safety goal-setting, nor did it lend itself to developing or implementing adequate process safety performance indicators which could boost a company's ability to prevent catastrophic

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MDL-010072579, see Exhibit 5766 http://www.mdl2179trialdocs.com/releases/release201304041200022/Hart_Derek-Depo_Bundle.zip (accessed October 7, 2015).

[538] Internal Company Document, Transocean. *Asset Reliability Project/Phase I: Discovery & Defintion*, May 2009, p 57, TRN-MDL-01134224, see Exhibit 5638 http://www.mdl2179trialdocs.com/releases/release201304041200022/Hart_Derek-Depo_Bundle.zip (accessed October 7, 2015).

[539] Transocean. *Annual Report;* 2009; Performance Award and Cash Bonus Plan, p 35. The bonus plan is described as "a goal-driven plan that gives participants, including named executive officers, the opportunity to earn annual cash bonuses based on performance measured against predetermined performance goals." *Id*. at 34. The annual report explains that the bonus plan and the performance goals connected to it are set by the Board, through the Executive Compensation Committee, not the Health Safety and Environment Committee, in accordance with the company's "safety vision" for "an incident-free workplace—all the time, everywhere," stating: "The Committee sets our safety performance targets at high levels each year in an effort to motivate our employees to continually improve our safety performance towards this ultimate goal." *Id*. at 35.

[540] As defined by Transocean, "TPSR is a proprietary safety measure that we use to monitor the total potential severity of incidents and comprises 35% of this metric. Each incident is reviewed and assigned a number based on the impact that such incident could have had on our employees and contractors, and the total is then combined to determine the TPSR;" Transocean. *Annual Report;* 2009.

[541] As defined by Transocean, "HPDO is a dropped object that has a potential of causing a serious injury (an injury in which the employee is out of work for six months or more) or a fatality. HPDO is calculated by multiplying the mass of the object by the height dropped and then applying an industry standard formula to determine potential severity. HPDO comprises 30% of this measure. The occurrence of a fatality can override the safety performance measure;" Transocean. *Annual Report;* 2009.

accidents. Furthermore, Transocean's 70 percent weighting toward financial goals broke down into three sub-elements: cash flow value add (relative to budget), overhead costs, and lost revenues. These economic measures are arguably valid business measures, yet process safety measures are necessary to indicate how those economic optimizations may affect the company's ability to effectively manage the process safety risks.

Process Safety Metrics Necessary to Counter Unintended Safety Consequences of Small Steps to Optimization

"Drift into failure is marked by… small steps … Constant organizational and operational adaptation around goal conflicts, competitive pressure and resource scarcity produces small, step-wise normalizations. Each next step is only a small deviation from the previously accepted norm, and [meanwhile] continued operational success is relied upon as a guarantee of future safety."[†]

[†]Dekker, S. Drift into Failure: From Hunting Broken Components to Understanding Complex Systems; Ashgate Publishing: Burlington, VT, 2011, p 179.

Without process safety indicators, the company may be rewarding organizational performance that weakens or masks its ability to effectively manage and control its major hazards. In fact, Transocean's bonus calculation was configured to reward its top-level corporate executives with significant financial bonuses for the company's "best year in safety" in 2010 despite the 11 fatalities onboard the Deepwater Horizon.[542] These bonus calculations and awards raise questions about the validity of Transocean's chosen safety performance indicators and metrics, and what the company was measuring and rewarding. This public expression of Transocean's bonuses was the cause of widespread backlash by media, government, and the public, prompting an apology from Transocean's CEO and the donation of the executives' safety bonuses to the families of the 11 workers killed during the incident.[543]

3.4 Advancing the Development and Use of Process Safety Performance Indicators

This section focuses on recent efforts to further develop and effectively manage safety performance indicators to prevent major accidents.

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[542] Internal Company Document, Transocean. *Proxy Statement Pursuant to Section 14(a) of the Securities Exchange Act of 1934; Definitive Proxy Statment*, April 1, 2011, pp P-35, P-45. As stated in the document, "Based on the foregoing safety performance measures, the actual TRIR was 0.74 and the TPSR was 35.4 for 2010. These outcomes together resulted in a calculated payout percentage of 115% for the safety performance measure for 2010. However, due to the fatalities that occurred in 2010, the Committee exercised its discretionary authority to modify the TRIR payout component to zero, which resulted in a modified payout percentage of 67.4% for the safety performance measure."

[543] McMahon, J. Transocean Execs Keep Most of Their Bonuses. *Forbes*, April 6, 2011.

3.4.1 CSB Efforts to Advance Understanding and Use of Process Safety Performance Indicators

On July 23-24, 2012, the US Chemical Safety and Hazard Investigation Board conducted a two-day public hearing in Houston, Texas focused on safety performance indicators.[544] The CSB's hearing brought together international regulators, workforce representatives, and industry groups, along with representatives of other high-hazard industries, where process safety indicators are monitored, with an eye toward exploring how companies and the regulator could expand and improve the use of safety performance indicators to manage risks and drive continual safety improvements.

The hearing underscored a growing recognition within the oil and gas industry that actively monitoring leading process safety indicators is critical for high-hazard safety management. The event outlined the challenges faced by industry and regulators in using safety performance indicators. It also illuminated the development and implementation of process safety indicators in offshore oil-producing jurisdictions outside the US and other high-hazard industries within the US. One speaker at the hearing noted that no "silver bullet" set of indicators ensures catastrophic accidents will never happen,[545] but the hearing concluded that indicators effective in reducing the risk of a major accident event share several characteristics:

- Indicators should measure the health of the company's safety management system (SMS) and the specific barriers in place to prevent or mitigate major accident hazards.[546]
- The amount of indicator data should suit the intended use, with enough data collected to facilitate long-term studies as well as intracompany or industrywide comparisons.[547]
- Indicators should be statistically robust so that trends can be monitored not only for large changes or safety upsets (e.g., fire or explosion), but also smaller safety changes that may be a leading indicator for an underlying, latent problem, such as when a process upset triggers the functioning of a safety control and prevents a release of hazardous material, a fire, or explosion.[548]

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[544] CSB Public Hearing: Safety Performance Indicators, Houston, TX, July 23-24, 2012; http://www.csb.gov/events/csb-public-hearing-safety-performance-indicators/ (accessed October 7, 2015). (including the agenda, the verbatim transcript of the proceedings, working papers submitted, and PowerPoint presentations and other materials from the proceedings are all available and included as part of the CSB's record pertaining to the Macondo investigation).

[545] *Ibid*.; testimony of Ian Whewell, *Performance Indicators in Major Hazard Industries– An Offshore Regulator's Perspective*, p 135, http://www.csb.gov/assets/1/19/CSB_20Public_20Hearing.pdf (accessed October 7, 2015).

[546] *Ibid*.; testimony of Gunhild Eie, *Performance Indicators for Major Accident Prevention*, p 183, http://www.csb.gov/assets/1/19/CSB_20Public_20Hearing.pdf (accessed October 7, 2015).

[547] *Ibid*.; testimony of Joe Stough, *Overview of Leading Indicator and Usage*, p 187, http://www.csb.gov/assets/1/19/CSB_20Public_20Hearing.pdf (accessed October 7, 2015).

[548] *Ibid*.; testimony of Manuel Gomez and Kara Kane, *Using Performance Indicators to Drive Improvement: CSB Overview* and *Summary of CSB Evaluation of ANSI/API Recommended Practice 754*, pp 18, 25, http://www.csb.gov/assets/1/19/CSB_20Public_20Hearing.pdf (accessed October 7, 2015).

- "An indicator is an indicator of something, not the phenomena itself;" therefore, other tools such as cultural surveys, sociological studies, and accident investigations, can be the most effective method to triangulate actual risk areas.[549]
- Indicators should be "intuitive in the sense what is measured is considered intuitively by the workforce to be important for the prevention of major accidents."[550]As major accidents are rare, a company, or even the personnel assigned to a particular facility or work crew, may have never experienced a major accident. Therefore, it may be difficult for employees and managers to understand the importance of accurately reporting specified indicator data without intuitively linking it to the major hazard risks. Moreover, having indicators that closely reflect actual hazard mechanisms may also "contribute to maintaining the awareness about the risk mechanisms."[551]
- The selected indicators should be actionable in terms of the necessary actions to improve some specific aspect of safety performance. To this end, once managers observe an undesirable trend, they "[should be able to] turn around and do something about it."[552]
- Avoiding too many indicators is important. Some organizations solve this problem by "rolling-up" multiple indicators into combined indicators with more information available when desired.[553]
- Contractors should be required to provide data for company indicator programs, as they most often perform the bulk of the front-line work in deepwater drilling operations, including safety critical work capable of preventing major accidents, and they are often uniquely positioned to capture—and rely on—important safety data that can prevent accidents.[554]

Finally, for an indicators program to be effective and ensure continual risk reduction of major accident events, upper management must be involved and act on the data. As one speaker cautioned at the CSB's indicator hearing,

> "unless at board and senior management level there is a recognition and an understanding of the significance of the data and the data drives decision-making, then its collection becomes an ineffectual exercise and leads to cynicism. [Oil and gas industry leaders] should be able to demonstrate that they understand the role of major hazard risk controls and the significance of key performance indicators. In addition, to achieve a convincing safety culture at all levels in the organization, industry leaders must acknowledge their responsibility for the effective

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549 *Ibid.*; testimony of Oyvid Lauridsen, *Trends in Risk Level Norwegian Petroleum Activity (RNNP)*, pp 147-148, http://www.csb.gov/assets/1/19/CSB_20Public_20Hearing.pdf (accessed October 7, 2015).

550 *Ibid.*, p 180.

551 *Ibid*.

552 CSB Public Hearing: Safety Performance Indicators, Houston, TX, July 23-24, 2012; testimony of Joe Stough, *Overview of Leading Indicator and Usage*, p 187, http://www.csb.gov/assets/1/19/CSB_20Public_20Hearing.pdf (accessed October 7, 2015).

553 CSB Public Hearing: Safety Performance Indicators, Houston, TX, July 23-24, 2012; testimony of Martin Sedgwick & Angela Wands, *The Implementation of Effective Key Performance Indicators to Manage Hazard Risks*, p 86.; testimony of Gunhild Eie, *Performance Indicators for Major Accident Prevention*, pp 183 - 185, http://www.csb.gov/assets/1/19/CSB_20Public_20Hearing.pdf (accessed October 7, 2015).

554 CSB Public Hearing: Safety Performance Indicators, Houston, TX, July 23-24, 2012; testimony of Martin Sedgwick & Angela Wands, *The Implementation of Effective Key Performance Indicators to Manage Hazard Risks*, p 92, http://www.csb.gov/assets/1/19/CSB_20Public_20Hearing.pdf (accessed October 7, 2015).

management of major accident hazard risks. There must also be a recognition that the culture of the organization is important in ensuring that Board-level data is accurate and reflects reality, again, not what the Board or senior management would like reality to be."[555]

3.4.2 Selection of Effective Performance Indicators[556]

ANSI/API RP 754, *Process Safety Performance Indicators for the Refining and Petrochemical Industries*,[557] was created in response to findings and recommendations that came out of the CSB's investigation of the BP Texas City onshore disaster. Specifically, the CSB found that BP—and the oil and chemical industries in general—did not have effective programs for developing and using process safety performance indicators. As such, the CSB recommended to API and the United Steelworkers that the two jointly develop a voluntary consensus standard for creating leading and lagging process safety indicators in the refining and petrochemical industries.[558] Leading indicators are those that record performance before an incident occurs, such as monitoring open action items identified in an audit, while lagging indicators record the consequences of an unwanted event, such as a hydrocarbon release. The recommendation aimed to develop a standard that would provide guidance on how to develop key process safety indicators, to drive measurable facility, company-level, and industrywide improvement, and to make publicly available individual company and industrywide performance data after collection.

API 754 served as a significant and positive step forward in establishing safety performance indicators, and was part of the development of the international recommended practice, *Process Safety - Recommended Practice on Key Performance Indicators Report No. 456* (IOGP 456),[559] generated by International Association of Oil & Gas Producers (IOGP). Both API 754 and IOGP 456 identify process safety indicators by four tiers:[560]

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[555] CSB Public Hearing: Safety Performance Indicators, Houston, TX, July 23-24, 2012; testimony of Ian Whewell, *Performance Indicators in Major Hazard Industries– An Offshore Regulator's Perspective*, p 136, http://www.csb.gov/assets/1/19/CSB_20Public_20Hearing.pdf (accessed October 7, 2015).

[556] The only U.S. guidance document specifically pertaining to offshore safety indicators is API RP 75, *Recommended Practice for Development of a Safety and Environmental Management Program [SEMP] for Offshore Operations and Facilities*. However, API RP 75 focuses on personal safety metrics such as "recordable injuries/illnesses," "DART injuries/illnesses," and the like, as well as infrequent, lagging safety performance indicators of infrequent incidents such as the "blow-out incident rate," "fire/explosion incident rate," and the "number of [oil] spills" suffered by a driller, among others. API Recommended Practice 75, 3rd ed. (2004, reaffirmed 2008), *Recommended Practice for Development of a Safety and Environmental Management Program for Offshore Operations and Facilities*, Appendix E, pp 37 - 41.

[557] API Recommended Practice 754, 1st ed., Process Safety Performance Indicators for the Refining and Petrochemical Industries, April 2010.

[558] USCSB, 2007. *Refinery Explosion and Fire*, *Texas City*, *TX*, *March 23*, *2005*, Report No. 2005-04-I-TX, March 2007, pp 25 – 26, 144 – 146, 149, 154 – 155, 159, 163, 165, http://www.csb.gov/assets/1/19/CSBFinalReportBP.pdf (accessed October 7, 2015).

[559] IOGP, *Process Safety - Recommended Practice on Key Performance Indicators, Report No. 456*, November 2011.

[560] API Recommended Practice, 754, 1st ed., Process Safety Performance Indicators for the Refining and Petrochemical Industries, April 2010; International Association of Oil & Gas Producers Recommended Practice, Process Safety - Recommended Practice on Key Performance Indicators, Report No. 456, November 2011.

- Tier 1: A Loss of Primary Containment (LOPC) that results in the release of material with the greatest consequence, such as a fatality or large fire or explosion;
- Tier 2: An LOPC, but of lesser consequences than a tier 1 incident (e.g., no casualties, property damage less than $2,000, on a release of process chemical less than pre-defined reportable quantities). These events also play a "leading" role in preventing more serious events if the company uses them as a learning opportunity to improve its process safety performance;
- Tier 3: A challenge to a safety system, which results when exceeding defined process limits and a safety system is initiated to bring the system back to an accepted safe state (e.g., the activation of a shutdown system or a pressure relief device);
- Tier 4: Performance of barriers and management system components, such as management of change (MOC) compliance, inspections, or timely training schedules.

Tiers 1 and 2 tend to be more lagging and infrequent, and they are more generally applicable throughout an industry, while 3 and 4 indicators tend to be more leading, frequent, and company specific. As both the API and IOGP guidelines indicate, monitoring process safety and barrier performance can be complex, requiring a combination of indicators, so the tiers help differentiate the frequency, severity, and timing (leading or lagging) of a monitored event or process.

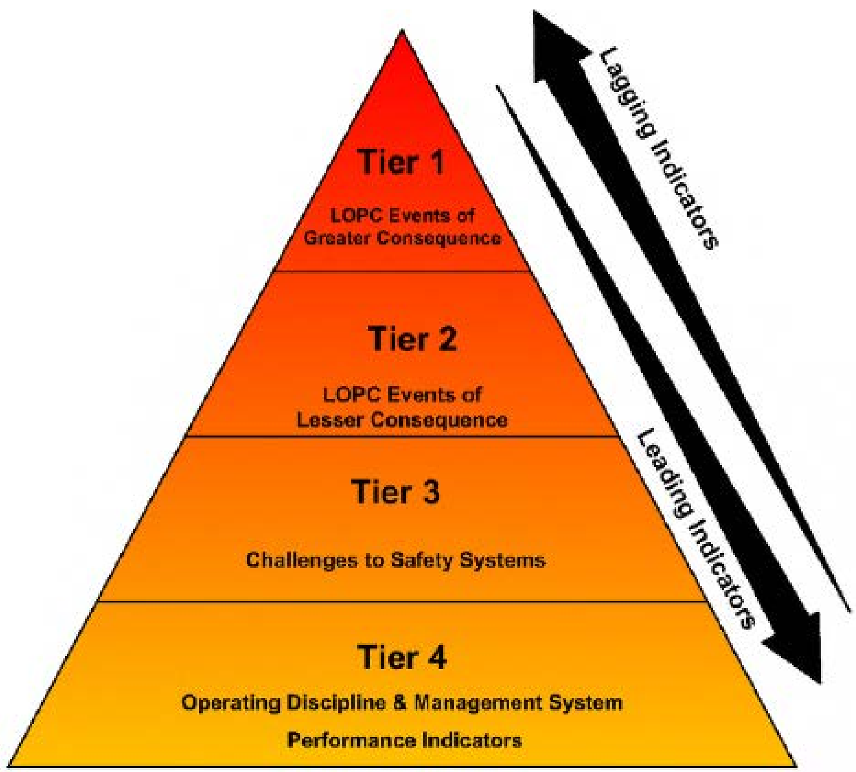

Figure 3-2. Process Safety Indicator Pyramid as identified by the American Petroleum Institute and the International Association of Oil & Gas Producers.[561]

[561] API Recommended Practice, 754, 1st ed., *Process Safety Performance Indicators for the Refining and Petrochemical Industries*, April 2010, p 8; International Association of Oil & Gas Producers Recommended

At least two professional groups, the Oil and Gas UK's Well Lifecycle Practices Forum (WLCPF)[562] and the Center for Offshore Safety (COS),[563] have been advancing initial efforts by API and IOGP by more clearly defining or tracking indicators for offshore drilling and well operations.[564] For instance, COS expands the API RP 754 Tier 1 and 2 definitions, which COS refers to as Safety Performance Indicators (SPI) (Table 3-4), and publicly reports indicator data from its members:[565]

Table 3-4. COS definitions of SPI 1 and SPI 2 process safety events.[566]

	SPI Number	
	1	**2**
SPI Definition	A. Fatality (one or more) B. Five of more injuries in a single event C. Tier 1 (API RP 754) process safety event D. Loss of well control E. ≥$1 million direct cost from damage to or loss of facility, vessel and/or equipment F. Oil spill ≥ 10,000 gallons (238 barrels)	A. Tier 2 (API RP 754) process safety event B. Collision resulting in property or equipment damage ≥ $25,000 C. Crane or personal/material handling operations incident D. Loss of station keeping resulting in a drive off or drift off E. Life boat, life raft, rescue boat event

Practice, *Process Safety - Recommended Practice on Key Performance Indicators, Report No. 456*, November 2011, Section 2.2.

[562] The Well Lifecycle Practices Forum is a group of over 45 well operators and management companies established by Oil and Gas UK in 2010, which provides a forum for discussion and industry guideline development. See http://www.oilandgasuk.co.uk/knowledgecentre/Well_Life_Cycle_Practices.cfm for more information (accessed October 7, 2015).

[563] COS is an industry-sponsored group created in 2011 to focus exclusively on deepwater drilling in the Gulf of Mexico (Http://www.centerforoffshoresafety.org/, accessed October 7, 2015).

[564] Oil and Gas UK Well Lifcycle Practices Forum. Guide to Drilling Process Safety Performance Measurement, Draft Form, Version 2.

[565] One major part of the COS mission, as stated on its webpage, is "compiling and analyzing key industry safety performance metrics." The COS convened a committee aimed at developing an indicators program for use offshore. COS published its first indicators report in 2015 for the 2013 reporting yes; *Annual Performance Report for 2013 Reporting Year;* April, 2015; http://www.centerforoffshoresafety.org/COS%202013%20Annual%20Performance%20Report.pdf (accessed October 7, 2015). COS published a second report for the 2014 reporting year: *Annual Performance Report for 2014 Reporting Year;* September 21, 2015; http://www.centerforoffshoresafety.org/2015_COS_2nd%20APR_FINAL.pdf (accessed December 7, 2015).

[566] Center for Offshore Safety. *Annual Performance Report for 2013 Reporting Year;* April, 2015, Appendix 3; http://www.centerforoffshoresafety.org/COS%202013%20Annual%20Performance%20Report.pdf (accessed October 7, 2015).

The WLCPF decided that Tier 1 and 2 indicators (blowouts or high potential blowouts where an incident almost occurred) were well defined, but decided that Tier 3 and 4 indicators need more clarification, so it was considering classifying Tier 3 indicators in four categories:[567,568]

1. Engineering Design and Execution of the Well
    a. Double Barrier principle compromised with or without an influx
    b. Dispensations from technical standards granted
    c. Deviations from well design parameters during operations
    d. Company defined exceedences of safe operational envelopes related to the well design
2. Safety-critical Equipment on the Drilling Unit
    a. Operation with Rig Audit "Critical Items" outstanding
    b. Partial or complete failure of safety-critical well monitoring system
    c. Partial or complete failure of safety-critical rig equipment or systems in operation or during testing
    d. Operation of safety-critical systems outside their performance limitations
3. Control of Work
    a. Noncompliance with or uncontrolled deviations from safety-critical standard operating procedures
    b. Noncompliance with or uncontrolled changes to detailed operations plans
4. Personnel Competency
    a. Presence of incompetent or unqualified personnel at the work site
    b. Personnel inappropriately qualified for the task at hand

The WLCPF also grappled with identifying effective Tier 4 indicators and recognized them as more difficult because testing organizational or human barriers is not as straightforward as is testing physical barriers. Since the health of organizational and human barriers is closely linked to an individual company's safety management systems, the WLCPF is not suggesting specific Tier 4 indicators (like it does with Tier 3), but rather areas that a company can use to focus its own company-specific activities in defining its own parameters. These areas include six foci that may provide information on the health of the organization:[569]

1. HSE (or other) Audit Action Tracker – Receive reports on overdue items and number of close-outs. Include critical items from rig audits and outcomes from formal audits of HSE activities from global reviews, a local business unit, or team-based periodical reviews.
2. Well Control Equipment, Personnel, Barrier Integrity Log – Monitor status of well control equipment certification, people qualifications, barrier integrity, and pressure tests.
3. MOC & Program Changes –Review the register of changes, dispensations, or changes to identify common themes potentially requiring further action or review.
4. Well Examination Report – Review on a quarterly basis summary statistics from the well examination process. Some organizations may do this as an annual formality. This report, if

[567] Oil and Gas UK Well Lifcycle Practices Forum. Guide to Drilling Process Safety Performance Measurement, Draft Form, Version 2, p 9.

[568] The WLCPF notes that in some cases, these indicators could be normalized against man hours worked, but that others would be best normalized on a rig-months or per-well basis.

[569] Oil and Gas UK Well Lifcycle Practices Forum. Guide to Drilling Process Safety Performance Measurement, Draft Form, Version 2, p 12.

submitted quarterly and reviewed by leadership, might provide valuable information concerning the health of the well examination process.

5. Competency Assurance – Track activities and outcomes associated with a competency management program of company staff and contractors.
6. Log of Minor Events – Review minor events, such as alarm systems switched off and related to barrier integrity, but which do not represent a threat to the primary barriers.

The WLCPF draft guidance document suggests that the data collected on the 6 focus areas can be incorporated into a metric dashboard[570] that summarizes safety status of an organization. The trends evident on the dashboard could then be used to identify areas for attention or interventions to reestablish safe operations determined by previously established targets, as part of a risk-based approach to maximize efforts for managing risk.[571] Not all barriers necessarily provide metrics that can be assessed on the same time scales, and identifying slow moving and "real-time" barrier metrics will maximize indicator efforts to manage risks.[572]

About ten years before API 754 and IOGP 456 were developed, Statoil defined a framework that identified four types of indicators, some of which correlate to the four-tier classification system created by API, but Statoil more specifically addressed the timescale of these indicators.[573] Statoil not only distinguished lagging and leading metrics, but also between slow moving and real-time metrics. The timescale distinction summarized in Table 3-5 is useful in describing CSB indicator findings in connection with the Macondo incident described in the next section.

[570] Some companies create visual displays for the status of various process safety indicators. For instance, green could indicate a healthy barrier while yellow and rid could indicate barriers in need of attention. For example, see Sedgwick, M. *Process Safety Key Performance Indicators*, CSB Public Hearing: Safety Performance Indicators, Houston, TX, July 24, 2012; http://www.csb.gov/UserFiles/file/Sedgwick%20%28Scottish%20Power%29%20PowerPoint%20-%20printed.pdf (accessed October 7, 2015).

[571] Pitblado, R. *Real-Time Safety Metric and Risk-Based Operations*, 11th International Symposium Loss Prevention, 2004; p 5.

[572] Kortner, H.; Sorum, M.; Brandstorp, J. M. *Framework For Life-Cycle Assessment of Technical Safety Conditions at Statoil Operated Plants*, ESReDA Seminar on Lifetime Management, Erlangen, Germany, November 5-6, 2001. Cited in Pitblado, R. *Real-Time Safety Metric and Risk-Based Operations,* 11th International Symposium Loss Prevention, 2004; p 5.

[573] Kortner, H.; Sorum, M.; Brandstorp, J. M. *Framework For Life-Cycle Assessment of Technical Safety Conditions at Statoil Operated Plants*, ESReDA Seminar on Lifetime Management, Erlangen, Germany, November 5-6, 2001.

Table 3-5. Four indicators as defined by Statoil in 2001.[574]

Indicator Type as per Statoil	CSB Correlation with Tier Indicator System Developed by API	Description[575]
Lagging measures	Tiers 1 and 2	Statistical accumulations of actual incidents or near-miss events for a facility. Typically these are slow moving and make sense only over longer time periods (e.g., annual averages).
Leading measures	Tier 4	Measures of PSM management system elements that support environmental, health, and safety (EHS), such as management of change systems, training systems, etc. These are mainly assessed by 2-3 year audits. They are slow moving measures not well suited for day-to-day operational management.
Barrier/Real-Time measures	Tier 3 and 4 (as defined by the WLCPF)	Measures of the status of EHS barriers from fully functional to seriously degraded or non-functioning. Suitable candidate for real-time measure.
Threat measures	No Correlation	Measures of the degree of threat to the facility. These are typically EHS challenges at a rate higher than anticipated in the risk assessment that underlies the safeguarding system. These can be determined by monitoring / predicting weather, nearby ship traffic, work permit activity, contractors on board, etc. This is also a suitable candidate for real-time measure.

3.5 Process Safety Metrics Gleaned from the Macondo Blowout

Operators and contractors look to industry-specific trade associations for good practice guidance and recommendations for all manner of operational concerns, including performance indicators. However, as efforts by the WLCPF group indicate, industry guidance pertaining to safety performance indicators could be further improved to provide practicable indicator suggestions. Benefiting from a perspective admittedly enlightened by hindsight, this section explores potential lead indicators that the Macondo well operations crew and onshore management could have used to manage risk.

[574] Kortner, H.; Sorum, M.; Brandstorp, J. M. *Framework For Life-Cycle Assessment of Technical Safety Conditions at Statoil Operated Plants*, ESReDA Seminar on Lifetime Management, Erlangen, Germany, November 5-6, 2001.

[575] These descriptions come from Pitblado, R. *Real-Time Safety Metric and Risk-Based Operations*, 11th International Symposium Loss Prevention, 2004, p 5.

3.5.1 Real-time Indicators for Safety Critical Elements

Volume 2 identified barriers as safety critical elements (SCEs), tasks, or pieces of equipment that lead to a disproportionate level of protection against major accident events (MAE), and conversely whose failure can lead to an immense increase in risk for a MAE.[576] In Volume 2, these safety critical elements appear on a bowtie diagram which illustrates how a major accident might evolve through the failure of a series of technical, organizational, and operations barriers. (Figure 3-3 is another bowtie example depicting various barriers.)

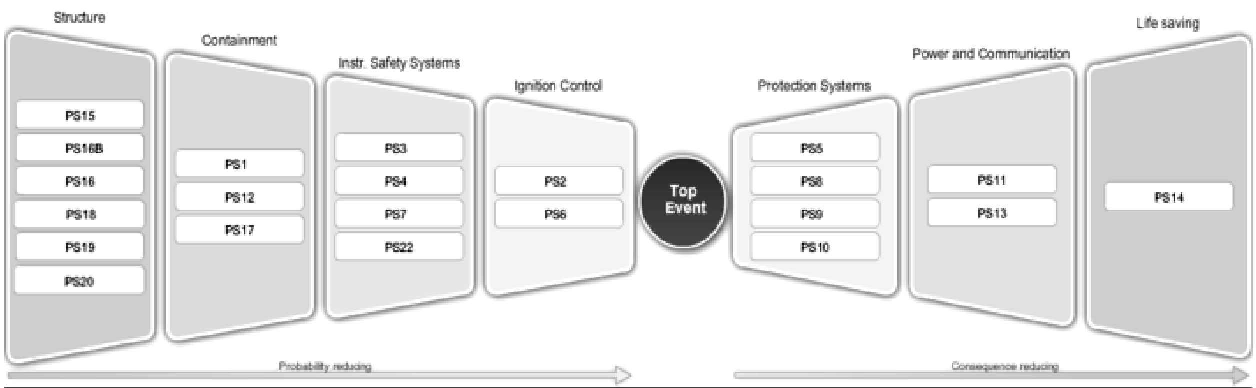

Figure 3-3. A Bowtie diagram model used by Statoil to track the health of specific barriers that are preventive or mitigative for major accident risks.[577]

As proposed in Volume 2, safeguarding an SCE's effectiveness throughout its lifetime should begin by clearly identifying and distinguishing it from noncritical equipment and tasks.[578] Standards should be developed to define the required performance of an SCE to reduce the risk of an MAE. Written assurance and verification activities should then define the needed activities to maintain SCE. Through this monitoring, improvements to performance gaps should be initiated to reestablish targets.

These SCE activities are candidates for indicators that can be used to influence daily operations in real time as they coincide with WLCPF recommendations to develop Tier 3 indicators for safety critical equipment on the unit. For example, trends and analysis on SCE maintenance backlogs and SCE verification activity failures could provide information on the robustness of the safety critical elements. The Macondo incident demonstrated several instances when the emergency functions of the BOP intended to prevent and mitigate an MAE were not tested or properly maintained:

1. Transocean and BP conducted routine inspections and weekly function testing of operational BOP components necessary for daily drilling operations, but these were insufficient to identify latent failures of the emergency systems (Volume 2, Chapter 5.0);

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[576] Volume 2, Section 4.2.3.1, p 58.

[577] Eie, G. *Performance Indicators for Major Accident Prevention*, CSB Public Hearing: Safety Performance Indicators, Houston, TX, July 24, 2012, slide 5. http://www.csb.gov/UserFiles/file/Eie%20(Statoil)%20PowerPoint.pdf (accessed October 7, 2015).

[578] Volume 2, Chapter 5 presents the lifecycle in more detail.

2. For an extended time during the drilling process, the Deepwater Horizon BOP blind shear ram could not have reliably sheared the drillpipe used at Macondo during an emergency situation[579] (Volume 2, Section 5.2.1); and
3. A miswired solenoid valve in the yellow pod and the deficient wiring in the blue pod needed to function the Deepwater Horizon BOP in an emergency system could not have passed the manufacturer's factory acceptance testing procedures (Volume 2, Sections 5.3.1 and 5.3.2).

These findings highlight the importance of clearly identifying safety critical functions and performance expectations during an emergency scenario of equipment that might also serve an operational function.[580] Once identified, the appropriate assurance activities needed to test the safety critical functions must be defined, executed, and monitored as appropriate for deviations from the performance metrics.

3.5.1.1 Well Kicks

A kick is an indicator that the primary well barrier failed and secondary well control actions by the crew are needed. After a kick, if the crew does not recognize the need to activate the BOP or is delayed in activating it—as was the case with Macondo—then a gas-in-riser event or even a blowout can occur.[581]

Transocean compiled a Well Control Events & Statistics report covering the years 2005 to 2009.[582] In the report, Transocean reviewed data from various well types (e.g., development or exploration) during various phases of the drilling operations (e.g., abandonment or active drilling) to explore well control trends and compare previous years to 2009. Transocean noted 121 well control events in 2009 that spanned 32 different operators from various geographical locations. Of those 121 well events, 71 were categorized as kicks. In the report, Transocean identifies several potential indicators:[583]

- Kick volume – indicator of rig and crew performance in shutting in the well;
- Kick intensity – indicator of operator's accuracy in predicting pore pressure; and
- Riser unloading events,[584] which the Transocean report identified as the biggest concern.

A well kick falls under the Tier 3 definition provided in Section 3.4.2 because it represents a challenge to a safety system—the human actions to detect and activate the BOP and the original threat analysis to predict anticipated pore pressures. Although Tier 3 indicators are generally company-specific, this not the case for well kicks. The Transocean data demonstrates that well kicks are not an isolated problem which only BP or the Gulf of Mexico region face, but rather kicks happen under the supervision of many

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[579] In manual mode, the Deepwater Horizon crew developed a multi-step work-around where the crew would fist close the Casing Shear Ram, move drillpipe stub clear, and then close the Blind Shear Ram to seal the well. The rig's AMF/deadman automatic emergency system also relied upon the blind shear ram and was similarly impaired, but had no workaround as it could not close the casing shear ram before the blind shear ram.

[580] For another example, see the diverter discussion in Section 1.2.1.

[581] See Chapter 2.0, which describes incidents when late kick detection occurred, but the BOP was able to seal the well.

[582] Internal Company Document, Transocean. *Well Control Events & Statistics 2005 to 2009*, TRN-INV-00760054, http://www.mdl2179trialdocs.com/releases/release201303211200016/TREX-05649.pdf (accessed June 24, 2015).

[583] *Ibid.*, TRN-INV-00760059.

[584] Riser loading events occur when riser fluids (e.g., drilling mud, sea water, or hydrocarbons from the well) are released onto the drilling rig. They can occur only on floating rigs using a subsea BOP.

operators all around the world. Well kick data can be used as a safety benchmark for the offshore industry both intracompany and industrywide. For example, international analyses of offshore blowout and well release frequencies have been completed, like one by Lloyd's Register that analyzed a SINTEF well release and blowout database[585] for three international geographical regions.[586]

3.5.2 Slow Moving Indicators for SMS Elements

3.5.2.1 Emerging MOCs Themes

The WLCPF suggested monitoring MOC programs to identify common themes. Safety management program performance metrics are categorized as slow moving indicators in 3.4.2, implying that larger timeframes (i.e., a year or longer) are needed to assess safety trends. The CSB also observes that monitoring one SMS element will likely lead to learnings for other safety management systems. Both of these facts were evident for the Deepwater Horizon.

3.5.2.1.1 MOC Indicators - Transocean

The CSB examined Transocean-identified DWH MOCs completed during the seven years prior to the Macondo incident for changes to the blowout preventer (BOP). Transocean corporate policies mandate that all changes to safety critical systems, such as a BOP,[587] should trigger a formal MOC and risk assessment.[588] Table 3-6 lists 10 MOCs for the BOP from 2003 to 2009. A preliminary theme emerging from the table[589] is that the BOP was not consistently identified as safety critical in the MOCs. Instead, only four MOCs identified it as such, and further, only four of the MOCs indicated that a risk assessment was required to complete the change.

585 See https://www.sintef.no/en/projects/sintef-offshore-blowout-database/ (accessed December 7, 2015).

586 Lloyd's Register. *Blowout and Well Release Frequencies based on SINTEF Offshore Blowout Database 2009 (Draft A);* 80.005.003/2010/R3; Lloyd's Register: March 17, 2010; p BP-HZN-BLY00104032. See Exhibit 4156, http://www.mdl2179trialdocs.com/releases/release201302281700004/Baxter_John-Depo_Bundle.zip (accessed May 28, 2015).

587 Transocean identified the BOP as safety critical in its Major Accident Hazard Risk Assessment; Internal Company Document, Transocean. *Major Accident Hazard Risk Assessment Deepwater Horizon*, Revision 01, August 29, 2004, TRN-MDL-01184581, http://www.mdl2179trialdocs.com/releases/release201303141200012/TREX-02188.pdf (accessed October 7, 2015).

588 Internal Company Document, Transocean. *Field Operations Policies & Procedures Manuel*, Issue 01, Revision 00, HQS-POP-PP-01, August 8, 2009, Management of Change, TRN-CSB-0002251-0002260.

589 Internal Company Document, Transocean. *Managment of Change 2004 2005 2006 2009 Deepwater Horizon*, TRN-INV-00758181; Internal Company Document, Transocean. *Change Proposal SS-024*, April 12, 2009, BP-HZN-BLY00395154.

Table 3-6. Summary of MOCs documented by Transocean for the Deepwater Horizon BOP.

ID #	Date	Subject	BOP identified as Safety Critical?	Indication of a Required Risk Assessment?	Description†
1	12/29/2003	Upper Annular (UA) Failure	**No**	**No**	Hydraulic leak on the UA, so electronically locked. Will rely on lower annular.
2	1/5/2004	BOP MOC for Horizon	**No**	**No**	Changes to the control and mechanical systems. Required modifications to installation drawings and operating procedures, vendor involvement, and engineering approval.
3	8/28/2004	LMRP failsafe panel removal	**No**	**No**	Removed unnecessary BOP components; required modification of installation drawings, acceptance testing, and engineering approval.
4	11/21/2004	BOP Test Rams	**No**	*Yes*	Converted the lowest pipe ram into a test ram.
5	2/6/2006	Auto Shear Circuit Not Working	*Yes*	*Yes*	Autoshear circuit leaked, so disabled.
6	3/9/2006	18-3/4" Annular stripper packer	**No**	**No**	Installed a different UA to allow for stripping of 6 5/8" drillpipe which changed operating procedures.
7	1/11/2006	BOP Operation	**No**	**No***	Yellow pod malfunctioning, so remainder of well drilled with the blue pod selected which changed operating procedures.
8	3/5/2007	Software Modification	*Yes*	**No**	Software modification to address erroneous faults, required vendor involvement and acceptance testing upon completion.
9	10/29/2008	Auto Shear Circuit Not Working	*Yes*	*Yes*	Autoshear circuit leaked, so disabled.
10	4/12/2009	Auto Shear Circuit Not Working	*Yes*	*Yes*	Autoshear circuit leaked, so disabled.

† Definitions for technical terms used in this column appear in Volume 2 of the CSB's Macondo investigation report.

*Six days after the facility manager signed this MOC (and original date of MOC), the technical manager noted, "Moot as BOP is on the deck at this point; however, a) This would normally require a risk analysis and b) steps must be taken to communicate this change to those who follow (placards on control panels, for example)."

A review of the Deepwater Horizon MOCs for the autoshear emergency function points to another potential theme: the MOC process might have devolved into a check-the-box activity. Three MOCs from 2006, 2008, and 2009 addressed leaks in the autoshear system[590] (MOC # 5, 9, and 10 from Table 3-6). Each of the autoshear MOCs indicated a risk assessment was required to address disabling the system, and the later MOCs from 2008 and 2009 noted the previous situation(s) when the same issue arose.[591] The risk of operating without an autoshear for a finite period might be acceptable compared to (a) operating with a leak or (b) bringing the BOP to the surface for repair. But that risk management choice, the real-time well conditions, or the duration of operating without the autoshear are not indicated on any of the approved MOCs.

A final theme emerges that the MOC process was documenting changes, but other safety management systems were not being updated to reflect the controls needed to mitigate the risks introduced by the changes. MOC #4 in Table 3-6 concerns the conversion of a pipe ram to a test ram.[592] Pipe rams like those installed on the Deepwater Horizon BOP are designed to hold pressure from one direction and normally are installed to hold pressure coming up from the well, such as would be expected during a well kick. To save time and money during required subsea pressure tests of the BOP stack, BP requested that the lowest pipe ram in the Deepwater Horizon's BOP be installed upside down to hold pressure from above. [593] A consequence of this change is the loss of a pipe ram for well control, leaving only two, so less redundancy. Despite the indication on the MOC that a risk assessment was needed, the CSB could not identify any Transocean-authored risk assessments concerning the test ram. For Transocean, the new hazards introduced by the conversion of the pipe ram to a test ram included new operational procedures and practices that would be required by the crew and third-party contractors.

Hazards introduced by the new test rams procedures and practices were highlighted in a February 2010 Transocean investigation report that documented an incident when the Deepwater Horizon well

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[590] The autoshear system is a safety critical element designed to close the BOP's blind shear rams and seal the well in the event the lower marine riser package (LMRP) is inadvertently disconnected from the wellhead. The disconnect could result from, for example, either an accidental push of the LMRP unlatch button on one of the rig-based BOP control panels or from a malfunction within the BOP control system. See Section 2.1, Volume 2 for more details.

[591] Internal Company Document, Transocean, *Change Proposal SS-15: Auto Shear Circuit Not Working*, February 6, 2006, TRN-INV-01262584, see Exhibit 4312, http://www.mdl2179trialdocs.com/releases/release201304041200022/Odenwald_Jay-Depo_Bundle.zip; *Change Proposal SS-23: Auto Shear Circuit Not Working*, October 29, 2008, TRN-INV-01595873.; *Change Proposal SS-23: Auto Shear Circuit Not Working*, October 29, 2008, TRN-INV-01595873.; *Change Proposal SS-24: Auto Shear Circuit Fluid Leak*, April 12, 2009, BP-HZN-2179MDL00359935, see Exhibit 4610, http://www.mdl2179trialdocs.com/releases/release201304041200022/Odenwald_Jay-Depo_Bundle.zip;

[592] Internal Company Document, Transocean. *Change Proposal SS-10: BOP Test Rams*, November 21, 2004, TRN-INV-01262577, see Exhibit 4309 http://www.mdl2179trialdocs.com/releases/release201304041200022/Odenwald_Jay-Depo_Bundle.zip (accessed October 7, 2015).

[593] Hearing before the U.S. District Court for the Eastern District of Louisiana under the Multi-District Litigation docket MDL No. 2179, August 17, 2011, see Keeton Designations Vol 1 p 43, http://www.mdl2179trialdocs.com/releases/release201302281700004/Keeton_Jonathan-Depo_Bundle.zip (accessed October 7, 2015).

operations crew failed to close the test rams before beginning subsea pressure test procedures.[594] Transocean's investigation report noted that the Task Specific THINK Procedure for the subsea test did not explicitly require closing the test rams[595] and that on two occasions, closing the test rams had been a step added to the procedure, but that not all test sheets were updated to include this critical step.

3.5.2.1.2 Dispensation/MOC Indicators - BP

Internal company standards contain the boundaries, requirements, and practices that management agrees upon, essentially describing the risk an organization formally accepts for a process. For drilling and well operations, BP's company standards appear in the Drilling and Well Operations Practice (DWOP) and related Engineering Technical Practices[596] (ETPs). At the time of the Macondo blowout, BP stated that "deviations from the Drilling and Well Operations Practice and ETPs shall only be considered in exceptional circumstances." [597] During the planning of the Macondo well, BP processed six MOCs for dispensations from the DWOP and seven more after drilling began. Actively monitoring the number of dispensations or MOCs for a well or a rig provides indications of possible safety issues to manage for MAE potential.

First, several Macondo well MOCs completed by BP noted that the company standards in the DWOP and ETP were not appropriate for deepwater wells,[598] implying that similar MOCs would be required for BP to drill other deepwater wells. An increase in dispensations from company standards may indicate that they need updating or expansion. The potential danger is clear. Relying on outdated company standards increases improvisation because the standards do not accurately represent the work conditions, and it perpetuates a lack of organizational controls for managing risk to acceptable levels commensurate with the company's goals. One potential solution might be to develop an ETP that specifically addresses deepwater drilling.

Second, no one metric can define when an organization's focus on the risk of a major accident event begins to drift, and will likely require a triangulated approach that includes reviewing the content of dispensations and MOCs. For example, some of the BP MOCs completed for Macondo describe conditions that could lead to burst casing, but then state, "This scenario has a very low probability of occurring."[599] Low probability still means some probability, a point highlighted in another Macondo

[594] Internal Company Document, Transocean. *Deepwater Horizon BOP Test Rams*, Feburary 9, 2010, TRN-MDL-00481481, see Exhibit 1441, http://www.mdl2179trialdocs.com/releases/release201302281700004/Burgess_Mark-Depo_Bundle.zip (accessed October 7, 2015).

[595] Transocean indicated that no one involved in the task actually reviewed the TSTP.

[596] BP's used Engineering Technical Practices (ETPs), Site Technical Practice (STPs), and Group Practices to define minimum engineering and operations corporate standards.

[597] Internal Company Document, BP. *GP 10-00 Drilling and Well Operations Practice*, Issue 1, October 2008, p A-4, BP-HZN-BLY00034504, http://www.mdl2179trialdocs.com/releases/release201304110900026/TREX-06121.pdf (accessed May 26, 2015).

[598] For example: Internal Company Document, BP. DCMOC-09-0048: Kick tolerance less than 25 bbls with a 1.0 ppg kick intensity, July 10, 2009.; Internal Company Document, BP. DCMOC-09-0049: Design Pore Pressure (DPP) requirements, July 10, 2009.

[599] See text from MOCs for 22" and 16" casing burst designs, Internal Company Document, BP. *Dispensation from Drilling and Well Opeartions Policy*, BP-HZN-2179MDL00252262, BP-HZN-2179MDL0025226, see Exhibit

MOC where the requester stated, "This would certainly be a worst-case scenario; however, I have seen it happen so know it can occur."[600] Minimizing the probability of a worst-case scenario could lead those responsible for risk management to prematurely stop looking for controls to prevent or mitigate the unwanted consequences.

Indicators Developed by BP Post-Macondo

BP itself came to recognize potential safety performance indicators in the aftermath of Macondo. BP's internal investigation team recognized an opportunity to initiate revisions to its safety performance indicator program. As a result, the team recommended the following improvements to the company:[†]

> *Establish D&C leading and lagging indicators for well integrity, well control and rig safety control equipment, to include but not be limited to:*
>
> - *Dispensations from DWOP.*
> - *Loss of containment (e.g., activation of BOP in response to a well control incident).*
> - *Overdue scheduled critical maintenance on BOP systems.*
>
> *Require drilling contractors to implement an auditable integrity monitoring system to continuously assess and improve the integrity performance of well control equipment against a set of established leading and lagging indicators.*

[†]*BP. Deepwater Horizon Accident Investigation Report; September 8, 2010; pp 184.*

3.5.2.2 Cross Reference Indicators Between the Operator/Drilling Contractor

An independent 2009 Deepwater Horizon rig audit requested by BP[601] observed:

> The TSTP which provides the core risk assessment procedure is only used if one is available for the job. It was evident that the extensive TSTP library was not being fully utilised. That said the written THINK plans reviewed were generally of an acceptable quality and personnel were seen to be actively involved during the THINK Planning process.

6092 http://www.mdl2179trialdocs.com/releases/release201302281700004/Thierens_Henry-Depo_Bundle.zip (accessed October 15, 2015).

[600] See text from MOC for 9-7/8" production casing collapse design; Internal Company Document, BP. *Dispensation from Drilling and Well Opeartions Policy*, BP-HZN-2179MDL00252277, see Exhibit 6092 http://www.mdl2179trialdocs.com/releases/release201302281700004/Thierens_Henry-Depo_Bundle.zip (accessed October 15, 2015).

[601] Internal Company Document, BP. *Deepwater Horizon Follow Up Rig Audit, Marine Assurance Audit and Out of Service Period September 2009*, September 2009, p 5, BP-HZN-I IT -0008875, http://www.mdl2179trialdocs.com/releases/release201305171200030/TREX-000275.pdf (accessed October 7, 2015).

The acceptable quality noted in the audit conflicts with observations made in this report on the Deepwater Horizon TSTPs as well as TSTPs associated with serious near-misses Transocean had recently experienced:

- As a result of Transocean's Sedco 711 incident, Shell recommended that TSTPs include loss of well barrier risks and well control implications.[602]
- In connection with the M.G. Hulme incident, Transocean's investigation report noted that the TSTP was not approved and did not adequately identify the hazards and cover risk mitigation and preventive controls.[603]
- At Macondo, the TSTP for the negative test was general, lacking process parameters or other criteria to assist the crew in recognizing when the well began drifting outside safe conditions.[604]

Hindsight can be a powerful tool in examining the quality of risk assessment tools. Cross referencing findings in routine audits, either internal or client-requested, with those from incidents and near-misses, regardless of where they occurred, could provide a new perspective on what should be considered acceptable.

Improvements in the selection and use of process safety performance indicators are necessary to effectively reduce the risks of a major accident event offshore. BP, Transocean, and industry more broadly had access to data that provided insights into the performance of safety critical barriers and safety management systems before the April 20 blowout. Yet the focus from both companies—in audits, performance contracts, and award measures— was on personal safety without an equal and sufficient emphasis on major accident risks.

3.6 Regulatory Requirements for Indicators Reporting

At the time of the Macondo incident, MMS required operators to report primarily lagging and infrequently occurring events, such as losses of well control, fires, explosions, collisions, and incidents that damaged or disabled safety systems or equipment.[605, 606] MMS also voluntarily collected from its lessees and operators information on the number of recordable injuries/illnesses of company and contract employees, DART[607] injuries/illnesses of company and contract employees, notices of EPA noncompliance, and oil spills greater than one barrel annually, as well as the total volume for those

[602] See Section 2.2.

[603] Internal Company Document, Transocean. *EAU Incident Investigation Report - M.G. Hulme, Jr. Well Control Incident - Riser Unloading*, OER-MGH-09-005, March 26, 2009, p 12, TRN-INV-01143039, http://www.mdl2179trialdocs.com/releases/release201303211200016/TREX-05650.pdf (accessed October 7, 2015); see also Section 2.1.

[604] See Section 1.8.3.

[605] More detail is available in Volume 4, Section 4.3.

[606] Oil and Gas and Sulphur Operations in the Outer Continental Shelf - Incident Reporting Requirements, 71 Fed. Reg. 19,640 (April 17, 2006).

[607] DART stands for Days Away from work, Restricted duty, and Transfer situations; US DOI MMS Performance Measures Data, MMS-131, http://www.ocsbbs.com/ntls/ntl2005-n02-formmms-131.pdf, (accessed October 7, 2015).

reported spills.[608] Appendix E of API 75, which was merely a voluntary recommended practice at the time of Macondo, recommended the collection of those same safety performance metrics, as well as fire, explosion, and blow-out incident rates, and Incidents of Noncompliance issued by MMS.[609] Since these data reporting recommendations were voluntary, the regulator did not have access to a full range of data possible to assess industry performance, identify negative safety trends, or set targets for industry improvement. Post-Macondo, the potential for the US regulator to use safety performance indicator data to further advance safety offshore is recognized, with the regulator's voluntary request becoming mandatory in February 2011 and the introduction of an anonymous near-miss reporting program, SafeOCS, in 2015.[610] Volume 4 describes approaches BSEE might take to promote offshore safety improvements using indicator data it collects.[611]

3.7 Conclusion

The imperative to prevent another offshore catastrophe supports efforts by industry to actively monitor safety performance indicators that capture barrier and safety management system health. This chapter highlights some of the more advanced work on the issue to suggest ways companies can effectively collect and use safety data to manage major accident hazards. Volume 4 of the CSB Macondo Investigation Report, describes in detail how the regulator can play an influential role in developing and using safety performance indicators.

[608] US DOI MMS Notice to Lessees and Operators of Federal Oil and Gas Leases on the Outer Continental Shelf: Performance Measures for OCS Operators and Form MMS-131, NTL2005-N02, https://ocsbbs.com/ntls/ntl05-n02.asp, and US DOI MMS Performance Measures Data, MMS-131, http://www.ocsbbs.com/ntls/ntl2005-n02-formmms-131.pdf, (accessed October 7, 2015).

[609] API Recommended Practice, 75, 3rd (2004, reaffirmed 2008) ed., Recommended Practice for Development of a Safety and Environmental Management Program for Offshore Operations and Facilities, Appendix E, pp 37-41.

[610] https://near-miss.bts.gov/ (accessed January 15, 2015).

[611] Section 4.3.

4.0 Ineffective Risk Management Approaches at Macondo and the Challenges of the Multi-Employer Offshore Work Environment

Chapter 4.0 Overview

This chapter examines various BP and Transocean policies for managing major accident risks during drilling operations. The chapter demonstrates how despite contracted rigs represent a majority of BP's blowout risks and Transocean's rigorous corporate management risk policies, neither company sufficiently managed major hazard risks at the Macondo well.

Major process safety incidents such as the 1988 UK Piper Alpha (offshore production facility)[612] and the 1989 Phillips 66 Chemical Complex (petrochemical production facility)[613] explosions were shaped by factors related to contractor management and ensuring safe operations in a multi-employer environment. At Piper Alpha, causal factors included deficiencies in contractor training and communication related to safety critical procedures as well as emergency response.[614] For the 1989 Phillips 66 incident, findings addressed dispersed responsibility for employee safety where one or more contractors were engaged in potentially hazardous activities at the worksite.[615] In its Phillips 66 investigation report, OSHA compared the owner/contractor problem to threats that can arise from dividing safety responsibility at construction sites where procedures were not in place.[616] Similar lessons presented themselves at Macondo, but with nuances specific to the offshore drilling industry.

As detailed in Section 1.8, while BP designed the Macondo well, Transocean supplied most of the workforce and drilling equipment. Before drilling began, BP agreed to use Transocean's Safety

[612] On July 6, 1988, an explosion occurred aboard the Piper Alpha oil production platform 120 miles off the coast of Scotland in the North Sea. A series of explosions and fire killed 167 workers and almost completed destroyed the platform. This incident became the deadliest accident in the history of the offshore industry.

[613] On October 23, 1989, an explosion occurred at the Phillips 66 Company's Houston Chemical Complex where high-density polyethylene plastic for milk bottles and other containers was produced, killing 23 workers and injuring 130 others. This was one of the worst industrial workplace accidents in the United States.

[614] Department of Energy. *The Public Inquiry into the Piper Alpha Disaster; Presented to Parliament by the Secretary of State for Energy by Command of her Majesty*; November, 1990; noted in several locations, including examples on pp 194, 213, 293, and 356.

[615] U.S. Department of Labor Occupational Safety and Health Administration, The Phillips 66 Company Houston Chemical Complex Explosion and Fire: Implementation for Safety and Health in the Petrochemical Industry, April 1990, p vii.

[616] OSHA noted, "Following the L'Ambiance Plaza apartment complex collapse in Bridgeport, Connecticut, in April 1987, in which 28 workers were killed, OSHA held the primary contractor responsible for not meeting the safety and health requirements at the site. It was the agency's position that the primary contractor, in its role of supervisor of the entire project, could have prevented those violations regardless of whether part of the work was subcontracted." U.S. Department of Labor Occupational Safety and Health Administration, *The Phillips 66 Company Houston Chemical Complex Explosion and Fire: Implementation for Safety and Health in the Petrochemical Industry*, April 1990, p 63.

Management System (SMS) on the Deepwater Horizon.[617] For the workforce under the drilling contractor, consistently working within one safety management system should improve front-line activities as the drilling rig moves from one well to another or as crew members work on wells managed by different operators. However, as Section 1.8 indicates, the interface of the safety management systems between the operator and the contractors, particularly the drilling contractor, can play an important role in bridging the natural gap between work-as-imagined in the drilling program and work-as-done by the well operations crew. To do so effectively, the interface must encompass fundamental hazard identification and both companies' process safety risk management practices.

At Macondo, BP and Transocean did not clarify hazard identification and risk management roles and responsibilities for safety critical activities contained within the temporary abandonment program. Consequently, while both companies had more rigourous corporate policies for risk management, neither assumed effective responsibility for ensuring their implementation at Macondo. This chapter addresses the corporate policies that establish the basis for BP and Transocean's risk managment expectations.

4.1 BP and Transocean Risk Reduction Goal: ALARP

Companies need an effective, and realistic, risk reduction goal because they cannot eliminate every risk completely—absolute safety is not possible. The question then becomes, when are efforts to reduce the level of residual risk sufficient? This challenge led to reducing risk to a level as low as is reasonably practicable, or ALARP, an important concept to explore in risk reduction practices employed during the Macondo drilling project since both BP and Transocean had policies to apply ALARP principles.[618]

[617] Internal Company Document, BP. *Transocean Drilling Contract for the Deepwater Horizon, 1998*, http://www.mdl2179trialdocs.com/releases/release201305171200030/TREX-004271.pdf (accessed May 27, 2015).; Hearing before the Hearing before the U.S. District Court for the Eastern District of Louisiana under the Multi-District Litigation docket MDL No. 2179, June 29, 2011, see Mogford Designations Vol 2 pp 22-25, http://www.mdl2179trialdocs.com/releases/release201302281700004/Mogford_John-Depo_Bundle.zip (accessed October 7, 2015); Hearing before the U.S. District Court for the Eastern District of Louisiana under the Multi-District Litigation docket MDL No. 2179, June 21, 2011, see Baxter Designations Vol 1 pp 26-27, http://www.mdl2179trialdocs.com/releases/release201302281700004/Baxter_John-Depo_Bundle.zip (accessed October 7, 2015).

[618] BP's OMS Exploration and Production Drilling and Well Operations Practice (DWOP) states, "all risks shall be managed to a level which is as low as reasonably practical" or ALARP, Internal Company Document, BP. *GP 10-00 Drilling and Well Operations Practice*, Issue 1, October 2008, "This document contains the practices that have been agreed by BP management as current and relevant for drilling and well operations.", p A-8, BP-HZN-BLY00034518, http://www.mdl2179trialdocs.com/releases/release201304110900026/TREX-06121.pdf (accessed May 26, 2015). Transocean policies require employees to manage risks to ALARP, which Transocean defines as "… requiring personnel to consider the various additional risk reduction measures (additional controls) and determine if the effort and cost of those measures justify the additional amount of risk reduction obtained" Internal Company Document, Transocean. *Health and Safety Policies and Procedures Manual*, Issue 03, Revision 07, HQS-HSE-PP-01, December 15, 2009, Section 4 (Safety Policies, Procedures and Documentation), p BP-HZN-2179MDL00132218, see Exhibit 4942, BP-HZN-2179MDL00132055, http://www.mdl2179trialdocs.com/releases/release201302281700004/Farr_Daniel-Depo_Bundle.zip (accessed October 7, 2015).

No prescribed methodology defines the type or number of barriers needed to demonstrate ALARP.[619] The determination relies on informed judgments supported by a robust hazard analysis process that weighs the strengths and weaknesses of a range of potential barriers. Generally, proof that ALARP levels have been achieved is accepted when companies can show they adhere to generally recognized codes, standards, and relevant good practices.[620] ALARP is also defined as "efforts to reduce risk [that are] continued until the incremental sacrifice (in terms of cost, time, effort,or other expenditure of resources) is grossly disproportionate to the incremental risk reduction achieved."[621] In practice, these efforts by the company are twofold. First, they are the initial identificaton and implementation of physical, operational/human, and organizational safety barriers to reduce the risk of a major accident as determined by a hazard analysis. Second, they are adherence to safety managment systems intended to ensure strong barriers throughout the lifetime of an operation. The success of these systems hinges on the risk management approach and corporate oversight of that approach to create a strong and supportive culture. Collaboration of this magnitude means actively monitoring for, and then addressing, barrier performance gaps appropriately. Thus, while an initial effort to address risk levels is necessary, the efforts should be continual and in response to various factors such as new technology developments, updated industry standards, or lessons learned from an incident.

ALARP is not required by the SEMS Rule. Despite its lack of presence, several widely recognized standards and guidelines recommend using ALARP. Specific to drilling, ALARP is recommended by the IADC, a trade association of which Transocean is a member.[622] While this chapter details ALARP provisions stipulated in both BP and Transocean corporate policies to demonstrate inadequacies in their risk management approaches, Volume 4 expands the ALARP conversation and addresses the important role of the regulator in overseeing and verifying adequate risk reduction measures by industry in an ALARP environment.

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[619] Executive, H. a. ALARP "at a glance", http://www.hse.gov.uk/risk/theory/alarpglance.htm (accessed October 7, 2015), 2015.; NOPSEMA. *Guidance Note: ALARP;* N-04300-GN0166 Revision 6; June, 2015; pp 5-7. http://www.nopsema.gov.au/assets/Guidance-notes/N-04300-GN0166-ALARP.pdf (accessed October 7, 2015).

[620] The Center for Chemical Process Safety (CCPS) identifies ALARP as an appropriate risk reduction approach in their hazard identification and risk analysis guidance; Center For Chemical Process Safety. *Guidelines for Risk Based Process Safety;* John Wiley & Sons: Hoboken, NJ, 2007; see generally Chapter 9, Hazard Identification and Risk Analysis, pp 209-244.

CCPS is a not-for-profit industry alliance within the chemical engineering professional society - the American Institute of Chemical Engineers (AIChE) "that identifies and addresses process safety needs within the chemical, pharmaceutical, and petroleum industries, http://www.aiche.org/ccps/about (accessed February 28, 2015). CCPS's mission is to "eliminate process safety incidents in all industries" but much of CCPS safety guidance has historically focused on onshore process safety issues, http://www.aiche.org/ccps/about/mission-vision (accessed February 28, 2015). Member companies include major oil companies such as BP, Chevron, ConocoPhillips, ExxonMobil, Total and Shell that manage process safety both on and offshore.

[621] Center For Chemical Process Safety. *Guidelines for Risk Based Process Safety;* John Wiley & Sons: Hoboken, NJ, 2007; pp xxxvii.

[622] With the exception of the US, regulators of the leading oil and gas producing countries of the world have recognized or adopted these guidelines. IADC Safety Case Guidelines web page detailing the 21 countries where the guidelines have been adopted or are pending adoption, http://www.iadc.org/iadc-hse-case-guidelines/ ; International Association of Drilling Contractors *Health, Safety and Environment Case Guidelines for Mobile Offshore Drilling Units,* January 2015, Issue 3.6, Part 4, pp 22-23.

4.2 Contractor Safety Management Guidance Calls for Clear Definition of Roles and Responsibilities

The International Association of Drilling Contractors (IADC), the Center for Chemical Process Safety (CCPS),[623] and API guidance identify that keys to managing major process risk between a contracting company and a contractor are clear definition and communication of safety critical roles and responsibilities.[624] IADC recommends that a drilling contractor identify in writing hazardous operations and barriers that likely fall under its responsibility, including running drillpipe into and out of a well, well testing, and displacing a well.[625] The objective of such an activity is to incorporate input from relevant stakeholders (like an operator) on the uncertainties and assumptions made when identifying risk reduction measures, and then communicating the information to the workforce.[626] The IADC also identifies that a bridging document between the operator and contractor should describe "individual and collective stakeholder responsibilities during the various operational phases,"[627] which include HSE management responsibilities and authorities[628] as well as HSE critical activities and verification of effectiveness.[629]

CCPS emphasizes that owners/operators need to "establish expectations, roles and responsibilities for safety program implementation and performance."[630] CCPS states that one key principle for owners/operators in contractor management is to "maintain high standards of safety performance during the conduct of the contracted services," and it further asserts that the contracting company must implement a contractor management program to ensure safe operations.[631] Maintaining a dependable process safety practice and ensuring consistent implementation require "compliance with specific company, facility or regulatory requirements. Responsibility for each associated work activity should be identified and designated, as appropriate to the company or contractor."[632] CCPS also states that most companies require that contractor safety standards and practices be comparable to the owner/operator's.

[623] Guidelines for managing risk have been produced by various authors including the CCPS and IADC. While the CCPS guidelines were not expressively written for offshore operations, they have recently been effectively implemented in drilling and well operations (Chajai, H.; Smith, C. *Defining and Improving Process Safety for Drilling and Well Services Operations*, IADC/SPE Drilling Conference and Exhibition, Fort Worth, TX, March 4 - 6, 2014) As such, they complement the IADC guidelines for assessing policies and practices relevant to the Macondo incident.

[624] Center For Chemical Process Safety. *Guidelines for Risk Based Process Safety;* John Wiley & Sons: Hoboken, NJ, 2007; p 365.

[625] International Association of Drilling Contractors *Health, Safety and Environment Case Guidelines for Mobile Offshore Drilling Units*, January 2015, Part 4, Section 4.8, p 36.

[626] *Ibid*., Part 4, Section 4.8.1, p 37.

[627] *Ibid.*, Part 2, Section 2.2.1, p 4.

[628] *Ibid.*, Part 2, Section 2.2.3.4, p 8.

[629] *Ibid.*, Part 6, Section 6.4, pp 6-7.

[630] Center For Chemical Process Safety. *Guidelines for Risk Based Process Safety;* John Wiley & Sons: Hoboken, NJ, 2007, p 367.

[631] *Ibid.*, p 368.

[632] *Ibid.*, p 370.

API Recommended Practice 76,[633] *Contractor Safety Management for Oil and Gas Drilling and Production Operations*, establishes owner/operator responsibilities for contractor safety performance, including drilling contractors, and advises that the "operator should identify the safety requirements and communicate them to the contractor." [634] Where contractors have specialized expertise and knowledge of expected hazards, it is important that a determination be made "as to which individual or company will have the primary responsibility for implementing additional safety requirements applicable to their specialty."[635]

4.3 Transocean did not apply its More Rigorous Corporate Risk Management Policies to the Deepwater Horizon and Macondo Well

This section shows that Transocean offered minimal internal guidance and unclear expectations of the risk management tools its personnel should use for an offshore operation or facility, and the more rigorous ones were not applied at the Macondo well. Transocean claims not to have used the more rigorous ones because US regulations did not require them.[636]

Transocean's rig crews manage risk with the THINK planning process (Section 1.8.3), a hierarchical approach with levels of risk assessment that depended on factors such as the complexity and potential safety impact of the task.[637] As the complexity and severity of the potential risk increases, responsibility should shift from the rig crew to further up the organizational hierarchy, and the company should use more rigorous risk management approaches, including HAZOP/HAZID, Major Accident Hazard Risk Assessment (MAHRA; sometimes referred to as MHRA or Major Hazard Risk Assessment), and the Health Safety and Environmental (or safety) case and operations integrity case (OIC) (see Figure 4-1 and Table 4-1).

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[633] API RP 76 has been cited as a potentially helpful document in "developing guidelines for contractor selection" in API Recommended Practice 75 that was made mandatory in offshore regulations post-Macondo. See Volume 4, Section 2.1 for more discussion.

[634] Note that API 76 has not been updated since 2007 or revised in the aftermath of the Macondo incident. API Recommended Practice 76, 2nd ed., *Contractor Safety Management for Oil and Gas Drilling and Production Operations*, November 2007 (, reaffirmed January 2013), p 1.

[635] It should be noted that the language used in API RP 76 revolves around permissive "should" and not "shall" requirements. Also, API 76 has not been updated since 2007 or revised in the aftermath of the Macondo incident; API Recommended Practice 76, 2nd ed., *Contractor Safety Management for Oil and Gas Drilling and Production Operations*, November 2007 (reaffirmed January 2013), p 1.

[636] See text in Section 4.3.1.1.; Internal Company Document, Transocean. *Investigations - Hazard Studies*, July 29, 2010, p TRN-INV-03403088.

[637] Internal Company Document, Transocean. *Health and Safety Policies and Procedures Manual*, Issue 03, Revision 07, HQS-HSE-PP-01, December 15, 2009, Risk Management Think Planning Process, see Exhibit 4942, BP-HZN-2179MDL00132218 - 20, http://www.mdl2179trialdocs.com/releases/release201302281700004/Farr_Daniel-Depo_Bundle.zip (accessed October 7, 2015).

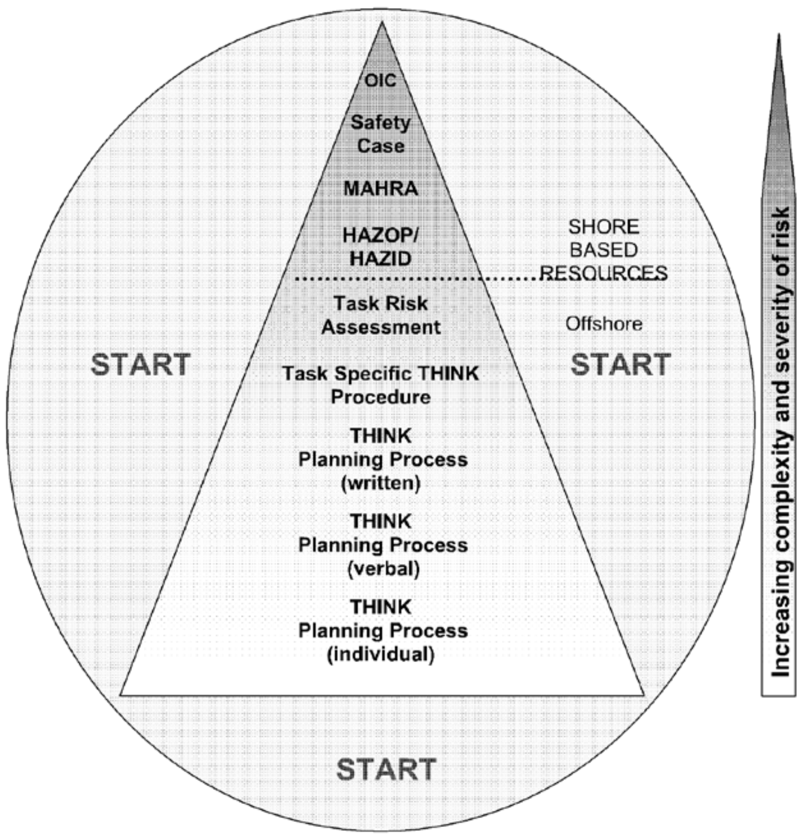

Figure 4-1. Transocean's Levels of Risk Management. The higher level risk management approaches were applied to activities with greater complexity and severity of risk. [638]

[638] *Ibid.*, BP-HZN-2179MDL00132220.

Table 4-1. Shore-based risk management tools as identified and described in Transocean's *Health and Safety Policies and Procedures Manual-Level*.

Risk Management Tool	Transocean Description[639]
Hazard Identification (HAZID)/ Hazard and operability (HAZOP)	A HAZID study is the structured, systematic risk assessment of an activity in order to identify the hazards associated with it. A HAZOP study is used to identify health, safety, and environmental hazards and operability issues for equipment or systems to reduce risks to ALARP. HAZOPs are primarily used during a design stage.
Major Hazard Risk Assessment (MAHRA)	Demonstrates that the company has identified the major hazards of an installation, qualitatively assessed the risk associated with those hazards, and identified the preventive and mitigating controls necessary to reduce the risk to ALARP.
Safety Case	A summary of the installation, installation management, and company safety management system, showing the company has identified and evaluated all major hazards that may affect the installation and has appropriate means for controlling risks of those hazards.
Operation Integrity Case (OIC)	Assures that the company has identified major and other workplace hazards, assessed the risks associated with these hazards, and possesses the necessary controls to reduce the risk to as low as reasonably practicable. A person is assigned to each identified control. The OIC process is based on the Company Management System.

These tools, requiring varying levels of analysis and organizational responsibility, should assist in identifying and managing needed safeguards. For the Macondo well, scant evidence exists that Transocean used any of these risk management tools to adequately assess hazards and implement effective controls to manage loss-of-well control risks.

4.3.1 Transocean Lacks Implementation Guidance for its Risk Management Tools

The Transocean Health and Safety Manual (HSE Manual) in effect at the time of the incident provided little guidance on the selection of risk management tools and their requirements. For the higher level risk tools, Transocean merely states that every vessel in the fleet must have a current version of the MHRA, Safety Case, or OIC. [640] Of these three tools, Transocean does not describe which tool is required under given conditions except to say that countries such as the UK use the Safety Case to demonstrate that risks are ALARP.[641] While the Transocean HSE Manual indicates that these three tools should be used where the severity and complexity of risk "increases" (Figure 4-1), it provides no direction about their benefits for major accident prevention under different risk conditions. In April 2010, Transocean commissioned Lloyd's Register to review its safety management systems.[642] Lloyd's Register reported that Transocean's

[639] *Ibid.*, BP-HZN-2179MDL00132229.

[640] *Ibid.*

[641] *Ibid*.

[642] Internal Company Document, Transocean. *An Independent Review of CMS and SMS, Client: Transocean*, April 9, p 11, 2010,TRN-INV-02825041.

offshore workforce was confused about the risk management hierarchy and that the workers viewed the tools as poorly described and lacking guidance on "when and how [the tools] should be applied." The report found that while Transocean's risk management procedure required quantifying hazards and reducing risks to ALARP, the management system lacked a procedure to do so.

The various levels of Transocean's risk management hierarchy were all intended to demonstrate that risks were reduced to ALARP.[643] However, Transocean did not use the good practice test for ALARP for the Deepwater Horizon rig or the Macondo well project, which requires that the incremental sacrifice (in terms of cost, time, etc.) be grossly disproportionate to the incremental risk reduction achieved. Rather Transocean stated that ALARP "requires personnel to consider the various risk reduction measures (additional controls) and determine if the effort and cost of those measures justify the additional amount of risk reduction obtained."[644] By eliminating the gross disproportionality test, Transocean expressly allowed risk reduction to carry less weight and cost factors to play a greater role in the ALARP determination.

BP notes that traditional risk assessments are not appropriate for managing the risk of low probability, high consequence major accident events, requiring instead a different strategy that does not lead to excluding them from further risk reduction efforts (see Section 4.4.1).

4.3.1.1 Transocean Identified Risk Mitigation Tool Weaknesses Post Incident

Despite the high severity of known risks in exploring high pressure/high temperature wells in deep water, like Macondo, the only Transocean higher level risk management activity completed was a generic Major Hazard Risk Assessment (MHRA) for the Deepwater Horizon rig.[645] While Transocean's HSE Manual required a review and update of the MHRA,[646] the Horizon MHRA had not been revised since 2004, nearly six years before the Macondo incident. The purpose of the MHRA was to "demonstrate that adequate controls were in place so that HSE risks on the Deepwater Horizon can be considered both tolerable and ALARP." The MHRA examined a number of hazards using a generic risk matrix that defined the categories of severity and likelihood.[647] Ultimately, this led to a designation that a well

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[643] Internal Company Document, Transocean. *Health and Safety Policies and Procedures Manual*, Issue 03, Revision 07, HQS-HSE-PP-01, December 15, 2009, Demonstrating Risks are ALARP, see Exhibit 4942, BP-HZN-2179MDL00132229, http://www.mdl2179trialdocs.com/releases/release201302281700004/Farr_Daniel-Depo_Bundle.zip (accessed October 7, 2015).

[644] *Ibid*.

[645] Internal Company Document, Transocean. *Major Accident Hazard Risk Assessment Deepwater Horizon*, Revision 01, August 29, 2004, TRN-MDL-01184581, http://www.mdl2179trialdocs.com/releases/release201303141200012/TREX-02188.pdf (accessed October 7, 2015).

[646] Internal Company Document, Transocean. *Health and Safety Policies and Procedures Manual*, Issue 03, Revision 07, HQS-HSE-PP-01, December 15, 2009, Risk Management Think Planning Process, see Exhibit 4942, BP-HZN-2179MDL00132229, http://www.mdl2179trialdocs.com/releases/release201302281700004/Farr_Daniel-Depo_Bundle.zip (accessed October 7, 2015).

[647] The likelihood categories were based on the subjective determination of the personnel involved. For a medium likelihood, an event such as a blowout would have had to occur on the Horizon. Low likelihood was assigned if the staff knew the event occurred in industry. The report has no justification for using the categories or the significant gap between "known to have occurred in the industry" and "occurs on this rig." Based on this subjective approach, the MHRA concluded that while the consequences of a well blowout were judged to be

blowout was a "medium risk" for the Deepwater Horizon and required review, but Transocean did not issue recommendations for the well blowout hazard under its scheme.[648] (See also Volume 2, Section 5.1.1.) Despite the critical role of manual activation of the BOP in ensuring the BOP can act as a physical barrier against a well kick or blowout,[649] Transocean has no record that it identified, evaluated, and implemented the necessary corresponding human and process controls.

Post-incident, Transocean technical personnel concluded that the MHRA approach was less effective than what other countries require and observed an absence of a Macondo bowtie[650] analysis to address safety barriers.[651] A Transocean outside risk consultant agreed, noting that the use of MHRA is "not as good as the bowties," in part as they are not "user friendly" and do not address barrier effectiveness or circumstances that could compromise barriers.[652] The Transocean DWH Investigation team identified that regulatory requirements to undertake more in-depth analysis of major hazard events influenced the level of analysis actually conducted by the company.[653] The comments from the Transocean investigation team portray the use of MHRA as a minimum compliance approach—Transocean will use the more effective approach only if the regulatory regime requires it. This minimal compliance approach undermines Transocean's claim of reducing major accident risk to ALARP. If the same company recommends and uses a more effective risk management approach for the same activity, then the less rigorous approach clearly is not ALARP.

"extremely severe" based on the fact that no blowout had occurred on the Deepwater Horizon, the likelihood of occurrence was low.

[648] Internal Company Document, Transocean. *Major Accident Hazard Risk Assessment Deepwater Horizon*, Revision 01, August 29, 2004, TRN-MDL-01184597 and TRN-MDL-01184589 - 91, http://www.mdl2179trialdocs.com/releases/release201303141200012/TREX-02188.pdf (accessed October 7, 2015).

[649] Volume 2, Section 2.2.

[650] Bowtie diagrams are introduced in Volume 2, Section 4.2.1. A bowtie diagram (also referred to simply as a bowtie) is a visual tool that depicts the relationships between hazards, barriers, and the major accident events the barriers are intended to prevent.

[651] Internal Company Document, Transocean. *Investigations - Hazard Studies*, July 29, 2010, TRN-INV-03403088.

[652] Email from Operations Manager, Marex, to Deepwater Horizon Investigation Team, Transcoean, Subject: FW: Champion's - Major Hazard Risk Assessment or Safety Case, May 13, 2010, TRN-INV-02872965. The email specifically states "barrier effectiveness, escalation." 'Escalation' factors are commonly used to describe barrier threats, see Lewis, S.; Smith, K. *Lessons Learned From Real World Application of hte Bow-tie Method*, American Institute of Chemical Engineers 2010 Spring Meeting 6th Global Congress of Process Safety, San Antonio, TX, March, 2010.

[653] Internal Company Document, Transocean. *Investigations - Hazard Studies*, July 29, 2010, p TRN-INV-03403088.

4.4 Post-Texas City Refinery Disaster, BP Developed but Macondo did not Benefit from the Robust Corporate Risk Management System

The 2007 Baker Panel and CSB reports[654] issued in the wake of the 2005 BP Texas City refinery accident led to a renewed global emphasis on process safety performance for many high-hazard industries and regulators beyond the oil refining sector. Two major lessons with broad implications from both reports were (1) the necessity to focus on process safety separate and distinct from personal safety and (2) the influential power of corporate leadership and organizational culture in driving continual process safety improvement.[655]

The Baker Panel report recommended that BP implement "an integrated and comprehensive process safety management system that systematically and continuously identifies, reduces, and manages process safety risk."[656] BP agreed to adopt the Baker Report recommendations, establishing a Board reporting process to track progress to implementation. BP also responded to findings and recommendations from the CSB and Baker Panel by developing an overhaul of its corporate safety management system approach to its entire global operations. It termed this approach the BP Operating Management System Framework or OMS, which in 2008 replaced the business-wide HSE management system Getting Health, Safety, and Environment Right (GHSER).[657] The BP Group Chief Executive Tony Hayward asserted "the operating management system (OMS) is fundamental to delivering safe and reliable operating activities in BP."[658]

The CSB Texas City report noted that GHSER, the OMS predecessor, listed "expectations" encompassing both personal safety and some limited process safety elements, but the reporting requirements to corporate leaders focused on personal safety, which weakened BP's ability to prevent the Texas City incident.[659] In contrast, OMS addresses both process and personal safety in its risk approach and included a larger collection of process safety-related policies and engineering and technical practices that represented, as a whole, a more structured and rigorous approach to major accident prevention. BP

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[654] The Baker Panel. *The Report of the BP US Refineries Independent Safety Review Panel;* January, 2007; http://www.csb.gov/assets/1/19/Baker_panel_report1.pdf (accessed October 7, 2015).; USCSB, 2007. *Refinery Explosion and Fire, Texas City, TX, March 23, 2005*, Report No. 2005-04-I-TX, http://www.csb.gov/assets/1/19/CSBFinalReportBP.pdf (accessed October 7, 2015), March 2007.

[655] Hopkins, A. Failure to Learn - the BP Texas City Reginery Disaster; CCH Australia Limited: 2009; pp 63-64.

[656] The Baker Panel. *The Report of the BP US Refineries Independent Safety Review Panel;* January, 2007; p xvi. http://www.csb.gov/assets/1/19/Baker_panel_report1.pdf (accessed October 7, 2015).

[657] Internal Company Document, BP. *The BP Operating Management System Framework, Part 1, An Overview of OMS*, Version 2, November 3, 2008, BP-HZN-2179MDL00333196, see Exhibit 2352 http://www.mdl2179trialdocs.com/releases/release201302281700004/Lynch_Richard-Depo_Bundle.zip (accessed October 7, 2015).

[658] *Ibid*., p 2, BP-HZN-2179MDL00333198.

[659] USCSB, 2007. *Refinery Explosion and Fire, Texas City, TX, March 23, 2005,* Report No. 2005-04-I-TX, p 149, http://www.csb.gov/assets/1/19/CSBFinalReportBP.pdf (accessed October 7, 2015), March 2007.

explicitly approved these policies for implementation "across the BP Group"[660] and intended to apply them to onshore and offshore operations, including drilling and completions.[661]

Under OMS, BP required the systematic identification of process safety hazards, risk assessment, and risk reduction measures at the plant, process, and people levels.[662] OMS's risk approach required an annually updated risk register that identified specific safety and environmental risk reduction measures.[663] Implementing OMS was intended to include at least an annual gap assessment of the entity's operations based on the OMS guidance and related standards at all levels of the organization.[664] The standards included Group Engineering Technical Practices, which defined minimum engineering and operations process safety corporate standards for reducing risks, including Integrity Management,[665] a Hazard and Operability Study,[666] Inherently Safer Design,[667] and Layers of Protection Analysis (LOPA).[668] As the CSB shows in recently published investigation reports, policies like these have the potential of more robustly reducing process safety risk.[669] Other risk management practices that BP required included BP's

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[660] BP Group management is the global corporate management responsible for business operations, including exploration and production (E&P).

[661] Internal Company Document, BP. *Gulf of Mexico SPU Operating Plan (OMS Handbook)*, December 3, 2008, BP-HZN-2179MDL00333155, http://www.mdl2179trialdocs.com/releases/release201305171200030/TREX-002908.pdf (accessed October 7, 2015).

[662] *Ibid*.

[663] Internal Company Document, BP. *The BP Operating Management System Framework, Part 2, Elements of Operating including Group Essentials*, Issue 2, November 3, 2008, see Exhibit 2352, BP-HZN-2179MDL00333245, http://www.mdl2179trialdocs.com/releases/release201302281700004/Lynch_Richard-Depo_Bundle.zip (accessed October 7, 2015).

[664] *Ibid*.

[665] "This practice provides requirements for designing, constructing, operating and maintaining […] floating structures throught their lifecycle. The intent is to prevent loss of containment, structural failure or unintended release of stored energy;" Internal Company Document, BP.

[666] Internal Company Document, BP. *GP 48-02 Hazard and Operability (HAZOP) Study*, June 12, 2008, BP-HZN-CSB00181666.

[667] Internal Company Document, BP. *GP 48-04 Inherently Safer Design (ISD)*, June 5, 2008, BP-HZN-CSB00181764, "Inherently safer design (ISD) is a way of thinking differently from traditional hazard management. Instead of identifying hazards and adding layers of protection to prevent and minimise hazards, inherently safer design first challenges whether the hazard can be eliminated completely or reduced in severity."

[668] Internal Company Document, BP. *GP 48-03 Layers of Protection Analysis (LOPA)*, June 5, 2008, "This GP describes the method used to evaluate the effectiveness of independent protection layer(s) in reducing the likelihood or severity of an undesirable event." BP-HZN-CSB00181723.

[669] USCSB, 2013. *Final Investigation Report: Chevron Richmond Refinery Pipe Rupture and Fire, Richmond, CA, August 6, 2012*, Report No. 2012-03-I-CA, http://www.csb.gov/assets/1/19/Chevron_Interim_Report_Final_2013-04-17.pdf (accessed October 7, 2015), April 2013.; USCSB, 2014. *Catashtrophic Rupture of Heat Exchanger, Anacortes, WA, April 2, 2010*, Report No. 2010-08-I-WA, http://www.csb.gov/assets/1/7/Tesoro_Anacortes_2014-May-01.pdf (accessed October 7, 2015), May 2014.

Major Accident Risk Process[670] and the Drilling and Well Operations Practice (DWOP). [671] Both are detailed in this section.

4.4.1 OMS Roll-out Lags Macondo Well Planning and Drilling—Related Safety Practices were not Effectively Applied at the Macondo Well

BP pledged to implement OMS as a response to the Texas City recommendations across all operations. As indicated on the timeline in Figure 4-2 BP first announced OMS in 2006, with piloting of the new system beginning in 2007 and large company rollout in 2008.[672] In 2008, BP CEO Tony Hayward stated at an annual general meeting for shareholders, "Our intense focus on process safety continues. We are making good progress in addressing the recommendations of the Baker Panel and have begun to implement a new Operating Management System across all of BP's operations."[673] By 2009, BP announced rollout was 80% complete businesswide, and specifically in the Gulf of Mexico by December 2009.[674]

[670] Internal Company Document, BP. *BP Group Engineering Technical Practices, Major Accident Risk (MAR) Process, GP 48-50*, June 5, 2008, BP-HZN-2179MDL00407937, http://www.mdl2179trialdocs.com/releases/release201302281700004/TREX-01734.pdf (accessed May 22, 2015).

[671] Internal Company Document, BP. *GP 10-00 Drilling and Well Operations Practice*, Issue 1, October 2008, "This document contains the practices that have been agreed by BP management as current and relevant for drilling and well operations." BP-HZN-BLY00034504, http://www.mdl2179trialdocs.com/releases/release201304110900026/TREX-06121.pdf (accessed May 26, 2015).

[672] See BP Sustainability Reviews from 2006 – 2008 at http://www.bp.com/en/global/corporate/sustainability/about-our-reporting/Sustainability-report/sustainability-report-archive.html (accessed March 3, 2016).

[673] Hayward, T. *Tony Hayward's speech at the 2008 Annual Genearl Meeting*, Docklands, London, April 17, 2008; see Exhibit 6015, http://www.mdl2179trialdocs.com/releases/release201302281700004/Hayward_Anthony-Depo_Bundle.zip (accessed 7 2015, October).

[674] See BP Sustainability Reviews from 2008 – 2010 at http://www.bp.com/en/global/corporate/sustainability/about-our-reporting/Sustainability-report/sustainability-report-archive.html (accessed March 3, 2016).

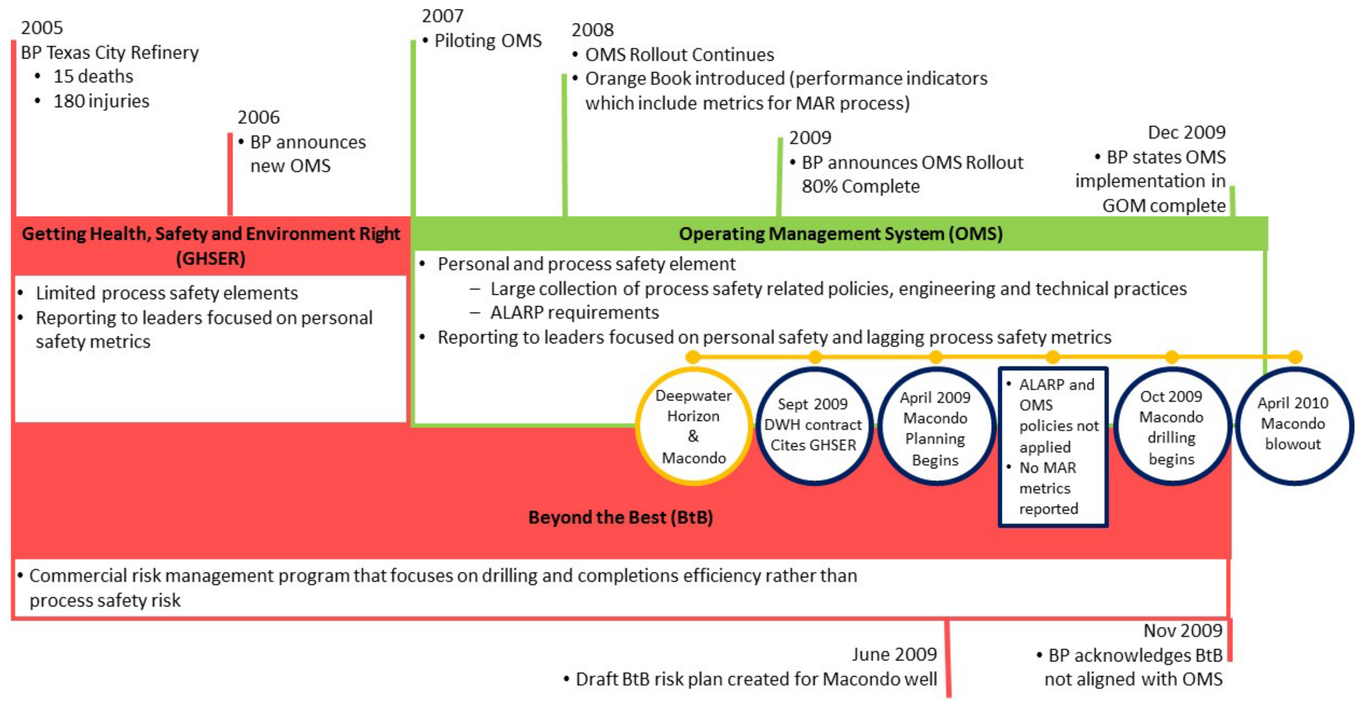

Figure 4-2. OMS Rollout at BP, 2006-2009.

BP's guidance indicates that the OMS requirements would be applicable to contractor-owned rigs,[675] but the "delivery of HSSE [health, safety, security and environment] would be accomplished through the drilling contractor's Safety Management System (SMS)."[676,677] Even though BP did not require

[675] For example, BP's *Gulf of Mexico SPU, Drilling and Completions OMS Implementation Terms of Reference* states that "OMS is not an option; it is a requirement … OMS applies to all operations and premises, controlled or owned by BP and sites operated or controlled on BP's behalf … For GoM D&C this document serves to define the activities planned for 2009 to ensure clarity around how OMS will apply to both BP-owned and contractor-operated and contractor-owned and operated rigs and further how the organization is currently conforming to OMS expectations." Internal company document, BP, *Gulf of Mexico SPU Drilling and Completions OMS Implementation Terms of Reference*, February 13, 2009, BP-HZN-2179MDL00369586, see Exhibit 0784 http://www.mdl2179trialdocs.com/releases/release201302281700004/Grounds_Cheryl-Depo_Bundle.zip (accessed October 7, 2015).

[676] Hearing before the Hearing before the U.S. District Court for the Eastern District of Louisiana under the Multi-District Litigation docket MDL No. 2179, June 29, 2011, see Mogford Designations Vol 2 pp 22 - 25, http://www.mdl2179trialdocs.com/releases/release201302281700004/Mogford_John-Depo_Bundle.zip (accessed October 7, 2015); Hearing before the U.S. District Court for the Eastern District of Louisiana under the Multi-District Litigation docket MDL No. 2179, June 21, 2011, see Baxter Designations Vol 1 pp 26 - 27, http://www.mdl2179trialdocs.com/releases/release201302281700004/Baxter_John-Depo_Bundle.zip (accessed October 7, 2015).

[677] Internal Company Document, BP. *Gulf of Mexico SPU Drilling and Completions The Way We Work*, 2200-T2-PM-RP-000001, May 12, 2009, p 24, BP-HZN-2179MDL00394896,

Transocean to directly apply OMS in lieu of its own management system, OMS expressly applied to BP's drilling projects with contracted rigs in the GoM in two key ways:

1. OMS applied to BP's well drilling planning and execution activities, "performed under the control or supervision of BP, or on behalf of BP"; and[678]
2. BP's Drilling and Well Operations Practice (DWOP) requires a well control bridging document; thus, BP's GoM Drilling and Completion (D&C) procedures required that the parties execute a bridging document to align BP and the drilling contractors' safety management system.[679]

Consequently, while contractors do not have to adopt OMS verbatim, its associated technical practices do apply to contracted wells like Macondo. Unfortunately, as indicated in Figure 4-2, OMS requirements were just starting for D&C during the initial Macondo planning stages and when the well was first drilled.[680] The CSB found no evidence that BP retroactively initiated OMS elements at Macondo that could have impacted risk management at the well. The following sub-sections describe those OMS examples.

4.4.2 Macondo Risk Analysis Lacked BP ALARP Requirements

Before Macondo, BP did not apply the Baker and CSB process safety lessons learned that led it to adopt OMS. Rather, it employed the pre-Texas City "Beyond the Best (BtB) Common Process" for contracted rigs.[681] BtB was a commercial risk management approach for D&C projects that "focused on improving drilling and completions efficiency."[682] BtB had a typical project management stage-gate approach that

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http://www.mdl2179trialdocs.com/releases/release201302281700004/Lacy_Kevin-Depo_Bundle.zip (accessed October 7, 2015).

[678] Internal Company Document, BP. *GP 10-00 Drilling and Well Operations Practice*, Issue 1, October 2008, Section 1.3, p A-4, BP-HZN-BLY00034514, http://www.mdl2179trialdocs.com/releases/release201304110900026/TREX-06121.pdf (accessed May 26, 2015).

[679] Internal Company Document, BP. *Gulf of Mexico SPU Drilling and Completions The Way We Work*, 2200-T2-PM-RP-000001, May 12, 2009, p 24, BP-HZN-2179MDL00394896, http://www.mdl2179trialdocs.com/releases/release201302281700004/Lacy_Kevin-Depo_Bundle.zip (accessed October 7, 2015).; Internal Company Document, BP. *GP 10-00 Drilling and Well Operations Practice*, Issue 1, October 2008, Section 15.2.17, p B-10, BP-HZN-BLY00034545, http://www.mdl2179trialdocs.com/releases/release201304110900026/TREX-06121.pdf (accessed May 26, 2015).

[680] Additionally, as communicated in a CSB interview, "we [D&C] had just started this year [2010] with [OMS]. And we were in the process of rolling it out to the organization."

[681] Beyond the Best was developed in 2001 and was described as having "passed the test of time," Internal Company Document, BP. *Exploration and Production, Drilling and Completions, Beyond the Best Common Process*, June 2008, p 2, BP-HZN-2179MDL00333309, see Exhibit 6066 http://www.mdl2179trialdocs.com/releases/release201302281700004/Hayward_Anthony-Depo_Bundle.zip (accessed October 7, 2015).; Internal Company Document, BP. *GoM Drilling and Completions; GoM D&C Operating Plan/Local OMS Manual*, 2200-T2-DM-MA-0001, November 1, 2009, p 22, BP-HZN-MBI00193469, http://www.mdl2179trialdocs.com/releases/release201302281700004/TREX-06065.pdf (accessed October 7, 2015).

[682] Internal Company Document, BP. *Exploration and Production, Drilling and Completions, Beyond the Best Common Process*, June 2008, p 7, BP-HZN-2179MDL00333314, see Exhibit 6066 http://www.mdl2179trialdocs.com/releases/release201302281700004/Hayward_Anthony-Depo_Bundle.zip (accessed October 7, 2015).

defined risk not in terms of process safety, but as "uncertain future events" which could have "an impact on the delivery of well objectives."[683] The outputs of the process were to be recorded in a risk register where impact types could be categorized under safety and environment, but other commercial impact types were listed as well, such as cost and schedule.[684]

The November 2009 version of the GoM Drilling and Completions Local OMS Manual recognized that the BtB risk management approach needed to align with OMS.[685] While BtB listed commercial impacts, BP's Group Defined Practice (GDP) for *Assessment, Prioritization and Management of Risk*, GDP 3.1 – 0001, issued in 2008, focused specifically on "Health, Safety, Security and Environmental (HSSE) and operating risks in projects."[686] The Group practice emphasized the implementation of risk reduction action plans with deliverables and timelines for completion. It recommended the hierarchy of controls to assess the effectiveness of risk reduction measures and referenced BP's Layers of Protection Analysis practice as a tool.[687] Post-incident, the former D&C Vice President and a senior process safety engineer acknowledged the BtB approach did not meet the requirements of examining the HSSE impacts in Group Defined Practice 3.1 and that the BtB risk register provided "limited direction."[688]

BP D&C was moving to the consistent use of a tool that examined HSSE risk, but the required transition to the new BP Risk Assurance Tool (BP RAT), occurred for GoM D&C after developing the Macondo well risk register. Thus the BtB tool was used.[689] Also the risk management practices for the GoM

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[683] *Ibid*., p 54, BP-HZN-2179MDL00333361.

[684] Internal Company Document, BP. *Risk Register and Action Tracking Sheet for E&P Projects (Macondo),* Risk Rating Matrix: Type of Impact, p 12, see Exhibit 4189 http://www.mdl2179trialdocs.com/releases/release201302281700004/Jassal_Kalwant-Depo_Bundle.zip (accessed October 7, 2015).

[685] Internal Company Document, BP. *GoM Drilling and Completions; GoM D&C Operating Plan/Local OMS Manual*, 2200-T2-DM-MA-0001, November 1, 2009, p 22, BP-HZN-MBI00193469, http://www.mdl2179trialdocs.com/releases/release201302281700004/TREX-06065.pdf (accessed October 7, 2015).

[686] Internal Company Document, BP. *GDP 3.1-0001 Assessment, Prioritization and Management of Risk*, October 14, 2009, pp 6, 16-17, BP-HZN-2179MDL00998896, see Exhibit 8013 http://www.mdl2179trialdocs.com/releases/release201302281700004/Yilmaz_Barbara-Depo_Bundle.zip (accessed October 7, 2015).

[687] *Ibid*.

[688] Hearing before the Hearing before the U.S. District Court for the Eastern District of Louisiana under the Multi-District Litigation docket MDL No. 2179, May 4, 2011 pp 109-112, http://www.mdl2179trialdocs.com/releases/release201302281700004/Grounds_Cheryl-Depo_Bundle.zip (accessed October 7, 2015).; Hearing before the Hearing before the U.S. District Court for the Eastern District of Louisiana under the Multi-District Litigation docket MDL No. 2179, April 17, 2013 pp 9305-9307, http://www.mdl2179trialdocs.com/releases/release201303141200012/O'Bryan_Patrick-Depo_Bundle.zip (accessed October 7, 2015).

[689] Hearing before the Hearing before the U.S. District Court for the Eastern District of Louisiana under the Multi-District Litigation docket MDL No. 2179, April 17, 2013 p 9306, http://www.mdl2179trialdocs.com/releases/release201303141200012/O'Bryan_Patrick-Depo_Bundle.zip (accessed October 7, 2015).

Strategic Performance Unit (SPU)[690] were not scheduled to align with GDP 3.1-0001 until June 2010, after the Macondo accident.[691]

When BP developed the Macondo risk register, its GoM D&C draft Risk Management Plan noted that using the BtB risk tool was a fragmented approach lacking consistency.[692] The draft plan found significant issues with D&C's use of BtB, including lack of a single point of accountability, no clear roles and responsibilities, and little understanding of what OMS entails and how it impacts the risk management process.[693] The draft plan also noted that aggregating risks was difficult, a finding that would affect efforts to identify companywide process safety indicators (see Chapter 3.0).[694] Similar to the lack of HSSE impacts listed in the Macondo risk register, the draft plan found in many cases that "major hazard and accident risks are not included in register and subsequently not addressed as expected."[695] Despite these findings, the Macondo risk register completed later that month was not reviewed or revised to address HSSE risk consistent with GDP 3.1-0001.

The outputs of the risk register for the Macondo well were used to create a risk rating matrix. BP determined in the Macondo risk matrix that the impact of an uncontrolled well control event—just considering cost—would be "medium,"[696] judged to be $1-3 million based upon the team's subjective evaluation that comparable events were within their direct experience.[697] However, the case was not a well control event involving a kick and blowout, but rather a lost wellbore due to an unspecified problem within the well, presumably due to stuck pipe or lost circulation; in fact, both did occur earlier in the Macondo well.[698] The risk register also listed PP/FG (pore pressure/fracture gradient) uncertainty as a

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[690] BP divided its operating segments such as exploration and production into regional Strategic Performance Units or SPUs. The drilling of the Macondo well was conduct in BP's Gulf of Mexico.

[691] Internal Company Document, BP. *Gulf of Mexico SPU, Operating Plan (OMS Handbook)*, Revision 1, 2000-T2-OP-PL-0001, March 1, 2010, p 13, BP-HZN-2179MDL01160046, see Exhibit 3893 http://www.mdl2179trialdocs.com/releases/release201302281700004/Armstrong_Ellis-Depo_Bundle.zip (accessed October 7, 2015).

[692] The draft plan was based on interviews with D&C team leads and personnel responsible for managing risk; Internal Company Document, BP. *Gulf of Mexico SPU; GoM D&C; Risk Management Plan; Assessment, Recommendations and Implementation Plan*, Revision B, 2200-T2-PM-RP-000000, January 1, 2010, p 6, BP-HZN-2179MDL01793825, see Exhibit 4165 http://www.mdl2179trialdocs.com/releases/release201302281700004/Jassal_Kalwant-Depo_Bundle.zip (accessed October 7, 2015).

[693] Internal Company Document, BP. *Gulf of Mexico SPU; GoM D&C; Risk Management Plan; Assessment, Recommendations and Implementation Plan*, Revision B, 2200-T2-PM-RP-000000, January 1, 2010, pp 6-9, BP-HZN-2179MDL01793825-28, see Exhibit 4165 http://www.mdl2179trialdocs.com/releases/release201302281700004/Jassal_Kalwant-Depo_Bundle.zip (accessed October 7, 2015).

[694] *Ibid.*, p 7, BP-HZN-2179MDL01793826.

[695] *Ibid.*, p 7, BP-HZN-2179MDL01793826.

[696] *Ibid.*, p 7, BP-HZN-2179MDL01793826.

[697] *Ibid.*, p 7, BP-HZN-2179MDL01793826.

[698] National Commission on the BP Deepwater Horizon Oil Spill and Offshore Drilling. *Chief Counsel's Report: The Gulf Oil Disaster;* Feburary 17, 2011; p 59.

risk, implying a possible kick,[699] but one that would be controllable and therefore a "medium" risk for cost.

BP used an ALARP tool in the risk matrix to determine the need for risk reduction. For the moderate category, risk reduction was required only "where cost beneficial."[700] On that basis, BP accepted the well control risk for the Macondo project and proposed no additional actions. BP's approach minimized the risk of an uncontrolled kick or blowout. Ultimately, there was no evaluation of barriers and their effectiveness to prevent or mitigate such events. Despite BP's ALARP requirements, no documentation shows that BP performed any analysis that well control safeguards were effective and that safety risk was driven to as low as reasonably practicable.

BP had not yet applied its own OMS framework to its deepwater operations in the geologically difficult Gulf of Mexico, a clear example of failure to implement ALARP even to the risk level of its own safety standards.

4.4.3 BP's Major Accident Risk (MAR) Process was not Implemented

BP determined that traditional strategies for managing risk did not adequately address high consequence-low frequency events, so it developed the MAR Process. Acknowledging resources to reduce risk are finite, the MAR process requires the company to prioritize efforts to continually drive down risk of accidents.[701] The method for an MAR study starts by identifying and quantifying the likelihood of potential major accident events and their consequences.[702] The MAR Process allows for risk assessment across a group of multiple facilities.[703] For offshore operations, this includes risk scenarios like riser unloading events and blowouts.[704] The goal of the MAR study is to evaluate preventive and mitigative controls, and show that MAR is "on a steady decline."[705] Ultimately, the leader of each BP Operation, such as D&C, is accountable for ensuring a MAR study is completed, reviewed, and the results communicated to the appropriate level.[706]

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[699] See Volume 1, Section 2.1 for discussion of pore pressure/fracture gradient.

[700] Internal Company Document, BP. *Gulf of Mexico SPU; GoM D&C; Risk Management Plan; Assessment, Recommendations and Implementation Plan*, Revision B, 2200-T2-PM-RP-000000, January 1, 2010, p 7, BP-HZN-2179MDL01793826, see Exhibit 4165 http://www.mdl2179trialdocs.com/releases/release201302281700004/Jassal_Kalwant-Depo_Bundle.zip (accessed October 7, 2015).

[701] Internal Company Document, BP. *BP Group Engineering Technical Practices, Major Accident Risk (MAR) Process, GP 48-50*, June 5, 2008, pp 9-10, BP-HZN-2179MDL00407945-46, http://www.mdl2179trialdocs.com/releases/release201302281700004/TREX-01734.pdf (accessed May 22, 2015).

[702] *Ibid*,, p 13, BP-HZN-2179MDL004074949.

[703] *Ibid.*, p 17, BP-HZN-2179MDL004074953.

[704] *Ibid.*, p 24, BP-HZN-2179MDL00407960.

[705] *Ibid*, p 55, BP-HZN-2179MDL00407991.

[706] *Ibid.*, p 12, BP-HZN-2179MDL00407948.

The MAR Process applied to contractors and required that an MAR study be conducted with the cooperation of the contractor.[707] In January 2010, BP identified loss of well control, specifically blowouts, as one of the two highest MAR risks for D&C in the GoM and BP.[708] While BP included Transocean's Deepwater Horizon in the "high risk" category as part of its MAR review,[709] BP did not apply the MAR process or perform an MAR study with the Deepwater Horizon or other contracted rigs.[710] This inaction disregarded the fact that contracted rigs represented the greater percentage of BP's well blowout risk (see Call-out Box). As a result, BP used the MAR approach to identify actions plans that included developing barrier effectiveness tools and identifying controls and recovery measures to prevent and respond to loss of well control events; however, these action plans only applied to BP-owned drilling rigs.

If BP had worked with Transocean to develop an MAR study, it could have examined a Transocean 2009 report that expressed riser unloading events as "the biggest concern" when identifying areas for improvement.[711] Transocean experienced six such events in the previous year.[712] Transocean's report recommended preventing the riser unloading events by "treating every positive indicator as a kick, [and] shutting in the well quickly."[713] BP and Transocean could have used that analysis to improve well control planning, training, and response practices and continually reduce risk of a Macondo-type event.

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[707] Internal Company Document, BP. *BP Group Engineering Technical Practices, Major Accident Risk (MAR) Process, GP 48-50*, June 5, 2008, p 9, BP-HZN-2179MDL00407945, http://www.mdl2179trialdocs.com/releases/release201302281700004/TREX-01734.pdf (accessed May 22, 2015). The practice states, "If BP relies on a contractor to perform work that would be subject to GRP STD 01 if performed by BP employees … BP shall, after an appropriate risk assessment, endeavor to conduct a MAR study with the cooperation of the contractor/third party." The drilling and completions work would be subject to GRP STD 01 and OMS if performed by BP personnel so the MAR process should apply to contracted drilling rigs.

[708] Internal Company Document, BP. *BP Gulf of Mexico SPU Annual Engineering Plan, Rev 0*, January 15, 2010, p 27, http://www.mdl2179trialdocs.com/releases/release201304110900026/TREX-02910_NATIVE.pdf (accessed May 22, 2015).

[709] *Ibid*.

[710] Testimony given in the U. S. Districk Court for the Eastern District of Louisiana under the Multi-District Litigation docket MDL No. 2179, July 21, 2011 pp 20-21, see Jassal Designations (BP GoM SPU D&C Integrity Engineer and risk management specialist), http://www.mdl2179trialdocs.com/releases/release201302281700004/Jassal_Kalwant-Depo_Bundle.zip (accessed May 22, 2015).

[711] Internal Company Document, Transocean. *Annual Report - 2009 Well Control Events & Statistics 2005 to 2009*, p 7, TRN-INV-00760060, http://www.mdl2179trialdocs.com/releases/release201303211200016/TREX-05649.pdf (accessed May 22, 2015).

[712] *Ibid*.

[713] *Ibid*.

Contracted Rigs Represented Major Portion of BP's Drilling Operation Loss of Well Control and Blowout Risk

In March 2010, BP described itself as the largest oil and gas operator in the Gulf of Mexico, possessing approximately 30% of the total deepwater GoM production.[a] This included 8 platforms, which were BP assets, and 22 other producing fields for which BP held some financial interest. In early 2010, BP stated that in the Gulf of Mexico Thunder Horse was the only BP-owned drilling rig and that the remaining rigs were contracted mobile offshore drilling units (MODUs) operated by Transocean.[b] Worldwide, BP was the most significant client for Transocean based on operating revenue in 2008[c] and Transocean managed three-fourths of the global MODU drilling operations for BP.[d]

The BP GoM Drilling and Completion SPU maintained responsibility for two major accidents risks: loss of well control and loss of drilling riser.[e] BP recognized that "[b]oth risks represent major exposure to GoM SPU with a severity level of D and above." Severity levels were measured in terms of health, safety and environment. A Level D event was at the low end of the impact scale representing a "very major health/safety incident" with the potential for 3 or more fatalities. Level A was the most severe representing an event "comparable to the most catastrophic health/safety incidents ever seen in industry" with the potential for 100 or more fatalities. Because both risks involved activities conducted by drilling contractors, Transocean's GoM well drilling and completion activities represented a major percentage of BP's risk in these areas.

[a] Internal Company Document, BP. *Gulf of Mexico SPU, Operating Plan (OMS Handbook)*, Revision 1, 2000-T2-OP-PL-0001, March 1, 2010, BP-HZN-2179MDL01160037, see Exhibit 3893 http://www.mdl2179trialdocs.com/releases/release201302281700004/Armstrong_Ellis-Depo_Bundle.zip (accessed October 7, 2015).

[b] Internal Company Document, BP. *BP Gulf of Mexico SPU, Annual Engineering Plan 2009*, Revision 0, 2010-T2-PM-PR-2009, January 15, 2010, BP-HZN-2179MDL02206804 to BP-HZN-2179MDL02206805, see Exhibit 4170 http://www.mdl2179trialdocs.com/releases/release201302281700004/Jassal_Kalwant-Depo_Bundle.zip (accessed October 7, 2015).

[c] Internal Company Document, BP.

[d] Internal Company Document, BP, *Memo from BP's GoM Vice President of Drilling and Completion: Transocean Improvement Plan*, January 23, 2008, BP-HZN-CEC055713, see Exhibit 7205 http://www.mdl2179trialdocs.com/releases/release201302281700004/Baxter_John-Depo_Bundle.zip (accessed October 7, 2015).

[e] Internal Company Document, BP, *Drilling & Completions Recommended Practice*, 2200-T2-RM-DC-000000, January 20, 2010, BP-HZN-2179MDL00332282, see Exhibit 1975 http://www.mdl2179trialdocs.com/releases/release201302281700004/Jassal_Kalwant-Depo_Bundle.zip (accessed October 7, 2015).

4.4.4 Absent Reporting Requirements

BP's October 2008 E&P OMS Drilling and Well Operations Practice (DWOP) applied to well drilling and completions, requiring the DWOP to "form part of the contractual relationship between BP and the service providers."[714] The DWOP required that the contractor's safety management system "incorporate or be supplemented to address the requirements of the OMS framework."[715] The purpose of DWOP was to support BP's goal of "no accidents, no harm to people and no damage to the environment."[716] Since BP considered the DWOP critical for conformance with its OMS framework, all staff and contractors had to be knowledgeable in the DWOP.[717] However, the 2008 DWOP training was not initially rolled out to BP's own GoM Well Site Leaders until April 14-15, 2010, just a week prior to the well blowout.[718]

While BP applied the DWOP to the Macondo well, in part by MOCs where BP personnel sought deviations from the DWOP, the company did not implement key substantive provisions of the DWOP related to Macondo causal factors. DWOP well control practices require completion of a well control incident report in BP's Tr@ction electronic incident reporting system.[719] The BP OMS framework requires incident investigation reports to identify system-level causes and to establish safety improvement action items with specific due dates tracked to completion.[720] However, BP did not issue in Tr@ction an investigation report related to the March 8, 2010 well control incident (described in Section 2.3). Similar to the Macondo blowout, that incident also involved a delayed response to a well kick.[721] Post-incident, a BP Macondo Well Site Leader indicated that the "incident was not recorded in Tr@ction, as this was not the normal process in the Deepwater GoM." He further indicated he "did not know that reporting this type of an incident was a requirement of DWOP."[722]

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[714] Internal Company Document, BP. *GP 10-00 Drilling and Well Operations Practice*, Issue 1, October 2008, pp A-4, A-7, BP-HZN-BLY00034504, http://www.mdl2179trialdocs.com/releases/release201304110900026/TREX-06121.pdf (accessed May 26, 2015).

[715] *Ibid*., p A-7.

[716] *Ibid*., p A-1.

[717] *Ibid*., 1, A-4.

[718] Internal Company Document, BP. *BP Incident Investigation Team - Note of Interview with John Guide*, July 1, 2010, p 7, BP-HZN-BLY00124223, see Exhibit 0153 http://www.mdl2179trialdocs.com/releases/release201304041200022/Sepulvado_Murry-Depo_Bundle.zip (accessed October 7, 2015).

[719] Internal Company Document, BP. *GP 10-00 Drilling and Well Operations Practice*, Issue 1, October 2008, Section 15.2.12, p B-10, BP-HZN-BLY00034545, http://www.mdl2179trialdocs.com/releases/release201304110900026/TREX-06121.pdf (accessed May 26, 2015).

[720] Internal Company Document, BP. *The BP Operating Management System Framework, Part 2, Elements of Operating including Group Essentials*, Issue 2, November 3, 2008, Section 4.4, Incident Management, p 32, BP-HZN-2179MDL00333255, http://www.mdl2179trialdocs.com/releases/release201303071500008/TREX-45002.pdf (accessed October 7, 2015).

[721] BP Wells Team Leader for the Deepwater Horizon in his interview with the BP investigation team acknowledged that BP did not initiate a formal investigation of the March 8 incident that included a significant delay in well kick response for 35-40 minutes. Internal Company Document, BP. *BP Incident Investigation Team - Note of Interview with John Guide*, July 1, 2010, p 12, BP-HZN-BLY00124228, see Exhibit 0153 http://www.mdl2179trialdocs.com/releases/release201304041200022/Sepulvado_Murry-Depo_Bundle.zip (accessed October 7, 2015).

[722] Internal Company Document, BP. *BP Incident Investigation Team - Note of Interview with John Guide*, July 1, 2010, p 12, BP-HZN-BLY00124228, see Exhibit 0153 http://www.mdl2179trialdocs.com/releases/release201304041200022/Sepulvado_Murry-Depo_Bundle.zip (accessed October 7, 2015).

4.4.5 BP did not implement OMS-required Application to Contracted Rigs through Contracts and Bridging Documents

BP's Group OMS emphasized that OMS was "relevant to all projects as well as facilities, sites and operations" and included provisions on its application to contractors.[723] BP identified that OMS:

> shall as needed, include and apply contract provisions such that the work is carried out in a way that supports and is consistent with BP's application of OMS to BP's Operating activities. Where such contract provisions are not included in an existing contract, BP shall endeavor to amend the contract as needed, immediately or on renewal.

BP, however, did not amend its Deepwater Horizon contract with Transocean to ensure every drilling activity "supports and is consistent with" OMS. BP did not implement OMS provisions when it amended health and safety requirements in Deepwater Horizon contract on September 28, 2009.[724] In fact, the 2009 Amendment 38 included new safety management provisions introducing the outdated GHSER safety program.[725] Elsewhere, BP developed HSSE contract provisions for offshore drilling units that included OMS requirements;[726] however, it did not apply these provisions to the Deepwater Horizon contract. The 2009 amendment had no references to OMS, the DWOP, or other BP post-Texas City engineering technical practices. The contract did contain some process safety requirements described as "minimum conditions" attached as an Exhibit D, including the use of ALARP, the hierarchy of controls, risk assessment tools such as HAZID and HAZOP, and Major Accident Hazard Identification and Assessment. However, the listed requirements were not scheduled to apply until the renewal date of September 18, 2010, about five months after the Macondo incident.[727]

BP and Transocean each had their own safety management systems, but they agreed that Transocean's safety management systems would govern well drilling operations on the DWH, as supplemented by BP through a bridging document.[728] Transocean's Quality, Health, Safety, and Environment manager for North America asserted that a bridging document should provide "primacy" for operators and drillers in

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[723] Internal Company Document, BP. *The BP Operating Management System Framework, Part 4, OMS Governance and Implementation*, Issue 2, November 3, 2008, Section 4, Applicability and Deviation Requirements, p 7, BP-HZN-2179MDL00333144, see Exhibit 2352 http://www.mdl2179trialdocs.com/releases/release201302281700004/Lynch_Richard-Depo_Bundle.zip (accessed October 7, 2015).

[724] Internal Company Document, BP. *Amendment No. 38 to Drilling Contract No. 980249*, September 28, 2009, see Exhibit 1488, BP-HZN-CEC041519, http://www.mdl2179trialdocs.com/releases/release201302281700004/Hayward_Anthony-Depo_Bundle.zip (accessed October 7, 2015).

[725] *Ibid*., BP-HZN-CEC041493 and BP-HZN-CEC041513.

[726] Internal Company Document, BP.

[727] Internal Company Document, BP. *Amendment No. 38 to Drilling Contract No. 980249*, September 28, 2009, see Exhibit 1488, BP-HZN-CEC041519, http://www.mdl2179trialdocs.com/releases/release201302281700004/Hayward_Anthony-Depo_Bundle.zip (accessed October 7, 2015).

[728] Internal Company Document, BP/Transocean. *Drilling Contract RBS-8D Semisubmersible Drilling Unit, Contract No. 980249*, December 9, 1998, Section 3.0: Compatibility of HSE Management Systems, BP-HZN-MB100021887-8, http://www.mdl2179trialdocs.com/releases/release201305171200030/TREX-004271.pdf (accessed October 7, 2015).

determining which aspects of each companies' safety management systems would govern.[729] He stated, "[B]oth Transocean and BP have safety management systems. And we can't run both systems onboard one vessel. So in general terms, one would have to be selected over another. And there are times when one group's management system supersedes that of another and that would be clarified if it were the agreed wish of both parties use one management system . . . day-to-day. But [if] there is an issue or two that the other system was desired to be used, you could express those wishes in a bridging document."[730]

For Macondo, the two companies created a five-page bridging document signed by senior managers from each organization. It sought to address gaps between BP's and Transocean's safety management systems. Ultimately, the resulting bridging document was only envisioned for personal safety issues without mention of process safety items, such as the TSTPs or SIDs (discussed in Section 1.8) or other measures aimed at major accident prevention.[731] For example, the heart of the bridging document, the HSE Management Systems Table, referenced only six issues, five of which focused on personal safety:

- Fall Protection
- Personal Protective Equipment
- Travel
- General Safe Work Practices
- Incident Reporting
- Dive Operations

[729] Hearing before the U.S. District Court for the Eastern District of Louisiana under the Multi-District Litigation docket MDL No. 2179, March 24, 2011 pp 177-178, http://www.mdl2179trialdocs.com/releases/release201302281700004/Canducci_Gerald-Depo_Bundle.zip (accessed October 7, 2015).

[730] *Ibid*., p 178.

[731] BP's GoM SPU *Drilling and Completions The Way We Work* well project management guidance states that the GoM SPU "Safe Practices Manual" (SPM) would be bridged to the contractor's safety management systems. BP described the SPM as containing "BP-approved standards for personal safety, MOC and industrial hygiene," but the pre-Texas City manual first issued in 2002 contained little mention of process safety and no reference to the OMS framework. Internal Company Document, BP. *Gulf of Mexico SPU Drilling and Completions The Way We Work*, 2200-T2-PM-RP-000001, May 12, 2009, p 27, BP-HZN-2179MDL00394922, see Exhibit 0760 http://www.mdl2179trialdocs.com/releases/release201302281700004/Lacy_Kevin-Depo_Bundle.zip (accessed October 7, 2015).

The fifth issue, incident reporting, can cover both personal and process safety issues, but its utility depends largely upon what the receiver of that information does with the incident report (e.g., whether the information reported was used for learning and continual improvement or simply tallied and reported).

Nothing in the bridging document distinguished process safety or MAP.[732]

The bridging document notes some minimal process safety-type concepts in a section "Additional BP Requirements." For example, the General Safety Work Practices had an additional requirement to conduct an MOC for any worker asked to work in excess of 28 continuous days within a 42-day period. Another addition, under Incident Reporting, required "All Serious Incidents (HIPO, DAFWC, Medical Treatment and Restricted Work) will be investigated and led by Transocean and supported by BP to identify root cause and corrective actions within 30 day time frame set forth in BP reporting guidelines." But other than the HIPO category, these serious incidents typically capture personal safety events. All other additional BP requirements more plainly focused on personal safety (e.g., secondary fall protection requirements, respiratory protection program requirements, life vests, etc.).

API Bulletin 97,† Well Interface Control Document Guidelines *seek to help address deficiencies in the bridging process between leaseholders and drilling contractors. Included in the Bulletin are recommendations about what type of information should be shared between the leaseholder and the drilling contractor regarding well construction and rig-specific operating guidelines. The Bulletin intends to align the leaseholder's safety and environmental management system (SEMS) with the drilling contractor's safe work practices. Covered in this guidance is a recommended full informational exchange, along with other opportunities for alignment between the parties—a step forward compared to what occurred during the bridging process between BP and Transocean prior to drilling Macondo. However, API 97 is a Bulletin and not a recommended practice, and the language used in the Bulletin is permissive with the pervasive use of "should" denoting that its recommendations are at the discretion of the company.*

†American Petroleum Institute (API) Bulletin 97, Well Construction Interface Document Guidelines, First Edition, (November 2013), p. iii.

The bridging document also included a commitment to form an "HSE Steering Team" of representatives from both companies, with specific reference to the positions required for participation. They would meet quarterly to resolve "gaps across the different business units in the GoM operating area" to "review

[732] Even Section 4.0 of the bridging document itself, entitled "Revision Log," confirms that the four documented updates to the bridging document focused on personal safety, with attention paid to items such as fall protection, scaffolding, electrical safety and hazardous materials, or rudimentary administrative matters such as a change in document custodian. Internal Company Document, BP/Transocean. *BP Gulf of Mexico Transocean Offshore Deepwater Drilling Inc. North America HSE Management System Bridging Document*, September 8, 2008, see Exhibit 0948, p 5, BP-HZN-BLY00076264, http://www.mdl2179trialdocs.com/releases/release201302281700004/Canducci_Gerald-Depo_Bundle.zip (accessed October 7, 2015).

and implement new programs" and to delete or change existing programs.[733] However, the bridging document sets no dates for forming the HSE Steering Team and establishes no goals or objectives for reviewing safety surrounding well operations or making adjustments to anything as part of a continual improvement process.

In the months leading to the Macondo blowout, BP became aware of bridging document problems. In February 2010, BP commissioned a work team to investigate the effectiveness of bridging documents used at contractor rigs.[734] That team determined that most bridging documents were outdated or poorly understood and noted that many contractors' supervisors had a poor understanding of their own safety management systems.[735]

Multinational Audit of Safety Management Systems

The Macondo blowout prompted numerous international responses, including a multinational audit in the North Sea in 2012/2013 to assess the incorporation of organizational factors into operator and drilling contractor safety management systems.[a] A major conclusion from the audit was the lack of role clarity in bridging documents intended to identify and address potential gaps between the operator and drilling contractor's safety management systems. The audit team found:

- *The quality and content of the companies' bridging documents varied;*
- *Individuals directly affected by the bridging documents insufficiently verified their content; and*
- *Client auditing of the drilling contractor's safety management system was either nonexistent or focused upon equipment.*

The multinational audit focused on systems and standards, such as those found in well control manuals, and the audit's findings are similar to ones presented in this report.

[a] North Sea Offshore Authorities Forum (NSOAF). *Multi-National Audit Human and Organisational Factors in Well Control 2012-2013;* http://www.hse.gov.uk/offshore/nsoaf.pdf (accessed May 2016, 2015). Eleven audits of jack-up and semi-submersible rigs were completed in Netherlands, Denmark, Germany, Norway, and the UK during 2012/2013.

[733] Internal Company Document, BP/Transocean. *BP Gulf of Mexico Transocean Offshore Deepwater Drilling Inc. North America HSE Management System Bridging Document*, September 8, 2008, see Exhibit 0948, p 3, BP-HZN-BLY00076262, http://www.mdl2179trialdocs.com/releases/release201302281700004/Canducci_Gerald-Depo_Bundle.zip (accessed October 7, 2015).

[734] Hearing before the U.S. District Court for the Eastern District of Louisiana under the Multi-District Litigation docket MDL No. 2179, July 27, 2011 p 75, see Yilmaz Designations Vol 2 http://www.mdl2179trialdocs.com/releases/release201302281700004/Yilmaz_Barbara-Depo_Bundle.zip (accessed October 7, 2015).

[735] Internal Company Document, BP. *Improving Control of Work within Drilling & Completions*, Feburary 2010, slide 6, BP-HZN-MBI00109889, see Exhibit 0951 http://www.mdl2179trialdocs.com/releases/release201302281700004/Yilmaz_Barbara-Depo_Bundle.zip (accessed October 7, 2015).

4.5 BP Did Not Pursue Its 2008 Initiative to Engage GoM D&C Contractors in Risk and Barrier Management

In May 2008, BP's GoM Drilling and Completions (D&C) Leadership Group met with a new D&C Vice President to emphasize the importance of process safety and contractor engagement in preventing major accidents such as well blowouts. The intent of the meeting was to emphasize that deepwater drilling has special challenges that include reliance on manual crew intervention to prevent a major accident and contractor engagement for risk management.[736]

A BP presentation at the meeting, *Major Accident and Risk Management,* was prompted by findings and major themes expressed in the Baker Panel Report and recent major BP incidents, including:[737]

1. the importance of process safety culture that continually reduces risk;
2. defined expectations and accountability; and
3. the effective use of leading and lagging indicators.

The presentation identified that the scope of BP's risk management policy included major drilling projects where BP was the operator. The objectives included assessing and reducing risk through prevention and control measures using the Major Accident Risk Process with defined key management and engineering accountabilities.[738] Tools included risk registers and process safety ETPs such as HAZOP and LOPA. Key to the presentation was the use of bowtie diagrams with identified independent barriers and controls and the maintenance of safety critical systems. The presentation identified top GoM Strategic Performance Unit (SPU) and D&C risks as safety, environmental, or reputational, with a focus on BP assets.

In response to the question about who is responsible for managing the risk, the leadership presentation answered, "Ultimately it is the BP Wells Team."[739] Another important question addressed was "How do we engage contractors to manage risk?"

The implication was that nearly two years before Macondo, the "Major Accident and Risk Management" presentation provided a structured, robust proposal for strengthening the engagement with contractors to manage risk. The presentation proposed reviewing with contractors existing bowties to identify additional hazards, causes, and barriers. It recommended updating bowties, MAR registers, and risk mitigation plans

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[736] Internal Company Document, BP. *GOM-D&C Major Hazard and Risk Management Leadership Action*, 2008, Slide 3, see Exhibit 2952 http://www.mdl2179trialdocs.com/releases/release201302281700004/Jassal_Kalwant-Depo_Bundle.zip (accessed October 7, 2015).

[737] *Ibid*., Slide 6.

[738] Internal Company Document, BP. *GOM-D&C Major Hazard and Risk Management Leadership Action*, 2008, Slide 23, see Exhibit 2952 http://www.mdl2179trialdocs.com/releases/release201302281700004/Jassal_Kalwant-Depo_Bundle.zip (accessed October 7, 2015).; BP's Major Accident Risk Process, GP 48-50, was an ETP approved for implementation across the BP Group; Internal Company Document, BP. *GP 48-50 Major Accident Risk (MAR) Process*, June 5, 2008, BP-HZN-2179MDL00407937, http://www.mdl2179trialdocs.com/releases/release201302281700004/TREX-01734.pdf (accessed October 7, 2015).

[739] Internal Company Document, BP. *GOM-D&C Major Hazard and Risk Management Leadership Action*, 2008, Slide 19, see Exhibit 2952 http://www.mdl2179trialdocs.com/releases/release201302281700004/Jassal_Kalwant-Depo_Bundle.zip (accessed October 7, 2015).

with contractors as well as agreeing on the use of tools such as the BP risk register and the HAZID analysis.[740] The presentation emphasized the need to agree on risk management roles and responsibilities. Two types of barriers were identified: those BP directly and indirectly controlled under a contract and those the contractor controlled. The presentation noted the importance of potentially modifying existing agreements with contractors to assure conformance with the safety requirements. The path forward with contractor engagement was to "review risks and determine if there are any additional risks, barriers, mitigations … update register and bowties accordingly."[741] A responsibility matrix was presented for risk tasks, deliverables, and the role of the BP Wells Team and contractor (see Figure 4-3). The process intended to identify which barriers and controls BP and the contractor would manage and to demonstrate how they managed them.

The promise of the more robust approach presented at the Leadership Action presentation was not fulfilled. In the same month as the D&C Leadership Group presentation, BP personnel proposed a work plan for future risk assessment activities, use of risk tools, and contractor engagement,[742] but little evidence exists that BP pursued the path forward for contractor engagement presented to BP's D&C Leadership Team.[743,744] In fact, the use of bowties in the BP organization itself was not officially rolled out until January 2010,[745] and no document shows that either BP or Transocean used bowties or allocated barrier responsibility for risk management or communication at the Macondo well.

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[740] Internal Company Document, BP. *GOM-D&C Major Hazard and Risk Management Leadership Action*, 2008, Slide 52, see Exhibit 2952 http://www.mdl2179trialdocs.com/releases/release201302281700004/Jassal_Kalwant-Depo_Bundle.zip (accessed October 7, 2015).

[741] *Ibid*., Slide 57.

[742] Email from Engineering Manager, BP, to Drilling Engineering Team Leader, BP, Subject: IM Bowties - Let's try and simplify, May 22, 2008, BP-HZN-2179MDL01002350, see Exhibit 4187 http://www.mdl2179trialdocs.com/releases/release201302281700004/Jassal_Kalwant-Depo_Bundle.zip (accessed October 7, 2015).

[743] Hearing before the U. S. Districk Court for hte Eastern District of Louisiana under the Multi-District Litigation docket MDL No. 2179, July 21, 2011 pp 77-79, see Jassal Designations (BP GoM SPU D&C Integrity Engineer and Risk Management Specialist) http://www.mdl2179trialdocs.com/releases/release201302281700004/Jassal_Kalwant-Depo_Bundle.zip (accessed May 22, 2015).

[744] *Ibid*., pp 78-79.

[745] *Ibid*., p 79.

D&C Teams and Contractor Engagement

Responsibility Matrix

Task	Wells Team	Contractor	IM Team Lead	Deliverable
Internal Review				
Step1 – IM Overview	P		R	Agreed set of requirements and action plan
Step 2 – Review MAR Etc	R		F	ID (a) gaps and agree on MAR, Causes, and Consequences (b) Define how BP will manage barriers and controls
Step 3 – BP managed Barriers/Controls	R		F	
Step 4 – Update Register & Bowties	R		F	Updated risk register and Bowties for MAR
Session With All Contractors (Mini HAZID)				
Step 5 – IM Overview	R	P	F	Agreed set of requirements and action plan
Step 6 – Review MAR, Etc	R	P	F	ID gaps and agree on MAR, Causes and consequences
Step 7 – Review/ID Controls & Gaps	P	R	F/P	ID (a) gaps & agree on Causes, consequences barriers and controls (b) Define how contractor will manage barriers and controls
Step 8 – Contractor managed barriers	P	R	F	
Step 9 – Update Registers & Bowties	R		F	Updated risk register and Bowties for MAR
Step 10 – Action Plan for Roll-out	P	R	F	Formulate plan covering procedure, equipment
Step 11 – Demonstrate barriers	P	R	F	Demonstrate how Barriers and controls are being managed

R = Responsible; P = Participate: F = Facilitate

Integrity Management
Reducing Risk in GoM

Figure 4-3. May 2008 BP D&C Teams and Contractor Engagement from the Major Hazard and Risk Management Presentation to the D&C Leadership group. The presentation, two years before the Macondo incident, envisioned a detailed allocation of risk and barrier management responsibilities between BP and the contractor. BP did not implement the responsibility matrix approach.

4.6 Conclusion

Both this chapter and Section 1.8 demonstrate that BP and Transocean detailed daily operational tools and overarching corporate policies regarding how to handle major accident risk in a number of key areas during drilling operations. Also, internal BP and Transocean policies required risks to be reduced to an ALARP level. Unfortunately, these policies did not translate to practices at Macondo despite the bridging process intended to clarify safety roles and responsibilities while identifying potential gaps in the operative safety management systems. Instead, personal safety considerations predominated over process safety and major accident prevention, and the bridging document failed to look ahead in a meaningful way toward major accident prevention.

A fundamental question emerges: How in the United States can BP, Transocean, or any company operating in the areas subject to BSEE jurisdiction be required to implement effective risk management practices? Volume 4 addresses this question in depth, but the basic answer is to enact regulatory requirements for more robust risk management approaches, including demonstrated risk reduction to ALARP and explicit safety accountability by all parties creating the risk.

In the US, both the leaseholder/operator and the drilling contractor have well control responsibilities under offshore regulations.[746] But before the Macondo incident, the leaseholder/operator was held as the primary entity responsible for the safe conduct of offshore exploration and production in the US GoM. There was little, if any, history of citations against offshore contractors despite their legal responsibility for well control actions.[747]

As Volume 4 details, post-Macondo, contractors such as Transocean and Halliburton were cited for a number of safety violations, and BSEE, the offshore regulator, asserted that drilling contractors and other well service providers can be cited for future safety violations.[748] However, the key federal offshore safety regulations—the Safety and Environmental Management Systems (SEMS) Rule[749] issued in the wake of the Macondo incident—does not directly apply to contractors, does not have a requirement for demonstrated risk reduction to an ALARP level (or similar), and does not clarify major hazard roles and responsibilities of the operators and drilling contractors when it comes to design and operational risk.

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[746] This was true at the time of Macondo and present day, 30 C.F.R. § 250.400, 401.

[747] BSEE. Inspection and Enforcement: Incidents of Noncompliance, http://www.bsee.gov/Inspection-and-Enforcement/Enforcement-Programs/Incidents-of-Non-Compliance/ (accessed October 7, 2015).

[748] Notification of Incident(s) of Noncompliance, with respect to offshore operations in the Gulf of Mexico, off the coast of Louisiana. 00071 IBLA 2013-137 (District Supervisor, District Office, Bureau of Safety and Environmental Enforcement September 25, 2015).

[749] 30 C.F.R. § 250 Subpart S (2011).

5.0 Corporate Governance, the Influence of Shareholders and Public Disclosure of Process Safety Information

Chapter 5.0 Overview

This chapter examines the corporate governance approaches by both BP and Transocean to demonstrate both companies' efforts to manage personal safety and commercial risk without an equivalent focus on the effective management of barriers and safety management systems for preventing major accident events. This chapter explores the influence of shareholders in managing process safety and advances in corporate governance in other international offshore regions.

The importance of a corporation's board of directors cannot be overstated, especially when the corporation is involved in a high-hazard industry such as offshore drilling. The BP and Transocean boards of directors demonstrated varying levels of effectiveness in efforts aimed at helping their respective companies avoid a catastrophic event like the Macondo blowout. Despite efforts to manage process safety and major accident risk, the two companies' boards adopted governance approaches that emphasized personal safety and commercial risk without assuring process safety and major accident prevention. In part, these approaches are illustrated through a study of shareholder communications, required US Securities and Exchange Commission (SEC) [750] reporting, and other public information released by both companies. Some elements of this analysis are further explored in other chapters of Volume 3, including Chapter 2 (Organizational Learning), Chapter 3 (Indicators), Chapter 4 (Risk Management), and Chapter 6 (Safety Culture). This chapter primarily explores publicly available records and compares BP and Transocean's corporate governance approaches with best practices in other international jurisdictions with active offshore drilling, illustrating broader offshore sector issues concerning corporate governance and securities disclosures that merit further discussion and improvements.

As Macondo made clear, major accident events (MAEs) can interfere with drilling operations and production, damage reputation, and cause significant financial distress for a company with predictable, negative outcomes.[751] Consequently, corporate boards of directors must act vigilantly in preventing MAEs from their position as the highest echelon of leadership within the company. It is in shareholders' best interests to understand the relevant information needed to assess the companies in which they invest, and to benchmark the process safety performance of such companies. In doing so, shareholders would be positioned to better understand and question companies' business decisions. They can both directly and indirectly help to ensure or improve process safety and major accident prevention efforts of companies engaged in offshore drilling and production. Thus, enhanced reporting not only benefits shareholders, but all stakeholders, including workers, the public, and the environment.

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[750] The SEC is a Federal agency whose mission is "to protect investors, maintain fair, orderly, and efficient markets, and facilitate capital formation." http://www.sec.gov/about/whatwedo.shtml (accessed October 7, 2015).

[751] For example, reduction or elimination of dividend payments, inability to expand or otherwise initiate new profit-making activities, necessity of selling productive assets to raise cash for risk contingencies and potential liabilities, decrease in share price.

This idea is especially important for a company like BP, which suffered several significant process safety incidents in a ten-year period including Grangemouth (2000), BP Texas City (2005), BP Prudhoe Bay (2006), and Macondo (2010). This string of MAEs in such a short time and across different business segments within the company's worldwide operations raises a question as to whether the BP board of directors is sufficiently engaged in process safety matters, and even whether there is a corporate "failure to learn."[752] This is especially true in the BP Texas City incident, investigated independently by the CSB, and by the company itself through the BP US Refineries Independent Safety Review, the Baker Panel, an independent panel which examined BP's US refineries and the company's safety culture. Both reports recommended that the BP board deepen its commitment to adopt process safety policies, take preventive actions, and monitor indicators.[753] Despite BP board governance improvements since BP Texas City, serious problems remain that leave the company vulnerable to a Macondo-type of event.

For its own part, Transocean's board exhibited some of the same flawed approaches as BP, but exhibited less of a willingness to engage in self-reflection and the desire to make significant improvements concerning responsibility for the incident.

This chapter also explains that SEC reporting requirements for companies like BP and Transocean impede shareholder efforts to examine process safety matters related to major accident prevention which could impact the investment worthiness of companies working offshore. Inconsistent or even sometimes obscure information emerges from such companies, if at all, in a sometimes cumbersome or more generalized narrative style that avoids more straightforward inclusion of a full slate of health and safety metrics and other critical process data (e.g., leading and lagging process safety performance indicators) across the spectrum of corporate operations and related risk activities. To be clear, both BP and Transocean appeared to satisfy SEC requirements in their disclosures in shareholder communications, and in required reporting with the Commission. Therefore, this chapter more generally explores the information shareholders need to monitor the process safety performance of companies with MAE potential. BP and Transocean are referenced as salient examples to show the weakness of the US regulatory reporting scheme relating to the disclosure of material MAE risks offshore.

Lastly, this chapter describes the relationship between the regulator and the board of directors both in the US and other international regulatory drilling regimes. Various offshore oil and gas regulatory regimes adopted proactive approaches using audits, investigations, published guidance, and training to influence industry at the board level, whereas BSEE's mechanisms for change today are still primarily focused on the facility/site level through permit approvals, dispensations, inspections, compliance audits, accident investigations, and citations stemming from enforcement activities. As a result, BSEE now has an

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[752] Hopkins A. Failure to Learn – The BP Texas City Refinery Disaster; CCH Australia Limited: 2009. See also Reed S. & Fitzgerald A. In Too Deep; John Wiley & Sons: 2011, p. 156 ("The lessons learned at Texas City and Prudhoe Bay apparently had not reached the Gulf of Mexico.")

[753] The Baker Panel. *The Report of the BP US Refineries Independent Safety Review Panel;* January, 2007; p xvi. http://www.csb.gov/assets/1/19/Baker_panel_report1.pdf (accessed October 7, 2015); USCSB, 2007. *Refinery Explosion and Fire, Texas City, TX, March 23, 2005,* Report No. 2005-04-I-TX, Recommendations 2005-4I-TX-R11 to 2005-4I-TX-R13, http://www.csb.gov/assets/1/19/CSBFinalReportBP.pdf (accessed October 7, 2015), March 2007.

opportunity to work with industry more proactively to strengthen the role of boards of directors and to improve corporate governance for publicly traded companies at work in US waters.

5.1 Boards of Directors and Shareholders

5.1.1 What is Corporate Governance?

Corporate governance is broadly defined as "the system by which companies are directed and controlled," or "the whole set of legal, cultural, and institutional arrangements that determine what publicly traded corporations can do, who controls them, how that control is exercised, and how the risks and returns from the activities they undertake are allocated."[754] Shareholders typically vote for individuals to serve on a corporation's board of directors and expect them to serve as the highest echelon of an overall system of managerial activities as well as a means of checks and balances. Rooted in a series of fiduciary duties,[755] once directors are in place, a board must act to protect the best interests of the company as a whole, ensuring its overall success.

Historically, corporate boards have taken a hands-off approach to oversight. Chancellor of the Delaware Court of Chancery and judicial scholar on corporate governance William Allen explained:

> The conventional perception is that boards should select senior management, create incentive compensation schemes and then step back and watch the organization prosper. In addition, board members should be available to act as advisors to the CEO when called upon and they should be prepared to act during a crisis: an emergency succession problem, threatened insolvency or a management buy-out proposal, for example.[756]

Allen went on to challenge this view as inadequate, calling for boards of directors to play a more active role in ensuring the health of an organization:

> This view of the responsibilities of membership on the board of directors of a public company is, in my opinion, badly deficient. It ignores a most basic responsibility: the duty to monitor the

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[754] Clarke, D. C. Nothing But Wind? The Past and Future of Comparative Corporate Governance; *Am. J. Comp. L.* 2011**,** *75,* p 59, *citing* The Committee on the Financial Aspects of Corporate Governance . *The Financial Aspects of Corporate Governance;* "the Cadbury Report," 1992; http://www.icaew.com/~/media/corporate/files/library/subjects/corporate%20governance/financial%20aspects%20of%20corporate%20governance.ashx (accessed October 7, 2015). See generally: The Financial Reporting Council. *The UK Approach to Corporate Governance;* October, 2010; https://www.frc.org.uk/Our-Work/Publications/Corporate-Governance/The-UK-Approach-to-Corporate-Governance.aspx (accessed October 7, 2015).

[755] "A fiduciary duty is a legal duty to act solely in another party's interests. Parties owing this duty are called fiduciaries. The individuals to whom they owe a duty are called principals … A fiduciary duty is the strictest duty of care recognized by the US legal system. Examples of fiduciary relationships include those between a lawyer and her client, a guardian and her ward, *and a director and her shareholders*." (emphasis added) Legal Information Institute, Cornell University Law School, http://www.law.cornell.edu/wex/fiduciary_duty (accessed October 7, 2015).

[756] Martin Lipton & Jay W. Lorsch, *A Modest Proposal for Improved Corporate Governance,* The Business Lawyer, Vol. 48 (November 1992) pp 61-62, citing Chancellor William T. Allen, *Redefining the Role of Outside Directors in an Age of Global Competition,* presented at Ray Garrett, Jr., Corporate and Securities Law Institute, Northwestern University, Chicago (April 1992).

> performance of senior management in an informed way. Outside directors should function as active monitors of corporate management, not just in crisis, but continually. They should have an active role in the formulation of the long-term strategic, financial, and organizational goals of the corporation and should approve plans to achieve those goals. They should as well engage in the periodic review of short and long term performance according to plan and be prepared to press for correction when in their judgment there is need.[757]

The "informed way" implies that if a company goal is to avoid major accident events, boards must be equipped with adequate and timely information to question and hold management accountable, or even to assert a course of correction when such challenge is needed. To perform this role, however, at least some number of board members must have adequate levels of relevant education, training, and professional experience to allow them to assess the sufficiency of the information they receive and to challenge executive management, if necessary. This especially applies to independent directors.[758] In this role, boards as a whole, by committees or through individual directors playing specialized leadership roles, can help to shape corporate activity at the highest level (e.g., policies, communications, strategic goals and objectives, mergers and acquisitions, indicators, compensation and incentive pay programs). These decisions help to shape the corporation's overall culture and the degree to which that culture is focused on safety and major accident prevention. (See Chapter 6.)

5.1.2 The Role of Shareholders and their Influence on Corporate Governance

When shareholders become dissatisfied with corporate performance or governance, they can lobby for change either through direct dialogue with the board of directors, for instance, by speaking during open corporate meetings or filing formal shareholder proposals for shareholder vote.[759] These activities, referred to as "shareholder activism," can result in significant change, such as redirecting a company's business strategy (e.g., financial restructuring, spin-offs, acquisitions, increasing dividends) or affecting the organization's behavior as a corporate citizen (e.g., proposals concerning labor practices, political spending, lobbying, social issues, environmental issues).[760] Activists are typically single minority

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[757] Martin Lipton & Jay W. Lorsch, *A Modest Proposal for Improved Corporate Governance*, The Business Lawyer, Vol. 48 (November 1992) pp 61-62, citing Chancellor William T. Allen, *Redefining the Role of Outside Directors In an Age of Global Competition,* presented at Ray Garrett, Jr., Corporate and Securities Law Institute, Northwestern University, Chicago (April 1992).

[758] In defining an independent (also called a non-executive) director, the NYSE notes: "no director qualifies as 'independent' unless the board of directors affirmatively determines that the director has 'no material relationship' with the listed company, either directly or as a partner, shareholder or officer of an organization that has a relationship with the company," while the NASDAQ requires that an independent director "must not be an officer or employee of the company or its subsidiaries or any other individual having a relationship that, in the opinion of the company's board of directors, would interfere with the exercise of independent judgment in carrying out the responsibilities of a director." See generally Larkin, G. *Just What is an Independent Director Anyway?* The Conference Board, September 10, 2010, available at http://tcbblogs.org/governance/2010/09/10/just-what-is-an-independent-director-anyway/.

[759] Cossin, D.; Caballero, J. *Shareholder Activism Background Literature Review;* IMD Global Board Center: July, 2013, pp 5-6.

[760] PwC. Shareholder Activisim: Who, What , When and How?; March, 2015, p 2-4.

investors with large block holdings in a company, or institutional investors with majority holdings,[761] such as mutual, pension, or hedge funds. Labor unions and nonprofit organizations also engage in shareholder activism.[762] Activism occurs because a public company is, after all, owned by its shareholders. Regardless of the size of holdings, shareholders are always free to sell their shares, and non-shareholders can refrain from purchasing shares. Such decisions to sell or to refrain from buying can effectively weaken companies that investors deem to be poor investment choices, decisions which can be prompted through informed decision-making relating to a company's poor process safety practices or other insufficient efforts aimed at major accident prevention, among other issues. Thus, whether through activism or marketplace decisions to buy or sell, shareholders have demonstrated that they have influence.

Scholars acknowledge this reality, and note that a number of such "social controls" can

> indirectly influence industrial safety performance, such as laws and norms for corporate governance that cause companies to inform shareholders and potential investors about corporate activities so they can make informed decisions about financial risks. If the activities are hazardous, these sources of financial support may need to be convinced that their financial risks are held to acceptable levels by evidence of effective safety management, which thereby makes it necessary for companies to develop and implement codes of conduct and safety management practices that adhere to industrial standards and comply with government regulations.
>
> Similarly, corporate governance principles also establish management accountability to these financial stakeholders, and cause companies to take the pragmatic step of securing insurance coverage for losses and liabilities which could arise from accidents and other mishaps. This induces companies to maintain their safety performance at a level sufficient to convince insurers to provide sufficient coverage at affordable rates. Thus, "corporate governance is not only a legal concept but is also embedded in organizational theory." It creates a linkage between financial risk and risks to health, safety, property and the environment and can be an important promoter of safety management.[763]

Numerous high profile organizations, including Yahoo, Staples-Office Depot, Target, and eBay have recently been affected by shareholder activist efforts.[764] Currently, a number of active shareholder resolutions face several major US corporations that focus on issues such as climate change, energy, water scarcity, and sustainability reporting.[765]

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[761] Cossin, D.; Caballero, J. Shareholder Activism Background Literature Review; IMD Global Board Center: July, 2013, p 5.; PwC. Shareholder Activisim: Who, What , When and How? March, 2015, pp 2-4.

[762] Cossin, D.; Caballero, J. *Shareholder Activism Background Literature Review;* IMD Global Board Center: July, 2013, p 5.

[763] Lindoe, P; Baram, M; Renn, O, *Risk Governance of Offshore Oil and Gas Operations*, Cambridge University Press, 2014; pp 36-37; citing OECD (2012) *Corporate Governance for Process Safety*. OECD: Paris; CERES; Swiss Re (2011) *Operational Hazards in the Oil and Gas Industry*. Zurich; and De Groot, C (2009), *Corporate Governance as a Limited Legal Concept*. Wolters Kluwer Law & Business: Amsterdam, p. 128.

[764] Jay, M. Dow-DuPont-Activist Investors story. *AP*, December 14, 2015, http://finance.yahoo.com/news/agitators-behind-dow-dupont-yahoo-214607644.html (accessed December 16, 2015).

[765] "Ceres tracks shareholder resolutions filed by our investor network participants on sustainability-related issues that companies are facing, focusing on climate change, energy, water scarcity, and sustainability reporting. These resolutions are part of broader investor efforts encouraging companies to address the full range of environmental, social and governance issues. The resolutions are filed by some of the nation's largest public pension funds, foundations, and religious, labor and socially responsible investors. Many of the investors are members of Ceres'

Recent examples of successful shareholder activism involve two chemical manufacturers (DuPont Co. and Dow Chemical Co.), and even BP itself. Dow and DuPont recently announced a merger of the two companies to create one new company worth more than $120 billion, after which, the company will split into three separate companies.[766] The companies' chief executives worked with activist investors, including the Trian Fund Management LP (Trian), to plan and execute the deal.[767] As observed by Chris Davis, a lawyer who advises activists, "Seven months ago, DuPont had beaten Trian in a proxy fight, a victory some thought could mark a pushback on activism's rise. Now, Trian looks vindicated. America's corporate landscape is being permanently reshaped under the influence of two of its pre-eminent activists."[768]

In the case of BP, CCLA Investment Management formally led an effort to form a coalition of investor groups called "Aiming for A." Their proposal, Strategic Resilience for 2035 and Beyond, sought to influence BP, as well as Dutch oil and gas major Royal Dutch Shell, to adopt a strategic approach to the challenges posed by climate change and the desire to lower carbon emissions. The coalition put forward this resolution "to address our interest in the longer term success of the Company, given the recognised risks and opportunities associated with climate change."[769] The shareholders requested annual reporting about "ongoing operational emissions management … low-carbon energy research and development (R&D) and investment strategies; relevant strategic key performance indicators (KPIs) and executive incentives; and public policy positions relating to climate change." BP's board of directors supported the resolution, and after 98% in-favor vote, the resolution passed. One member group of the coalition, the Church of England, recently noted on its website that the positive reception offered by both BP and Shell in an area like this is "completely unprecedented,"[770] while a spokesperson for another member of the coalition, the Chair of the Local Authority Pension Fund Forum said: "This development from BP is a clear example of the effectiveness of shareholder engagement backed by investor commitment … taking an active approach to long-term risk, sustainability and carbon management issues has benefits both for our beneficiaries and for our underlying investments."[771]

These examples demonstrate the potential shareholder influence on a board of directors.

Investor Network on Climate Risk (INCR)," http://www.ceres.org/investor-network/resolutions (accessed December 17, 2015).

[766] Benoit, D. Dow, DuPont Deal Cements Activists' Rise. *The Wall Street Journal*, December 11, 2015, http://www.wsj.com/articles/dow-dupont-deal-cements-activists-rise-1449882586 (accessed December 16, 2015).

[767] *Ibid*.

[768] *Ibid*.

[769] Ceres. Investor Network > Sharehodler Resolutions > BP Report Annually on Carbon Asset Risk Mitigation , http://www.ceres.org/investor-network/resolutions/bp-report-annually-on-carbon-asset-risk-mitigation (accessed December 17, 2015).

[770] BP Board Advises Shareholders to Support Resolution on Climate Change at 2015 AGM, https://www.churchofengland.org/media-centre/news/2015/02/bp-board-advises-shareholders-to-support-resolution-on-climate-change-at-2015-agm.aspx (accessed March 2, 2016).

[771] *Ibid*.

5.1.3 Corporate Governance Risk Management and Sustainability

Informed oversight activities by a board of directors includes questioning management about significant risks challenging the company and its ongoing viability in worst-case scenarios. These concerns involve a concept of “corporate sustainability.” At its core, sustainability means that the corporation will remain viable and profitable for its shareholders while providing jobs for employees and products or services needed within the broader economy, but it is also inclusive of other factors reflective of a progressive society**.** For example, the “Dow Jones Sustainability Indexes (DJSI) defines corporate sustainability as ‘a business approach that creates long-term shareholder value by embracing opportunities and managing risks deriving from economic, environmental and social developments.’”[772]

Thus, sustainability can involve an assessment of how environmental stewardship and social policies affect long-term viability of the corporation as it aligns social and environmental demands with the need for profitability, products, and services, and the ability to provide healthy and safe jobs for employees.

At the macro level, risk assessment and management types of activity by boards of directors is termed enterprise risk management (ERM), the process by which a firm determines the major risks it faces and the risk management strategies it deploys to face those risks (e.g., acceptance, mitigation, transfer, elimination).[773] ERM is undeniably a critical board function.

[772] Center for Resilience, Ohio State University, available at http://www.resilience.osu.edu/CFR-site/resilienceandsustainability.htm (accessed on March 8, 2016).

[773] According to the leading ERM framework, designed by the Committee of Sponsoring Organizations of the Treadway Commission (COSO), ERM “is a process, effected by an entity’s Board of Directors, management and other personnel, applied in strategy settings and across the enterprise, designed to identify potential events that may affect the entity, and manage those risks to be within its risk appetite, to provide reasonable assurance regarding the achievement of the entity objectives.” Committee of Sponsoring Organizations. *Enterprise Risk Management – Integrated Framework, Executive Summary;* September, 2004, p 2.

Enterprise Risk Management

According to the Committee of Sponsoring Organizations,† the four broad categories of ERM focus are strategy, operations, reporting, and compliance. They include eight specific activities:

1. *Internal Environment – This activity encompasses the tone of an organization and sets the basis for how an entity's people view and address risk, including risk management philosophy and risk appetite, integrity and ethical values, and the environment in which they operate.*
2. *Objective Setting – Objectives must exist before management can identify potential events affecting their achievement. Enterprise risk management ensures management has in place a process to set objectives and that the chosen objectives support and align with the entity's mission and are consistent with risk appetite.*
3. *Event Identification – The entity must identify internal and external events affecting achievement of its objectives, distinguishing between risks and opportunities. Opportunities are channeled back to management's strategy or objective-setting processes.*
4. *Risk Assessment – The entity analyzes risks, considering likelihood and impact as a basis for determining how to manage them, and they assess risks inherently and residually.*
5. *Risk Response – Management selects risk responses—avoiding, accepting, reducing, or sharing risk—developing a set of actions to align risks with the entity's risk tolerances and risk appetite.*
6. *Control Activities – Management establishes and implements policies and procedures to help ensure the effective risk response.*
7. *Information and Communication – The entity identifies, captures, and communicates relevant information in a form and timeframe that enable people to carry out their responsibilities. Effective communication also occurs in a broader sense, flowing down, across, and up the entity.*
8. *Monitoring – Ongoing management activities and separate evaluations monitor of the entire enterprise's risk management and makes modifications as necessary.*

† COSO describes its mission on its website. "The Committee of Sponsoring Organizations' (COSO) mission is to provide thought leadership through the development of comprehensive frameworks and guidance on enterprise risk management, internal control and fraud deterrence designed to improve organizational performance and governance and to reduce the extent of fraud in organizations." http://www.coso.org/aboutus.htm (accessed October 7, 2015).

The Committee of Sponsoring Organizations (COSO) asserts that boards of directors should:

> discuss with senior management the state of the entity's enterprise risk management and provide oversight as needed. The board should ensure it is apprised of the most significant risks, along with actions management is taking and how it is ensuring effective enterprise risk management. The board should consider seeking input from internal auditors, external auditors, and others.[774]

[774] Committee of Sponsoring Organizations. Enterprise Risk Management—Integrated Framework, Executive Summary; September, 2004; pp 6-7.

A growing trend among US boards of directors is a greater readiness to engage whenever and wherever appropriate to ensure management is effectively leading and managing the many areas of a corporation's business activities.[775] The rationale for that development has been long in the making, but is straightforward: "By acting early and effectively, directors may prevent small problems from growing into a major crisis."[776] In terms of ERM responsibilities, the role of boards "has become increasingly challenging as expectations for board engagement are at all-time highs."[777] COSO recently opined about corporate failures during the last financial crisis, but the statements have broader applicability across the gamut of corporate risk:

> The benefit of hindsight has shown us that boards have a difficult task in overseeing the management of increasingly complex and interconnected risks that have the potential to devastate organizations overnight. At the same time, boards and other market participants are receiving increased scrutiny regarding their role … Boards are being asked—and many are asking themselves—could they have done a better job in overseeing the management of their organization's risk exposures.[778]

So whether through managing a CEO and executive management team, audit and oversight, or establishing corporate goals and objectives or other high-level policies (such as compensation systems and bonus structures), the role of a company's board of directors is multifaceted and ongoing. It is not enough to set certain goals and objectives or to delegate such activities to the CEO and the senior management team. Instead, the board must at least monitor the company's performance with an eye toward policies they have implemented, to ensure they take appropriate actions and achieve anticipated results. Perhaps for this reason, Bob Dudley, shortly after taking over as CEO at BP, instigated a review of BP's compensation practices, especially incentive pay, out of potential concern that the company was incentivizing behaviors contrary to corporate safety goals. Dudley said: "BP is reviewing its compensation practices so that they are aligned with BP's corporate safety goals. While safety has long been a component of the company's performance incentives plan, going forward, all compensation structures are being reviewed to ensure that safety-first behavior is appropriately and permanently incentivized across all of BP's businesses."[779] Mr. Dudley further explained he took this step "to be absolutely clear that safety, compliance and operational risk management is BP's number one priority."[780]

The rationale for board engagement in risk management and corporate sustainability in the offshore drilling sector takes on even more urgency, especially with the benefit of hindsight of a disaster like Macondo. As examples in this chapter indicate, economic, legal, and reputational damages of the magnitude caused by such catastrophic accidents threaten both a company's short-term performance and

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[775] Bussey, J. Governance Grows Up: Governance Grows Up in American Baord Rooms. *The Wall Street Journal*, October 12, 2010, pp 1, 5.

[776] Lipton, M.; Lorsch, J. W. A Modest Proposal for Improved Corporate Governance; *The Business Lawyer* **1992,** *48*, p 62.

[777] Committee of Sponsoring Organizations. Effective Enterprise Risk Oversight: The Role of the Board of Directors; 2009; p 1.

[778] *Ibid*.

[779] BP. *BP's COMMITMENT TO SAFETY*, p 1, December 13, 2010.

[780] *Ibid*., p 3.

long-term viability.[781] In effect, a board of directors' oversight and strategic leadership are vital for process safety and issues concerning major accident events. To be clear, micromanagement is not suggested or appropriate; rather, an engaged board willing and able to meet its oversight responsibility is the key. Boards of directors must be knowledgeable about the major accident risks in a company's operations, and they must insist on access to relevant information to play an active role in overseeing management of those risks and to ensure those risks are communicated appropriately to shareholders and regulators.

5.1.4 The Business Case for Effective Process Safety Oversight

The Organization for Economic Cooperation and Development (OECD) is an intergovernmental organization with representatives from 34 industrialized countries in North and South America, (including the US), Europe, and the Asia and Pacific region, as well as from within the European Commission. OECD meets as a body to coordinate and harmonize policies, discuss issues of mutual concern, and collaborate to respond to international problems.

In June 2012, through its "Environment, Health and Safety Chemical Accidents Program," OECD published the guidance *Corporate Governance for Process Safety: Guidance for Senior Leaders in High Hazard Industries*. OECD instructs "Good process safety management needs the active involvement of senior leaders, and it is important that they are visible within their organisation, because of the influence they have on the overall safety and organisational culture."[782] The document outlines a business case in favor of effective process safety management. Noting significant international incidents such as Bhopal,[783] BP Texas City, and Buncefield,[784] OECD asserts that a growing tide of corporate social responsibility is emerging around the globe, and that regulators, shareholders of companies in high-hazard

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[781] Coburn, J.; Salmon, R.; Grossman, D. *Sustainable Extraction? An Analysis of SEC Disclosure by Major Oil & Gas Companies on Climate Risk & Deepwater Drilling Risk;* CERES: August, 2012; pp 7-8. http://www.ceres.org/resources/reports/sustainable-extraction-an-analysis-of-sec-disclosure-by-major-oil-gas-companies-on-climate-risk-and-deepwater-drilling-risk/view (accessed October 17, 2015).

[782] Organisation for Economic Co-operation and Development (OECD). *Corporate Governance for Process Safety: OECD Guidance for Senior Leaders in High Hazard Industries;* June, 2012; p 9. http://www.oecd.org/chemicalsafety/chemical-accidents/corporate%20governance%20for%20process%20safety-colour%20cover.pdf (accessed October 7, 2015). Note, some existing guidance is unclear whether a term like "senior leadership" includes the board of directors (including independent directors), or is limited to the executive leadership team, or others further down the management chain. Many best practices in this area apply equally well to all levels of leadership, and some are more particularized; however, it is clear that as one considers the corporate hierarchy, the higher the level of leadership, the more appropriate it becomes to apply a higher scope of duties.

[783] On December 3, 1984, a methyl isocyanate (MIC) release at the Union Carbide insecticide plant in Bhopal, India resulted in an estimated 3,800 people that died within days, and tens of thousands that were injured. Eventually, the release killed tens of thousands of people. See http://www.csb.gov/on-30th-anniversary-of-fatal-chemical-release-that-killed-thousands-in-bhopal-india-csb-safety-message-warns-it-could-happen-again-/?pg=4 (accessed June 17, 2015).

[784] On December 11, 2005 a large vapor cloud explosion and multiple tank fires occurred after the overfilling of a tank when unnoticed. The explosion injured 43 people, damaged 22 additional tanks at the site, and $1.5 billion damage in a commercial and residential property; Johnson, D. The Potential for Vapour Cloud Explosions: Lessons from Buncefield; *Journal of Loss Prevention in the Process Industries* **2010,** *23,* pp 921-927.

industries, and citizens alike are all expecting more of business leaders in the modern business environment.[785] Businesses can suffer if they do not meet those expectations. Corporate leaders are expected to manage the risks posed by their businesses alongside other critical factors within their businesses, with severe consequences for failure to do so.[786]

Similar to the work of COSO, OECD reminds that major accidents are just like other significant business risks, especially when considering the integrated nature of many high-hazard businesses.[787] OECD explains that good corporate governance in process safety is not just about avoiding potential negative effects. Key commercial benefits of good process safety management include (1) less downtime and higher plant/facility availability, (2) easier-to-forecast maintenance budgets, (3) longer lifespans for plants/facilities and equipment, (4) improved efficiency and flexibility in operations, (5) enhanced employee, stakeholder-regulator relationships, and (6) improved access to capital and insurance at more attractive rates or premiums.[788] Stated differently, good process safety equates to good business.

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[785] Organisation for Economic Co-operation and Development (OECD). *Corporate Governance for Process Safety: OECD Guidance for Senior Leaders in High Hazard Industries;* June, 2012; pp 8-9. http://www.oecd.org/chemicalsafety/chemical-accidents/corporate%20governance%20for%20process%20safety-colour%20cover.pdf (accessed October 7, 2015).

[786] BP Plc., CEO Bob Dudley recently likened the Macondo blowout to a near-death experience, "Sometimes it takes a near death experience to radically change a company;" US Gulf oil spill nearly ruined BP, says chief Bob Dudley. *BBC News*, January 2, 2016, http://www.bbc.com/news/uk-35210450 (accessed January 15, 2016).

[787]Organisation for Economic Co-operation and Development (OECD). *Corporate Governance for Process Safety: OECD Guidance for Senior Leaders in High Hazard Industries;* June, 2012, pp 8-9. http://www.oecd.org/chemicalsafety/chemical-accidents/corporate%20governance%20for%20process%20safety-colour%20cover.pdf (accessed October 7, 2015).

[788] *Ibid*., pp 9-10.

Commitment to Safety, Sustainable Profits

In the UK, international utility giant Scottish Power demonstrates that a commitment to safety can be part of a strategy toward increased and sustainable profits and total shareholder value—key goals of any high performing corporate board of directors. Judith Hackitt, Chair of the UK HSE, recently cited Scottish Power as an example of a company whose board has "led the way" in demonstrating commitment to safety and reliability from the top to the bottom of the organization, and throughout the process delivered real benefits in terms of both safety and profitability.[a] *With a formal governance model that involves monthly meetings on reviewing process safety dashboard information from the facility level up to the board itself, the company started to "establish ownership and accountability for process safety management" and to foster a corporate culture intentionally designed "to ensure people are always thinking about what could go wrong and never complacent."*[b]

[a] Hackitt, J. *Why Corporate Governance and Why Now?*, Conference on Corporate Governance for Process Safety, Paris, France, June 14-15, 2012; http://www.hse.gov.uk/aboutus/speeches/transcripts/hackitt140612.htm (accessed October 7, 2015).

[b] CSB. CSB Public Hearing: Safety Performance Indicators, Houston, TX, July 23-24, 2012, p 86 http://www.csb.gov/assets/1/19/CSB_20Public_20Hearing.pdf (accessed October 7, 2015); Sedgwick, M.; Wands, A. *The Implementation of Effective Key Performance Indicators to Manage Major Hazard Risks*, CSB Sfaety Performance Indicator Public Hearing, Houston, TX, July 23, 2012. slide 4. http://www.csb.gov/UserFiles/file/Sedgwick%20%28Scottish%20Power%29%20PowerPoint%20-%20printed.pdf (accessed October 7, 2015).

5.1.5 The Need for Better Reporting Illustrated by Consequences Stemming from the Macondo Blowout

The messages to shareholders in annual reports illustrate what a board of directors and senior management team consider necessary to demonstrate the investment value of the company. These reports include a domestic company's 10-K report,[789] a foreign issuer's 20-F report,[790] and any company reports produced for the benefit of shareholders and the public, such as BP's sustainability reports, or annual board performance reports. US reporting regulatory requirements apply to foreign companies, such as BP (United Kingdom) or Transocean (Switzerland), whose stock trades in US markets as American Depositary Shares or American Depositary Receipts.[791]

[789] 10-K reports are comprehensive annual financial reports required by the SEC, the requirements for which are detailed in the Securities and Exchange Act of 1934. http://www.investopedia.com/terms/1/10-k.asp (accessed October 7, 2015).

[790] 20-F reports are comprehensive annual financial reports required by the SEC from "foreign private issuers" who issue equity shares available in US markets, the requirements for which are detailed in the Securities Exchange Act of 1934. *See* http://www.investopedia.com/terms/s/sec-form-20-f.asp (accessed October 7, 2015).

[791] BP Shares trade as American Depositary Shares rather than American Depositary Receipts, which are similar instruments. See http://www.bp.com/en/global/corporate/investors/shareholder-information/managing-your-shares---ads-holders.html. Transocean shares trade as American Depositary Receipts.

BP and Transocean are required to communicate relevant information to shareholders about major hazard risks, especially where information about risks are determined to be material. Failure to do so could lead to liability under Section 10(b) of the Securities Exchange Act of 1934.[792] Failure to disclose material information could also lead to potential civil liability arising from shareholder litigation.[793] The theory in this type of litigation is that insufficient disclosure prevents shareholders from understanding the risk they are taking by purchasing shares at what essentially is an artificially high share price, because the risk associated with the companies' activities could not adequately be factored into the market's assessment of share prices.

In a relevant example, following Macondo, BP shares fell in value by over 48% between April 20, 2010 and June 25, 2010.[794] The slide in share value was compounded by BP's need to set aside money for anticipated litigation costs related to the accident, in both criminal and civil contexts. These funds were to be generated by suspending regular shareholder dividend payments as well as the sale of potentially lucrative oil fields to competitors at a time of rising oil prices.[795] Other costs continue to mount, including a negotiated $18.7 billion dollar settlement the company reached with the US government,[796] along with

http://deepwater.com/investor-relations.html. See generally http://www.investopedia.com/ask/answers/06/adrvsads.asp (all sites accessed October 7, 2015).

[792] Codified at 15 U.S.C. § 78j(b); see also 17 C.F.R. § 240.10b-5, "Employment of Manipulative and Deceptive Practices," which states, in part: "It shall be unlawful for any person, directly or indirectly, by the use of any means or instrumentality of interstate commerce, . . . (b) To make any untrue statement of a material fact *or to omit to state a material fact necessary in order to make the statements made, in the light of the circumstances under which they were made, not misleading* . . ." (Emphasis added.)

[793] Although factual allegations in a complaint cannot be presumed as true, and can only be accepted as fact after litigation on the merits, shareholder litigation pending against both BP and Transocean asserts safety disclosure failures relative to the Macondo blowout. See *Alameda County Retirement Association v. BP* which asserts, inter alia, that shareholder-plaintiffs lost millions of dollars on their BP investments as a result of false and misleading statements made by the defendants regarding the extent of BP's commitment to a "safety first" approach to oil drilling and a "profits first" corporate culture. See Consolidated Complaint, ¶ 2, Case No.: 12-CV-01256, 12-CV-01261, 12-CV01614. Similarly, a suit against Transocean by shareholder-plaintiffs Thomas Yuen and Sumni Ahn accused Transocean of misrepresenting a string of failures involving blowout preventers. This class action suit alleged that false claims by management caused the price of Transocean stock to rise artificially due to a lack of understanding of actual risks, and then to plunge when the truth was later revealed. See Complaint – Class Action, ¶¶ 1, 6 Case No: 2:10-CV-01467-JCZ-SS. The common underpinning of these suits is the fact that the risk of a subsea blowout was well understood by industry, making such information inherently "material," defined as "of such a nature that knowledge of the item would affect a person's decision-making process." *Black's Law Dictionary*, 7th ed. (1999); see also *TSC Industries v. Northway*, 426 U.S. 438, 449 (1976) (must be a substantial likelihood that the reasonable investor would view the disclosure of an omitted fact as having significantly altered the "total mix" of available information in a manner that shareholders would consider relevant to the buying and selling of stocks).

[794] *Alameda County Retirement Association v. BP,* Consolidated Complaint, ¶¶ 399-402, Case No.: 12-CV-01256, 12-CV-01261, 12-CV01614.

[795] BP. *Annual Report and Form 20-F 2011,* p 103 http://www.bp.com/content/dam/bp/pdf/investors/bp-annual-report-and-form-20f-2011.pdf (accessed December 17, 2015); See also, http://dealbook.nytimes.com/2012/09/10/bp-said-to-be-in-talks-to-sell-gulf-of-mexico-assets-for-6-billion/?_r=0 (sales in the Gulf of Mexico and sales pending in Russia); http://articles.latimes.com/2010/jul/12/nation/la-na-0712-oil-spill-bp-20100712 (Alaska).

[796] http://www.bloomberg.com/news/articles/2015-07-02/bp-said-to-settle-2010-gulf-oil-spill-claims-with-u-s-states. This settlement was approved by the judge presiding over the case on April 5, 2016; see

ongoing environmental remediation costs and marketing costs related to rebuilding BP's image with the American public. The possibility remains of more adverse judgments stemming from other pending legal actions.[797] BP's 2014 annual report noted that potential costs related to the Macondo blowout still could not be fully estimated, and "they have had and could continue to have a material adverse impact on the group's business, competitive position, financial performance, cash flows, prospects, liquidity, shareholder returns and/or implementation of its strategic agenda, particularly in the US."[798] Transocean had a similar statement in its own annual report that indicated "the Macondo well incident could result in increased expenses and decreased revenues, which could ultimately have a material adverse effect on us … we are currently unable to estimate the full impact the Macondo well incident will have on us."[799]

Issues of required disclosures in the case of BP and Transocean must, however, be kept in proper context. For its part, based on annual reports filed in 2011 for the 2010 performance year, BP was recognized by public interest group Ceres as having provided shareholders with "good" disclosures relating to deepwater drilling risks in four of five categories among the world's ten largest publicly-owned oil and gas companies.[800]

As this chapter explains, more could have been disclosed but disclosure was not required, in light of controlling SEC regulation or other accompanying guidance. Moreover, as Ceres found even in a post-Macondo world, none of the world's ten largest publicly traded oil and gas companies produced "excellent" disclosures with respect to climate change and deepwater drilling risks; yet, these companies continue to make extensive capital investments in extracting oil and gas and expanding deepwater exploration and production efforts. In doing so, they are "posing significant risks to investors and stakeholders."[801] To that end, Ceres called on investors to push for better quality disclosure from oil and gas companies, and for securities regulators to "keep close tabs" on the quality of corporate disclosures of

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http://www.cnbc.com/2016/04/05/us-judge-approves-bp-settlement-for-2010-gulf-of-mexico-oil-spill.html?__source=facebook%7Cbusiness%7Clink%7C040416%7C5AM%7Cjudge-approves-bp-settlement.

[797] For example, on December 11, 2015 Acciones Colectivas de Sinaloa filed a class action lawsuit against BP seeking compensation for environmental damage sustained in Mexico as a consequence of the 2010 oil spill; Rodriguez, J. C. Mexico Files Class Action Lawsuit Against BP plc (ADR) over Deepwater Horizon Spill. *Law360*, December 11, 2015, http://www.law360.com/articles/737080/bp-hit-with-class-action-in-mexico-over-deepwater-horizon (accessed January 15, 2015).

[798] BP *Annual Report and Form 20-F 2014*, p 228. http://www.bp.com/content/dam/bp/pdf/investors/bp-annual-report-and-form-20f-2014.pdf (accessed December 17, 2015).

[799] Transocean. *Annual Report*, 2014, pp AR15-AR16.

[800] For its 2010 annual report, Ceres recognized BP for "Good Disclosures" with respect to Safety & Environmental Statistics, Drilling Risk Management, Safety R&D, and Corporate Governance on Drilling, while it recognized BP for "Fair Disclosures" relating to Spill Response. Coburn, J.; Salmon, R.; Grossman, D. *Sustainable Extraction? An Analysis of SEC Disclosure by Major Oil & Gas Companies on Climate Risk & Deepwater Drilling Risk;* CERES: August, 2012; pp 1-3. http://www.ceres.org/resources/reports/sustainable-extraction-an-analysis-of-sec-disclosure-by-major-oil-gas-companies-on-climate-risk-and-deepwater-drilling-risk/view (accessed October 17, 2015).

[801] Coburn, J.; Salmon, R.; Grossman, D. *Sustainable Extraction? An Analysis of SEC Disclosure by Major Oil & Gas Companies on Climate Risk & Deepwater Drilling Risk;* CERES: August, 2012; pp i, 1, 4-5. http://www.ceres.org/resources/reports/sustainable-extraction-an-analysis-of-sec-disclosure-by-major-oil-gas-companies-on-climate-risk-and-deepwater-drilling-risk/view (accessed October 17, 2015).

those companies working offshore in the extractive industry with specific regard to deepwater drilling risks, while “prodding companies that continue to fall short.”[802]

Ceres’ recognition of companies with better reporting is further tempered by the fact that “even the best reporting provided narrative discussions of deepwater drilling policies and actions, without providing investors sufficient metrics to evaluate the success of new policies designed to reduce the risks of accidents.”[803]

5.2 BP and Transocean: Corporate Governance and Communication of Process Safety and Major Accident Prevention Information

BP and Transocean boards of directors met requirements for disclosing material information about safety, but neither board effectively communicated process safety performance in the form of leading indicator data and lagging metrics of sufficient scope and frequency, which could have provided greater depth concerning the safety of drilling operations. As this section describes, shareholder communications and other public information about board activities and corporate risk demonstrate missed opportunities by BP’s and Transocean’s boards to communicate additional information from the highest level to focus their companies’ efforts on safety in a manner that could help to minimize the potential for a catastrophic event like the one on April 20, 2010. The rationale underpinning this critique is straightforward. In business, “your measurement system will determine what your staff will pay attention to.”[804] On the executive level, “Leaders create cultures by what they systematically pay attention to.”[805] In effect, a successful corporate safety program aimed largely at personal safety provides little insight into how well the company is controlling, mitigating, and managing major hazards and catastrophic risk, especially in the area of process safety risk. As described in Section 3.1, it could even lull observers from all levels of a company—and even shareholders—into a false sense of security over major hazards.

5.2.1 A Case Study of Board Involvement Demonstrated in Shareholder Communications

BP and Transocean both publicly reported health and safety information about risk and the sustainability of operations to shareholders in annual reports for many years. An analysis of BP board communications before and after the BP Texas City disaster in 2005, and of BP and Transocean communications before and after the Macondo disaster, illustrate an evolving focus and approach to process safety and major

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802 *Ibid*., p i.

803 *Ibid.,* p 2.

804 Eves, D.; Gummer, J. *Questioning Performance: Essential Guide to Health, Safety and the Environment ;* IOSH Services Ltd: Wigston, United Kingdom, 2011, p 103 (as attributed to Peter Drucker). HSE also commissioned research into the types of KPIs a company could select, which investment institutions would likely regard as significant, with obvious implications for a company’s access to capital, and simultaneously an easy way for directors to drive safety and profit. See *id.* at p 106.

805 Schein, E. H. *Organizational Culture and Leadership,* 4th ed.; Jossey-Bass: San Francisco, CA, 2010, as cited in Ellis, G. Process Safety Begins in the Board Room. *Chemical Processing*, March 21, 2013, http://www.chemicalprocessing.com/articles/2013/process-safety-begins-in-the-board-room/?show=all (accessed October 7, 2015).

accident prevention communications from BP's board of directors' perspective, and a somewhat more static and traditional approach taken by Transocean.

5.2.1.1 BP Shareholder Communications Before and After BP Texas City

Following the BP Texas City disaster, the Baker Panel found a "substantial gulf" between the information management reported to the BP board of directors and the reality in the field, where company personnel were generating process safety information and making operational decisions which had major accident risk implications for the company. Specifically:

> BP's Board of Directors has been monitoring process safety performance of BP's operations based on information that BP's corporate management presented to it. A substantial gulf appears to have existed, however, between the actual performance of BP's process safety management systems and the company's perception of that performance. Although BP's executive and refining line management was responsible for ensuring the implementation of an integrated, comprehensive, and effective process safety management system, BP's Board has not ensured, as a best practice, that management did so. In reviewing the conduct of the Board, the Panel is guided by its chartered purpose to examine and recommend any needed improvements. In the Panel's judgment, this purpose does not call for an examination of legal compliance, but calls for excellence. It is in this context and in the context of best practices that the Panel believes that BP's Board can and should do more to improve its oversight of process safety at BP's five US refineries.[806]

Consider that following the Texas City disaster, BP was assessed $50 million in penalties for felony safety violations leading to the event. BP's sustainability report in 2005, issued after Texas City, communicated the message that the company was learning from its mistakes and working toward safer performance.[807] In particular, the report commented in detail on BP's response to the Texas City disaster with its own investigations, a "fundamental" review of its safety systems and processes, and a whole host of new measures and investments to "maintain the safety of our people and the integrity of our plant."[808]

In fact, little changed in BP's management of Texas City. When OSHA re-inspected the facility 2009, OSHA found "439 instances of 'willful' violations, most or all of which were designated with gravity of 10 on a scale of 1 to 10."[809] OSHA issued notices of violations in response to several significant

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[806] The Baker Panel. *The Report of the BP US Refineries Independent Safety Review Panel;* January, 2007, p XV. http://www.csb.gov/assets/1/19/Baker_panel_report1.pdf (accessed October 7, 2015).

[807] BP. *Making energy more-Sustainability Report 2005;* pp 3-4. http://www.bp.com/content/dam/bp/pdf/sustainability/group-reports/bp_sustainability_report_2.pdf (accessed October 7, 2015).

[808] United States Department of Labor. Fact Sheet on BP 2009 Monitoring Inspection, https://www.osha.gov/dep/bp/Fact_Sheet-BP_2009_Monitoring_Inspection.html (accessed December 15, 2015).; Sanford, L. Lessons on Corporate "Sustainability" Disclosure from Deepwater Horizon; *New Solutions* 2011**,** *21,* p 202.

[809] OSHA. Inspection: 311962674 - BP Products North America, Inc., https://www.osha.gov/pls/imis/establishment.inspection_detail?id=311962674&id=310266085#311962674; US Department of Labors OSHA issues record-breaking fines to BP, https://www.osha.gov/pls/oshaweb/owadisp.show_document?p_table=NEWS_RELEASES&p_id=16674 (accessed October 7, 2015).

remaining safety concerns.[810, 811] By August 12, 2010, BP still had not addressed these issues fully. For its failure to act, BP negotiated yet another agreement with OSHA to pay a $50.6 million penalty for ongoing failure-to-abate violations—the largest penalty ever paid in the history of OSHA enforcement.[812] Shareholders, for their part, received little in the way of specifics, despite a narrative-style summary of the ongoing issues and their resolution.

BP's 2009 annual report, issued before Macondo, carried another important message to shareholders. Opening with a letter from Carl-Henric Svanberg, the Chairman of the BP's board, the company made it clear that it remained ready and able to take on the risks presented by its operations. He noted:

> Risk remains a key issue for every business, but at BP it is fundamental to what we do. We operate at the frontiers of the energy industry, in an environment where attitude to risk is key. The countries we work in, the technical and physical challenges we take on and the investments we make – these all demand a sharp focus on how we manage risk. We must never shrink from taking on difficult challenges, but the board will strive to set high expectations of how risk is managed and remain vigilant on oversight.[813]

CEO Tony Hayward's own letter in the 2009 annual report paralleled the Chairman:

> Our priorities have remained absolutely consistent—safety, people and performance—and you can see the results of this focus with improvements on all three fronts. This year we have increased emphasis on operational efficiency, with a particular focus on compliance and continuous improvement. Achieving safe, reliable and compliant operations is our number one priority and the foundation stone for good business. This year we achieved a reported recordable injury frequency of 0.34, an improvement of 20% over 2008. In Refining and Marketing reported major incidents have been reduced by 90% since 2005. All our operated refineries and petrochemicals plants now operate on the BP operating management system (OMS), which governs how BP's operations, sites, projects and facilities are managed. In Exploration and Production 47 of our 54 sites completed the transition to OMS by the end of 2009, and I expect all BP operations to be on OMS by the end of 2010.This represents good progress and we must remain absolutely vigilant.[814]

Together, these letters communicated the company's willingness to operate at the "frontiers" of the energy sector, essentially willing to take on bigger risks for bigger rewards. Macondo represented just this

[810] "Our information indicates that for some identified hazards, BP has not specified or allocated the specific layers of protection needed and for other identified hazards where BP has specified the layers of protection it will use to control the hazards, the specified instrument controls have not been installed or are not operational." From Sanford, L. Lessons on Corporate "Sustainability" Disclosure from Deepwater Horizon; *New Solutions* 2011**,** *21,* p 202.

[811] OSHA warned in September 2009 that its audit identified "systemic deviations from the industry standards" and further noted that "areas of concern included a failure, four years after the blast, to complete a determination of which alarm functions in each unit were critical to process safety." From Sanford, L. Lessons on Corporate "Sustainability" Disclosure from Deepwater Horizon; *New Solutions* 2011**,** *21,* p 202.

[812] Sanford, L. Lessons on Corporate "Sustainability" Disclosure from Deepwater Horizon; *New Solutions* 2011**,** *21,* p 199. To be clear, these violations were not the same issues that led to the Texas City disaster, but instead were violations occurring afterward due to the failure of BP to implement needed fixes.

[813] BP 2009 Annual Report, letter from Carl-Henric Svanberg, Chairman of the Board, p 3.

[814] BP 2009 Annual Report, letter from Tony Hayward, Group CEO, p 6.

kind of risk/reward, referred to as the "well from hell,"[815] and presenting BP and Transocean numerous operational challenges, while promising a significant payoff of potential hydrocarbon reserves. The letters also sought to communicate a sense of safety to investors, presenting not only the board's perspective on safety in general, but even some specific safety results deemed important from the perspective of the CEO. The remainder of the report, however, provided little in the way of process safety, major hazards, and process safety indicators—perhaps because no express regulatory requirement existed for the reporting of such information, and because BP's industry peers do not report the same type of information.

5.2.1.2 BP Shareholder Communications Before and After Macondo

In its 2009 annual shareholder report, four years after BP Texas City but one year before Macondo, BP included only three indicators which the company described as having to do with safety: Recordable Injury Frequency (RIF), oil spills, and greenhouse gas emissions. As noted in Chapter 3 and as Hayward touts in his letter, BP achieved strong results with respect to personal safety as measured by RIF. The BP workforce (employees and contractors) achieved a RIF of "0.34, significantly below 2008 and 2007 levels of 0.43 and 0.48, respectively." Oil spills, which were defined as spills of one barrel or more, also showed a reduction from the two prior years, down from 340 in 2007, 335 in 2008, and 234 in 2007. In contrast, greenhouse gas emissions were up in 2009 from levels as reported in 2007 and 2008, which the company attributed to "increases in operational activity" in various regards. This is the type of data upon which shareholders could assess BP's performance in personal safety issues impacting the company's workforce. These two limited lagging indicators on oil spills and greenhouse gas emissions illustrate environmental concerns and give some indication of process safety management results.

At the same time, however, safety data also illustrates the area of potential improvement open to BP, notwithstanding the current absence of a regulatory requirement for more. The company provided no leading process safety indicators that could have given shareholders or the regulator insight into specifics about process safety issues or major accident prevention.[816] While BP discussed both personal and process safety concepts and issues throughout the report, the absence of meaningful indicator data weakens the effectiveness of the communication. It gave no KPI or metrics-driven discussions relating to success in process safety management issues, especially for offshore drilling and production.

In another example, similar to the phrasing noted in Hayward's letter and the "90% reduction in major incidents," the Exploration and Production section noted, "We also achieved improvements in the number of process safety-related incidents and a significant reduction in the number of spills."[817] These statistics

[815] See http://www.nytimes.com/2014/09/05/business/bp-negligent-in-2010-oil-spill-us-judge-rules.html?_r=0 (referencing exploration and production challenges "in the deep waters of the Gulf of Mexico, where high pressures and temperatures in the wells test the most modern drilling technologies.") See also in re: Oil Spill by the Oil Rig "Deepwater Horizon" in the Gulf of Mexico on April 20, 2010, Findings of Fact and Conclusions of Law, Judge Barbier, ¶56 ("Drilling the Macondo well did not go smoothly. Some called it the "well from hell."); and exhibit TREX-22924, "Macondo Was the Well from Hell," (timeline showing challenges in drilling Macondo), available at http://www.mdl2179trialdocs.com/releases/release201304041200022/D-3126.pdf.

[816] BP. *Annual Report and Accounts;* 2009; p 15. http://www.bp.com/content/dam/bp/pdf/investors/bp-annual-report-accounts-2009.pdf (accessed October 15, 2015).

[817] *Ibid*., p 12.

are not particularly illuminating to shareholders, even from a lagging indicators perspective. Although on its face a 90% reduction in major incidents is a positive development, a reader cannot know the number of major incidents that actually occurred, how near-misses were handled in terms of data collection, or whether these incidents had a common causation. Also absent were the operational goals for this area, leaving a shareholder uncertain as to whether BP met its objectives in this area. Missing as well is any attempt to benchmark the number of major incidents against industry standards.

In contrast, in the Refining and Marketing section of the report, BP provides some financial indicators about specific industry benchmarks.[818] In terms of safety, Refining and Marketing again repeated the 90% reduction of "reported major accidents" as well as the previously noted reduction of oil spills and RIF and the absence of workplace fatalities for the year.[819] Some improvement in the area of reporting would be helpful because BP appeared to be tracking matters like reported major accidents internally, so bringing that type of data into its annual reports would cost little, but could add much by way of transparency.

In deeper consideration of BP's indicators chosen for report, oil spills and greenhouse emissions are lagging indicators, providing shareholders and the regulator with little more than notice of events that already occurred, rather than including any specific mention of near-misses or the myriad of more sophisticated leading process safety indicators that are frequently tracked and trended offshore which, if disclosed, could have provided readers with far better insights into major process safety issues. Such indicators could have included, for example, data pertaining to challenges to barriers, problems with barriers discovered during inspections, overdue inspections and audits, well kick frequency, response time to well kicks, and the like.

Ceres also cited the improvement in BP's 2010 report over its previous edition in its study on the disclosures made by companies engaged offshore, as well as the limitations in that reporting, noting, "BP's and several other companies deepwater drilling disclosure improved significantly after Macondo. As explained above, however, even the best narrative-style reporting relative to offshore operations, without the addition of indicators, KPIs, or metrics, cannot provide the basis to understand and evaluate the impact of policies and procedures designed to reduce the risk of accidents."[820] This finding by Ceres corroborates the CSB's findings, which is that although BP described issues concerning process safety risk in narrative form, it provided little about significant process safety performance indicators before or immediately after Macondo.

In a positive development, post-Macondo, BP's communication from its board to its shareholders evolved through more transparent and complete reporting related to major hazards. Only briefly in its 2010 annual

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[818] Such benchmarks include refining margin and refining availability percentage. See BP. *Annual Report and Accounts;* 2009; p 18. http://www.bp.com/content/dam/bp/pdf/investors/bp-annual-report-accounts-2009.pdf (accessed October 15, 2015).

[819] BP. Annual Report and Accounts; 2009, p 21. http://www.bp.com/content/dam/bp/pdf/investors/bp-annual-report-accounts-2009.pdf (accessed October 15, 2015).

[820] Coburn, J., Salmon, R., Grossman, D. Sustainable Extraction? An Analysis of SEC Disclosure by Major Oil & Gas Companies on Climate Risk & Deepwater Drilling Risk; CERES: August, 2012, p 2. http://www.ceres.org/resources/reports/sustainable-extraction-an-analysis-of-sec-disclosure-by-major-oil-gas-companies-on-climate-risk-and-deepwater-drilling-risk/view (accessed October 17, 2015).

report, and then more fully its 2011-2014 reports,[821] BP's communications with shareholders began to provide even more information relating to the company's safety performance. For example, the 2011 report emphasized work on a wide swath of corporate activity aimed at improving safety, including coverage of numerous and significant critical safety issues. The report highlighted categories of key accomplishments, such as safety and operational risk, upstream restructuring, operational review, values and behaviors, individual performance and reward, contractor management, technology, and joint ventures not operated by BP.[822] The core of the report, the "Business Review—BP in More Depth" section, included detailed subsections on topics such as risk factors, safety and operational risks, and environmental and social responsibility.[823] It also included a special section detailing ongoing issues in the Gulf of Mexico cleanup efforts.[824] Most of this type of information would benefit the entire sector in publicly traded companies' annual reports.

5.2.1.3 Transocean Shareholder Communications Before and After Macondo

The year before Macondo, in the Chairman's and CEO's joint letter to shareholders accompanying Transocean's 2009 annual report and proxy statement, the company related a corporate message focused on personal safety: "Unfortunately, despite our continued focus on safety and operational excellence and our best-ever total recordable incident rate of 0.77 incidents per 200,000 hours worked, four of our employees suffered fatal accidents while working on our rigs in 2009."[825] Transocean related no other safety performance indicators or other metrics-driven safety data in this public disclosure, with no specific reference to process safety or major accident prevention.

In Transocean's 2009 annual report to shareholders, Transocean defined safety performance through a formula that related to bonus calculations used to reward individual executives and employees. However, safety performance translated to only 20 percent of any total bonus payment, while financial performance related to 70 percent, and "new builds" accounted for the final 10 percent. Thus, per the public transmission of information in its annual report, Transocean intended to incentivize financial performance and new building activity versus safety in an 80/20 split. Moreover, for the 20 percent allocation to safety performance, the report indicated that a total score on this component is computed by reference to three variables: (1) Total Recordable Injury Rate, (2) Total Potential Severity Rate, and (3) High Potential Dropped Objects, with the total score used to calculate employee bonus payments.[826]

The variables used in Transocean's bonus calculation formula were mainly personal safety statistics relating to the higher frequency—and typically lower consequence—events that most often result in a

[821] BP. Annual reporting archive, http://www.bp.com/en/global/corporate/investors/results-and-reporting/annual-report/annual-reporting-archive.html (accessed December 17, 2015), 2015.

[822] BP. *Annual Report and Form 20-F 2010;* p, 36. http://www.bp.com/content/dam/bp/pdf/investors/bp-annual-report-and-form-20f-2010.pdf (accessed October 2015, 2015).

[823] *Ibid.*, p, 59-72.

[824] *Ibid.,* p, 76-79.

[825] Transocean. *Annual Report,* 2009, 2009 Letter to the Shareholders, p 1.

[826] Transocean. *Annual Report,* 2009. The three variables comprised 35%, 35%, and 30 % of the measure respectively. TRIR is described in Section 0. TPSR is a proprietary measure used to monitor the total potential severity of incidents, and High Potential Dropped Objects are dropped objects that could cause serious injury resulting in an employee being out of work for six or more months.

single person injury, but could potentially include a fatality. [827] However, there was no mention of process safety, major hazards or issues of catastrophic accidents, which represent the potential for numerous serious injuries/fatalities, as well as large scale damage to property or the environment. By choosing these measures, the Transocean board of directors did not provide for appropriate process safety goal-setting. Instead, Transocean's 70 percent weighting toward financial goals broke down into three sub-elements: (1) cash flow value add relative to budget, (2) overhead costs, and (3) lost revenues,[828] each of which provides incentives to push drilling along faster, without an accompanying set of factors or overarching philosophical approach to help employees meet company goals safely.

Transocean's 2010 annual report is largely the same, with the exception of the company's acknowledgment of the Macondo disaster and a promise to produce a publicly available investigation report as well as a "risk assessment" for shareholders regarding the risks to the company presented by Macondo in terms of business interruption, lawsuits, and the like.[829] Conversely, BP initiated its own investigation, publicly releasing a report on September 8, 2010.[830] Notably, no accounting from Transocean's Health, Safety and Environment Committee[831] appeared in the report, despite the inclusion of reports by other standing committees of the board of directors, including the Audit and Executive Compensation committees on unrelated matters. In addition, notwithstanding the sinking of the Deepwater Horizon, the deaths of 11 workers, and a massive oil spill, Transocean also disclosed bonuses for the company's "best ever" year in safety.[832]

Transocean's 2011 report appeared similar in content to the 2010 version, although it mentions Transocean's overall findings and conclusions of its investigation of the Macondo well blowout.[833] However, the annual report's summary of the investigation focuses only on the safety shortcomings of BP

[827] Transocean. *Annual Report;* 2009, "Performance Award and Cash Bonus Plan," p 35. The bonus plan is described as "a goal-driven plan that gives participants, including named executive officers, the opportunity to earn annual cash bonuses based on performance measured against predetermined performance goals." *Id*., p 34. The annual report explains that the bonus plan and the performance goals connected to it are set by the Board, through the Executive Compensation Committee—not the Health Safety and Environment Committee—in accordance with the company's "safety vision" for "an incident-free workplace—all the time, everywhere," stating: "The Committee sets our safety performance targets at high levels each year in an effort to motivate our employees to continually improve our safety performance towards this ultimate goal." *Id.*, p 35.

[828] Transocean. *Annual Report;* 2009, pp 34-35.

[829] *Ibid*., pp 34-35.

[830] BP. *Deepwater Horizon Accident Investigation Report;* September 8, 2010.

[831] Transocean. *Annual Report*, 2010, pp 27. Despite the Macondo disaster and the loss of the Deepwater Horizon and eleven employees, the HSE Committee met only once in 2010. In contrast, the Corporate Governance Committee met 4 times, the Finance/Benefits Committee met 4 times, the Executive Compensation Committee met 5 times, and the Audit Committee met 17 times. *Id*., p 28.

[832] *Ibid*., p 44. This public expression of Transocean's bonuses was the cause of widespread backlash by media, government and the public alike, prompting an apology from Transocean's CEO. *See, e.g.,* McMahon, J. Transocean Executives Get Bonuses for "Best Year in Safety" Despite Gulf Oil Disaster. *Forbes*, April 4, 2011."Notwithstanding the tragic loss of life in the Gulf of Mexico, we achieved an exemplary statistical safety record as measured by our total recordable incident rate and total potential severity rate. As measured by these standards, we recorded the best year in safety performance in our Company's history, which is a reflection on our commitment to achieving an incident free environment, all the time, everywhere."

[833] Transocean. *Annual Report*, 2010, p 5.

in its role as operator and the party that was legally responsible as the leaseholder, from Transocean's perspective. There is no mention of Transocean internal safety lapses or other deficiencies and no lessons learned for improving the safety of its offshore drilling operations. The 2011 report also lacks any discussion of process safety management issues, major hazards, or catastrophic risk beyond mentioning the formation of a risk management subcommittee that would help the Transocean audit committee to analyze risk for the company in varied settings. In any event, such support would prove fruitless with no apparent application of process safety principles or adequate consideration of MAP and related operational risk. The substance surrounding the work of that subcommittee, however, was not explained.

In a positive development, Transocean recently updated its most current compensation scheme. Its 2014 annual report includes process safety considerations as part of the overall individual calculations for employees. Now, 30 percent of compensation relates to safety, and the measurement is based on "process safety events" that the company is treating as indicators with potential for a major accident event in their fleet's operations.[834] According to the report, Transocean is using standard industry definitions to describe the "process safety events," but limited to incidents involving fire, explosion, release of a hazardous substance with serious injury or fatality, major structural damage, serious injuries/fatalities, and uncontrolled release of hazardous fluids.

5.3 Historical BP Corporate Governance Issues

During its investigation of the 2005 explosion at the BP Texas City refinery, the CSB found that BP exhibited ineffective corporate leadership and oversight of refinery operations, which cascaded from the company's board of directors through successive layers of corporate management, creating a safety culture vulnerable to catastrophe.[835]

The CSB's report in that case made specific reference to the existing Turnbull Guidance adopted by the UK's Financial Reporting Council. It also referenced guidance in the UK Health and Safety Executive's report on the BP Grangemouth refinery and provided references to other HSE directives to make clear the existing health and safety responsibilities that a corporate board of directors must meet in major accident prevention.[836] In detail, the CSB report stated:

> Directors should, at least annually, review systems of control including risk management, financial, operational, and compliance controls that are the key to the fulfillment of the company's business objectives. The HSE has prepared guidance for directors in order to help them ensure that the health and safety risks arising from their organizations' activities are properly managed. Directors should be fully aware of their corporate responsibilities in relation to the control of major accident hazards.[837]

[834] Transocean. *2014 Extraordinary General Meeting Definitive Proxy Statement;* Schedule 14A; March 23, 2015; p P-28. http://phx.corporate-ir.net/External.File?item=UGFyZW50SUQ9NTUxMDI5fENoaWxkSUQ9MjQ1NDY1fFR5cGU9MQ==&t=1 (accessed October 7, 2014).

[835] USCSB, 2007. *Refinery Explosion and Fire*, *Texas City, TX, March 23, 2005,* Report No. 2005-04-I-TX, pp 187-191. http://www.csb.gov/assets/1/19/CSBFinalReportBP.pdf (accessed October 7, 2015), March 2007.

[836] *Ibid*., pp 189-190.

[837] *Ibid*., p 190.

The CSB's report noted that at the time of the BP Texas City incident, no independent member of the board of directors had a background in refinery operations and process safety management. Thus, no then-serving member had the professional background necessary to discern whether the board as a whole had received all necessary information, and whether the information received from management reflected appropriate consideration of the process safety impacts on corporate decisions. As a result, the CSB recommended that BP "Appoint an additional non-executive member of the Board of Directors with specific professional expertise and experience in refinery operations and process safety. Appoint this person to be a member of the Board Ethics and Environmental Assurance Committee."[838] At the time of the Macondo blowout, BP had still not met the express terms of this recommendation, and no independent member of the board of directors on April 20, 2010 had a background in refinery operations and process safety.[839] Similarly, no then-serving independent board member of the company's Safety, Ethics and Environment Assurance Committee (SEEAC) committee had a professional background in offshore drilling relevant to the major accident risks undertaken at a well like Macondo.

Of course, these are difficult issues, but a legitimate question can be posed as to whether the presence of an independent board member with a background in process safety and refining operations could have helped to inform the board of emerging safety issues at BP Texas City, and whether an independent board member with process safety and offshore drilling and production experience could have provided more effective board oversight for major accident risk management at Macondo. One example relates to the Orange Book, discussed earlier. BP established the Orange Book after hiring Duane Wilson, the board's retained process safety expert. Chapter 3 noted the limitations of the Orange Book process safety indicators. This data is provided to the SEEAC in the form of quarterly reports. The SEEAC, and even the Board as a whole, would be in a disadvantageous position with this limited safety information without a fellow board member with the experience and knowledge to parse through the information, identify any limitations, and ask insightful process safety questions of its corporate personnel. SEEAC members lacking an educational and professional experience in process safety within the refining or drilling sector could find themselves wholly reliant on an employee of the company to identify for them potential gaps in the information. Refining and drilling are two critical areas that represent the most significant business risks facing the company. Thus, adequate representation of those sectors in conjunction with process safety are critical for informed board decision-making. Despite several other actions intended to improve board function, BP's board remained less effective in oversight and risk mitigation than it might otherwise have been. Governance experts agree that oversight and risk management are among a board's chief obligations, and any actions to improve board function in these areas should be encouraged.

This challenge is not unique to BP. The safety committee of Pike River Coal Company was chaired by the company's CEO, an executive board member with an extensive background in iron mining; however, he

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[838] *Ibid.*, p 190.

[839] Instead, the company chose to take a number of alternative actions in light of the CSB recommendation, along with the Baker Panel's recommendations. For example, the company (1) hired an outside expert to advise the board on process safety matters for a fixed term of five years; (2) created the Group Operational Risk Committee (GORC) at the highest level within the company to help understand and manage risk; (3) created the Orange Book in an attempt to communicate both leading and lagging indicators directly to the Board of Directors in general and the SEEAC in particular; and (4) reinvigorated the SEEAC through an expansion of the committee's role and authority with respect to assessing health and safety risk of all types.

lacked experience in coal mining, which posed unique hazards, and the company proved unable to steer clear of disaster in that case. (See callout box.)

In addition, board members without industry-specific knowledge may assess inadequate information without realizing its profound impact on process safety and the company's sustainability. They may not readily detect critical correlations between seemingly tangential issues and process safety and major accident prevention. This shortcoming makes it difficult for boards to decide wisely on policy or strategy. For example, Chapter 3 discusses BP management employee's individual performance contracts, which focused primarily on operational success measures such as drilling speed and well completions, and safety was rewarded in a lower percentage than other measures of operational success. Even where safety was mentioned, it related primarily to personal safety indicators, such as Recordable Injury Frequency and Days Away from Work Case Frequency. Without understanding the implications of this model, board members were not positioned to foresee potential shortcomings, and could not challenge this construct. Board decisions on setting corporate goals and objectives cascade through the organization through a traditional management-by-objective methodology.[840] Thus, board decisions based on incomplete information could guide a company's actions towards less safe operations in a push for target completions.[841] In sum, board involvement and oversight of process safety management and major accident prevention can serve to sharpen a company's focus on safety. Various tools, described in Section 5.5, aim to improve levels of operational safety while boosting overall corporate performance.[842]

[840] *See*, *e.g.*, Drucker, P. *The Practice of Management;* Harper & Row: New York, 1954 (establishing "management by objective" as the management theory most capable of driving execution in business through the balancing of competing corporate needs with goal-setting). However, critics of "management by objective," including business scholars such as W. Edwards Deming, actually argued against management by objective, stating that a lack of understanding of contextual environment and other interrelated systems commonly results in the misapplication of objectives by managers and companies, and that setting production targets encourages resources to be allocated to meet those potentially arbitrary production targets through whatever means necessary, which can result in poor quality or other negative consequences. Deming, E. *Out of the Crisis*.

[841] In re: Oil Spill by the Oil Rig "Deepwater Horizon" in the Gulf of Mexico on April 20, 2010, Report of Expert Witness Patrick Hudson, PhD., pp 23-29 (describing BP's decision to continue a strategy rooted in "loss avoidance" and a culture that "continued to encourage excessive risk taking in pursuit of commercial targets.")

[842] Martin Sedgwick & Angela Wands, *The Implementation of Effective Key Performance Indicators to Manage Major Hazard Risks*, testimony presented by Martin Sedgwick Head of Engineering ScottishPower/Iberdrola Group on July 23, 2012 at the CSB's public meeting, "CSB Public Meeting: Safety Performance Indicators," transcript pp 85-86, http://www.csb.gov/about/publichearing.aspx. See also Martin Sedgwick & Angela Wands, *The Implementation of Effective Key Performance Indicators to Manage Major Hazard Risks*, pp 2-3, 8, Figures 10-12 (2012), presented by Martin Sedgwick Head on July 23, 2012.

Corporate Governance "Underlying Cause" of Pike River Coal Mine Disaster –International Lessons for the Offshore Industry

Accident investigations from the entire spectrum of all high-hazard industries present opportunities for lessons learned that cross industry-specific boundaries. For example, accidents in coal mining, nuclear energy production, chemical manufacturing, oil refining, natural gas production, and even air travel all create learning opportunities for those who wish to avoid similar events. Many lessons from a variety of industrial accidents can be used to improve the safety of offshore drilling. For example, following the Pike River Coal Mine disaster in New Zealand that killed 31 people, the Royal Commission, which investigated the disaster, issued a 400-plus page report along with a series of associated safety recommendations.[a] Three of those recommendations focused on good corporate governance—something found to be lacking at the board level in that particular case and which the Royal Commission identified as an underlying cause of the disaster.

The key failing of the Pike board of directors centered around the company's rush to begin producing coal before it was ready to do so safely, particularly because this company was new, and this was its only coal mine. The board tried to make the mine productive as quickly as possible to staunch the flow of heavy borrowing for funding initial mine operations. The Royal Commission concluded that Pike had "not completed the safety systems and infrastructure needed to safely produce coal."

The Royal Commission found that the Pike board provided ineffective oversight in risk management, internal reporting, and legal compliance, and that the board over-relied on management to bring to its attention significant safety issues; meanwhile, the board lacked efficient mechanisms to ensure management was meeting critical health and safety requirements. For example, the board did not know about the results of an insurance risk survey, which disclosed several significant safety risks, including the risk of methane gas explosion—the cause of the fateful disaster that claimed so many lives. Content to rely on management's assurances about safety, including statements about methane gas being "more a nuisance and daily operational consideration than a significant problem or barrier to operations," the board was not well positioned to hold management accountable or to act correctively. Instead the board remained "distracted by the financial and production pressures that confronted the company." In addition to the tragedy of 31 miners killed in the blast, the company itself was believed to have been reduced instantly to "worthless" when it closed the mine and stopped production indefinitely. The court placed the company in receivership.[b] Eventually, the mine was sold, but its new owner has not yet conceived of a way to reopen the mine safely, whether for commercial mining, or just to recover the remaining 29 bodies of the 31 employees killed who remain entombed inside.

At the time of the incident, Pike's board had six members, but none of them were found to have any underground coal mining experience. The Chairman of the board had experience in metalliferous mining, but no professional experience with coal mining. In fact, shortly before the incident, the board realized there was a knowledge gap and undertook a search to find new board members to replace retiring board members who had underground coal mining experience. This is not unlike BP's SEEAC committee's lack of experience in offshore drilling, and BP's resistance to the CSB's 2007 BP Texas City recommendation that BP add an independent board member with professional training and experience in refinery operations and process safety management in light of the findings of that accident.

The Royal Commission also found that the Pike board worked in a dysfunctional manner. It had three committees, one which focused on Health, Safety and Environment (HSE) consisting of two individuals: the Chairman and one board member who had professional training as a mechanical engineer. The HSE committee was tasked specifically with ensuring that "Pike provided a safe workplace, monitoring compliance with environmental consents, permits and agreements, and reviewing projects," but it was not specifically asked to look at major hazards or to provide oversight on issues of catastrophic risk, notwithstanding Pike's operations in underground coal mining, a high-hazard industry with well-known and significant potential for disaster. At the time of the explosion, the HSE subcommittee had not met for 13 months despite being chartered to meet at least once every six months, and no HSE committee meetings were scheduled for 2011.

The HSE committee also had little knowledge of major legal compliance problems derived over the course of eight site visits by a leading mine safety consultant, and was only vaguely aware of a number of serious incidents in the months leading up to the fateful explosion. The committee also lacked an appreciation of the dangers associated with certain conditions at the mine, such as not having remote gas monitoring systems observable in the control room and inadequate ventilation systems combined with documented incidents where levels of methane gas reached its lower explosive limit within the mine.

In light of these failings, the Royal Commission made the following recommendations:

- *Recommendation 5: The statutory responsibilities of directors for health and safety in the workplace should be reviewed to better reflect their governance responsibilities.*
- *Recommendation 6: The health and safety regulator should issue an approved code of practice to guide directors on how good governance practices can be used to manage health and safety risks.*
- *Recommendation 7: Directors should rigorously review and monitor their organization's compliance with health and safety law and best practice.*

The Royal Commission's findings pertaining to the Pike River Coal board of director's failures being an underlying cause of the disaster, and the recommendations intended to prevent recurrence of similar circumstances in the future, apply equally well to the formulation of corporate governance policy, guidance, and best practices in the offshore drilling environment in the Gulf of Mexico in the post-Macondo world.

[a] Royal Commission on the Pike River Coal Mine Tragedy*;* Wellington, New Zealand, October, 2012; Volume 1: pp 12, 13, 18, Volume 2: 46, 50, 5-55. http://pikeriver.royalcommission.govt.nz/vwluResources/Final-Report-Volume-One/$file/ReportVol1-whole.pdf and http://pikeriver.royalcommission.govt.nz/vwluResources/Final-Report-Vol2-Part1-only/$file/Report-Vol2-Part1-only.pdf (accessed October 7, 2015).

[b] Behrmann, E. Pike River Coal's Future 'Bleak' After Mine Blasts. *Bloomberg Business*, November 24, 2010, http://www.bloomberg.com/news/articles/2010-11-24/pike-river-coal-s-future-bleak-after-new-zealand-mine-blast (accessed October 7, 2015).; NZ Oil and Gas. Receivers appointed for PRCL. *Scoop Business Independent News*, December 13, 2010, http://www.scoop.co.nz/stories/BU1012/S00406/receivers-appointed-for-prcl.htm (accessed October 7, 2015).

5.4 US Financial Regulation Absent Regarding HSE Reporting

US securities laws and regulations contain numerous requirements for disclosure of material information to shareholders, whether the company issuing shares is a domestic or foreign company, so long as they issues shares in some form on US exchanges for trading. Most of these requirements are general, requiring interpretation of the company and its counsel as to whether a specific issue must be reported. Few specific data points relevant to a company's health, safety, and environment operations are specifically required for disclosure to shareholders of companies trading in the US under regulations promulgated by the SEC pursuant to the Securities and Exchange Act of 1933 or 1934, Sarbanes-Oxley, Dodd-Frank, or any other existing financial law or regulation.[843]

The obligation of companies to disclose information in shareholder reports or other communications includes not only the specifics required by SEC disclosure forms, but also the often more relevant requirement to disclose any other information necessary to prevent the disclosed information from being misleading. Yet, a recent investigation by Ceres, an internationally recognized public interest firm comprising representatives from over 100 institutional investment firms and other private sector organizations, found that "companies making extensive capital investments related to [environmental] climate change and deepwater drilling are failing to adequately disclose their substantial material risks in those areas."[844] In fact, the Ceres study showed that "based on the annual financial filings submitted in the first quarter of 2011 by ten of the world's largest oil and gas companies, [the Ceres investigation] finds that none of them provided high quality reporting of their [environmentally-related] climate change and deepwater drilling risks and opportunities."[845] This is true despite the unique and numerous exposures to a variety of risk heightened by the "massive capital employed in the extractive industries and the importance of natural resource access and management to the national security and strategic objectives of the United States,"[846] along with broader worldwide markets.

Notwithstanding this exposure, "the SEC's guidance for disclosure in these areas does not yet require complete, and therefore completely accurate, assessment of companies' climate or deepwater drilling performance or risks."[847] This absence of a regulatory requirement limits the potential for increasing

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[843] Regulation S-K, Item 103, a securities regulation enforced by the US Securities and Exchange Commission, presents a small but under-enforced exception. Item 103 requires disclosure of certain environmentally related legal proceedings where anticipated penalties could result in monetary sanctions of over $100,000. However, as one legal commentator observed, based on the US EPA's own findings as well as a study by the University of Arkansas, documented noncompliance in this area by US corporations is as high as 74%.

[844] Coburn, J.; Salmon, R.; Grossman, D. *Sustainable Extraction? An Analysis of SEC Disclosure by Major Oil & Gas Companies on Climate Risk & Deepwater Drilling Risk;* CERES: August, 2012, p i. http://www.ceres.org/resources/reports/sustainable-extraction-an-analysis-of-sec-disclosure-by-major-oil-gas-companies-on-climate-risk-and-deepwater-drilling-risk/view (accessed October 17, 2015).

[845] *Ibid*.

[846] Bugala, P. *Materiality of disclosure required by the Energy Security through Transparency Act;* Calvert Investments: 2010; http://www.calvert.com/NRC/literature/documents/10003.pdf (accessed October 7, 2015).

[847] Coburn, J.; Salmon, R.; Grossman, D. *Sustainable Extraction? An Analysis of SEC Disclosure by Major Oil & Gas Companies on Climate Risk & Deepwater Drilling Risk;* CERES: August, 2012; p i. http://www.ceres.org/resources/reports/sustainable-extraction-an-analysis-of-sec-disclosure-by-major-oil-gas-companies-on-climate-risk-and-deepwater-drilling-risk/view (accessed October 17, 2015).

shareholder knowledge, and thus is an inherent limit on safety because shareholders are not equipped with the information needed to benchmark companies against one another, or to challenge decisions by corporate management or boards.

However, the SEC does require disclosure of trends, events, and other uncertainties in the management discussion and analysis (MD&A).[848] According to the SEC, one of most critical responsibilities includes "communicating with investors in a clear and straightforward manner," not just for technical disclosure requirements or a recitation of financial statements in narrative form, but to share information about the company as seen through the eyes at the top of the corporate hierarchy and that is "informative and transparent"[849] for the benefit of shareholders. One area for improvement by most Fortune 500 companies, the SEC's Division of Corporate Finance found, is "the focus and content of MD&A (including materiality, analysis, key performance measures and known material trends and uncertainties)."[850] In fact, the SEC emphasized that:

- companies should identify and discuss key performance indicators, including nonfinancial performance indicators, that their management uses to manage the business and that would be material to investors;
- companies must identify and disclose known trends, events, demands, commitments, and uncertainties that are reasonably likely to have a material effect on financial condition or operating performance; and
- companies should provide not only disclosure of information responsive to MD&A requirements, but also an analysis that is responsive to those requirements by explaining management's view of the implications and significance of that information[851]

These rules may have particular relevance to significant safety issues for offshore drilling, especially as shareholders appear to be pressing the SEC to articulate more clearly for companies the requirements concerning materiality about disclosures of enterprise risk issues. In response, the SEC is starting to seek greater disclosures from companies in these areas.[852]

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[848] 17 C.F.R. § 299.303. *See also* "Interpretation: Commission Guidance Regarding Management's Discussion and Analysis of Financial Condition and Results of Operations," Release Nos. 33-8350; 34-48960; FR-72 (December 29, 2003), p 1: "Information provided in the MD&A by companies are "intended to elicit more meaningful disclosure in MD&A in a number of areas, including the overall presentation and focus of MD&A with general emphasis on the discussion analysis of known trends, demands, commitments, events and uncertainties, and specific guidance on disclosures about liquidity, capital resources and critical accounting estimates."

[849] "Interpretation: Commission Guidance Regarding Management's Discussion and Analysis of Financial Condition and Results of Operations," Release Nos. 33-8350; 34-48960; FR-72, (December 29, 2003), pp 1-2.

[850] *Ibid*., p 2.

[851] *Ibid*., p 2.

[852] Heller, M. SEC Encouraging Firms to 'Tell Their Story' in MD&A. November 25, 2014, http://ww2.cfo.com/auditing/2014/11/sec-encouraging-firms-tell-story-mda/ (accessed October 7, 2015). In addition to recommending a balanced summary of key challenges, drivers and risks, the SEC has recently been encouraging companies to disclose known trends and uncertainties, quantify components of overall changes in financial statement line items, and enhance their explanation and analysis of the factors causing those changes.

Case in point: After Macondo, the SEC corresponded with both BP and Transocean about statements they made pertaining to safety, insurance coverage, oil spill containment, and the like.[853] Although helpful or even necessary under some circumstances, this type of back-and-forth dialogue could be minimized or avoided by enhanced SEC reporting requirements concerning what the securities regulator considers to be material information for companies engaged in offshore drilling (e.g., leading and lagging safety performance indicators, other related metrics such as KPI's relating to health, safety and the environment, safety culture survey results, etc.), while helping shareholders and the investing public at large with enhanced information about the investment worthiness of companies engaged offshore, at least in terms of process safety and major accident prevention efforts.

That is why, rather than focusing on the individual companies involved in Macondo where compliance requirements appear to have been met, another option is a regulatory change at the SEC, requiring enhanced disclosure of drilling risks as a means of advancing the public policy interest of offshore drilling safety. This could be accomplished in the same manner that the Dodd-Frank Act now requires expanded disclosures about mine safety pursuant to Section 1503 of that legislation.[854] Such disclosures could track those required of mining, with the addition of various leading and lagging safety performance indicators relevant to offshore, as well as records of citations or other enforcement activities. All of these records could better inform shareholders while causing boards, senior executives, and legal counsel to highlight results in these areas in annual reports, all of which have the potential to boost process safety performance.

Along these lines, in December 2010, the California and Pennsylvania state treasurers, whose pension funds had been affected by investments in companies offshore at the time of Macondo, requested that the National Oil Spill Commission make a recommendation to the SEC to develop new guidance specifically focused on deepwater drilling disclosures, and subsequently asked the SEC to take steps to improve existing reporting in this area.[855] This request dovetails with a similar filing by the Social Investment Forum,[856] which requested that the SEC (1) require all issuers to report annually on a comprehensive set

[853] BP corresponded with the SEC at least 13 times between August 10, 2010 and September 29, 2013, on matters ranging from disclosures about safety to issues pertaining to the oil spill, containment, and remediation. For an examples, see letter of August 6, 2010 to H. Roger Schwall of the SEC Re: BP plc, Form 20F for Fiscal Year Ended December 31, 2009 (the "Form 20F"), filed March 5, 2010, File No. 00106262; and letter of September 19, 2013 to H. Roger Schwall of the SEC BP p.l.c. Form 20F for the Fiscal Year Ended December 31, 2012 filed March 6 2013 File No. 00106262. Similarly, Transocean engaged with the SEC in about the same fashion with respect to safety disclosures during a similar period. See letter OF September 23, 2014 to Peggy Kim of the SEC Re: Transocean Ltd. Revised Preliminary Proxy Statement on Schedule 14A, filed March 26, 2013, File No.053533; letter of September 23, 2014 to Karl Hiller of the SEC Re: Transocean Ltd. Form 10K for Fiscal Year ended December 31, 2013 filed February 27, 2014; and Response Letter of September 2, 2014 File No. 053533.

[854] See The Dodd-Frank Wall Street Reform and Consumer Protection Act, Pub. L. No. 111-203, 124 Stat. 1376 (2010).

[855] Coburn, J.; Salmon, R.; Grossman, D. *Sustainable Extraction? An Analysis of SEC Disclosure by Major Oil & Gas Companies on Climate Risk & Deepwater Drilling Risk;* CERES: August, 2012, p 7, http://www.ceres.org/resources/reports/sustainable-extraction-an-analysis-of-sec-disclosure-by-major-oil-gas-companies-on-climate-risk-and-deepwater-drilling-risk/view (accessed October 17, 2015).

[856] The Social Investment Forum (now called US SIF), or The Forum for Sustainable and Responsible Investment "is the US membership association for professionals, firms, institutions and organizations engaged in sustainable, responsible, and impact investing. US SIF and its members advance investment practices that consider

of sustainability indicators using the Global Reporting Initiative's reporting guidelines, and (2) issue new interpretive guidance that would clarify requirements relating to short- and long-term sustainability risks in the Management Discussion and Analysis section of the 10-K.[857] Such indicators could already be implicated under applicable SEC guidance, which requires disclosure of "key performance indicators including non-financial performance indicators, that … management uses to manage the business, and that would be material to investors."[858]

Additional help for greater transparency with respect to health and safety issues may also come from another source as well: the Sustainability Accounting Standards Board (SASB), an independent nonprofit organization whose mission "is to develop and disseminate sustainability accounting standards that help public corporations disclose material, decision-useful information to investors."[859] Part of SASB's mission is to help define materiality of sustainability metrics for determining what information belongs in a company's SEC-required reports, across numerous industries and sectors. The SASB stated that its work involves "revealing the value of material information about companies' environmental stewardship, social policies and corporate governance," and that its mission is to develop and disseminate sustainability accounting standards that help public corporations disclose material, decision-useful information to investors. SASB describes its decisions regarding which criteria are material as evidence-based, meaning it established standards for what they were able to find evidence of financial materiality.

SASB created health, safety, and emergency management reporting standards for both onshore and offshore operations, though currently SASB standards recommend different metrics for the two. For onshore activities, SASB references API RP 754 Tier 3 challenges to safety systems indicator rates, as well as a discussion of measuring operations discipline and management system performance data through reporting of a Tier 4 indicator (see Section 3.4.2). As indicated in Chapter 3.0, Tier 3 and 4 indicators also can be developed for offshore operations. Adding these types of reporting requirements, as well as other potential indicators (e.g., specific metrics that relate to safety culture) could make SASB's recommendations more informative to shareholders, which in turn could drive major accident prevention.

5.5 The Offshore Regulator's Role – An International Perspective

In other countries with active offshore drilling, regulators are engaging corporate boards of directors on process safety by (1) conducting audits and investigations with a specific focus on factors that can inform

environmental, social and corporate governance criteria to generate long-term competitive financial returns and positive societal impact." http://www.ussif.org/about.

[857] Letter from Lisa Woll, CEO of SIF to the Honorable Mary L. Schapiro, Chairman of the US Securities and Exchange Commission, July 21, 2009, p 2.

[858] Coburn, J.; Salmon, R.; Grossman, D. Sustainable Extraction? An Analysis of SEC Disclosure by Major Oil & Gas Companies on Climate Risk & Deepwater Drilling Risk; CERES: August, 2012; p 9, citing 2003 SEC MD&A Guidance at p. 3. http://www.ceres.org/resources/reports/sustainable-extraction-an-analysis-of-sec-disclosure-by-major-oil-gas-companies-on-climate-risk-and-deepwater-drilling-risk/view (accessed October 17, 2015).

[859] http://www.sasb.org/sasb/vision-mission/ (accessed October 7, 2015). SASB's vision is also instructive: "SASB envisions a world where a shared understanding of corporate sustainability performance allows companies and investors to make informed decisions that drive value and improve sustainability outcomes."

management teams and boards of directors to drive major accident prevention, and (2) providing training and a number of good practice documents. These efforts can help corporate boards to take a more active oversight role in HSE matters and to ensure adequate protections against hazards and risks are in place for their companies.

Conversely, US regulators have not yet promulgated good practice guidance and training materials on corporate governance with specific reference to process safety, major hazards, or catastrophic risk in the offshore environment. BSEE can learn from these other jurisdictions, following up on its new safety culture policy guidance, by fashioning its own broader guidance on good practice in corporate governance, and then by engaging boards of directors through training and other initiatives. BSEE is best positioned to work with other government agencies, industry, labor, environmental groups, and interested stakeholders on creating guidance for the offshore industry in the US.

5.5.1 Norway: Management Findings from Audits and Investigations

In Norway, the Petroleum Safety Authority (PSA) studied serious drilling, production, and refining incidents of all types, especially offshore. PSA's audits and investigations led to a number of important findings and suggested practices that advance major accident prevention and safety improvement offshore, some focusing on corporate governance. For example, PSA's work demonstrated that a management team's focus on safety—complemented by the involvement and oversight provided by its board of directors—makes a significant difference in a company's safety performance in major accident prevention. Specifically, "Experience confirms that management of major accident risk is part of a continuous interplay between actions that permeate all the activities and are integrated in the way the management runs the activities, also at the company [Board] level."[860]

Drawing from its history of offshore investigations, PSA initiated a study to review past incidents and surveys of 11 major offshore operators. PSA distilled important factors that can inform management teams and boards of directors to drive major accident prevention in their organizations, many of which echo the CSB's findings in Volume 3. They include:

1. Clarity in the distribution of responsibilities concerning prevention of major accidents, including among various levels of corporate leadership;
2. Knowledge of and attention to major accident risk inherent in the company's activities, including major accident risk associated with change processes;
3. Capacity and competency in the organization regarding handling the risk of major accidents;
4. Ability to learn from serious incidents; and
5. Ability to effectively self-evaluate the overall work needed to reduce the risks of major accidents.[861]

[860] Petroleumstilsynet (Petroleum Safety Authority Norway). *Managing the Risk of Major Accidents in a Governance Perspective;* http://www.ptil.no/getfile.php/PDF/REB-TX-17303-tilsyn%20styring%20storulykkesrisiko%20samlerapport-eng%20%28endelig%20versjon%29.pdf (accessed October 7, 2015).

[861] *Ibid*., pp 3-4.

PSA also found other factors that could positively influence major accident prevention through effective board oversight. One key finding was understanding that "links between different processes and goals are under-estimated, including safety-related consequences of cost reductions, organisational changes and incentive schemes."[862] Boards of directors can make a priority of monitoring management of organizational changes, in light of a board's fiduciary duties and the scope of information that should be available to boards for their high level oversight. Another pair of related findings focused on the commonalities of high-reliability organizations, including an organization's attention to "so called weak signals of hazardous conditions and their approach to uncertainty, complexity, redundancy and learning," including the use of activities such as resilience engineering, and an "emphasis on the connections between different processes … which together can affect the organization's ability to monitor, predict and interpret factors that are important for major accident risk."[863] Again, board oversight can guide a corporation's CEO and senior management team along appropriate pathways through varied means, seeking the right balance between competing factors (e.g., production pressures versus safety, etc.) in a suitable enterprise risk framework.

PSA repeatedly identified the need for clarity in managerial roles because different functions, tasks, disciplines, and operations each have their own particular role and importance in safety. PSA noted that phrases such as "responsibility rests with the line" are too ambiguous to ensure that line managers understand the risk they are accountable for, or that they have the information they need to handle that particular risk, and the means to handle relevant responsibilities. Based on PSA's work in this area, the CSB finds that individual directors working collectively would benefit from the same role clarification within the corporate framework so that they can play an appropriate role in their company for the risks they face. The obligation for safety rests with the board, which must ensure safety responsibilities are divided and managed appropriately throughout all managerial levels, and which the board must monitor and assess.

PSA also noted that in many of its investigations following major accidents, organizations had been "confronted with clear and repetitive symptoms of deterioration of safety-critical barriers," but the "information was not recognized as alarming and/or was not adequately handled." PSA found that much of this phenomena stemmed from two possible causes: (1) faulty assumptions (e.g., safe historical performance which appeared to provide reliable information about risk, so that a decline in the number of incidents by itself unreasonably became an indicator of the robustness of barriers that are preventing accidents), or (2) "systematic under-estimations" of the importance that a myriad of potential changes could have on corporate safety ranging from new investments, procurements, alliances, mergers, change processes, inadequate safety margins, or even an exaggerated confidence at the company level in the systems or barriers standing in the way of a major accident. Boards of directors are perfectly situated to monitor all of these issues though effective and ongoing oversight, in a management of change capacity, provided they are engaged, have all relevant information, and are positioned to test or, if needed, to challenge management's words and actions.

[862] *Ibid.*, p 7.

[863] *Ibid.*, p 7.

Major Accidents and Corporate Integrity

The Norwegian oil company Statoil, an example of strong corporate governance, provided helpful testimony at the CSB's two-day safety performance indicators event in July 2012. According to Statoil's Vice President of HSE Competence Centre, the company's CEO recently noted that the two top threats to Statoil are major accidents and a loss of [corporate] integrity.[a] Along those lines, three of Statoil's top four focus areas for HSE are Leadership and Compliance to our Governing [Governance] System, Improved Risk Management, and Simplification and Harmonization of Work Processes and Governing System.[b] Based on the testimony presented, these activities suggest healthy corporate governance, competent ERM, active efforts aimed at nurturing of a robust safety culture, and a sustainable company overall.

[a] Eie, G. Performance Indicators for Major Accident Prevention, CSB Public Hearing: Safety Performance Indicators, Houston, TX, July 24, 2012, slide 2. http://www.csb.gov/UserFiles/file/Eie%20(Statoil)%20PowerPoint.pdf (accessed October 7, 2015).

[b] Ibid., pp slide 3; see also Statement of Statoil delivered by Guhild Holtet Eie at CSB Public Hearing: Safety Performance Indicators, Houston, TX, July 23-24, 2012, p 184. http://www.csb.gov/assets/1/19/CSB_20Public_20Hearing.pdf (accessed October 7, 2015).

5.5.2 United Kingdom: Guidance and Training

In the UK, seminal guidance jointly published by that country's Health and Safety Executive and the Institute of Directors & Health and Safety Executive offers three essential principles that corporate boards of directors must heed to drive effective corporate governance in health and safety:

1. Boards must take ownership of health and safety from the top down using a strong downward communication and management approach that demonstrates the board is leading the initiative in an active and visible manner, and that health and safety is integrated into the business from the highest level in terms of how management and safety decisions are made.
2. Boards must engage the workforce in promoting and achieving safe and healthy conditions, creating the means for effective upward communication with employees, while providing high-quality training aimed toward safe operations.
3. Boards must identify and manage key health and safety risks, seeking and following competent advice, and then monitoring, reporting, and reviewing safety performance. In a recommended good practice, at least yearly, HSE indicates that each board member should seek to understand and record all relevant data, including auditing results and conclusions from relevant reports, and ensure the information is communicated in the company's annual reports to investors and stakeholders.[864]

[864] Insititute of Directors, Health and Safety Executive. *Leading Health and Safety at Work: Actions for directors, board members, business owners, and organisations of all sizes;* INDG417(rev1), June, 2013, p 1. http://www.hse.gov.uk/pubns/indg417.pdf (accessed October 7, 2015). Many of these same ideas have also been captured and expanded on separately in another helpful treatise produced by IOSH, the chartered body for health

To implement this guidance, HSE lays out a multi-step series of elements in the form of desired "core actions," which include planning, delivering, monitoring, and reviewing a company's health and safety performance, with each step having a number of key components recommended to create full board engagement. HSE explains that these core actions are to be effected through a series of good practices which are practical, actionable steps that help to aim a board's actions toward an increasingly safer company. This and other guidance provides boards with an action-oriented checklist by which directors can methodically consider their corporation's performance in HSE matters, both good and bad, with an eye toward continual improvement.[865]

Combined, these factors can spark board discussion and engagement during oversight activities and management of executive performance, as well as the fuller scope of corporate activities more generally. By doing so, boards can be challenged to think through worst-case scenarios of instances when leadership may fall short in meeting responsibilities, or even where regulators may need to step in to address issues of compliance that management did not handle appropriately.

In 1999, the UK's FRC adopted guidance for risk management and internal controls, *Internal Control: Guidance for Directors on the Combined Code,*[866] commonly referred to as the Turnbull Guidance, advising on oversight responsibilities, decision-making activities, and communications expected of corporate boards of directors across the full spectrum of corporate activity. The Turnbull Guidance also helps directors understand their obligations under existing British law.[867]

In addition to detailing the many critical areas for board member involvement and direction, the Turnbull Guidance and requirements of its Combined Code enshrined in British law notes that board members may have to play an even more significant role in certain areas, depending on the nature of a corporation's business operations. This approach recognizes the need for "a degree of flexibility … boards must see

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and safety professionals in the U: Eves, D.; Gummer, J. *Questioning Performance: Essential Guide to Health, Safety and the Environment ;* IOSH Services Ltd: Wigston, United Kingdom, 2011.

[865] See generally Leading Health and Safety at Work: Actions for directors, board members, business owners, and organisations of all sizes; INDG417(rev1); June, 2013; http://www.hse.gov.uk/pubns/indg417.pdf (accessed October 7, 2015); see also Health and Safety Executive. Leadership for the Major Hazard Industries; INDG277(rev1); September, 2011; http://www.hse.gov.uk/pubns/indg277.pdf (accessed October 7, 2015)., a booklet produced for senior leadership to help them achieve "continuous improvement in health and safety;" Eves, D.; Gummer, J. Questioning Performance: Essential Guide to Health, Safety and the Environment ; IOSH Services Ltd: Wigston, United Kingdom, 2011, explaining that directors must communicate its attitude and expectations around health and safety, the articulated intention of going "beyond compliance" and the desire for a level of HSE performance that delivers cost savings in accident prevention and reduction in lost days, the board's position that HSE is a business risk to be managed, and the board's recognition that it needs to know how the company is managing HSE functions to uphold the company's reputation.

[866] The Institute of Chartered Accountants. *Internal Control Guidance for Directors on the Combined Code;* The Institute of Chartered Accountants: London, England, September, 1999; http://www.ecgi.org/codes/documents/turnbul.pdf (accessed October 7, 2015).

[867] Accomplishment of HSE recommended "good practices" and compliance with the Turnbull Guidance is in accord with the "UK Corporate Governance Code," maintained and enforced by the UK's Financial Reporting Council, the UK analog to the United States' Securities and Exchange Commission. *See* The Financial Reporting Council. *The UK Approach to Corporate Governance;* October, 2010; https://www.frc.org.uk/Our-Work/Publications/Corporate-Governance/The-UK-Approach-to-Corporate-Governance.aspx (accessed October 7, 2015).

good governance as a means to improve their performance, not just a compliance exercise. To be effective it [governance] needs to be implemented in a way that fits the culture and the organization of the company. This can vary enormously . . . depending on factors such as size, ownership, structure and complexity of activities."[868]

Additionally, the Turnbull Guidance cautions boards that assembling a list of risks for the board's attention and action is a "multidimensional" exercise.[869] The guidance pointedly asks directors, "Are the significant internal and external operational, financial, compliance and other risks identified and assessed on an ongoing basis? (Significant risks may, for example, include those related to market, credit, liquidity, technological, legal, health, safety and environmental, reputation, and business probity issues.)"[870] Turnbull makes clear that where such issues are present, it is incumbent upon the board members to play a larger role than might otherwise be expected of a board member at a company that does not face those same risks. The updated Turnbull Guidance (2005)[871] continues to instruct directors to drive health and safety from the top of the organization, thereby protecting their respective companies from all manner of harm, including catastrophic risk.

To facilitate existing UK corporate legislation's effectiveness, and to complement written guidance and training materials, the UK provides corporate boards of directors with other sources of best practices and training materials through partnerships with trade groups and professional associations. For example, at a 2012 conference on corporate governance, Judith Hackitt, Chair of the UK HSE spoke of the agency's "Process Safety Leadership Programme" aimed at board and senior executive level, along with its "Principles of Process Safety Leadership," that industry had "enthusiastically adopted." [872] This model is touted as a successful alternative to the more traditional approach of introducing tougher legislation in the face of challenges. Despite calls for more stringent regulation, a voluntary partnership between government and industry in the UK is being pursued, but as Ms. Hackitt warned, "If you believe, as I think you do, that a voluntary approach is preferable to regulation then demonstrate that you can deliver

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[868] The Financial Reporting Council. *The UK Approach to Corporate Governance;* October, 2010, p 6. https://www.frc.org.uk/Our-Work/Publications/Corporate-Governance/The-UK-Approach-to-Corporate-Governance.aspx (accessed October 7, 2015).

[869] Belcher, A. Corporate Risk Managment and Legal Strategy. In *Legal Strategies: How Corporations Use Law to Improve Performance;* Masson, A., Shariff, M. J., Eds.; Springer-Verlag Berlin Heidelberg: New York, 2010; p 262. Citing Turnbull Guidance and its various focus areas envisioned for corporate boards of directors.

[870] The Institute of Chartered Accountants. *Internal Control Guidance for Directors on the Combined Code;* The Institute of Chartered Accountants: London, England, September, 1999; Appendix, p 13. http://www.ecgi.org/codes/documents/turnbul.pdf (accessed October 7, 2015).

[871] Financial Reporting Council. *Internal Control-Revised Guidance for Directors of the Combined Code;* The Financial Reporting Council: London, October, 2005; https://www.frc.org.uk/getattachment/5e4d12e4-a94f-4186-9d6f-19e17aeb5351/Turnbull-guidance-October-2005.aspx (accessed October 7, 2015). Based on the information gathered by this group, the FRC found that "respondents considered that substantial improvements in internal control instigated by application of the Turnbull guidance have been achieved without the need for detailed prescription as to how to implement the guidance," all through the use of a "principles-based approach [that] has required boards to think seriously about control issues and enabled them to apply the principles in a way that appropriately dealt with the circumstances of their business."

[872] Hackitt, J. (HSE Chair) *Why Corporate Governance and Why Now?*, Conference on Corporate Governance for Process Safety, Paris, France, June 14-15, 2012, http://www.hse.gov.uk/aboutus/speeches/transcripts/hackitt140612.htm (accessed October 7, 2015).

and don't take too long to do it."[873] Hackitt also commented on the fact that major hazards industries within the UK are starting to deliver training to executives and board members on process safety management.[874]

The UK's tripartite Step Change for Safety also contributed with similar initiatives. Step Change for Safety hosted a number of informational trainings and discussions focused on good governance and safety leadership, which benefited leaders at all levels in industry, including boards and senior management.[875]

In parallel, the UK's Chemical Industries Association[876] also created guidance for boards of directors in effective process safety leadership within the UK's chemical industry. This guidance includes establishing:

- A board champion for process safety, ensuring discussion at all board meetings to review performance and set priorities;
- Communication of process safety policies, stressing the importance set by the board and the role of people at all levels in protecting against major hazards;
- Visibility of board-level management (e.g., visiting control rooms, making presentations on major hazard risks);
- Use of effective leading and lagging process safety performance indicators to allow board-level monitoring;
- Board-endorsed formalized process safety improvements plan for ensuring continuous improvement; and
- Outward-looking approaches taken by the company, and the board itself, including a cross-industry approach to learning and sharing the lessons from incidents.[877]

[873] Hackitt, J. (HSE Chair) *Why Corporate Governance and Why Now?* Conference on Corporate Governance for Process Safety, Paris, France, June 14-15, 2012, http://www.hse.gov.uk/aboutus/speeches/transcripts/hackitt140612.htm (accessed October 7, 2015).

[874] Hackitt, J. (HSE Chair) *Why Corporate Governance and Why Now?* Conference on Corporate Governance for Process Safety, Paris, France, June 14-15, 2012, http://www.hse.gov.uk/aboutus/speeches/transcripts/hackitt140612.htm (accessed October 7, 2015).

[875] https://www.stepchangeinsafety.net/about-step-change-safety/previousevents.

[876] The Chemical Industries Association includes primarily chemical and pharmaceutical companies, as well as some drilling services and petrochemical companies, http://www.cia.org.uk/AboutUs/AboutCIA.aspx (accessed October 7, 2015).

[877] Chemical Industries Association. *Best Practice Guide: Process Safety Leadership in the Chemicals Industry;* Chemical Industries Association: London, 2008, in Ellis, G. Process Safety Begins in the Board Room. *Chemical Processing*, March 21, 2013, http://www.chemicalprocessing.com/articles/2013/process-safety-begins-in-the-board-room/?show=all (accessed October 7, 2015).

Case Study: Board of Directors' Vital Role

Under the auspices of the Health and Safety Commission, the HSE published a series of case studies demonstrating the vital role of directors in ensuring that risks are properly managed in all types of companies and industries.[a] *Of particular note is the case study on Amec, a UK company that serves the oil and gas, clean energy, environment and infrastructure, and mining markets.*[b] *According to HSE's case study, Amec's corporate governance includes:*

- *One of the company's directors having the necessary experience in petrochemicals, oil and gas, and gas pipelines across the company's many business lines and in operations around the globe;*
- *A corporate approach to safety that is rooted in major accident avoidance;*
- *Board-level training initiatives including a variety of health and safety training courses germane to high-hazard industries, as well as the creation of company-specific programs such as Amec's SHAPE (Safety and Health in Amec Process & Energy) program with a specific emphasis on process safety;*
- *A deep commitment for the Director who leads safety oversight and other initiatives on behalf of the board, which includes:*
    - *monthly safety briefings at Board meetings,*
    - *real-time updates on safety incidents that are occurring,*
    - *his or her own personal performance contract with safety goals that are available for all the company to see on the company's intranet,*
    - *personal site visits at least once per month,*
    - *operational safety reviews for all businesses quarterly,*
    - *an annual review of each business that specifically covers HSE and sustainability,*
    - *sit-down discussions during all site visits with local management teams focused on safety,*
    - *a companywide safety, health, and environment conference every two years; and*
- *Consistent corporate policies, as well as:*
    - *procedures for hazard identification, risk assessment, and controls,*
    - *documented plans and objectives,*
    - *a clear management structure with established responsibilities,*
    - *competence assurance and training,*
    - *excellent communications and timely notifications,*
    - *established operating procedures, document control, performance indicators,*
    - *investigations and documentation of findings, and*
    - *an audit system, management reports and management reviews.*

[a] McMahon, A.; Shaw, J.; Cash, B.; Wright, M.; Antonelli, A. *Case studies that identify and exemplify Boards of Directors who provide leadership and direction on occupational health and safety;* Research Report 499; Greenstreet Berman Ltd: Reading, Berkshire pp 26-47. http://www.hse.gov.uk/research/rrpdf/rr499.pdf (accessed October 7, 2015); Health and Safety Executive. Case Studies-Successful Leadership, http://www.hse.gov.uk/leadership/casestudies.htm (accessed October 7, 2015).

[b] http://www.amecfw.com/aboutus/at-a-glance (accessed October 7, 2015).

5.6 **Conclusion**

Board engagement in major accident risk management has the potential to make companies safer, assuming boards receive all relevant information needed to inform decision-making, and the board members are empowered to use the information for the benefit of the company. Good communication of those efforts could also then ensure that shareholders receive critical information to hold management, and even the board itself, accountable for a company's safety performance. Thus, a collateral benefit of improved corporate transparency creates an additional layer of safety oversight that comes from the informed self-interest of the corporations' shareholders. Good safety practices and oversight then become self-reinforcing from an additional perspective as the company's equity owners continually obtain information needed to monitor their boards and their companies' safety performance. Transparent reporting rounds out the system of checks and balances needed to maximize effective corporate governance, and thus sustainability.

With appropriate guidance and increased board engagement through interactions with the regulator, more effective board governance can be encouraged, which can translate into a more mature and robust corporate safety culture for companies, with the result being improved major accident prevention fostered by continuous and effective oversight. Additionally, future modifications to existing SEC regulation or other guidance could better guide the entire offshore industry toward greater transparency, helping to focus boards more specifically on process safety and major hazard risks, leading to shareholders empowered with sufficient information to help guide their own decision-making and potential advocacy efforts. Meanwhile, BSEE is well positioned to begin to engage with the US offshore industry, as the agency's international counterparts are doing, to promote major accident prevention through yet another established mechanism.

6.0 Culture for Safety: Focus and Response

Chapter 5.0 Overview

This chapter briefly explores the issue of culture, highlighting the challenges through a review of relatively recent safety culture surveys conducted by BP and Transocean. Measuring and influencing safety culture is a challenge that continues to deserve industry and regulator attention.

"A strong safety culture cannot eliminate all accidents, especially in technologically complex and dynamic industries such as deepwater drilling. There is always a risk that an accident will happen. Strong safety cultures can reduce the likelihood of accidents and the severity of accidents should they occur."[878] For this reason, the CSB addresses culture—as it relates to Macondo, and more broadly to major accident prevention—as part of the human and organizational analysis presented in this volume.

Throughout Volumes 2 and 3, the CSB Macondo report addresses technical, organizational and operational barrier failures that were intended to create multiple layers of defense so that no single barrier became an exclusive line of defense. James Reason describes how culture affects such a defense-in-depth[879] approach: "Because of their diversity and redundancies, the defenses-in-depth will be widely distributed throughout the system. As such, they are only collectively vulnerable to something that is equally widespread. The most likely candidate is safety culture. It can affect all elements in a system for good or ill."[880]

This evidence given in these CSB volumes reveals that the BP and Transocean organizational cultures did not promote process safety. Both companies exhibited organizational behaviors and practices depicting an overarching focus on personal safety without equal attention to managing the barriers and control systems for preventing major accident events. Furthermore, evidence suggests both companies had an organizational focus more akin to minimal compliance with US regulations. To various degrees, both companies exhibited the following organizational behaviors that were detrimental to process safety:

- Poor adherence to their own corporate major hazard management policies, which contained more stringent risk reduction responsibilities than regulations stipulated (Chapters 1.0 and 4.0);
- Inadequate consideration for human and organizational factors in work planning, risk assessment, and incident investigations (Chapters 1.0 and 2.0);
- Inadequate individual performance contracts and bonus structures with limited inclusion of process safety goals (Chapter 3.0);
- Inadequate development and usage of relevant process safety performance indicators (Chapter 3.0);
- Failed efforts aimed toward bridging major risks (Chapter 4.0); and
- Boards of Directors not sufficiently engaged in process safety (Chapter 5.0).

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[878] Expert report of Kathleen M. Sutcliffe, October 17, 2011, for the United States District Court for the Eastern District of Louisiana, MDL No. 2179, Section: J, re. Oil Spill by the Oil Rig "Deepwater Horizon" in the Gulf of Mexico, on April 20, 2010, p 92.

[879] Defense-in-depth is discussed in the CSB Macondo Investigation Report, Volume 2, Section 4.2, pp 51-52.

[880] Reason, J. *A Life in Error* 2013, p 81.

This chapter briefly defines culture as a concept that needs to be understood, along with some of the underlying complexities in interpreting and working with culture. To illustrate these challenges, the chapter describes a number of safety culture assessments conducted of BP and Transocean both preceding and post-incident. The chapter then discusses how culture can be influenced from the top of an organization and addresses efforts BSEE implemented to encourage a focus on a culture for safety offshore.

6.1 Assessing Culture and whether it Promotes Process Safety

Organizational culture refers to the characteristics of the environment, such as the values, rules and common understandings that influence employees' perceptions and attitudes. A culture for process safety refers to those environmental characteristics that influence employees' perceptions and attitudes *about the importance the organization places on process safety*.[881] Many aspects of an organization's culture are unstated, underlying, and often operate at a subconscious level. As such, efforts to assess and change culture are challenging.[882] Frequently depicted visually as an iceberg, only a small portion of culture is actually observable (Figure 6-1). Examples of these artifacts include the proclaimed values of the company, the messages it communicates to its management, workforce, and the public; the policies it establishes and the practices it implements; and the organizational behaviors it exhibits in its daily operation. But underneath the water's surface are the shared values and assumptions that might not be so readily apparent—the norms, attitudes, actual values, shared understandings, and basic assumptions that drive employee behavior and performance.[883] Change must occur throughout the entire iceberg for culture to be impacted.

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[881] Haber, Sonja, Culture for Safety, Human Performance Analysis, Corp., February 17, 2016. CSB Learning Seminar.

[882] Schein, Edgar H. 2004. *Organizational Culture and Leadership, 3rd ed.*, Jossey-Bass: San Francisco, CA, pp 25-37.

[883] Haber, Sonja, Culture for Safety, Human Performance Analysis, Corp., February 17, 2016. CSB Learning Seminar.

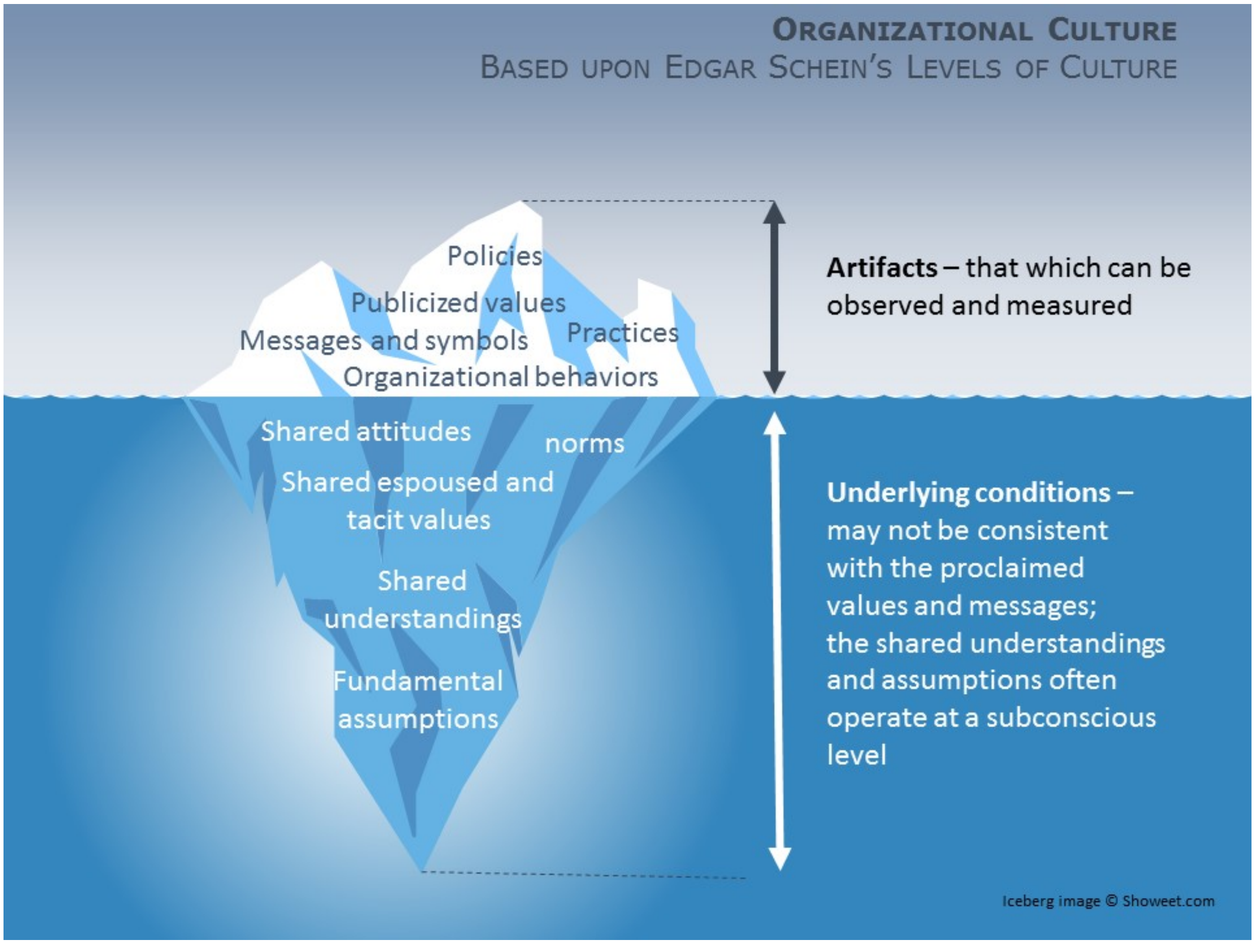

Figure 6-1. Visual representation of organizational culture, based on Edgar Shein's levels of culture.[884]

The observable artifacts tell only one piece of the culture story, but they are the outcomes of the shared understandings and fundamental assumptions. They can provide clues of disparities between proclaimed cultural values and actual shared values. Therefore, culture is expressed not only in the stated goals, policies, procedures, and practices that a company formally adopts to enhance process safety, but also in the actual commitment by leaders, management, and the workforce to meet those corporate requirements. This commitment impacts "how the organization behaves when no one is watching" [885] and influences decisions by personnel at all levels of the organization.

Comparing what actually happens in the organization to the proclaimed values and stipulated corporate policies provides insights into the unstated values of the organization that influence daily worker actions and decisions. Incongruences between the proclaimed values and the actual practices give evidence that

[884] Schein, Edgar H. 2004. *Organizational Culture and Leadership, 3rd ed.*, Jossey-Bass: San Francisco, CA, pp 25-37.

[885] American Institute of Chemical Engineers (AICHE). Safety Culture: What is at Stake?; *Safety Science* 2015**,** *77*, pp 102-111.

what is being said is not necessarily indicative of the actual culture and the basic assumptions at the organization's core. The practice(s) reflect the actual values.[886] With this perspective, the CSB examines a number of culture assessments of BP and Transocean in the next section.

6.2 Culture Assessments of BP and Transocean

In the years leading up to the Macondo incident, both BP and Transocean commissioned reviews of their respective safety cultures. For BP, the review took the form of the Baker Panel commission, which was prompted by an urgent CSB recommendation in response to the 2005 BP Texas City explosion.[887] In that post-incident safety culture assessment, the Baker panel noted five fundamental observations concerning BP's safety with respect to its US refineries:

1. BP had not provided effective process safety leadership to establish a focus on process safety as a core value, rather emphasizing personal safety;
2. BP had not established a positive, trusting, and open environment with effective lines of communication;
3. BP had not always ensured it identified and provided resources, both financial and human, required for strong process safety performance;
4. BP did not effectively incorporate process safety consideration into management decisions; and
5. BP did not instill a common, unifying culture among its various refineries.

Arriving at these conclusions, the Baker panel employed a multifaceted approach that included (but was not limited to) a process safety culture survey of the BP refinery workforce and interviews with corporate-level management.

A culture/climate review of Transocean's North American Division (including the Deepwater Horizon) was commissioned by the company months before the Macondo incident, after the company experienced four separate fatality incidents.[888] The review determined that, in some respects, the company displayed evidence of a relatively strong culture for safety:[889]

> Overall, […] Deepwater Horizon was relatively strong in many of the core aspects of safety management. The strong team culture onboard Deepwater Horizon and the levels of mutual trust evident between crews means that the rig safety culture was deemed to be robust, largely fair, and inclusive, which was contributing to a 'just culture.'… The findings from the […] review

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[886] Wilkinson, P., 2016, Culture: Values and Practices – can you have one without the other? p 2, available at the csb.gov website; Hopkins, A., 2005. *Safety, Culture and Risk,* CCH Australia Ltd, pp 6-11

[887] The Baker Panel. *The Report of the BP US Refineries Independent Safety Review Panel;* January, 2007, p 94. http://www.csb.gov/assets/1/19/Baker_panel_report1.pdf (accessed October 7, 2015).

[888] Internal Company Document, Transocean, *Transocean Launches Evaluation Safety and Processes and Culture*, October 21, 2009, TRN-MDL-04335708. http://www.mdl2179trialdocs.com/releases/release201303211200016/TREX-52646.pdf (accessed October 8, 2014).

[889] Internal Company Document, Transocean. *Safety Management and Safety Culture/Climate: North America Division Summary Report*, July 2, 2010, see Exhibit 0929, TRN-HCEC-00090579, http://www.mdl2179trialdocs.com/releases/release201304041200022/Bertone_Stephen-Depo_Bundle.zip (accessed October 7, 2015).

> indicated that the overwhelming majority of participants felt empowered with regard to safety on the rig. In particular, almost everyone felt they could raise safety concerns and these issues would be acted upon if this was within the immediate control of the rig. Supervisor support for legitimate safety concerns was praised on a number of occasions, and it was clear that issues were elevated (when appropriate) via line management structures. In short, individuals reported that they could confidently approach rig management with any safety concerns they may have, knowing that, if their concern is justified, they will receive full backing.

Yet a disparity between rig culture and the larger organization was also identified. The review followed the positive statements about culture by noting, "It must be stated at this point, however, that the workforce felt that this level of influence was restricted to issues that could be resolved directly on the rig, and that they had little influence at Divisional or Corporate levels."[890] This finding alludes to the influential role of leadership from the highest levels on culture, particularly on important issues like communication, trust, and engagement throughout the organizational hierarchy. The review went on to describe several safety issues, including management and communication of change and the complexities and inconsistencies with implementation of the various risk management policies. Section 4.3 highlighted a number of specific disparities between corporate policy and worksite practice.

Post-Macondo, BP commissioned another safety culture assessment of its organization, which concluded that "BP succeeded in creating a well elaborated safety culture,"[891] citing evidence that the company regularly and continuously reflects on safety performance and the causes of incidents, makes efforts to learn from them in real time in both formal and informal ways, and encourages learning and continuous improvements in safety in the programs, policies and procedures it has implemented. [892] While this professional assessment of safety culture certainly identified strong points in the organization, in its attempt to examine how the safety culture is *enabled*, *enacted*, and *elaborated*,[893] it did not assess whether the company's policies for risk management and operational success were followed at Macondo.

A culture that truly promotes safety extends beyond workers' perceptions, espoused values, and documented policies. As described in Section 6.1, a culture for safety is characterized not only by goals, policies, and procedures, but by the company's commitment to them and what it actually does. Chapters 1.0 and 4.0 describe many situations where the company did not initiate or uphold safety policies meant to manage major accident hazards. For example, Transocean's planning and risk management processes

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[890] Internal Company Document, Transocean. *Safety Management and Safety Culture/Climate: North America Division Summary Report*, July 2, 2010, see Exhibit 0929, TRN-HCEC-00090579, http://www.mdl2179trialdocs.com/releases/release201304041200022/Bertone_Stephen-Depo_Bundle.zip (accessed October 7, 2015).

[891] Expert report of Kathleen M. Sutcliffe, October 17, 2011, for the United States District Court for the Eastern District of Louisiana, MDL No. 2179, Section: J, re. Oil Spill by the Oil Rig "Deepwater Horizon" in the Gulf of Mexico, on April 20, 2010, p 70.

[892] *Ibid*., 70.

[893] The culture assessor defines these terms as the three elements of a strong safety culture: "(1) it is enables, meaning that the organization and its leaders emphasize safety and create a positive safety climate; (2) it is enacted, meaning that members of the organization put the organization's safety policies and procedures into practice; and (3) it is elaborated, meaning that the organization rigorously reflects on its safety performance and seeks to improve its policies and procedures as a result." Expert report of Kathleen M. Sutcliffe, October 17, 2011, for the United States District Court for the Eastern District of Louisiana, MDL No. 2179, Section: J, re. Oil Spill by the Oil Rig "Deepwater Horizon" in the Gulf of Mexico, on April 20, 2010, p 5.

at Macondo lacked implementation, yet the safety culture survey indicated a belief that "the THINK process was sound and contributed to safe working practices." The Deepwater Horizon crew also indicated they felt good about safety on the rig, but the metric the crew judged this performance on was the Lost Time Incident (LTI) personal safety metric. In fact, the crew indicated the LTI rate was a "key driver in raising awareness and promoting safe behaviors." [894] Akin to the LTA metric described in Section 3.1 [895] LTI is an indication of good personal safety but conveys little about process safety performance.

Furthermore, it is commendable that BP can cite policies and efforts to investigate incidents,[896] but as Chapter 2.0 describes, the focus and type of investigation conducted will influence the lessons derived. If the focus is on technical matters, without exploration into the human and organizational factors, and without a systemic approach, as was the case, for example, with the March 8 kick, then the lessons derived will reflect that limitation. A culture that values process safety must examine such issues for future prevention. As another example, BP's Macondo investigation did not include an analysis of management and organizational factors that contributed to the incident,[897] thus choosing not to explore that avenue of potential learning that might have revealed systemic deficiencies. If an incident on the scale of Macondo does not evoke action to explore systemic causes, what does that convey about the underlying values of the organization? Sound process safety risk awareness and management is a focus throughout this report, and Transocean's positive pre-incident safety culture assessment findings suggest that sufficient information on the culture of the organization cannot be derived without effectively addressing all levels of culture, including identifying the underlying basic assumptions. Then the company must strive to support those values and basic assumptions in practice.[898]

6.3 Influencing a Culture for Process Safety from the Top

The manner in which culture change is accomplished is multifaceted and beyond the scope of this investigation; however, this discussion is mindful that "Companies have found that if safety and health values are not consistently and (constantly) shared at all levels of management and among *all* employees, any gains that result from declaring safety and health excellence a "priority" are likely to be short-lived."[899] "Shared" does not mean that all employees have the same level of influence on culture, or the

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[894] Internal Company Document, Transocean. *Safety Management and Safety Culture/Climate: North America Division Summary Report*, July 2, 2010, see Exhibit 0929, TRN-HCEC-00090587, TRN-HCEC-00090598, http://www.mdl2179trialdocs.com/releases/release201304041200022/Bertone_Stephen-Depo_Bundle.zip (accessed October 7, 2015).

[895] In company documents, Transocean referred to this metric as the total recordable injury rate (TRIR), but the crew referred to the safety metric in terms of LTIs rather than the TRIR. See Section 0 for the introduction to TRIR.

[896] Expert report of Kathleen M. Sutcliffe, October 17, 2011, for the United States District Court for the Eastern District of Louisiana, MDL No. 2179, Section: J, re. Oil Spill by the Oil Rig "Deepwater Horizon" in the Gulf of Mexico, on April 20, 2010.

[897] BP, *Deepwater Horizon Accident Investigation Report*, September 8, 2010, p 12 and Appendix A.

[898] Wilkinson, P., 2016, Culture: Values and Practices – can you have one without the other? p 2, available at the CSB.gov website.

[899] Quoted in *The Report of the BP US Refineries Independent Safety Review Panel;* January, 2007, p 23, footnote 19. http://www.csb.gov/assets/1/19/Baker_panel_report1.pdf (accessed October 7, 2015).

actual authority to get things done. Indeed, "implementing practices is a leadership responsibility and requires great care to avoid unintended consequences, as well as active monitoring[900] to verify they are applied as intended."[901] Thus, a company's most senior leadership, starting at the board of directors, plays the pivotal role in influencing a culture that robustly promotes process safety. Cases show that actual practices repeated by a group over time, when enforced and verified by an authoritative entity, can lead to a culture change.[902] Institutional actions offer deep insight into a corporate culture: "critical controls to prevent a major incident are just another way of describing important organisational practices."[903]

The relationship between major accident prevention and organizational culture has been recognized across the full spectrum of high-hazard industries, including offshore drilling, aviation safety, underground mining, and nuclear power. For more than 25 years, the US Nuclear Regulatory Commission has been refining its safety culture expectations for organizations performing or overseeing regulated nuclear activities.[904] It defines safety culture as the "core values and behaviors resulting from a collective commitment by leaders and individuals to emphasize safety over competing goals to ensure protection of people and the environment."[905]

In light of the DWH incident and repeated calls for promoting a culture for safety offshore, BSEE released its *Safety Culture Policy Statement*, announcing expectations "that individuals and organizations performing or overseeing activities regulated by BSEE establish and maintain a positive safety culture commensurate with the significance of their activities and the nature and complexity of their organizations and functions." [906]

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[900] For a description of "Active Monitoring" in the context of major accidents, although the principles have wider application, see: http://www.csb.gov/assets/1/7/Wilkinson_Active_Monitoring.pdf Accessed 31 December 2015.

[901] Wilkinson, P., 2016, Culture: Values and Practices—can you have one without the other? p 3, available at the CSB.gov website.

[902] Andrew Hopkins gives the example of legal requirements for seatbelts in vehicles; this practice was initially rejected and challenged, seen as a burden. Over time, as financial consequences for not wearing them became prevalent, it gradually became habitual to wear one. Now wearing seatbelts is perceived to be sensible. Hopkins, Andrew, *Why safety cultures don't work*, Future Media Training Resources, p 1.

[903] Wilkinson, P., 2016, Culture: Values and Practices—can you have one without the other? p 3, available at the CSB.gov website.

[904] [Online]; http://www.nrc.gov/about-nrc/safety-culture/sc-policy-statement.html#dev (accessed October 7, 2015).

[905] 76 Fed. Reg. 34773-34778 (June 14, 2011).

[906] BSEE, *Safety Culture Policy Statement*, http://www.bsee.gov/Safety/Safety-Culture-Policy/ (accessed October 7, 2015).

BSEE's Safety Culture Policy Statement

According to BSEE, the following characteristics "typify a robust safety culture":[†]

1. ***Leadership Commitment to Safety Values and Actions.*** *Leaders demonstrate a commitment to safety and environmental stewardship in their decisions and behaviors;*
2. ***Hazard Identification and Risk Management.*** *Issues potentially impacting safety and environmental stewardship are promptly identified, fully evaluated, and promptly addressed or corrected commensurate with their significance;*
3. ***Personal Accountability.*** *All individuals take personal responsibility for process and personal safety, as well as environmental stewardship;*
4. ***Work Processes.*** *The process of planning and controlling work activities is implemented so that safety and environmental stewardship are maintained while ensuring the correct equipment for the correct work;*
5. ***Continuous Improvement.*** *Opportunities to learn about ways to ensure safety and environmental stewardship are sought out and implemented;*
6. ***Environment for Raising Concerns.*** *A work environment is maintained where personnel feel free to raise safety and environmental concerns without fear of retaliation, intimidation, harassment, or discrimination;*
7. ***Effective Safety and Environmental Communication.*** *Communications maintain a focus on safety and environmental stewardship;*
8. ***Respectful Work Environment.*** *Trust and respect permeate the organization with a focus on teamwork and collaboration; and*
9. ***Inquiring Attitude.*** *Individuals avoid complacency and continuously consider and review existing conditions and activities in order to identify discrepancies that might result in error or inappropriate action.*

[†] BSEE, *Safety Culture Policy Statement*, http://www.bsee.gov/Safety/Safety-Culture-Policy/ (accessed October 7, 2015).

BSEE's *Safety Culture Policy Statement* is a commendable first step. It could be improved by explicitly acknowledging the role that all levels in an organization play in influencing how the culture promotes process safety, including the role of the board of directors. This includes ownership of process safety risk from the top down, with the board leading and supporting the initiative, engaging the workforce to promote health and safety, and identifying key performance safety indicators to monitor efforts.

Future BSEE culture efforts could also require that companies formally assess their organizational cultures and whether the culture has sufficient focus on process safety. Culture assessments have the potential to identify the safety perceptions of employees and the commitment of individuals from all levels of the organization to the formally-adopted corporate process safety goals, policies, procedures, and practices. A variety of culture assessment methods can be used to explore willingness to report incidents and near-misses, the effectiveness of workforce participation efforts, and organizational drifts from safety policies and procedures. The assessment results can be the basis of conversation between the industry, workforce/management, and the regulator to create, "a qualitative shift in industry and regulatory safety cultures from the minimalist compliance … to the philosophy of best practice and continuous improvement."[907] While companies can employ assessment approaches specific to their own safety management systems and policies, it would be useful for BSEE to work with industry, workforce, and culture experts to develop culture assessment methods that can be used industrywide to gain further insights into safety perceptions offshore. Creating and using such validated methods will allow for collecting information to support improvements, not only within each organization, but also broadly across the US offshore industry.

6.4 Conclusion

There will be situations when "individual behavior [i]s inconsistent with the organization's commitment to safety."[908] However, one individual did not cause the Macondo event. A multitude of decisions and actions up and down the organizational chains of both companies impacted the events of April 20, 2010, and those decisions and actions are influenced by the invisible and often unstated basic assumptions and shared values of the involved companies.

Identifying incongruities between proclaimed values and the actual basic assumptions and values of the organization is one step toward understanding and working with culture. Culture assessments could be a useful tool to help organizations understand their culture and whether it adequately promotes safety. This information would also be useful for regulators in helping to identify potential issues and their mitigation in the interest of accident prevention. The assessments need to be conducted with a multifaceted approach that (1) addresses worker perceptions, (2) delves into the context of those perceptions as they relate to the values of the organization, d an(3) identifies the basic assumptions of the organization. The information must be assessed in conjunction with an examination of how the artifacts (e.g. actual practices) reflect those values and assumptions.

All levels of culture require monitoring and modification for change to occur. Indicators monitoring the actual implementation of process safety policies and practices can shed light on where actual practices differ from stated policies and values—a first step for an organization to identify potential conflicts. Having a better understanding of their organizational culture, management, the workforce, and the regulator can take proactive steps to remediate inadequacies while reinforcing effective practices, thus driving more sustainable, long-term safety improvements.

[907] Department of Industry, Science, and Resources: Offshore Safety and Security, Petroleum and Electricity Division, Report of the Independent Review Team, Australian Offshore Petroleum Safety Case Review, February-March 2000 Stakeholder Survey, http://www.industry.gov.au/resource/Documents/upstream-petroleum/safety/Australian_Offshore_Petroleum_Safety_Case_Review_Feb-Mar_2000.pdf (accessed March 2, 2015).

[908] Expert report of Kathleen M. Sutcliffe, October 17, 2011, for the United States District Court for the Eastern District of Louisiana, MDL No. 2179, Section: J, re. Oil Spill by the Oil Rig "Deepwater Horizon" in the Gulf of Mexico, on April 20, 2010, p.91.

7.0 Volume 3 Conclusion

Chapter 1.0 describes how, due to the tightly coupled interdependencies, complex systems like offshore drilling operations are susceptible to performance variability and organizational drift, and the adaptability and flexibility of the humans within the system determine operational success. To successfully minimize undesirable consequences, therefore, industry must shift from correcting individual "errors" identified post-incident to a systematic approach for managing human factors. Such a risk management approach would include a proactive process for assessing human factors for major accident prevention, concentrated focus on minimizing the gap between work-as-imagined and work-as-done, and a concerted effort to improve the non-technical skills of both workforce and management.

Major catastrophes, fortunately, are infrequent. For this reason, investigations of those rare events, and the more frequent near-misses, provide critical insight into potential safety gaps for those operating offshore. Yet, as Chapter 2.0 highlights, organizational learning poses many challenges for industry, including the effective culling and disseminating of lessons between operators and leaseholders, the successful sharing of those lessons across global corporations, and the still all-too-frequent focus on technical causes without sufficient focus on systemic and organizational factors. Actual implementation of corrective actions, and not just dissemination of incident facts and findings, is imperative, and the regulator has an opportunity to influence companies in this endeavor.

History has repeatedly proven that personal safety indicators are inaccurate predictors for major accident events. Chapter 3.0 demonstrates that, at the time of the Macondo incident, both BP and Transocean collected, measured, and rewarded personal safety metrics and, correspondingly, both companies achieved low personal worker injury rates. However, process safety did not receive the same attention from either company. Further work is needed on developing and implementing effective performance metrics that indicate the health of major accident barriers and the safety management systems meant to ensure their reliability. While Chapter 3.0 provides suggested potential indicators based on findings from the CSB's Macondo investigation, appropriate process safety KPIs for the individual company and industrywide needs additional focus from numerous stakeholders, including management, workforce, and regulators.

Chapter 4.0 demonstrates how the complexities of multi-party risk management in the offshore industry led to vaguely established safety roles and responsibility between the operator (BP) and the drilling contractor (Transocean). Ultimately, while both companies had corporate policies for risk management, neither BP nor Transocean assumed responsibility for implementing those policies at Macondo, and no regulatory requirements or oversight ensured that such policies were upheld and that the major accident risks inherent in their operations were effectively managed.

Chapter 5.0 explores the influential role of corporate governance in deciding what and how safety is managed throughout the organizational hierarchy, as well as the influential role shareholders and the regulator could have in ensuring corporate boards are conversant in the major hazards influencing their business.

Chapter 6.0 uses the numerous examples of operational practices of both BP and Transocean from preceding chapters to illustrate that both companies were perpetuating a culture of minimal compliance. Both companies exhibited failures to follow internal risk management policies, safety management system programs and provisions for risk reduction to ALARP, despite organizational requirements to do so.

As a result of the analyses presented in this volume, and in pursuit of major accident prevention, Chapter 8.0 lists several recommendations addressing human factors, corporate governance, safety performance indicators, and culture.

The analyses presented in this volume provide the evidentiary foundation for the regulatory analysis presented in Volume 4. These two final volumes work in tandem to argue for further safety improvements to industry risk management practices through additional regulatory provisions and authorities that place the onus of major accident prevention squarely on industry while improving the oversight capabilities of the regulator.

8.0 Recommendations

Volume 3 issues one recommendation to the American Petroleum Institute (CSB2010-I-OS-R5), three recommendations to the US Department of Interior (CSB-2010-10-I-OS-R6 and –R8), one to the Sustainability Accounting Standards Board (CSB-2010-10-I-OS-R9), and one to the Ocean Energy Safety Institute (CSB-2010-10-I-OS-R10).

CSB2010-10-I-OS-R5 Recommends Augmenting API 75 to include the various process safety concepts and major accident prevention (MAP) management systems

American Petroleum Institute

Based on the analysis presented in the CSB Macondo investigation report, Volumes 3 and 4, and the requirements listed in R11, revise Recommended Practice 75, *Development of a Safety and Environmental Management Program for Offshore Operations and Facilities, 3rd ed*., May 2004 (reaffirmed May 2008), to require a specific focus on major accident prevention and address the following issues:

a. Incorporate the following listed safety management system issues as explicit program elements and include language throughout API 75 regarding each element's explicit and defined applicability to all of the other existing program elements:
    1. Human factors program requirements for the design, planning, execution, management, assessment, and decommissioning of well operations for the prevention of major accidents, as well as in the investigation of accidents and near-misses;
    2. Corporate governance and Board of Director responsibilities for major accident risk management;
    3. Workforce involvement and engagement in all aspects of the SEMS program;
    4. Contractor oversight and effective coordination for major accident prevention; and
    5. Leading and lagging key performance indicators that drive major accident prevention.

b. Define and expand the roles and responsibilities for major accident prevention among the primary parties engaged in offshore drilling and production (i.e., the leaseholder/operator *and* owner/drilling contractor) by expanding applicability of this standard to the parties with primary control over major hazard operations and day-to-day activities and thus best positioned to implement and oversee a safety and environmental management system (SEMS) program to control major accident hazards.

c. Incorporate into the Principles section of the document, as well as within the Setting Objectives and Goals section, as overarching provisions for the overall successful implementation and execution of a SEMS program:
    1. Management of major accident risk to As Low As Reasonably Practicable or similar risk-reduction target;
    2. Use the hierarchy of controls for identifying, establishing, and implementing barriers meant to prevent or mitigate major accident hazards.

CSB2010-10-I-OS-R6 Recommends Development of Human Factors Guidance for Major Accident Prevention

United States Department of Interior

Drawing upon best available global standards and practices, develop guidance to assist industry in the incorporation of human factors principles into the systematic analysis of their major accident hazards, development of their SEMS programs, and in the preparation of their major hazards report documentation. This standard shall provide guidance on topics including, but not limited to, safety critical task assessment and the development and verification of non-technical skills. Include the participation of diverse expertise in the development of the standard including industry, workforce, and subject matter expert representatives.

CSB2010-10-I-OS-R7 Recommends Development of Corporate Governance Guidance and the Engagement of Corporate Boards and Executives for Risk Management and Major Accident Prevention

United States Department of Interior

Drawing upon best available global standards and practices, develop guidance addressing the roles and responsibilities of corporate board of directors and executives for effective major accident prevention. Among other topics, this standard shall provide specific guidance on how boards and executives could best communicate major accident safety risks to their stakeholders, as well as corporate level strategies to effectively manage those risks.

CSB2010-10-I-OS-R8 Recommends Regulatory Requirements for Safety Culture Improvements

United States Department of Interior

Expand upon the principles of the BSEE Safety Culture policy and establish a process safety culture improvement program for responsible parties as defined in R11(a) that periodically administers process safety culture assessments and implements identified major accident prevention improvements. The process safety culture improvement program shall include a focus on items that measure, at a minimum, willingness to report incidents and near-misses, effectiveness of workforce participation efforts, organizational drift from safety policies and procedures, and management involvement and commitment to process safety.

CSB2010-10-I-OS-R9 Recommends Strengthening and Finalizing the Sustainability Accounting Standards Board's Oil & Gas Exploration & Production Sustainability Accounting Standard (Provisional, dated June 2014)

Sustainability Accounting Standards Board

Update, strengthen, and finalize the SASB's provisional Oil & Gas Exploration & Production Sustainability Accounting Standard by enhancing standard NR0101-18. Expand recommended coverage of "Process Safety Event rates for Loss of Primary Containment of greater consequences" in accordance with the findings of this report. Specifically, this expanded coverage shall:

a. Recommend the disclosure of additional leading and lagging indicators and emphasize the greater preventive value of disclosure of a company's use of leading indicators to actively monitor the health and performance of major accident safety barriers and the management systems for ensuring their effectiveness. Specifically add:
    1. Indicators addressing the health of safety barriers to be communicated to the workforce, and to shareholders in required SEC disclosures, and also to be made readily available to the regulator.
    2. Guidance emphasizing and promoting the concept that personal safety metrics such as those captured in NR0101-17 (total recordable injury rate, fatality rate, near-miss frequency rate) are important but separate from leading and lagging process safety performance indicators, which better correlate to major accident prevention.
        - Accomplish this communication within NR0101-18.
        - Supplement this effort within the SASB's Oil & Gas Exploration & Production Research Briefs, based on the findings of this report as well other current safety scholarship that demonstrates the lack of correlation between personal safety efforts and process safety and major accident prevention initiatives.

CSB2010-10-I-OS-R10 Recommends further study to advance industry's understanding of the gas-in-riser hazard.

Ocean Energy Safety Institute

Conduct further study on riser gas unloading scenarios, testing, and modeling and publish a white paper containing technical guidance that communicates findings and makes recommendations for industry safety improvements.

By the

U.S. Chemical Safety and Hazard Investigation Board

Vanessa A. Sutherland
Chairperson

Manuel Ehrlich
Member

Rick Engler
Member

Kristen Kulinowski
Member

Date of Board Approval: April 17, 2016

U.S. CHEMICAL SAFETY AND HAZARD INVESTIGATION BOARD

INVESTIGATION REPORT
VOLUME 4

DRILLING RIG EXPLOSION AND FIRE AT THE MACONDO WELL

(11 Fatalities, 17 Injured, and Serious Environmental Damage)

DEEPWATER HORIZON RIG

MISSISSIPPI CANYON 252, GULF OF MEXICO

APRIL 20, 2010

KEY ISSUES:

- US OFFSHORE SAFETY REGULATION DURING AND AFTER MACONDO
- ATTRIBUTES OF AN EFFECTIVE REGULATOR AND REGULATORY SYSTEM

REPORT NO. 2010-10-I-OS
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Acronyms and Abbreviations

AB	Accreditation Body
ACOP	Approved Code of Practice
AEC	Atomic Energy Commission
ALARA	As Low As Reasonably Achievable
ALARP	As Low As Reasonably Practicable
ANSI	American National Standards Institute
AOC	Acknowledgement of Compliance
API	American Petroleum Institute
ASME	American Society of Mechanical Engineers
ASP	Audit Service Provider
ASTM	American Society for Testing and Materials
BAST	Best Available and Safest Technology
BOEM	Bureau of Ocean Energy Management
BOEMRE	Bureau of Ocean Energy Management, Regulation, and Enforcement
BOP	Blowout Preventer
BSEE	Bureau of Safety and Environmental Enforcement
CCPS	Center for Chemical Process Safety
C.F.R.	Code of Federal Regulations
COMAH	Control of Major Accident Hazards
COS	Center for Offshore Safety
CSB	U.S. Chemical Safety Board
CUPA	Certified Unified Program Agency
DAFW	Days Away From Work
DNFSB	Defense Nuclear Facilities Safety Board
DNV	Det Norske Veritas
DOI	Department of Interior
DWH	Deepwater Horizon
EPA	Environmental Protection Agency
EPP	Employee Participation Plan

FRC	Financial Reporting Council
GAO	US Government Accountability Office
GASCET	Guidance for the Topic Assessment of Major Accident Hazard Aspects of Safety Cases
GoM	Gulf of Mexico
HSE	Health Safety Executive (of the United Kingdom)
IADC	International Association of Drilling Contractors
INC	Incident of Noncompliance
INPO	Institute of Nuclear Power Operations
IPD	Interim Policy Document
IRF	International Regulators' Forum
ITL	Information to Lessee
JSA	Job Safety Analysis
LCM	Loss Circulation Material
LTI	Lost Time Incident
MBI	Marine Board of Investigation
MDL	Multi-District Litigation
MESA	Mining Enforcement and Safety Administration
MMS	Minerals Management Service
MOA	Memorandum of Agreements
MOC	Management of Change
MODU	Mobile Offshore Drilling Unit
MSHA	Mine Safety and Health Authority
NAE	National Academy of Engineering
NOPSA	National Offshore Petroleum Safety Authority; formally NOPSEMA (of Australia)
NOPSEMA	National Offshore Petroleum Safety and Environmental Management Authority
NRC	Nuclear Regulatory Commission
NTL	Notice to Lessee
OCS	Outer Continental Shelf
OCSLA	Outer Continental Shelf Lands Act
OECD	Organization for Economic Co-operation and Development
OESAC	Ocean Energy Safety Advisory Committee

OIAC	Offshore Industry Advisory Committee
OIM	Offshore Installation Manager
ONRR	Office of Natural Resources Revenue
OOC	Offshore Operators Committee
OSDR	Offshore Safety Directive Regulator
OSHA	Occupational Safety and Health Administration
OTC	Offshore Technology Conference
PHMSA	Pipeline and Hazardous Materials Safety Administration
PINC	Potential Incident of Noncompliance
PSA	Petroleum Safety Authority
PSM	Process Safety Management
RIF	Recordable Injury Frequency
ROP	Reactor Oversight Process
SEC	Securities and Exchange Commission
SEMP	Safety and Environmental Management Program
SEMS	Safety and Environmental Management System
SHE	Safety, Health and Environment
SMS	Safety Management System
SOP	Standard Operating Procedure
SWA	Stop Work Authority
TRB	Transportation Research Board
TPSR	Total Potential Severity Rate
TRIR	Total Recordable Injury Rate
UK	United Kingdom
US	United States
USCG	United States Coast Guard
UWA	Ultimate Work Authority
WCS	Well Construction Standards
WEST	Workforce Engagement Support Team
WOMP	Well Operations Management Plan

Volume 4

Regulatory Oversight of U.S. Offshore Oil and Gas Operations: A Call for More Robust and Proactive Requirements

Volume 4 – Introduction

In the aftermath of the Macondo incident, the US offshore safety regulations for drilling and completions activities on the outer continental shelf have been reviewed, debated, and revised.[1] Amid several reorganizational efforts, the Department of Interior established the Bureau of Safety and Environmental Enforcement (BSEE) in October 2011 to oversee safety of the US offshore oil and gas operations.[2] BSEE's immediate predecessor, the Bureau of Ocean Energy Management, Regulation & Enforcement, (BOEMRE),[3] promulgated the Safety and Environmental Management Systems (SEMS) rule in October 2010,[4] requiring the previously voluntary practices in the American Petroleum Institute's (API) Recommended Practice 75 (API 75).[5] After BSEE's creation, the agency amended SEMS in 2013 to further its initiative for performance-based[6] regulations to "reduce the occurrence of accidents, injuries, and spills during oil and gas activities on the Outer Continental Shelf (OCS)."[7] In April 2015, BSEE proposed well control regulations that it identified as the "most substantial rulemakings in the history" of offshore safety in the United States.[8] Most recently, on December 7, 2015, BSEE announced the launch of a pilot Risk-Based Inspection Program to complement its existing inspections and audits with the goal of more efficiently and effectively managing the limited inspection and auditing resources of the agency.[9] In support of these endeavors, BSEE has made efforts over the last five years to educate its staff and

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[1] See Appendix A for a history of offshore US oil and gas safety regulation. Including pre-Macondo events.

[2] http://www.bsee.gov/About-BSEE/BSEE-History/index/ (accessed January 19, 2016).

[3] BOEMRE replaced the Minerals Management Service (MMS) shortly following the Macondo incident in 2010.

[4] Oil and Gas and Sulphur Operations in the Outer Continental Shelf, 75 Fed. Reg. 63609 (Final Rule, October 15, 2010) (to be codified at 30 C.F.R. Part 250).

[5] API Recommended Practice 75, 3rd ed., *Recommended Practice for Development of a Safety and Environmental Management Program for Offshore Operations and Facilities*, May 2004 (Reaffirmed May 2008).

[6] The US Nuclear regulatory commission defines performance-based regulation as "a regulatory approach that focuses on desired, measurable outcomes, rather than prescriptive processes, techniques, or procedures. Performance-based regulation leads to defined results without specific direction regarding how those results are to be obtained;" http://www.nrc.gov/reading-rm/basic-ref/glossary/performance-based-regulation.html (accessed January 19, 2016).

[7] Oil and Gas and Sulphur Operations in the Outer Continental Shelf—Revisions to Safety and Environmental Management Systems, 78 Fed. Reg. 20423 (Final Rule, April 5, 2013) (to be codified at 30 C.F.R. Part 250);

While the original SEMS rule became effective on November 15, 2010, this subsequent enhancement effective June 4, 2013 is referred to as SEMS II. SEMS II incorporated additional safety requirements that addressed stop work authority, ultimate work authority, employee participation plans, guidelines for reporting unsafe work conditions, job safety analyses, and independence of accredited audit service providers. Unless otherwise stated, when the CSB refers to SEMS, it is addressing both the original SEMS rule and the subsequent SEMS II revisions; see also, BSEE. *Safety and Environmental Management Systems (SEMS) Fact Sheet;* http://www.bsee.gov/BSEE-Newsroom/BSEE-Fact-Sheet/SEMS-II-Fact-Sheet/ (accessed March 21, 2016).

[8] Oil and Gas and Sulphur Operations in the Outer Continental Shelf—Blowout Preventer Systems and Well Control, 80 Fed. Reg. 21504 (Proposed Rule, April 17, 2015) (to be codified at 30 C.F.R. Part 250).

[9] *Bureau of Safety and Environmental Enforcement to Launch Pilot Risk-Based Inspection Program for Offshore Facilities.* December 7, 2015. http://www.bsee.gov/BSEE-Newsroom/Press-Releases/2015/Bureau-of-Safety-and-Environmental-Enforcement-to-Launch-Pilot-Risk-Based-Inspection-Program-for-Offshore-Facilities / (accessed December 21, 2015).

engage in dialogue with industry, regulatory bodies, and safety experts worldwide to improve its function as the regulator of offshore safety.

While the acknowledging these positive efforts, the CSB concludes that the SEMS regulations do not provide BSEE with an adequate framework for major accident prevention, and an improved approach is needed to reduce the risk of another Macondo-like event. SEMS does not utilize goal-setting, meaning the reduction of risks to a goal such as "as low as reasonably practicable" (ALARP). In addition, notwithstanding the implementation of SEMS, BSEE audit findings suggest that a culture of minimal regulatory compliance continues to exist in the Gulf of Mexico and risk reduction continues to prove elusive.[10] Ultimately, the offshore regulatory changes made thus far do not sufficiently place the onus on industry to reduce risk or empower the regulator to ensure proactive and effective industry management and control of major hazards.

1.1 Approach to Analysis

The CSB's preventive mission as a federal agency is to reduce chemical hazards as broadly as possible (e.g., through recommendations that will effect national preventive changes). The CSB, therefore, focuses its recommendation efforts on changing national legislation, regulation, voluntary consensus standards, and industry recommended practices. As a result of an investigation or study, the CSB may issue "proposed rules or orders" to regulators such as the EPA Administrator and the Secretary of Labor "to prevent or minimize the consequences of any release of substances that may cause death, injury or other serious adverse effects on human health or substantial property damage as the result of an accidental release."[11] The CSB's investigative analytical approach, therefore, must look beyond technical and management system causes.

The CSB approach to regulatory analysis and recommendations starts with an examination of key investigative findings and an analysis of whether the applicable regulatory and enforcement regime manifests weaknesses or gaps that were causally related to the incident. The CSB formulates recommendations that, if effectively implemented, work to prevent or reduce the similar incidents or hazards to as great an extent as possible. For example, key findings in Volumes 3 and 4 of the Macondo Report show that the US offshore regulator lacks effective use of key process safety indicators and guidance addressing corporate boards of directors and human factors focused on major accident prevention. The CSB report analysis shows that addressing these significant gaps could help reduce the risk of similar incidents.

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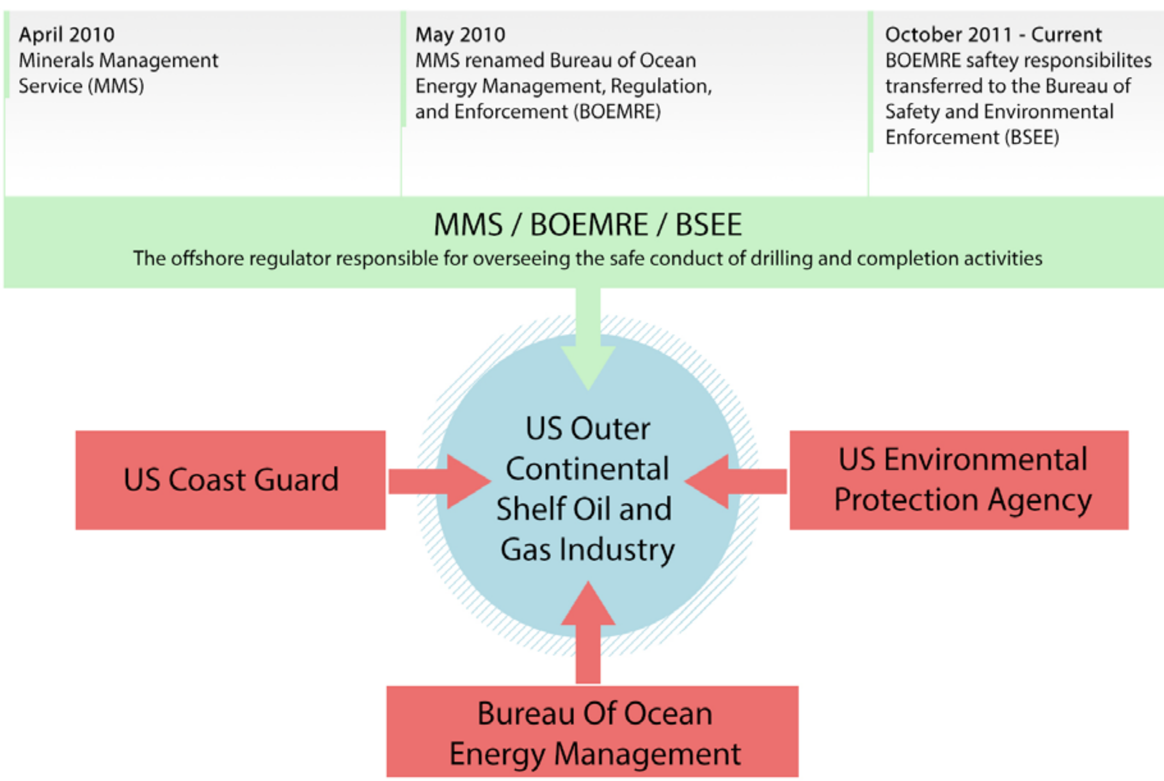
[10] See Section 4.2 and Bureau of Safety and Environmental Enforcement. *BSEE Priorities Regarding SEMS*, Offshore Technology Conference, Houston, TX, 2015; http://www.bsee.gov/uploadedFiles/BSEE/BSEE_Newsroom/Speeches/2015/OTC%202015%20Mtg%20SEMS%20Presentation.pdf (accessed December 19, 2015).

[11] 42 USC sec. 7412(r)(6)(c)(ii).

Throughout Volume 4, the CSB refers to "the regulator" or "offshore regulations" to indicate either MMS or BSEE and their respective safety regulations for drilling and completions activities on the outer continental shelf. As indicated in the figure below, MMS evolved into BSEE after the Macondo incident occurred. In reality, several regulatory bodies oversee the offshore oil and gas industry, including the US Coast Guard (USCG), the Bureau of Ocean Energy Management (BOEM), and the Environmental Protection Agency (EPA), but the CSB generally limits its discussion to MMS and BSEE due to its specific authority over the safe conduct of offshore drilling and completion operations.



1.2 Attributes of an Effective Regulatory Model

Various international models for offshore safety regulation can be used to compare and contrast what the US regulator has adopted since Macondo. No one approach is an undisputed panacea for all accidents, partly because prevention requires active and sustained participation in risk reduction from industry, the workforce, and the regulator. Ultimate responsibility for preventing incidents and protecting workers and the public always remains with the employers and parties who create or control major accident risk. Yet regulatory systems have an important role to play in establishing sufficient requirements, guidance, and oversight to establish a floor of practice that if covered employers implement effectively works to reduce major incidents.

As part of the agency's investigative approach, the CSB frequently compares international regulatory regimes from what existed at the worksite under investigation to examine the strengths and weaknesses of different models and methodologies. [12] It would be incorrect, however, to assume that an effective model found in some other international jurisdiction could necessarily be imported to the US with no allowance for important variances that may exist among cultures, existing legal and regulatory structures, political systems, as well as numerous and varied industry stakeholder interests and levels of involvement. To that end, the CSB reviews international regulatory models to identify various attributes that could strengthen the current US offshore regulatory environment. This helps clarify key attributes that could provide more effective safety regulation for addressing identified gaps and weaknesses. Recent CSB reports used this approach, such as those analyzing the 2010 Tesoro Anacortes and 2012 Chevron Richmond refinery incidents, and have identified attributes from other regulatory regimes to address causal regulatory gaps related to the incidents. [13] Those attributes related to the Macondo incident causal factors include:

Continual Risk Reduction to Levels As Low As Reasonably Practicable (ALARP)

The intention of a goal-based, risk-reduction regulatory framework is to eliminate or sufficiently minimize the risks in an operation. Although risk can never be completely eliminated, any such framework must continually strive toward this goal. With major accident hazards, the key question becomes: Is there anything more that can be done to reduce the risk? ALARP is a standard familiar to industry in other global offshore regimes, and even in other high-hazard industries in the US. In such regimes, the government sets the goal, and the duty holder demonstrates how it will meet that goal through submitted documentation. The regulator then holds the duty holder accountable to execute that

[12] In the investigation of a 1999 fire that killed four workers at the Tosco Avon refinery in Martinez, California, the CSB report identified features and attributes from the UK HSE's regulatory guidance related to safe piping and equipment opening in process plants that supported the analysis and recommendations in the report. See USCSB, 2001, *Refinery Fire Incident, Martinez, CA, February 23, 1999*, Report No. 99-014-I-CA, Section 3, pp 31-44, March 2001, http://www.csb.gov/assets/1/19/Tosco_Final_Report.pdf (accessed March 25, 2016).

In the 2002 CSB Hazard Investigation Report, Improving Reactive Hazard Management, the CSB concluded that the UK HSE and European Union utilize a comprehensive "all hazards" approach to reactive hazard management with regulatory requirements based upon a facilities' written analysis of specific hazards and needed controls rather than limited to an approach that only reviews listed chemicals based upon their inherent instability. Those regulatory attributes buttressed CSB's recommendations that called upon EPA and OSHA to base reactive hazard coverage upon classifications beyond a list that would include combinations of chemicals and process specific conditions. See USCSB, 2002, *Improving Reactive Hazard Management*, Section 8.1.3, pp 83-84, October 2002, http://www.csb.gov/file.aspx?DocumentId=355 (accessed March 25, 2016).

[13] USCSB, 2013. *Regulatory Report: Chevron Richmond Refinery Pipe Rupture and Fire, Richmond, CA, August 6, 2012*, Report No. 2012-03-I-CA, April 2013, http://www.csb.gov/assets/1/19/Chevron_Regulatory_Report_11102014_FINAL_-_post.pdf (accessed January 25, 2016).

USCSB, 2014. *Catashtrophic Rupture of Heat Exchanger, Anacortes, WA, April 2, 2010,* Report No. 2010-08-I-WA, May 2014, http://www.csb.gov/assets/1/7/Tesoro_Anacortes_2014-May-01.pdf (accessed October 7, 2015).

plan. The regulator will work with duty holders to obtain the necessary improvement if their work raises significant safety concerns at any point in the lifecycle of the hazardous operation.

The post-Macondo US offshore regulatory framework still does not provide goal-setting, risk-reduction requirements for oil and gas operations in the same manner as ALARP, though that may change, in part, if the well control rule BSEE recently proposed is adopted.[14]

Regulator Adaptability

The regulator has the tools to encourage industry to adopt new technologies and safer practices without additional rule-making. Such improvements may result from learnings from major accidents that occur within jurisdictional waters or internationally. The regulator must be capable of assessing the duty holders' chosen methods to assure that they remain adequate in terms of good practice and achieve a satisfactory level of safe operation.

Safety Responsibility is Maintained by those that Control or Create the Risk

Liability, and thus responsibility, for safety resides with the companies ("duty holders") that have the most direct control over the design, management, and execution of hazardous activities being undertaken. For example, an operator is responsible for the safe design of a well, while the drilling contractor supplies most of the workforce and infrastructure, resulting in control over the primary drilling operations and well response actions.

Active Worker Participation

Past CSB investigations have consistently identified the important role workers and their representatives play in major accident prevention. A fundamental element in effective safety management for major accident prevention is active and meaningful participation from the regulator, industry, and labor. Each of these entities provides unique and essential insights, so denying their effective participation removes critical voices in health and safety matters. Recognizing this operating principle, the United Kingdom (UK) and Norway established tripartite systems of industry, the regulator, and the workforce to deal with safety and health issues. Yet, the US offshore framework does not endow the workforce with a legally empowered voice on matters concerning safety. Similarly, US offshore regulations do not support a more traditional tripartite arrangement like those in other high-hazard industrial settings, domestically and internationally, where the regulator, industry, and workforce all play important roles.

Required Written Safety Documentation by Duty Holders

Duty holders submit or make available to the regulator documentation that analyzes all major hazards; the risks associated with those hazards; and the technical, operational, and organizational controls to reduce those risks to ALARP or a similar goal. Also included is a description of the safety management systems

[14] Oil and Gas and Sulphur Operations in the Outer Continental Shelf—Blowout Preventer Systems and Well Control, 80 Fed. Reg. 21504 (Proposed Rule, April 17, 2015) (to be codified at 30 C.F.R. Part 250).

to continually monitor and respond to health and safety hazards. These documents become the basis for regulator audits to confirm that duty holders are following their own stated practices.

Regulatory Assessment and Verification

Regulators have a number of proactive tools at their disposal to evaluate and monitor safety performance. These include preventive assessments to verify that a company's technical and safety management practices are aligned with their written safety documentation, controlling regulations, industry standards, and good practice guidance before hazardous work begins, as well as audits and inspections to review the on-going effectiveness of a company throughout the lifecycle of the hazardous operation.

Regulator uses Process Safety Indicators that Drive Performance

The aim of collecting and using safety performance indicators is to publicly identify safety trends and to establish initiatives for industry to meet higher performance levels. An effective safety indicators program allows for regulatory focus on key indicators, target-setting to drive industry improvements, and issue-specific regulatory program initiatives.

Regulator Transparency

Through real-time publication of appropriate indicators, inspection results, and safety documentation, a regulator prompts companies to reduce risk. These safeguards illuminate for all stakeholders the companies that are experiencing superior safety results because of improved technologies or enhanced operational methodologies, and they can help companies with weaker safety performance to improve. Such transparency can also spur workforce and public pressure on companies to improve safety, protecting the lives of workers and the offshore environment.

Independent, Qualified, and Adequately Funded Regulator

An independent, technically qualified, and adequately resourced regulator is necessary to ensure that regulatory oversight does not devolve into an exercise in compliance-checking and paperwork. The regulator must be able to vigorously question and dialogue with industry regarding the offshore hazards, barriers, and safety management systems industry members have established to manage those hazards.

This final volume builds on Volume 3 analysis to support the conclusion that the offshore safety management regulations, specifically the SEMS Rule, do not adequately employ rigorous approaches to process safety management and major accident prevention. Despite the restructuring of the US offshore regulatory system and new safety management regulations for drilling and completion operations, critical gaps remain. Current safety management regulations fail to establish goal-oriented risk reduction measures for preventing major incidents; do not adequately support a tripartite system of industry, workforce, and regulator collaborating to improve safety; do not feature adequate proactive audits and inspections by the regulator; and do not sufficiently use leading and lagging safety performance indicators to avoid major accidents and influence ongoing safety improvements. The regulatory attributes identified in this final volume of the CSB's Macondo investigation series highlight the important roles of the regulator, industry, and workforce in a goal-setting, risk-reduction regime.

2.0 Reviewing International Regulatory Models

Volumes 2 and 3 of the CSB's Macondo Investigation Report demonstrate that the incident would have been less likely to occur if BP and Transocean had implemented modern process safety good practices applicable to offshore (e.g., those concerning safety critical barrier identification and management, human factors, safety performance indicators of barrier health and safety system reliability, ALARP, and corporate governance of major accident hazards). While Transocean and BP had adopted some of these process safety concepts into their corporate policies, they did not apply them at Macondo. This disregard of their stated commitments reveals a culture of minimal compliance with regulations and demonstrates the need for regulatory action to prevent such an approach.

Before Macondo, offshore US regulations did not address safety management systems and risk management, relying instead on voluntary participation by operators to adopt safety and environmental management programs. Since Macondo, BSEE has promulgated SEMS, which incorporates by reference API's *Recommend Practice for Development of a Safety and Environmental Management Program for Offshore Operations and Facilities*. Process safety management good practice has advanced considerably since API 75 was first published, but those advances are not reflected in the recommended practice, and consequently not in SEMS.

After reviewing the regulatory history of safety management systems offshore in the US, this chapter introduces a regulatory model referred to as the "safety case regime," which has been widely recommended post-Macondo in numerous investigation reports. Volume 4 examines the safety case models used in the UK and Australia as well as the regulatory model adopted in Norway to review how the attributes identified in Section 0 might be implemented in the US to address regulatory gaps and weakness highlighted by the Macondo incident.

2.1 History of Safety and Environmental Management Systems Offshore in the US

In 1991, the then-US offshore regulator, MMS, proposed a regulatory model for offshore safety management, the Safety and Environmental Management Program (SEMP). [15] SEMP was to address key points such as written management policies, procedures, training, accident prevention and investigation, and corrective action plans. Some industry commenters requested that MMS wait until the voluntary API 75 standard was published before making a decision, while some recommended MMS simply set safety goals for the industry rather than promulgating regulations.[16] Ultimately, MMS did not promulgate SEMP regulations, but after helping to develop API 75, MMS requested that offshore operators[17] voluntarily adopt the principles contained in it once published.[18]

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[15] Oil and Gas and Sulphur Operations in the Outer Continental Shelf, 56 Fed. Reg. 30400 (Notice, July 2, 1991).

[16] Oil and Gas and Sulphur Operations in the Outer Continental Shelf, 59 Fed. Reg. 29277 (Notice, June 30, 1994).

[17] 'Operators' as referenced in US offshore regulations refer explicitly to the leaseholders of the well; this term does not include drilling contractors or other well service providers.

[18] Oil and Gas and Sulphur Operations in the Outer Continental Shelf, 59 Fed. Reg. 29277 (Notice, June 30, 1994).

API 75 recommended that OCS operators have a safety and environmental management program for their operations that included elements such as: [19]

- safety and environmental information;
- hazards analysis;
- management of change;
- safe work practices
- training;
- assurance of quality and mechanical integrity of critical equipment;
- and audit of safety and environmental management program elements.

Rather than ensuring continual safety improvement and evaluation of the effectiveness of safeguards through more rigorous requirements (e.g., using language such as “shall”), the standard relied upon permissive language such as “should” and “recommends.” For example, API 75 only permissively stated that owners and operators “should,” rather than “shall,” require that program elements be documented and reviewed to assure they continued to be suitable, adequate, and effective.[20]

On June 30, 1994, MMS published a notice in the Federal Register stating that it would closely monitor the voluntary adoption of API 75 by OCS operators for two years.[21] In another notice published in the Federal Register on July 18, 1996, MMS stated that it collaborated with API to conduct an annual series of surveys to gauge how well OCS operators were implementing SEMP through API 75.[22] The MMS stated that surveys conducted in January 1995 and January 1996 showed OCS operators “well on their way to implementing SEMP plans,” and if progress similar to this were maintained, the MMS expected that many of these companies’ SEMP plans would be “fully implemented in the field within the next 1-2 years.”[23] As MMS continued to collect information, it deferred deciding for a mandatory or voluntary adoption of the SEMP by OCS lessees.

Throughout the 1990s and 2000s then, MMS monitored the voluntary adoption of SEMP, but it was not until 2006 that MMS again addressed making SEMP, and potentially elements addressed by API 75, a regulatory requirement.[24] At that time, MMS published a study of 310 incident that resulted in 13 fatalities and 97 injuries.[25] MMS’s analysis indicated that the contributing causes to the majority of these incidents were associated with four SEMP elements: hazards analysis, management of change, mechanical integrity, and operating procedures. MMS observed, “requiring operators to implement

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[19] API Recommended Practice, 75, 3rd ed., *Recommended Practice for Development of a Safety and Environmental Management Program for Offshore Operations and Facilities,* May 2004 (Reaffirmed May 2008).

[20] *Ibid.*, p 2.

[21] Oil and Gas and Sulphur Operations in the Outer Continental Shelf, 59 Fed. Reg. 29277 (Notice, June 30, 1994).

[22] Safety and Environmental Management Program (SEMP) on the Outer Continental Shelf (OCS), 61 Fed. Reg. 37493 (Notice, July 18, 1996).

[23] *Ibid.*

[24] Oil and Gas and Sulphur in the Outer Continental Shelf (OCS)—Safety and Environmental Management Systems, 71 Fed. Reg. 29278 (Advanced Notice of Proposed Rulemaking, May 22, 2006).

[25] *Ibid.*

these critical elements of an integrated safety management system could address MMS's concerns with performance and ultimately improve safety and environmental compliance on the OCS."[26]

This proposal was not without strong opposition. The Offshore Operators Committee (OOC),[27] a large industry group comprising major oil company representatives of which BP is a member, conducted a workshop in September 2009.[28] The OOC resisted making SEMP a required regulation. Instead, OOC compared MMS's proposal to adopt API 75 as regulation to the potential damage from a hurricane: "Both are disruptive to operations and are costly to recover from!"[29] OOC also asserted that MMS failed to understand that the existing voluntary programs for safety and environmental protections were effective, that the industry's safety record continued to improve without the need for prescriptive regulation. OOC asserted that the "recordkeeping" envisioned in SEMP/SEMS did nothing to keep people safe, thereby making the implementation of SEMS unnecessary.[30] OOC concluded that offshore safety could be most improved through the continued use of voluntary safety programs that allowed the "various operators the opportunity to style their programs to fit their corporate culture and operations" and the need to "modify worker behavior."[31] Ultimately, it was only after the consequences of Macondo were fully realized did safety and environmental management systems become a regulatory requirement.

2.1.1 The Outdated API Offshore Safety Management System Approach

API 75 was, in part, based upon API 750, "Management of Process Hazards," whose safety focus is for the "prevention of catastrophic releases of toxic and explosive material." API 75, though, lacks the explicit purpose of preventing major hazard accidents and instead encompasses offshore safety and environmental protection in general.[32] As generally discussed in Volume 2, the low probability of major accidents can lead to low perception of risk. As a result, offshore drillers may not assess major accident scenarios and identify controls to prevent or mitigate them.[33] Both BP and Transocean illustrated this lapse at Macondo. For example, BP's risk matrix for Macondo did not consider potential blowouts, but

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[26] *Ibid.*

[27] According to the Offshore Operators Committee Mission Statement, available on its website: "The Offshore Operators Committee (OOC) is a non-profit organization comprised of any person, firm or corporation owning offshore leases and any person, firm or corporation engaged in offshore activity as a drilling contractor, service company, supplier or other capacity that desires to participate in the work of OOC or the Offshore Operators Committee…The Committee's activities are focused on providing its member operators with information and technical support that will assist them in conducting their offshore activities in a manner that will promote sound safety and environmental operational practice." See "About the OOC" at http://www.offshoreoperators.com (Accessed March, 26, 2016).

[28] OOC. Offshore Operators Committee SEMS Feedback, September 2, 2009; http://big.assets.huffingtonpost.com/MMS-2008-OMM-0003-0030.3.pdf (accessed March 26, 2016).

[29] Verret, A. *MMS Expectations*, Offshore Operators Committee SEMS Feedback, September 2, 2009; http://big.assets.huffingtonpost.com/MMS-2008-OMM-0003-0030.3.pdf (accessed March 26, 2016).

[30] Parker, W. *Closing Statement*, Offshore Operators Committee SEMS Feedback, September 2, 2009; http://big.assets.huffingtonpost.com/MMS-2008-OMM-0003-0030.3.pdf (accessed March 26, 2016).

[31] Parker, W. *Closing Statement*, Offshore Operators Committee SEMS Feedback, September 2, 2009; http://big.assets.huffingtonpost.com/MMS-2008-OMM-0003-0030.3.pdf (accessed March 26, 2016).

[32] API Recommended Practice, 750, 1st ed., *Management of Process Hazards,* January 1990.

[33] Volume 2, Section 4.1.

rather other more probable well control issues such as a stuck pipe or lost circulation.[34] In the case of Transocean, safety critical procedures identified and addressed personal safety hazards or relatively minor spills rather than potential loss of well control events.[35]

API 75 states that operators should develop SEMP documentation addressing 11 management program elements such as hazard analysis, management of change, incident investigation, and audits.[36] While the 11 elements are important safety management systems, they fall short of the more rigorous approach taken by the Center for Chemical Process Safety (CCPS), which details additional elements that include process safety culture, management review and continual improvement, workforce involvement, and measurement and metrics.[37] These key topics and others are either missing or not effectively addressed in API 75. Moreover, language of the SEMP/SEMS guidelines weakens their impact. API 75 does not recommend a specific safety goal such as preventing accidents or controlling hazards, nor does it reference a risk goal such as ALARP.

The provisions listed in API 75 for each management program element are typically activity-based,[38] meaning that the mere completion of an activity does not necessarily focus on the effectiveness of accident prevention measures, or necessarily result in actual risk reduction. For example, the hazard analysis element in API 75 states the purpose of the analysis is "to identify, evaluate, and where unacceptable, reduce the likelihood and/or minimize the consequences of uncontrolled releases and other safety or environmental incidents."[39] Without a risk-reduction requirement such as ALARP, this formulation leaves what is "unacceptable" entirely to the discretion of owners/operators, rendering the regulator powerless to proactively question or intervene, even if the owners/operators' efforts seem minimal or insufficient.

Both API RP 750 and API 75 were first issued early in the development of process safety principles. API 750 is no longer published, and although API 75 was reaffirmed in 2008 and 2013, has not been updated since 2004. Neither reflects current process safety principles described throughout Volume 3, yet API 75 is a cornerstone of offshore US safety regulations requiring operators to "develop, implement, and maintain a safety and environmental management system (SEMS) program [that addresses] elements described in American Petroleum Institute's Recommended Practice for Development of a Safety and Environmental Management Program for Offshore Operations and Facilities." [40]

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[34] Volume 3, Section 4.4.2.

[35] Volume 3, Sections 1.8.2 - 1.8.4.

[36] API Recommended Practice, 75, 3rd ed., *Recommended Practice for Development of a Safety and Environmental Management Program for Offshore Operations and Facilities*, May 2004 (Reaffirmed May 2008).

[37] Center For Chemical Process Safety. *Guidelines for Risk Based Process Safety;* John Wiley & Sons: Hoboken, NJ, 2007.

[38] The CSB coined the term "activity-based" in its Chevron regulatory report; USCSB, 2013. *Regulatory Report: Chevron Richmond Refinery Pipe Rupture and Fire, Richmond, CA, August 6, 2012*, p 9, Report No. 2012-03-I-CA, April 2013, http://www.csb.gov/assets/1/19/Chevron_Regulatory_Report_11102014_FINAL_-_post.pdf (accessed January 25, 2016).

[39] API Recommended Practice, 75, 3rd (2004, reaffirmed 2008) ed., *Recommended Practice for Development of a Safety and Environmental Management Program for Offshore Operations and Facilities*, p 7.

[40] 30 C.F.R. § 250.1900 (2016).

2.2 Purpose of the Regulations and Role of the Regulator

Offshore safety regulators exist, in part, to hold industry accountable for health, safety, and environmental protection standards in their offshore operations, and to address other issues not necessarily related to safety, such as licensing, revenue collection, and environmental protection and stewardship. Due to the dangers posed by high-hazard offshore oil and gas operations, the US government has an interest in establishing minimum safety standards and outside verification mechanisms to oversee that industry follows those standards to benefit of workers and the environment. The catastrophic potential for injuries, deaths, or damage that could result without an effective regulator cannot in good conscience be tolerated, and companies may not always choose to operate with appropriate protections unless the government requires it. At a minimum, offshore regulations explain to industry and the public the boundaries and expectations for those protections. These offshore resources are to some extent considered held in public trust, so another of the regulator's key tasks relates to effective stewardship of the deepwater assets themselves. Moreover, the regulator must act on environmental protection issues, driven by the growing need to safeguard the natural environment and the interest of all stakeholders as it grants operators and drillers a public license to extract offshore resources safely for the benefit of the corporation and the overall US economy.

Regulators can conduct oversight responsibilities through varied mechanisms, both proactively and reactively, to influence industry safety improvements. Regulators can challenge safety claims that industry makes and assure their implementation of safety management systems in general through inspections, audits, and incident investigation. Some regulatory attributes inherently provide a regulator with more tools or position the regulator to provide more effective—and even more proactive—oversight in high-hazard industries like offshore drilling. [41]

[41] See Section 0 for a summary of these regulatory attributes, though they will be discussed more in depth throughout Volume 4.

2.3 An Alternative Regulatory Model: The Safety Case

Following the Macondo blowout, numerous widely circulated official investigative reports recommended broad improvements to the US offshore regulatory regime. Many specifically promoted adopting a fundamentally different regulatory model for deepwater drilling in the outer continental shelf region of the US, the “safety case.” They included:

- The National Commission on the BP Deepwater Horizon Oil Spill (National Commission) which stated, “The Department of the Interior should develop a proactive, risk-based performance approach specific to individual facilities, operations and environments, similar to the ‘safety case’ approach in the North Sea. … Require operators to develop a comprehensive ‘safety case’ as part of their exploration and production plans—initially for ultra-deepwater (more than 5,000 feet) areas, areas with complex geology, and any other frontier or high-risk areas—such as the Arctic.”[42]
- The National Academy of Engineering (NAE), along with the National Research Council (NRC), examined the probable causes of the Macondo explosion, fire, and oil spill, recommending that the US “fully implement a hybrid regulatory system that incorporates a limited number of prescriptive elements into a proactive, goal oriented risk management system for health, safety, and the environment.” [43]
- Det Norske Veritas (DNV), one of the leading classification and certification bodies operating worldwide, asserted, “The current safety regime for the US Gulf of Mexico is largely a prescriptive regulation with no requirement for safety cases to be performed.… an offshore safety regime based on a performance-based regulation requiring safety cases including risk assessments supplemented by required or recommended specific prescriptive regulation for selected areas is the most effective regime model.”[44]
- The Department of Interior recommended several improvements concerning its offshore safety regime, including specific reference to the safety case model: “The Department Will Adopt Safety Case[45] Requirements for Floating Drilling Operations on the OCS … based on IADC [International Association of Drilling Contractors] Health, Safety and Environmental Case Guidelines for Mobile Offshore Drilling Units (2009).”[46] The DOI further recommended:

[42] National Commission on the BP Deepwater Horizon Oil Spill and Offshore Drilling. *Deepwater: The Gulf Oil Disaster and the Future of Offshore Drilling - Report to the President;* Janurary, 2011; pp 252-253.

[43] National Academy of Engineering and National Research Council. *Macondo Well Deepwater Horizon Blowout: Lessons for Improving Offshore* Drilling *Safety*; December 14, 2011; p 90.

[44] Pitblado, R.; Bjerager, P.; Andreassen, E. *An Effective US Offshore Safety Regime;* Det Norske Veritas: 22 2010, July; p 3. http://www.dnvusa.com/Binaries/1008-001%20Offshore%20Update_Key%20aspects_tcm153-430982.pdf (accessed March 16, 20106).

[45] DOI defines the safety case as follows: “A safety case is a comprehensive and structured set of safety documentation to ensure the safety of a specific vessel or equipment. This documentation is essentially a body of evidence that provides a basis for determining whether a system is adequately safe for a given application in a given environment;” Department of Interior. *Increased Safety Measures for Energy Development on the Outer Continental Shelf;* May 27, 2010; p 27.

[46] Department of Interior. *Increased Safety Measures for Energy Development on the Outer Continental Shelf;* May 27, 2010; p 27.

"Finalize a rule that would require operators [on the OCS] to develop a robust safety and environmental management system for offshore drilling operations," which DOI described as "a comprehensive, systems-based approach to safety and environmental management that incorporates best practices from around the globe."[47]

- The United States Coast Guard (USCG) recommended that it "work with BOEMRE to evaluate the benefits of shifting to a "Safety Case" approach similar to that used in the North Sea, a method in which there is a more holistic approach to safety.[48]

These recommendations reflect a logical progression of a regulatory approach seen throughout the history of offshore oil and gas regulation. It makes sense for society to protect its interests through appropriate regulation if an industry, such as offshore oil and gas exploration and production is capable of endangering the lives or safety of workers or creating significant health and safety or environmental risk to its citizens. Such a regulatory regime could be: (1) a state-run, nationalized industry centrally controlled by the government; (2) a prescriptive licensing and approval regime with audits and inspections and penalties for failure to comply with regulations; or (3) a safety case type of regime where the company proposes to conduct its activities and then explains its major accident hazards assessment and control plan to the regulator, typically (but not always) for acceptance before commencing drilling exploration or production operations.

Some prescriptive regulation is typically present in a safety case regime, such as technical requirements for equipment, but overall, the safety case approach refers to a goal-setting, risk-reduction approach intended to drive the risk of a major accident event to as low as reasonably practicable. Upon drilling a new well, this begins in the project development stage, when the leaseholder has a duty to demonstrate to the regulator that the risks of its design are ALARP, and how it will reassess any significant changes to maintain risk levels. The well design inherently defines what operational risks drilling contractors will manage and how they will implement, monitor, and maintain effective barriers (also referred to as controls) for each of those risks. Ultimately, the drilling contractor submits for the offshore regulator's acceptance its "case" concerning the controls it has implemented to maintain operational safety.

A key advantage of this type of a goal-setting regulatory approach, in contrast to a regulatory scheme based on compliance with prescriptive requirements, is the freedom or flexibility it provides companies to control risks, and to be able to rely on good practice using their own preferred methods to achieve safe operation. This flexibility is particularly necessary for both the regulator and the company in situations affecting unique scenarios on the cutting edge of technology where good engineering practice continues to develop, such as Arctic operations. In fact, as explained by offshore expert Peter Wilkinson, "[o]ne of the main benefits [of the safety case model] is not the finished product, but the actual process of preparing

[47] *Ibid.*, pp 27- 28.

[48] As offshore safety regulators in the US, BOEMRE and USCG formed a Joint Investigation Team to investigate the Deepwater Horizon disaster. BOEMRE and the USCG published separate reports addressing their respective areas of safety responsibility; USCG, *Report of the Investigation into the Circumstances Surrounding the Explosion, Fire, Sinking and Loss of Eleven Crew Members Aboard the Mobile Offshore Drilling Unit Deepwater Horizon in the Gulf of Mexico, April 20-22, 2010*, Volume 1, MISLE Activity Number 3721503; p 127. http://www.uscg.mil/hq/cg5/cg545/dw/exhib/DWH%20ROI%20-%20USCG%20-%20April%2022,%202011.pdf (Accessed March 26, 2016).

the safety case and having to identify hazards and review the installation design, construction and operation."[49]

A regulatory model like the safety case regime, however, demands that the regulator play a fundamental role in ensuring that industry continually strives to reduce risks to ALARP. This means the regulator is instrumental in using a variety of means to ensure good practices exist across the sector. Put simply, the regulator sets the goals (e.g., drive the risk as low as reasonably practicable), reviews a company's proposed written case for safety in terms of its operations and management of hazards, and then ensures that a company performs as promised in meeting stated goals. If the regulator has concerns about a company's safety case or operational performance, then it has the resources and other tools to understand the company's position through direct engagement. The regulator can then can either accept the company's case, or alternatively initiate efforts to obtain necessary improvement. According to Wilkinson, the safety case regime even helps make regulators more effective. He noted: "safety cases make it possible for the regulator's interventions to be more effective because the safety case should identify the critical safety issues and the regulator's interventions can concentrate on these."[50] These interventions reach far beyond complying with items on a checklist or maintaining completed documentation about required tasks that the operators and drillers performed.[51] So a duty holder's systematic analysis of major hazards documenting the risks, control measures and safety management systems meant to ensure their effectiveness is a necessary improvement in the US offshore environment. This would be the case whether the BSEE adopts an entire safety case system or imports to the US attributes from safety case regimes to fill regulatory gaps.

The safety case model is not a form of self-regulation. The regulator's acceptance of a safety case does not constitute approval, in the traditional sense, that somehow the burden of maintaining safe operations shifts from the regulated to the regulator. Instead, acceptance is more akin to a comprehensive review of the operator's or driller's submitted safety case by the regulator. The regulator's acceptance of the safety case implies that the submitter's proposed documentation satisfactorily proposes good practice relating to identified hazards. Thereafter, the burden of operating safely continues to remain on the parties undertaking the risk, and the regulator will hold those parties to the submitted standards in the written cases for safety.

The regulator in a goal-setting, risk reduction regime must cultivate a sophisticated and nuanced approach, remaining nimble and playing different roles in different circumstances. The regulator's role ranges from one of challenging industry to establish sound safety strategies, and enforcing the prescriptive aspects of the existing system—as well as each duty holder's written case for safety—to partnering with operators and guiding industry toward continual improvements in offshore drilling safety.[52] This volume explains why the regulator must be independent and have adequate resources,

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[49] Shaw, S. *What's the Case for a US Version of the Safety Case?;* April 2, 2014; http://www.erm.com/en/news-events/platform/whats-the-case-for-a-us-version-of-the-safety-case/ (accessed March 26, 2016).

[50] *Ibid.*

[51] *Ibid.*

[52] Wilkinson, P. *Creating a New Offshore Petroleum Safety Regulator*, Presentation to IADC, Australian Petroleum Production & Exploration Association Conference, March 25, 2003; p 5 http://www.nopsema.gov.au/assets/document/IADC-Annual-General-Meeting.pdf (accessed March 26, 2016).

including necessary funding and a strong workforce with sufficient technical expertise, interpersonal skills, credibility, and authority to work alongside industry for continual improvement.[53]

While safety case type approaches were practiced by the UK and Australia before Macondo, recommendations for a safety case regime in response to the Macondo blowout also occurred internationally.[54] On September 23, 2013, based on its own independent studies, the European Commission implemented Safety of Offshore Oil and Gas Operations Directive that was "broadly based" on the preexisting UK offshore safety regime and related requirements, including preparation of a written case for safety.[55] This direct response to Macondo was in recognition of the more than 1,000 oil and gas production facilities offshore in the oceans surrounding EU member countries.

2.4 Managing Major Accident Hazards in the US

The CSB concludes that while adopting the SEMS regulation was an improvement for offshore US regulations, it remains inadequate for major accident prevention in offshore drilling, and BSEE is not fully empowered to accomplish its mission as the offshore regulator.

To illustrate by analogy, the current SEMS model in many ways parallels the Occupational Safety and Health Administration (OSHA) onshore Process Safety Management (PSM) regulation for fixed industrial facilities, which the CSB has studied extensively in its 17-year operating history.[56] The CSB has found that the onshore PSM approach used to regulate petroleum refineries in the US relies on a regulatory framework that duty holders can satisfy by "checking the box" when completing a variety of required safety-related activities, such as a process hazard analysis or management of change. Yet compliance with those requirements can still fail to improve safety. The activity may not adequately identify major hazards or control major accident events, in part, because the regulatory requirement lacks targeted risk-reduction, goal-setting requirements, and accommodations for a proactive regulator to engage with the facility. As such, the PSM approach has devolved into an activity-based, reactive regulatory climate. Activity-based approaches run contrary to longstanding onshore process safety good practice that advocates for the ultimate goal of continual risk reduction. In 1992, CCPS emphasized "after identifying hazards and analyzing effects of those hazards, a management system should be in place to assure that all practical steps have been taken to reduce the risks."[57]

Despite the improvements to the US offshore regulatory scheme, as with onshore, there is no risk-reduction goal of ALARP or equivalent. In addition, the current US offshore regulatory framework emphasizes the regulator's role to a reactive one rather than encourage meaningful proactive engagement

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[53] *Ibid.,* p 3.

[54] Norway has a regulatory model that reflects many of the attributes in Section 0, but distinct differences exist between its regulatory model and that in the UK and Australia. Some of those differences are described throughout this volume.

[55] http://www.hse.gov.uk/offshore/directive.htm (accessed January 26, 2016).

[56] For example, the CSB investigated major industrial accidents such as the 2005 BP Texas City explosion and fire, which resulted in 15 fatalities and 180 injuries; the 2010 heat exchanger catastrophic rupture at Tesoro Anacortes Refinery, which led to seven fatalities, and the Chevron Richmond Refinery pipe rupture and fire, which caused worker injuries and over 15,000 local residents to seek medical attention. See, www.csb.gov.

[57] CCPS. *Plant Guidelines for Technical Management of Chemical Process Safety;* American Institute of Chemical Engineers: New York, NY, 1992; p 67.

among the regulator, industry, and workforce. The outcome, therefore, may be similar to the PSM approach in which offshore operators may comply with SEMS requirements and communicate this compliance to the regulator, but they are not adequately or effectively identifying and controlling hazards or implementing good practice.

3.0 Inadequate Post-Macondo Safety Management Regulations

The offshore oil and gas industry is subject to legal requirements from a variety of regulators, including the US Environmental Protection Agency (EPA),[58] Bureau of Ocean Energy Management (BOEM),[59] US Coast Guard (USCG), and BSEE. Specific to safety, the Outer Continental Shelf Lands Act (OCSLA) [60] gives broad authority to the USCG and BSEE to regulate activities that affect the safety of life and property on facilities and vessels operating on the Outer Continental Shelf. The USCG and BSEE have signed Memoranda of Agreements (MOAs) to assign responsibilities between the two agencies for inspecting and overseeing systems and sub-systems on Mobile Offshore Drilling Units (MODUs)[61] and other fixed OCS facilities.[62] For example, on MODUs like the Deepwater Horizon, BSEE has lead regulatory oversight on systems related to drilling and completion activities, and the USCG has lead oversight of fire suppression systems. While the CSB acknowledges the dual regulatory role in maintaining safety on the OCS, the analysis contained in this report focuses on BSEE's regulatory responsibility because many of the systems for which the USCG has lead oversight (e.g., station keeping, fire protection, emergency evacuation plans, etc.) were not causal to the initial well release and explosion which were the focus of the CSB's investigation.

This chapter demonstrates that despite changes post-Macondo, US offshore safety regulations still do not provide an adequate safety management framework for major accident prevention. Without a continual risk-reduction goal like ALARP, the SEMS regulations are not as agile in driving ongoing industry improvement, especially because the US regulatory regime lacks mechanisms for rapidly adapting to

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[58] For example, 40 C.F.R. Part 122. See also Memorandum of Understanding Between the Environmental Protection Agency and the Department of the Interior Concerning the Coordination of SPDES Permit Issuance with the Outer Continental Shelf Oil and Gas Lease Program. http://www.bsee.gov/uploadedFiles/BSEE/Newsroom/Publications_Library/001_1984-MOU.pdf (accessed Feburary 26, 2016).

[59] "BOEM promotes energy independence, environmental protection and economic development through responsible, science-based management of offshore conventional and renewable energy and marine mineral resources," http://www.boem.gov/About-BOEM/ (accessed Feburary 26, 2016).

[60] 43 U.S.C. § 1331 et seq.

[61] As defined by 46 U.S.C. § 2101 15(a), a MODU is "a vessel capable of engaging in drilling operations for the exploration or exploitation of subsea resources."

[62] USCG and BSEE. Subject: Mobile Offshore Drilling Units (MODUs). Memorandum of Agreement between the Bureau of Safety and Environmental Enforcement - U.S. Department of the Interior and the U.S. Coast Guard - U.S. Department of Homeland Security; BSEE/USCG MOA: OCS008; June, 4 2013; http://www.bsee.gov/uploadedFiles/BSEE/Newsroom/Publications_Library/MOA_OCS-08_MODUs_signed_06.04.2013.pdf (accessed Feburary 26, 2016);

USCG and BSEE. Subject: Fixed Outer Continental Shelf (OCS) Facilities. Memorandum of Agreement between the Bureau of Safety and Environmental Enforcement - U.S. Department of the Interior and the U.S. Coast Guard - U.S. Department of Homeland Security; BSEE/USCG MOA: OCS008; September, 19, 2014; http://www.bsee.gov/uploadedFiles/BSEE/International_and_Interagency_Collaboration/Interagency/Agreements/MOA-2014-USCG-Fixed%20OCS%20Facilities.pdf (accessed Feburary 26, 2016);

ongoing advances in technology and safety practices.[63] This shortcoming results in weak, performance-based requirements that lead to the activity-based approach in which both industry and regulator can become preoccupied with the completion and documentation of activities without necessarily demonstrating that the implemented safety management activities can effectively control hazards and minimize risks. Moreover, SEMS regulations apply explicitly to the operator, whose SEMs program is intended to manage all the activities of third-party contractors. Finally, BSEE's safety management regulations do not adequately provide for worker participation throughout the lifecycle of hazardous operations.

To that end, companies' current SEMS plans may therefore not be adequate for major accident prevention because SEMS regulations:

- lack a risk-reduction methodology to drive continual improvement (e.g., ALARP);
- fail to facilitate the regulator's ability to require companies to make safety changes based on lessons learned from major incidents and newly identified hazards;
- lack a requirement for documented demonstration that the safety management system elements as implemented will reduce risk to the targeted level;
- favor of activity-based requirements;
- fail to focus specifically on process safety for major accident prevention, instead seeking to address health and safety matters as a general proposition;
- lack sufficient focus on human factors/safety critical task analysis requirements for each element;
- misapply legal responsibility for safety solely to operators even though contractors also create or control risk;
- lack clarity on the major accident safety responsibilities of key parties, such as operators and drilling contractors, for safety critical tasks; and
- do not adequately address the important role of workers and their representatives in safety management.

This chapter describes approaches taken by other international regimes that offer alternative means to ensure that those who control risk are responsible for managing it.

3.1 SEMS: No Goal-Setting Risk-Reduction Standard

A performance-based regulatory approach with a goal of reducing risk to ALARP increases both the industry's and regulator's flexibility. For industry, performance regulations provide freedom to conduct its work as it determines best as long as it can demonstrate the chosen methods will work consistently with good practice. Good practice, however, is not a static concept; in fact, it will evolve with time.[64] In some cases, standards for what is ALARP for a particular activity do not exist, so they will need to be developed to adequately control risks. As new technology is developed or costs of previously developed technologies decrease, the standard for "reasonably practicable" will change. Consequently, an ALARP approach provides the regulator with the flexibility to make ALARP judgements, keep what constitutes

[63] See Section 3.1.1.

[64] UK HSE. Principles and Guidelines to assist HSE in its judgements that duty-holders have reduced risk as low as reasonably practicable, http://www.hse.gov.uk/risk/theory/alarp1.htm (accessed March 1, 2016).

good practice under review, and influence the industry to adopt new practices. To that end, a credible, well-resourced regulator would have a full range of tools needed to advise and, if necessary, to challenge a company's assertion that its risk-reduction practices satisfy ALARP.

Pertinent to ALARP, the Baker Panel[65] notes in its 2007 report ("the Baker Report") on BP and its process safety performance following the 2005 BP Texas City disaster that an effective process safety management system builds on an "improvement cycle" that "should include, in practice, continual reduction of process risk and improvements in safety performance according to some measurable criteria."[66]

The Baker Panel defined "continuous improvement" as

- improving controls for process hazards, including process safety knowledge and competence of workers;
- improving process safety leadership of supervisors;
- improving process engineering to identify and design to remove or mitigate the effects of process hazards;
- extending legal compliance to reducing risks through best practices;
- extending mere compliance with internal standards to learning from operating experiences, incident and near-miss investigations, hazard studies, audits, and other assessments to improve those internal standards; and
- identifying and implementing not only those external standards that must be observed, but also those that represent best practices that can lead to process safety excellence.[67]

While offshore SEMS regulations require companies to identify hazards and manage safety,[68] they do so without a goal either the industry or regulator can work toward, such as maintaining good practice as an ALARP approach would. Therefore, the US still lacks a goal-setting risk-reduction standard in its offshore regulatory scheme to encourage continual improvement and adaptability.

Volume 3 of this report describes ALARP as the level at which further risk reduction, through incremental sacrifice (in terms of cost, time, effort, or other expenditure of resources) becomes grossly disproportionate to the incremental risk reduction achieved.[69] In practice, prescriptive legislation is easier to comply with and for regulators to enforce compliance (e.g., by inspecting or auditing by checking boxes concerning requirements contained on a list), whereas goal-setting legislation is a more challenging regime to operate.[70] But, the goal-based ALARP requirements demand more effort by the company to

[65] In the aftermath of the BP Texas City Incident, BP followed the recommendation of the CSB and formed an independent panel known as the Baker Panel to conduct a thorough review of the company's corporate safety culture, safety management systems, and corporate safety oversight at its US refineries. For a copy of their findings and recommendations, see http://www.csb.gov/assets/1/19/Baker_panel_report1.pdf (accessed January 25, 2016).

[66] *Ibid.*, p 166.

[67] *Ibid.*

[68] 30 C.F.R. § 250.1900.

[69] Volume 3, Section 4.1.

[70] The BSEE SEMS section Chief spoke on this issue. "We need to emphasize that compliance requires operators to demonstrate that they are implementing SEMS as a performance-based standard and not just checking off items on a list;" OTC: BSEE reports 100% SEMS compliance after first cycle. *Oil & Gas Journal*; Slocum, M., Ed.,

ensure risks are reduced to targeted levels, and they empower the regulator to drive further improvements over time.

The UK, Norwegian, and Australian offshore regulators have all adopted ALARP-type goals. The UK's Health and Safety Executive (HSE) has produced much guidance concerning ALARP. The agency's guidance on ALARP for onshore facilities explains that to achieve the goal of ALARP, the risk reduction measures to prevent major accidents should at least be "relevant good practice."[71] The duty holder must demonstrate that the good practice is relevant and up to date, and must review risks and risk reduction measures as circumstances, technology, knowledge, and information evolve.[72] When assessing whether risks are reduced to ALARP, companies in the UK weigh the risk "against the measures necessary to eliminate the risk. The greater the risk … the less will be the weight to be given to the factor of cost."[73]

In Norway, the Petroleum Safety Authority (PSA) regulates offshore safety[74] and ensures that companies adapt to safety and technological advances through its performance-based approach to regulatory oversight.[75] While Norwegian regulations do not specifically reference ALARP, they do require companies to choose the technical, operational, and organizational solutions that offer the best results, provided the costs are not significantly disproportionate to the risk reduction achieved.[76] For instance, the regulations call on "the operator and others participating in the activities" to address the goal of operational safety through any effective method, as opposed to requiring specific actions.[77] This approach ensures that duty holders are primarily responsible for determining the best methods to mitigate the risks they create, which in turn helps the regulator ensure that safety practices keep pace with advances in industry.

The Australian National Offshore Petroleum Safety and Environmental Management Authority (NOPSEMA) requires companies to reduce risks to the health and safety of people onboard offshore facilities to a level as low as reasonably practicable.[78] NOPSEMA explains that to do this, the company

May 7, 2015, http://www.ogj.com/articles/2015/05/otc-bsee-reports-100-sems-compliance-after-first-cycle.html (accessed March 26, 2016).

[71] UK HSE. Guidance *on ALARP Decisions in COMAH.* http://www.hse.gov.uk/foi/internalops/hid_circs/permissioning/spc_perm_37/ (accessed January 5, 2016).

[72] *Ibid*.

[73] UK HSE. Principles and guidelines to assist HSE in its judgements that duty-holders have reduced risk as low as reasonably practicable. http://www.hse.gov.uk/risk/theory/alarp1.htm#P4_129 (accessed January 5, 2016).

[74] See http://www.psa.no/about-us/category877.html (accessed March 26, 2016).

[75] See Petroleum Safety Authority Norway, Regulations Relating to Health, Safety and the Environment in the Petroleum Activities and at Certain Onshore Facilities (The Framework Regulations) (2013), http://www.ptil.no/framework-hse/category403.html (accessed March 26, 2016).

[76] Regulations Relating to Health, Safety and the Environment in the Petroleum Activities and at Certain Onshore Facilities (The Framework Regulations), Section 11 Risk Reduction Principles, http://www.ptil.no/framework-hse/category403.html#_Toc282603288 (accessed March 26, 2016).

[77] Regulations Relating to Health, Safety and the Environment in the Petroleum Activities and at Certain Onshore Facilities (The Framework Regulations), Section 7 Responsibilities pursuant to these regulation, http://www.ptil.no/framework-hse/category403.html#_Toc282603288 (accessed March 26, 2016).

[78] NOPSEMA. *ALARP Guidance Note;* N-04300-GN0166, Rev 6; June, 2015; http://www.nopsema.gov.au/assets/Guidance-notes/N-04300-GN0166-ALARP.pdf (accessed March 26, 2016).

"has to show, through reasoned and supported arguments, that there are no other practical measures that could reasonably be taken to reduce risks further."[79]

In the US offshore, the OCSLA states that it "shall be the duty of any holder of a lease or permit under this subsection to (1) maintain all places of employment within the lease area or within the area covered by such permit in compliance with occupational safety and health standards and, in addition, free from recognized hazards to employees of the lease holder or permit holder or of any contractor or subcontractor operating within such lease area."[80] Although it can be argued that this duty supports implementing a goal-setting regulatory requirement like ALARP, BSEE has yet to explicitly adopt such a requirement within its regulatory scheme or the SEMS rule. This may change with the proposal of new well control regulations described in Section 3.1.4.

The SEMS rule states that operators "through your management, are responsible for the development, support, continued improvement, and overall success of your SEMS program."[81] At specified intervals and at least annually, US operators are required to review their SEMS programs to determine if the program "continues to be suitable, adequate and effective (by addressing the possible need for changes to policy, objectives, and other elements of the program in light of program audit results, changing circumstances and the commitment to continual improvement) and document the observations, conclusions and recommendations of that review."[82] But without a benchmark such as ALARP in place establishing goals for risk reduction, this can become a documentation exercise that does not actually result in the reduction of risk.

Performance-based regulatory regimes already exist in the US. The US Nuclear Regulatory Commission (NRC) was an early adopter of the performance-based approach to regulation. The NRC defines performance-based regulation as "approach that focuses on desired, measurable outcomes, rather than prescriptive processes, techniques, or procedures" but does not specify precisely how to achieve the results.[83] According to the Commission, performance-based regulations permit licensees to "have flexibility to determine how to meet the established performance criteria in ways that encourage and reward improved outcomes."[84] Under this approach, a regulator focuses on whether the goal of as low as reasonably achievable, or ALARA (see callout box), has been achieved in "processes, procedures, and judgments" related to both design and operational risk[85] For design risk, quantitative judgements are more likely, but when operational risk is addressed, qualitative factors become more important. "What is essential, for ALARA practiced at any level, is that the choices be fully documented, together with the criteria which have [been relied on to make] those choices. When the criteria are qualitative, it is more

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[79] *Ibid*.

[80] 43 U.S.C. § 1348 (b).

[81] 30 C.F.R. § 250.1909.

[82] 30 C.F.R. § 250.1909 (d).

[83] US Nuclear Regulatory Commission. Performance-based regulation, http://www.nrc.gov/reading-rm/basic-ref/glossary/performance-based-regulation.html (accessed January 19, 2016).

[84] US Nuclear Regulatory Commission. Background and Staff Guidance on Performance-Based Regulation, http://www.nrc.gov/about-nrc/regulatory/risk-informed/concept/performance.html (accessed January 19, 2016).

[85] Fassò, A.; Rokni, S. *Operational Radiation Protection in High Engery Physics Accelerators. Implemenation of ALARA in Design and Operations of Accelerators;* SLAC-PUB-13800; SLAC National Accelerator Laboratory: May, 2009; p 7. http://www.slac.stanford.edu/cgi-wrap/getdoc/slac-pub-13800.pdf (accessed March 26, 2016).

likely that subjective judgments play a large role, but those judgements must be equally recorded [as they are for quantitative judgements].”[86]

In the US, the nuclear industry provides a model of continual risk reduction. Similar to ALARP, the target is “as low as reasonably achievable” (ALARA). The Nuclear Regulatory Commission’s Reactor Oversight Process (ROP), its primary performance-based regulation, is the means by which it achieves its mission of public health and safety in commercial nuclear power plant operations.[a] The ROP uses seven “cornerstones,” such as mitigating systems and barrier integrity, to monitor three performance areas (reactor safety, radiation safety, and security safeguards).[b] Licensee performance data, inspection plans, quarterly assessments, and assessment and inspection responses are tied to each performance area and several cross-cutting objectives, such as worker involvement and human performance.[c] Licensees may choose their own methods to meet overarching performance goals, which are guided by their duty to reduce risks to ALARA.[d] The Commission has stated that this flexibility is one of the main reasons its regulatory philosophy encourages continual improvement.[e]

[a] *US Nuclear Regulatory Commission. Reactor Overseght Process (ROP), http://www.nrc.gov/NRR/OVERSIGHT/ASSESS/ (accessed March 26, 2016).*
[b] *US Nuclear Regulatory Commission.* Reactor Oversight Process; *December, 2006; p 2. http://pbadupws.nrc.gov/docs/ML0708/ML070890365.pdf (accessed March 26, 2016).*
[c] *Ibid., p 3.*
[d] *US Nuclear Regulatory Commission..* Guidance for Performance - Based Regulation; *NUREG/BR-0303; December, 2002; p 1. http://www.nrc.gov/reading-rm/doc-collections/nuregs/brochures/br0303/br0303.pdf (accessed March 26, 2016).*
[e] *US Nuclear Regulatory Commission. Background and Staff Guidance on Performance-Based Regulation, http://www.nrc.gov/about-nrc/regulatory/risk-informed/concept/performance.html (accessed January 19, 2016).*

3.1.1 The Use of Standards and Guidance in ALARP-based Regulatory Regimes

For the most part, the goal-setting regulations in the UK, Norway, and Australia do not use prescriptive requirements to follow either national or international or industry standards. Where prescription is used, it is in connection with, for example, the areas to be covered in hazard analysis documentation or the frequency of examination and testing of lifting equipment.[87] Both the UK HSE and Norway PSA publish regulatory topic guidance to advise duty holders on how to achieve compliance with their respective regulations. For example, the UK has an Approved Code of Practice (ACOP) for preventing fire, explosion, and emergency response on offshore installations.[88] It is not mandatory to follow the guidance in an ACOP, but HSE has indicated “if you do follow the guidance you will normally be doing enough to

[86] *Ibid.*, pp 6-7.

[87] Whewell, I. Former Director, UK HSE Offshore Division, Personal communication, July 6, 2011.

[88] UK HSE. *Prevention of fire and explosion, and emergency response on offfshore installations;* L65; HSE: 2012; http://www.hse.gov.uk/pUbns/priced/l65.pdf (accessed March 2, 2016).

comply with the law."[89] A duty holder can also comply with the law if it demonstrates that alternative measures are likely to be just as effective as those specified in the ACOP. ACOPs tend not to refer to specific technical standards, but describe the way of achieving a specific outcome. ACOPs are being used less as they can have the effect of discouraging technical progress and innovation.

HSE also publishes guidance with every set of regulations it produces, giving the duty holder advice on interpreting the legislation and information on how to achieve compliance.[90] Following this guidance is not mandatory, but like ACOPs, in most cases an inspector will accept that if the duty holder follows the guidance, it complies with the requirement.

Guidance published HSE's Energy Division comes in a variety of forms:[91] leaflets, books on its webpages, advisory notices,[92] and research reports. While the latter is not strictly guidance, research reports represent available knowledge on hazards and risks, and duty holders would be expected to take into account the latest research in forming their hazard and risk control strategies. Although HSE does not publish lists of approved technical and other standards, some are referenced in the guidance HSE publishes. The best example is in Guidance for the Topic Assessment of Major Accident Hazard Aspects of Safety Cases (GASCET).[93] Ultimately, while industry good practices can form the basis for hazard assessments, the duty holder is required to effectively identify and control risks as lessons are learned, technology improves, and information is shared.[94] The key question for assessing major hazard risk is whether anything more can be done to reduce risk.[95] While technical guidance like GASCET helps relate assessors' technical judgements to good practice, it does not cover all major accident event hazards poised offshore. For instance, GASCET identifies basic well design and equipment hazards,[96] but it does not identify guidance and standards for the assessment of well conditions and operational activities, such as those occurring at Macondo at the time of the blowout. In effect, assessors and industry will rely on the general ALARP guidance previously described to assess the adequacy of organizational and operational barriers identified in Volumes 2 and 3.

Norway's offshore regulator publishes guidelines on how to achieve the requirements in its provisions.[97] When using a recommended standard in a regulatory guideline, the "party can normally assume that the

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89 UK HSE. Legal status of HSE guidance and ACOPs, http://www.hse.gov.uk/legislation/legal-status.htm (accessed March 3, 2016).

90 Whewell, I. Former Director, UK HSE Offshore Division, Personal communication, July 6, 2011.

91 UK HSE. Guidance, http://www.hse.gov.uk/guidance/index.htm (accessed March 2, 2016).

92 UK HSE. Safety alerts and notices, http://www.hse.gov.uk/offshore/notices/sn_index.htm (accessed March 2, 2016).

93 UK HSE. GASCET (Guidance for the topic assessment of the major accident hazard aspects of safety cases), http://webcommunities.hse.gov.uk/connect.ti/gascet/view?objectId=62036 (accessed March 2, 2016).

94 *Ibid.*

95 UK HSE. *Guidance on Risk Assessment for Offshore Installations*; Offshore Information Sheet No. 3/2006; http://www.hse.gov.uk/offshore/sheet32006.pdf (accessed March 2, 2016).

96 The main hazard sources identified in GASCET are intermediate formations, reservoir-introduced fluids, explosive, radioactive sources, pressure vessels, and dropped objects.

97 PSA. Guidelines Reguarding the Framework Regulations, http://www.psa.no/framework/category408.html (accessed March 2, 2016).

regulatory requirements have been met."[98] If a party wants to adopt an approach not specified in the guideline standards, the party must document how the same level of health, safety and environmental protection is achieved.[99] The regulatory guidelines are mostly technical in nature,[100] but parties must demonstrate "strategies and principles that form the basis for design, use and maintenance of barriers, so that the barriers' function is safeguarded throughout the offshore or onshore facility's life" for operational and organizational barriers not addressed in the guideline standards.[101]

In Australia, NOPSEMA does not endorse any ACOPs or standards.[102] NOPSEMA has clarified its stance on good practice, "the term 'good practice' in NOPSEMA guidance documentation therefore is taken to refer to any well-defined and established standard or codes of practice adopted by an industrial/occupational sector, including 'learnings' from incidents that may yet to be incorporated into standards. Good practice generally represents a preferred approach; however, it is not the only approach that may be taken. While good practice informs, it neither constrains, nor substitutes for, the need for professional judgement."[103]

3.1.2 Insufficient US Alternative Legal Mechanisms to Drive Continual Safety Improvements

The OCSLA calls upon the Secretary of the Interior to promulgate safety regulations that include "the use of the best available and safest technologies which the Secretary [of the Interior] determines to be economically feasible, wherever failure of equipment would have a significant effect on safety, health, or the environment."[104] But these requirements do not apply if the Secretary of the Interior determines that the safety improvements do not justify the costs of implementing the technology.[105]

A BSEE regulation calls for using the "best available and safest technology (BAST) whenever practical on all exploration, development, and production operations" [106] … "in general, we consider your compliance with BSEE regulations to be the use of BAST."[107] Limiting BAST to compliance with BSEE

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[98] Regulations Relating to Health, Safety and the Environment in the Petroleum Activities and at Certain Onshore Facilities (The Framework Regulations), Section 24 Use of recognized standards, http://www.psa.no/framework-hse/category403.html#_Toc357595254 (accessed March 26, 2016).

[99] *Ibid*.

[100] For a summary, see OGP. *Regulators' use of standards;* Report No. 426; OGP Standards Committee: March, 2010; p 33 and Annex F1.

[101] Regulations Relating to Management and the Duty to Provide Information in the Petroleum Activities and at Certain Onshore Facilities (The Management Regulations), Section 5, Barriers, http://www.psa.no/management/category401.html#_Toc377975494 (accessed March 26, 2016).

[102] NOPSEMA. *Guidance Note: ALARP;* N-04300-GN0166, Revision 6; June, 2015; p 6. http://www.nopsema.gov.au/assets/Guidance-notes/N-04300-GN0166-ALARP.pdf (accessed March 2, 2016).

[103] *Ibid*

[104] 43 U.S.C. § 1347 (b).

[105] 43 U.S.C. § 1347(b). The Supreme Court explained that this provision of the OCSLA is one in which Congress has imposed two independent requirements: that an administrative action be "feasible" and that it is justified by a balancing of costs and benefits. *Indus. Union Dep't., AFL-CIO v. Am. Petroleum Inst.*, 448 U.S. 607, 709 n. 27 (1980).

[106] 30 C.F.R. § 250.107(c).

[107] 30 C.F.R. § 250.107(d).

regulations, however, undermines the potential impact of requiring the use of the best available and safest technology not required in the BSEE regulatory scheme.

The BSEE Director may require additional measures to ensure using BAST to avoid equipment failure that would have a significant effect on safety, health, or the environment, so long as it is "economically feasible" and "the benefits outweigh the costs."[108] Nevertheless, the cost-benefit analysis needed to meet this requirement results in a high burden of proof on the regulator to require operators to do something not specifically stated in the regulations. It differs from the continual improvement mechanism of the North Sea and Australian regimes, which require companies to monitor new developments and continually drive risks to ALARP.[109]

30 C.F.R. § 250.198 is an example of a BSEE regulation that incorporates certain standards by reference, yet it is also an example of not being easily adaptable. The effect of incorporation by reference is that the incorporated documents are treated as if they were published in the Federal Register as part of the underlying regulation.[110] The incorporated material, like any other properly issued regulation, has the force and effect of law.[111] Some of the documents incorporated into that regulation include ANSI/ASME Codes, API Recommended Practices, ASTM Standards, American Welding Society Codes, and American Gas Association Reports. The regulation states that the documents incorporated in the rule are limited to the edition cited, but that BSEE will publish any changes to such documents in the Federal Register before amending the rule. Yet the regulation also states that BSEE may change the version of a document referenced in this rule without an opportunity for public comment if the agency determines the revisions would result in safety improvements or represent new industry standard technology and they do not impose undue costs on the affected parties.[112] The aim of this rule, to be able to adapt BSEE requirements to changing practices and technology without having to go through the rulemaking process, could therefore be subverted if a party challenges BSEE's finding that revisions do not impose "undue costs." This situation leaves updating the regulation to the more traditional process, which is time-consuming, burdensome, and often difficult, even where the regulated matters are far less complex.

Finally, BSEE regulations have a provision for alternative procedures or equipment, but the requirements to receive approval are vague in comparison to the guidelines international regulatory regimes have provided their own assessors.[113] Currently, to receive approval, "you must either submit information or give an oral presentation to the appropriate Regional Supervisor. Your presentation must describe the site-

[108] 30 C.F.R. § 250.107(d).

[109] Reducing to ALARP does not assure the best risk controls available are reasonably practicable. According to the UK HSE, "it is only if the cost of implementing these new methods of control is not grossly disproportionate to the reduction in risk they achieve that their implementation is reasonably practicable. For that reason, we accept that it may not be reasonably practicable to upgrade an older plant and equipment to modern standards. However, there may still be other required measures to reduce the risk ALARP: for example, partial upgrades or alternative measures;" UK HSE, Some fallacies about ALARP, http://www.hse.gov.uk/risk/theory/alarpglance.htm (accessed March 26, 2016).

[110] Update of Revised and Reaffirmed Documents Incorporated by Reference, 75 Fed. Reg. 22219 (Final Rule, April 28, 2010).

[111] 30 C.F.R. § 250.198(a)(3); Update of Revised and Reaffirmed Documents Incorporated by Reference, 75 Fed. Reg. 22219 (Final Rule, April 28, 2010).

[112] 30 C.F.R. §§ 250.198(a)(2)(i)-(ii).

[113] 30 C.F.R. 250.141

specific application(s), performance characteristics, and safety features of the proposed procedure or equipment."[114] As HSE has indicated, among other benefits, guidelines provide "transparency to the assessment decisions and criteria" and "a basis for consistency in the assessment process and its outcomes."[115] BSEE does not yet provide such guidance to its intended audience.

3.1.3 Ineffective Regulatory "Workarounds"

Since US offshore regulations do not have an effective continual safety improvement requirement, rulemaking is required to change any part of an existing regulation that may become outdated or irrelevant after new safety information emerges. Since the rulemaking process is onerous, BSEE sometimes communicates safety messages to offshore lessees through Notices to Lessees (NTLs),[116] Information to Lessees (ITLs),[117] and Safety Alerts.[118] NTLs are "formal documents that provide clarification, description, or interpretation of a regulation or OCS standard; provide guidelines on the implementation of a special lease stipulation or regional requirement; provide a better understanding of the scope and meaning of a regulation by explaining BSEE interpretation of a requirement; or transmit administrative information".[119] ITLs are "formal documents that provide additional information and clarification, or interpretation of a regulation, OCS standard, or regional requirement, or provide a better understanding of the scope and meaning of a regulation by explaining BSEE interpretation of a requirement".[120] Safety Alerts are used to inform industry of the circumstances surrounding an incident or a near-miss and to provide "recommendations that should help prevent the recurrence of such an incident on the OCS."[121]

These documents may be helpful in providing guidance for regulatory compliance, but the NTLs, ITLs, and Safety Alerts themselves cannot expand upon what BSEE regulations require, and BSEE has no ability to force operators or contractors to comply with the guidance in these documents. For instance, in 2000, MMS issued a Safety Alert urging offshore lease holders to install a backup mechanism for activating subsea blowout preventers.[122] In the Safety Alert, MMS stressed that a secondary activation system was an "essential component" of any rig's emergency response system. Although having a backup

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[114] 30 C.F.R. 250.141(c)

[115] UK HSE. GASCET (Guidance for the topic assessment of the major accident hazard aspects of safety cases), http://webcommunities.hse.gov.uk/connect.ti/gascet/view?objectId=62036 (accessed March 2, 2016).

[116] BSEE. Notices to Lessees and Operators, http://www.bsee.gov/Regulations-and-Guidance/Notices-to-Lessees-and-Operators/ (accessed March 2, 2016).

[117] BSEE. Information to Lessees and Operators, http://www.bsee.gov/Regulations-and-Guidance/Information-to-Lessees-and-Operators/ (accessed March 2, 2016).

[118] BSEE. Current Safety Alerts, http://www.bsee.gov/Regulations-and-Guidance/Safety-Alerts/Safety-Alerts/ (accessed March 2, 2016).

[119] BSEE. Notices, Letters, and Information to Lessees and Operators (NTL)s, http://www.bsee.gov/Regulations-and-Guidance/Notices-to-Lessees/index/ (accessed March 2, 2016).

[120] *Ibid*.

[121] BSEE. Current Safety Alerts, http://www.bsee.gov/Regulations-and-Guidance/Safety-Alerts/Safety-Alerts/ (accessed March 2, 2016).

[122] BSEE. *MMS Safety Alert: Accidental Disconnect of Marine Drilling Risers;* Safety Alert No. 186; March 2, 2000; http://www.bsee.gov/uploadedFiles/BSEE/Regulations/Safety_Alerts/Safety%20Alert%20No%20186.pdf accessed March 26, 2016).

activation system for BOPs should have been a best safety practice, BSEE's use of the Safety Alert could not require operators to install such backup systems because it was not contained in a regulation. Thus, Safety Alerts and Notices can provide useful guidance on a short-term basis, but because they are not incorporated into regulation, they cannot require timely adaptation of best safety practices.

3.1.4 Recent BSEE-proposed Regulatory ALARP-type Language

In April 2015, BSEE proposed new regulations that it described as "most substantial rulemakings in the history" of offshore safety in the United States.[123] As part of these regulations, BSEE introduced ALARP-type language to "reduce risks to the lowest level practicable" that if adopted, could empower BSEE with a more proactive regulatory authority. Table 3-1 lists some of the current language in § 250.107 and BSEE's proposed changes.

BSEE explained the proposed regulations were intended to consolidate equipment and operational requirements with a focus on blowout preventer equipment, well design, well control, casing, cementing, real-time well monitoring, and subsea containment. Just has described in Section 3.1.1, few standards exist for assessing well conditions and operational activities that form the basis of organizational and operational barriers intended to prevent a major accident. So, while BSEE and industry may be able to rely on good practice to guide the judgment on technical barriers, demonstrating that organizational and operation barriers reduce risks to the lowest level practicable will be a continual improvement process based on company's SEMS program.

As Volume 3 documents, neither BP nor Transocean effectively implemented their numerous programs to manage safety at Macondo. Furthermore, their indicators tended to be lagging instead of leading; thus, they did not sufficiently monitor the real-time health and effectiveness of the physical barriers and safety management systems to prevent a major accident. Therefore, a provision to "reduce risks to the lowest level practicable" will empower BSEE to challenge the efforts and claims that risks are being managed by companies' and require that more be done if necessary.

[123] Oil and Gas and Sulphur Operations in the Outer Continental Shelf—Blowout Preventer Systems and Well Control, 80 Fed. Reg. 21504 (Proposed Rule, April 17, 2015) (to be codified at 30 C.F.R. Part 250).

Table 3-1. Current and BSEE proposed language for § 250.107, What must I do to protect health, safety, property, and the environment?

Current	Proposed
(a) You must protect health, safety, property, and the environment by: (1) Performing all operations in a safe and workmanlike manner; and (2) Maintaining all equipment and work areas in a safe condition.	Paragraph (a) of this section would be revised to include a general performance-based requirement that operators utilize recognized engineering practices *that reduce risks to the lowest level practicable* during activities covered by the regulations and conduct all activities pursuant to the applicable lease, plan, or permit terms or conditions of approval. Recognized engineering practices may be drawn from established codes, industry standards, published peer-reviewed technical reports or industry recommended practices, and similar documents applicable to engineering, design, fabrication, installation, operation, inspection, repair, and maintenance activities. This risk reduction objective is used in other regulatory programs and is consistent with BSEE's goal of taking a more risk-based approach in its regulations. This risk reduction principle has also been included in a recently published industry document (API Bulletin 97) which addresses drilling, completion, and workover activities.
Does not currently exist.	Proposed paragraph (e) would be added to clarify BSEE's authority to issue orders when necessary to protect health, safety, property, or the environment. The first sentence authorizes BSEE to issue orders to ensure compliance with the regulations. The second sentence clarifies that BSEE may order that operations of a component or facility be shut-in because of a threat of serious, irreparable, or immediate harm to health, safety, property, or the environment posed by those operations or because the operations violate law, including a regulation, order, or provision of a lease, plan, or permit.

3.2 SEMS Activity-Based Requirements: A Compliance-Based Mentality

Although intended to deliver features of a performance-based regime, the SEMS rule does not drive improved safety performance as do the NRC or other international offshore regimes. SEMS requires operators to develop and implement a safety and environmental management system that incorporates several safety elements typically found in SMS models, including hazard analysis, management of change, operating procedures, and incident investigations. It directs operators to address all required elements and "maintain a safety and environmental management system."[124] But the SEMS rule does not contain a risk-reduction goal or target that would provide the regulator with the tools to drive continual risk-reduction at offshore facilities. It does not function like a strong performance-based regulation because completing these actions does not necessarily result in a reduction of risk. Directives such as "maintain,"[125] "comply,"[126] and "manage"[127] do not suggest what must be achieved with safety elements. In contrast, a goal-setting, risk-reduction, performance-based regulation would include a target (ALARP) and would specify what should be accomplished in order to meet the requirements of existing good practice.

Nor does SEMS require the operators to document recognized methodologies, rationales, and conclusions to claim that safeguards to control hazards will be effective. Rather, SEMS requires that facilities "manage" identified hazards,[128] with no further requirement regarding how far the operator must go to control those hazards. This is, in fact, weaker language than OSHA's PSM regulation, which specifically requires that hazards be controlled.[129] Terms such as "manage hazards" and "resolve recommendations" are activity-based, as they do not include a performance-based requirement to control hazards or prevent major accidents.[130] In fact, this formulation allows for managing hazards and resolving recommendations without determining that action be taken. Therefore, companies may conduct a weak or inadequate hazard analysis and not identify or manage the appropriate safety critical tasks and equipment—yet still comply with the regulation.[131]

Volume 2 highlights that while the SEMS regulations Rule promotes safety and environmental protection, it lack requirements for companies to explicitly address potential major accident events.[132] By identifying potential MAEs, companies can draw clear linkages between barriers created by safety critical tasks and equipment and the major accident hazards they are designed to prevent or mitigate.[133] As part of the process to reduce MAE risk to ALARP, companies could explicitly demonstrate the adequacy of the barriers and the distribution of the types of controls implemented (e.g., engineering, procedural, or administrative), among other factors.[134]

[124] 30 C.F.R. § 250.1900.

[125] *Ibid*.

[126] 30 C.F.R. § 250.1901.

[127] *Ibid*.

[128] 30 C.F.R. § 250.1911(a).

[129] 29 C.F.R. § 1910.119(e)(1).

[130] The CSB Macondo Investigation Report Volume 2, Section 6.1.1 details this point.

[131] Volume 2 of this report concludes the SEMS regulations are insufficient in guaranteeing safety performance improvements throughout the SCE lifecycle.

[132] Volume 2, Section 4.1.

[133] Volume 2, Section 4.2.3.

[134] Volume 2, Section 4.2.3.

BSEE incident investigation regulations are another example of activity-based requirements. Under SEMS requirements, operators must "establish" investigation procedures to "identify" contributing factors (human or otherwise) and "recommend" changes as a result of findings.[135] Companies must also "establish" corrective action plans based on the findings for investigations. BP actually met these requirements when it investigated the March 8, 2010 kick at Macondo, exemplifying the weakness of the current regulatory language.[136] During BP's investigation, Transocean identified the need to improve hazard recognition among the crew,[137] but neither BP nor Transocean examined Transocean's safety management systems meant to prevent a lack of hazard awareness. So while a human factor was "identified" as causal to the incident—delayed crew well kick response—only technical recommendations resulted from the investigation rather than effectively addressing the identified need to improve kick response—a causal factor in the Macondo incident. Ultimately, SEMS language requires an activity of conducting an investigation, but not implementing effective recommendations to reduce risk to a targeted level. Therefore, companies can still be in compliance with regulations without actually reducing risk when investigating incidents and resolving recommendations.

Critics have voiced their concern over the lack of robust performance-based, risk-reduction requirements in SEMS. The safety management subcommittee of BSEE's own advisory group, the Ocean Energy Safety Advisory Committee (OESAC), stated that the SEMS regulation, although well-intended, is essentially a prescriptive rule "promotes the idea that operators only have to meet the minimal requirements in order to comply with the regulations."[138] Similarly, the International Association of Drilling Contractors (IADC) called the SEMS rules "overly prescriptive" in its comments to BSEE.[139] IADC urged BSEE to "consider a wholesale re-write of 30 C.F.R. Subpart S to make it more goal-setting and less prescriptive."[140] Without sufficient goal-setting, risk-reduction features, a regime risks losing focus on risk reduction because companies are doing only the activities the rule requires—which may not be the safest practicable action.

IADC's position should carry some weight in this debate. The IADC HSE Case Guidelines have been required for use in 10 countries and are recognized as best practice in 10 additional countries, some of which had regulations pending to require adoption or use of the Guidelines, suggesting more jurisdictions are moving toward ALARP-type risk-reduction approaches.[141]

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[135] 30 C.F.R. § 250.1919.

[136] Volume 3, Section 2.4.

[137] *Ibid*. and Email from Macondo Rig Manager, Transocean, to Wells Team Leader, BP, Subject: Hazard Recognition, 18 March, 2010, BP-HZN-2179MDL00289217, http://www.mdl2179trialdocs.com/releases/release201305171200030/TREX-000684.pdf (accessed October 7, 2015).

[138] OESAC. *Safety Management System Enchancement Reccomendation;* SMS SC – Vector #2 Recommendation; April 10, 2012; p 4.

[139] IADC. *Re: Revisions to Safety and Environmental Management Systems (SEMS);* Docket ID BOEM; November 11, 2011; pp 4-5. http://www.bsee.gov/uploadedFiles/IADC%2011-11-2011.pdf (accessed March 26, 2016).

[140] *Ibid*.

[141] Countries having required use of the guidelines by force of regulation include Australia, Cuba, Denmark, Faeroe Islands, Germany, Ireland, the Netherlands, New Zealand, Norway, and the United Kingdom, while Angola, Canada, Brazil, India, Malaysia, Oman, Qatar, Senegal, South Africa, and Trinidad & Tobago have recognized the

Australia provides another example of a regulation requiring a performance-based hazards analysis, in contrast to BSEE's hazards analysis requirement in the SEMS rule. In Australia, safety case assessments must provide a "well-considered, detailed description of a suitable and sufficient formal safety assessment."[142] In that analysis, the duty holder must evidence an understanding of "the factors that influence risk and the controls that are critical to controlling risk, the magnitude and severity of consequences arising from major accident events for the range of possible outcomes, and the likelihood of potential major accident events."[143] These requirements are more nuanced, but similar in spirit, to the US SEMS requirement to "identify, evaluate, and manage the hazards involved in the operation,"[144] to "control technology applicable to the operation,[145] and to "evaluate possible safety and health effects on employees and potential impacts to the human and marine environments, which may result if the control technology fails."[146]

In contrast, the Australian regime also requires hazard analyses to clarify linkages between hazards, control measures, and the potential major accident events.[147] This is how Australian duty holders show that their chosen control measures will manage the risks to ALARP. Australia requires a prioritized list of actions in the hazard analysis to reduce risks to ALARP.[148] Because the SEMS rule is not accompanied by an ongoing duty to reduce risks to ALARP (or another appropriate goal-based target), the hazards analyses could be outdated (i.e., the controls could be ineffective or may not reduce risks to a practicable level) but still comply with the rule, which must be updated "when an internal audit is conducted to ensure that it is consistent with your facility's current operations."[149]

In Australia and the UK, the hazard analysis is a key component of a safety case document, which the regulator must accept before obtaining a license to operate. In these regimes, the regulator proactively reviews the operator's identified hazards and risk-reduction strategies to ensure that risks are reduced to the required standard. The regulator may require the installation of a missing control or barrier if it would further reduce risks to ALARP. Moreover, during the UK safety case acceptance process, the regulator often questions the hazard and risk analyses, and if necessary, updates or changes them if discovered to be insufficient, thus creating robust industry/regulator interaction before hazardous activities begin.[150]

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guidelines as best practice. Recent regulatory changes may have affected the status afforded the Guidelines by these countries. See http://www.iadc.org/iadc-hse-case-guidelines/ (accessed March 26, 2016).

142 NOPSEMA. *Guidance Note: Hazard Identification;* N- 04300-GN0107, Rev. 5; December, 2012; p 7. http://www.nopsema.gov.au/assets/Guidance-notes/N-04300-GN0107-Hazard-Identification.pdf (accessed March 26, 2016).

143 *Ibid*.

144 30 C.F.R. § 250.1911(a).

145 30 C.F.R. § 250.1911(a)(1)(iii).

146 30 C.F.R. § 250.1911(a)(1)(iv).

147 NOPSEMA. *Guidance Note: Hazard Identification;* N- 04300-GN0107, Rev. 5; December, 2012; p 7. http://www.nopsema.gov.au/assets/Guidance-notes/N-04300-GN0107-Hazard-Identification.pdf (accessed March 26, 2016).

148 *Ibid*.

149 30 C.F.R. § 250.1911(a).

150 Discussed in more detail in Section 4.1.2.

3.3 Safety Responsibility Offshore

Volume 3 introduced two categories of well risk: design and operational.[151] The operator's well design and drilling program are the basis for the drilling and well control operations undertaken by a drilling contractor and other well services providers. The well design is the first opportunity to assess hazards and ensure risks are reduced to ALARP. Once the well design has been determined, the operator then holds the primary responsibility to plan the work and apply the ALARP principle in selecting the contractor and rig. The well operator should review hazards throughout the lifecycle of the well, from initial spudding to final abandonment, and assess any significant changes to ensure well design risks remain ALARP. While the well operator controls design risk, the drilling contractor has the most direct control over the management of day-to-day operations, and a primary responsibility for the overall safety of the drilling installation and the personnel onboard.[152] The combination of facility and wellsite specific conditions could increase the risk or complexity of various drilling operations. Therefore, an integral second opportunity arises to assess hazards and ensure operational, organizational, and technical control measures are sufficient to reduce risks to ALARP, namely a review of the hazards in the facility's activities, equipment, personnel, and drilling and well control operations provides.

By illustration, Figure 3-1 depicts Transocean's corporate well delivery process, beginning with the development of a Well Construction Plan in conjunction with the operator (referred to as the "Customer" in Figure 3-1) that was considered a key component of the development, communication, and execution of a well plan. The process depicted in Figure 3-1 is a joint endeavor, and as such, the control of major accident risk requires the operator and the drilling contractor to play a role in managing risk. Central to this effort are the safety management systems the parties use to plan, conduct, and monitor well design and operational risk. While these safety management systems will overlap in some cases, they will each have their own focus and attributes.

[151] Volume 3, Section 1.8.1.

[152] As stated in Transocean's Well Control Handbook, "The OIM is responsible for overall safety of the Installation and all personnel onboard," Internal Company Document, Transocean. Well Control Handbook, Issue HQS-OPS-HB-01, Revision 00, July 22, 2011, Well Planning Considerations, Exhibit 5781, http://www.mdl2179trialdocs.com/releases/release201302281700004/Braniff_Barry-Depo_Bundle.zip (accessed October 7, 2015).

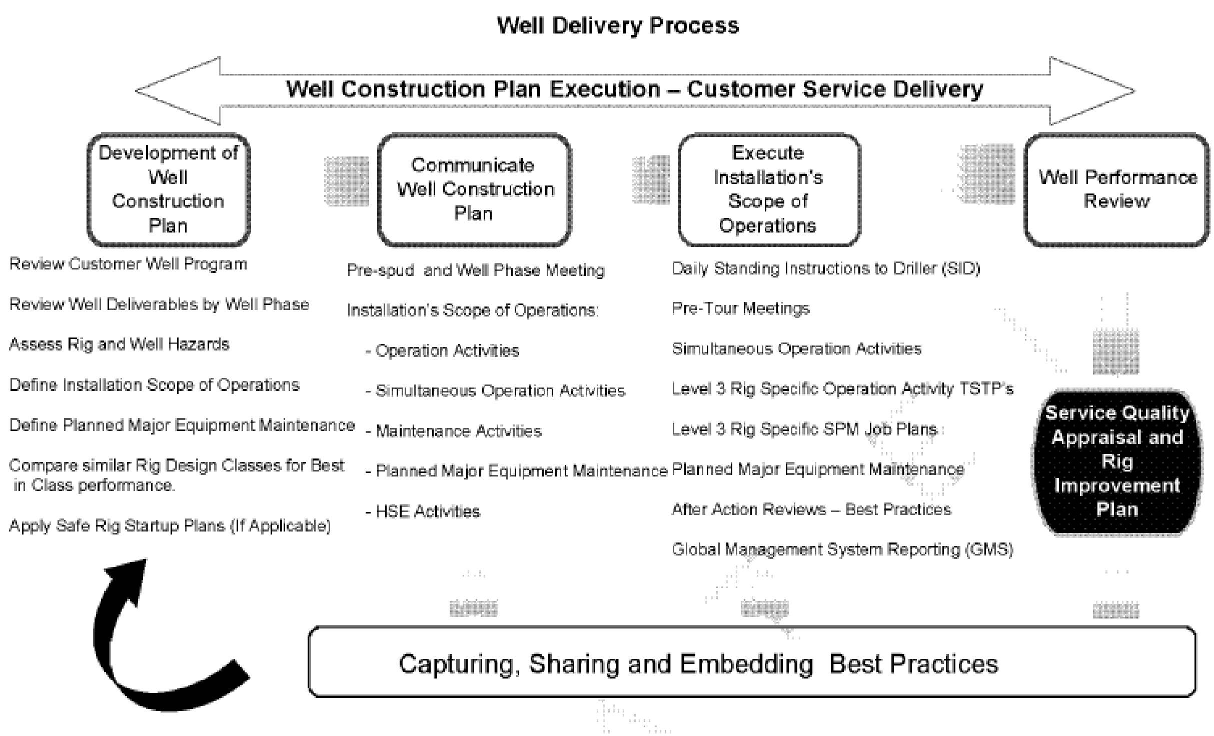

Figure 3-1. Transocean's Well Delivery Process as defined by Transocean corporate polices.[153]

Despite this, SEMS applies explicitly to the operator, and drilling contractors are not required to develop and implement a SEMS program.[154] Instead, an operator's SEMS program is intended to manage all the activities on an offshore facility, including those of the operator and any third-party contractors. The Rule states that operators have sole responsibility for creating and managing their SEMS program, even though contractors "may adopt appropriate sections of the operator's SEMS program."[155] This exclusion goes against a basic tenet of managing safety within high-hazard operations: those that create or have the

[153] Volume 3 provides evidence to indicate that Transocean did not follow its own internal well delivery process. This figure was taken from a document not publicly available (*Field Operations Policies & Procedures Manual*), but a similar figure and supporting text can be found in Transocean's *Performance and Operations Policies and Procedures Manual* which is publically available: *Performance and Operations Policies and Procedures Manual-Level L1A*, Issue #1, Revision # 00, April 19, 2010, Section 2 (Planning and Reporting), Subsection 1 (Well Construction Planning), TRN-MDL-00607022. http://www.mdl2179trialdocs.com/releases/release201302281700004/Rose_Adrian-Depo_Bundle.zip Exhibit 1474 (accessed January 28, 2015).

Internal Company Document, *Transocean. Field Operations Policies & Procedures Manual*, Issue 01, Revision 00, HQS-POP-PP-01, August 8, 2009, Performance Management: Rig and Well Operation Management, TRN-CSB-0002274-TRN-CSB-00023200.

[154] As stated by BSEE, "[BSEE] does not regulate contractors; we regulate operators;" Oil and Gas and Sulphur Operations in the Outer Continental Shelf, 75 Fed. Reg. 63609 (Final Rule, October 15, 2010) (to be codified at 30 C.F.R. Part 250).

[155] The rule exempts contractors from primary responsibility for compliance by stating that operators must document contractor selection criteria, obtain and evaluate information about the contractor's safety and environmental performance, and ensure that contractors have their own written safe work practices. 30 C.F.R. § 250.1914.

greatest control of the risks associated with a particular activity are responsible for managing them.[156] Members of BSEE's own advisory committee, the Ocean Energy Safety Advisory Committee, pointed out the dangers of this gap in contractor coverage in the SEMS Rule, which the committee described as "very confusing."[157] In fact, the committee recommended in April 2012 that BSEE address the jurisdiction the SEMS Rule covers[158] as well as the responsible party.[159]

Section 3.3.1 of this chapter describes the difficulties BSEE has had in holding contractors responsible for safety. Section 3.3.2 describes international regulatory obligations placed on both operators and drilling contractors to conduct a risk assessment of all major hazards, define the systems and barriers to control those hazards, and demonstrate their effectiveness throughout the drilling process.

3.3.1 Offshore Regulatory Ambiguity and Industry/Stakeholder Response

BP and Transocean had corporate polices for risk management that reflected their roles in the Macondo project, but neither company ensured the policy implementation, which could have minimized the gap between Transocean's work-as-done by BP and work-as-imagined.[160] Instead, a lack of clarity regarding hazard identification and risk management roles and responsibilities resulted in significant safety gaps, leaving the companies vulnerable to a major accident. Clarifying these roles and responsibilities is important because contractors compose an estimated 80% of offshore workers performing drilling and well completion activities.[161] In the case of Macondo, only 8[162] of the 126 individuals on the rig at the time of the blowout were BP employees, while 79 were Transocean employees, 25 were other third-party

[156] UK HSE. *Planning to do business in the UK offshore oil and gas industry;* October, 2011; p 2. http://www.hse.gov.uk/offshore/guidance/entrants.pdf (accessed March 26, 2016); NOPSEMA, What is a safety case, http://www.nopsema.gov.au/safety/safety-case/what-is-a-safety-case/ (accessed March 26, 2016).

[157] "As currently written the SEMS regulations state that only Operators are responsible for developing and implementing a SEMS program. In fact the preamble for the SEMS regulations specifically states, "This final rule does not require that a contractor have a SEMS program;" OESAC. *Safety Management System Enchancement Reccomendation;* SMS SC – Vector #2 Recommendation; April 10, 2012; p 3.

[158] The Committee explained that the term "system," when used in conjunction with the term "safety management system," typically represents a complete structure such as vessel or a fixed facility, and therefore encompasses all operations, processes, activities and systems that make up each structure. The BSEE SEMS regulations do not follow this logic because they apply only to operators and cover only operations and activities that fall under BSEE jurisdiction.

[159] OESAC. *Safety Management System Enchancement Reccomendation;* SMS SC – Vector #2 Recommendation; April 10, 2012; p 13.

[160] Volume 3, Section 1.8 illustrates the gap between Transocean's work-as-imagined and work-as-done at Macondo.

[161] MMS made this observation in 2003, and then it was reiterated after Macondo by the National Commission on the BP Deepwater Horizon Oil Sill and Offshore Drilling: Oil and Gas and Sulphur Operations in the Outer Continental Shelf—Incident Reporting Rule, 68 Fed. Reg. 40585 (Proposed Rule, July 8, 2003) and National Commission on the BP Deepwater Horizon Oil Spill and Offshore Drilling, *A Competent and Nimble Regulator: A New Approach to Risk Assessment and Management*, Staff Working Paper No. 21, p 7.

[162] Two of the individuals from BP were not part of the crew, but visiting management (the Vice President of Drilling & Completion and the Drilling & Completions Operations Manager.)

well providers, and 14 were caterers.[163] Despite the high reliance on contractors, a historical examination of MMS citations and regulatory action leading up to the Macondo blowout reveals that the regulator did not hold all employers accountable to this responsibility.[164] The data show that MMS chose to limit responsibility for safety (and other potential liability) to the operator/lessee.

In the aftermath of Macondo, BSEE issued Incidents of Noncompliance (INCs) to two contractors, Transocean (drilling contractor) and Halliburton (provider of cementing services), for violations of regulations leading to the Macondo incident.[165] This was the first time in the history of the agency or its predecessors that such action was taken against the drilling contractor and another well service provider. The INCs issued to Transocean were resolved in a 2013 consent decree, in which BSEE agreed not to pursue enforcement if Transocean paid $400 million in fines and met certain health and safety conditions.[166] This consent decree does not affect BSEE's overall ability to issue INCs because it did not address their validity vis-à-vis Transocean. Halliburton appealed its INCs, and the Interior Board of Land Appeals will consider that appeal after the District Court litigation (MDL) has concluded.[167]

Although BSEE started citing contractors under 30 C.F.R. § 250.107(a) pursuant to the agency's authority under the OCSLA, ambiguity still exists in US legislation and regulations regarding contractor accountability for safety. In a congressional hearing about the release of the Joint Investigation Team final report in October 2011, former Director Bromwich cited 43 U.S.C. §1350(b), as the provision in the Outer Continental Shelf Lands Act (OCSLA) that supports expanding BSEE enforcement oversight of contractors. OCSLA § 24(b), codified at 43 U.S.C. §1350(b), states:

> [e]xcept as provided in paragraph (2), if any person fails to comply with any provision of this subsection, or any terms of a lease, license, or permit issues pursuant to this subsection, or any regulation or order issued under this subsection after notice of such failure and expiration of any reasonable period allowed for corrective action, such person shall be liable for a civil penalty of not more than $20,000 for each day of the continuance of such failure.

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[163] Internal Company Document, Transocean. *Personnel On-Board as of 20 Apr 2010 17:09:15*, April 20, 2010, TRN-MDL-00030435, http://www.mdl2179trialdocs.com/releases/release201303071500008/TREX-00687.pdf (accessed March 26, 2016).

[164] For an example, BSEE Civil Penalties and Appeals, available at http://www.bsee.gov/Inspection-and-Enforcement/Civil-Penalties-and-Appeals/Civil-Penalties-and-Appeals/ (accessed March 26, 2016).

[165] BSEE. BSEE Issues Violations Following Investigation Into Deepwater Horizon: Notices Sent to BP, Transocean, and Halliburton. October 12, 2011, http://www.bsee.gov/BSEE-Newsroom/Press-Releases/2011/BSEE-Issues-Violations-Following-Investigation-Into-Deepwater-Horizon/ (accessed March 26, 2016).

[166] Partial Consent Decree Between the Plaintiff United States of America and Defendants Triton Asset Leasing GMBH, Transocean Holdings LLC, Transocean Offshore Deepwater Drilling Inc., and Transocean Deepwater Inc., Doc. 8608, case 2:10-md-02179 (E.D. La.) (Feb. 19, 2013).

[167] "In January 2012, the IBLA, in response to our and the BSEE's joint request, suspended the appeal and ordered us and the BSEE to file notice within 15 days after the conclusion of the MDL and, within 60 days after the MDL court issues a final decision, to file a proposal for further action in the appeal. The BSEE has announced that the INCs will be reviewed for possible imposition of civil penalties once the appeal has ended." Halliburton Form 10-K, report to the Securities and Exchange Commission for Fiscal Year 2012 (p 18), http://www.sec.gov/Archives/edgar/data/45012/000004501213000086/hal-12312012x10k.htm#sBEA207F94C6DF488FB8EE5FD8404B586 (accessed January 26, 2016).

Presumably, BSEE can regulate contractors because they are encompassed within the broad definition of "person" in the aforementioned provision.[168] Additionally, in 43 U.S.C. § 1334(a), the introductory section covering "Administration of Leasing" on the Outer Continental Shelf,[169] explains the subject and scope of regulations that the Secretary of the Interior can promulgate for OCS activities. The scope of this clause is broad:[170]

> the Secretary shall administer the provisions of this subsection relating to the leasing of the outer Continental Shelf, and shall prescribe such rules and regulations as may be necessary to carry out such provisions. The Secretary may at any time prescribe and amend such rules and regulations as he determines to be necessary and proper in order to provide for the prevention of waste and conservation of the natural resources of the Outer Continental Shelf . . . such rules and regulations shall, as of their effective date, apply to all operations conducted under a lease issued or maintained under the provisions of this subsection.[171]

Immediately, the drilling industry and its stakeholders publicly opposed BSEE's position and the issuance of INCs to Transocean and Halliburton, claiming the Bureau had "no express statutory authority to extend its jurisdiction"[172] to contractors and "there are no definitions of exactly who is covered, nor are there standards for performance."[173] Even some members of Congress are not persuaded by BSEE's asserted authority to hold contractors liable. In the Committee Report for the Department of Interior, Environment and Related Agencies Appropriations Bill for Fiscal Year 2013, congressional appropriators noted:

> The Committee continues to be concerned with the Bureau's stated intentions for the expansion of regulatory authority over nonlease holders under the Outer Continental Shelf Lands Act (OCSLA). The authority and need for this action has not been explained or justified to the Committee, nor how this diversion of limited resources would impact the Bureau's current mission and objectives identified in the fiscal year 2013 budget request. … the Committee directs

[168] In the statute, "person" means, in addition to a natural person, "an association, a State, a political subdivision of a State, or a private, public, or municipal corporation." 43 U.S.C. § 1331(d). In the accompanying regulations, "person" is similarly defined to include "a natural person, an association (including partnerships, joint ventures, and trusts), a State, a political subdivision of a State, or a private, public, or municipal corporation." 30 C.F.R. § 250.105. The Part 250 regulations define the word "you" as "a lessee, the owner or holder of operating rights, *a designated operator or agent of the lessee(s)*, a pipeline right-of-way holder, or a State lessee granted a right-of-use and easement." 30 C.F.R. § 250.105 (emphasis added). A plain language reading of the statute and these defining regulations could support BSEE's position that a contractor, as an agent of the lessee, may be legally responsible for compliance.

[169] In an Interim Policy Document issued on August 15, 2012, BSEE cites this section of the OCSLA to support its regulatory jurisdiction over all entities that perform activities under OCSLA leasing provisions; BSEE. *Issuance of an Incident of Non Compliance (INC) to Contractors;* IPD No. 12-07; August 15, 2012; http://www.bsee.gov/uploadedFiles/Issuance%20of%20an%20Incident%20of%20Non%20Compliance%20to%20Contractors.pdf (accessed March 26, 2016).

[170] A look at the legislative history for this section of the Act reaffirms its breadth. Congress contemplated that oil *companies* would be the primary actors in OCS leasing and related activities and did not differentiate among leaseholders, operators, or contractors. H. CONF. REP. 95-1474 at 1679 (1978).

[171] 43 U.S.C. § 1334(a).

[172] http://www.perkinscoie.com/bsee-asserts-jurisdiction-over-offshore-oil-and-gas-service-companies-12-08-2011/ (accessed August 28, 2012).

[173] http://rigzone.com/news/article.asp?a_id=116394 (accessed August 28, 2012).

> that no funds be expended for other purposes until the agency has fully explained its authority, intentions, and objectives to the Committee and the public.[174]

Furthermore, regulations in Title 30 Part 250, which include safety requirements, define the Secretary's authority to regulate oil, gas, and sulphur exploration, development, and production operations on the Outer Continental Shelf under the OCSLA.[175] The definitions section states that when the word "you" is used in the Part 250 regulations, it "means a lessee, the owner or holder of operating rights, a designated operator or agent of the lessee(s), a pipeline right-of-way holder, or a State lessee granted a right-of-use and easement."[176] Still, other regulations confuse the definition. For instance, one regulation ensures that only co-lessees are jointly and severally liable for regulatory compliance, but then adds in a subsequent part that the "person" actually performing the activity to which the lessee requirement applies is also jointly and severally responsible for complying with the regulation.[177]

3.3.1.1 Post-Macondo BSEE Efforts to Hold Contractors Responsible for Safety

BSEE's decision to issue the INCs to Transocean and Halliburton post-Macondo reflected "the severity of the incident, the findings of the joint investigation, as well as Secretary Ken Salazar's and Director Bromwich's commitment to holding all parties accountable."[178] In his keynote address to the IADC annual conference in November 2011, former BSEE Director Bromwich reaffirmed the departure from the agency's previous practice of issuing INCs only to operators. Bromwich noted that law did not require the MMS historical practice of limiting its citations to operators. He explained, "the fact that we had unilaterally decided to grant immunity to all non-operators was a misguided act of administrative grace rather than a result dictated by law or good policy. The fact that we had followed a bad practice was not a sufficient reason to continue it."[179]

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[174] Comittee on Appropriations. *Department of the Interior, Environment, and Related Agencies Appropriation Bill, 2013;* Report No. 112-586; July 10, 2012; https://www.gpo.gov/fdsys/pkg/CRPT-112hrpt589/html/CRPT-112hrpt589.htm (accessed March 26, 2016).

[175] 30 C.F.R. § 250.101.

[176] 30 C.F.R. § 250.105.

[177] "When you are not the sole lessee, you and your co-lessee(s) are jointly and severally responsible for fulfilling your obligations . . . unless otherwise provided in these regulations." 30 C.F.R. § 250.146(a). "Whenever the regulations in 30 C.F.R. parts 250 through 282 and 30 C.F.R. parts 550 through 582 require the lessee to meet a requirement or perform an action, the lessee, operator (if one has been designated), and the person actually performing the activity to which the requirement applies are jointly and severally responsible for complying with the regulation." 30 C.F.R. § 250.146(c).

[178] BSEE. BSEE Issues Violations Following Investigation Into Deepwater Horizon: Notices Sent to BP, Transocean, and Halliburton. October 12, 2011, http://www.bsee.gov/BSEE-Newsroom/Press-Releases/2011/BSEE-Issues-Violations-Following-Investigation-Into-Deepwater-Horizon/ (accessed March 26, 2016).

[179] BSEE. BSEE Director Delivers Keynote Address at International Association of Drilling Contractors Conference, November 11, 2011, http://www.bsee.gov/BSEE-Newsroom/Press-Releases/2011/BSEE-Director-Delivers-Keynote-Address-at-International-Association-of-Drilling-Contractors-Conference/ (accessed March 26, 2016).

On August 15, 2012, BSEE issued Interim Policy Document No. 12-07, entitled *Issuance of an Incident of Non Compliance (INC) to Contractors*,[180] which states that BSEE will issue enforcement actions against contractors who, after considering four factors,[181] it determines to have engaged in "egregious" conduct.[182] The document also notes that issuing INCs to contractors does not relieve lessees from liability, and in fact, INCs that are issued to contractors will also be issued to the lessee or operator.[183]

Since the Macondo incident and the issuance of Interim Policy Document No. 12-07, BSEE has continued to issue INCs to non-operators. BSEE investigated a November 16, 2012, incident at a platform in the Gulf of Mexico operated by Black Elk Energy Offshore Operations.[184] An explosion and fire on Black Elk's platform killed three workers and caused several other serious injuries during welding operations.[185] This was the second incident investigation for which BSEE issued INCs to contractors for failure to perform safe operations.[186]

On March 5, 2013, BSEE issued a single INC to Island Operating, a contractor working with Apache Corporation to work on an unmanned Apache platform. The INC, issued pursuant to 30 C.F.R. § 250.107(a) for failure to perform all operations on the Platform in a safe and workmanlike manner, followed an incident at the platform where two Island Operating employees improperly transferred chemicals into a chemical tank, causing a fire and damage to the platform.[187] Island Operating appealed, challenging BSEE's jurisdiction. In a recent decision that will likely have far-reaching impact on offshore contractors, the Department of Interior Board of Land Appeals upheld BSEE's issuance of the INC

[180] BSEE. *Issuance of an Incident of Non Compliance (INC) to Contractors;* IPD No. 12-07; August 15, 2012; http://www.bsee.gov/uploadedFiles/Issuance%20of%20an%20Incident%20of%20Non%20Compliance%20to%20Contractors.pdf (accessed March 26, 2016).

[181] The four factors are: 1) the type of violation; 2) the harm resulting from the violation; 3) foreseeability of harm; and 4) the extent of the contractor's involvement in the violation(s). *Ibid* at pp 1 and 2.

[182] *Ibid.*, p 2.

[183] *Ibid.*

[184] BSEE. *Investigation of November 16, 2012, Explosion, Fire and Fatalities at West Delta Block 32 Platform E;* BSEE Panel Report 2013-002; November 4, 2013; Gulf of Mexico Region, New Orleans Distric Lease No. OCS 00367; http://www.bsee.gov/uploadedFiles/BSEE/Enforcement/Accidents_and_Incidents/Panel_Investigation_Reports/Final%20BSEE%20Black%20Elk%20report.pdf (accessed March 26, 2016).

[185] *Ibid*. p 1.

[186] A total of 41 INCs were issued to Black Elk Energy Offshore Operations, Wood Group Production Service Network, Grand Isle Shipyard and Compass Engineering Consultants. See BSEE's Notifications of Incidents(s) of Noncompliance at, http://www.bsee.gov/uploadedFiles/BSEE/Enforcement/Enforcement_Programs/Compass%20INC's%20Signed%2011-13-13.pdf; http://www.bsee.gov/uploadedFiles/BSEE/Enforcement/Enforcement_Programs/GIS%20INC's%20Signed%2011-13-13.pdf; and http://www.bsee.gov/uploadedFiles/BSEE/Enforcement/Enforcement_Programs/Wood%20Group%20INC's%20Signed%2011-13-13.pdf (accessed March 26, 2016).

[187] *See* BSEE's Notification of Incident(s) of Noncompliance at http://www.bsee.gov/uploadedFiles/BSEE/Enforcement/Enforcement_Programs/Island%20INC.pdf (accessed December 22, 2015).

despite the fact that Apache Corporation was the lessee.[188] The Board noted that the Secretary is authorized under the Outer Continental Shelf Land Act (OCSLA) to prescribe regulations "necessary" to ensure that "operations" on the OCS are "conducted in a safe manner … sufficient to prevent or minimize … [any] occurrences which may cause damage to the environment or to property, or endanger life or health."[189] The Board held that BSEE has general authority under OCSLA to issue a regulatory violation or civil penalty to "any person" who has violated the statute or related regulations.[190] The Board also relied on 30 C.F.R. § 250.146(c), which provides that "[w]henever the regulations in 30 C.F.R. [P]art 250 … require the lessee to meet a requirement or perform an action, the lessee, operator[,] … and *the person actually performing the activity to which the requirement applies* are jointly and severally responsible for complying with the regulation."[191] Island Operating then had 90 days from the date of the opinion to file an action with the federal district court seeking judicial review of the opinion.[192]

BSEE has cited additional contractors under 30 C.F.R. § 250.107(a) as well: On March 9, 2013, BSEE issued one INC to Alliance Oilfield for allegedly failing to enact proper fall protection safeguards and creating hazardous conditions following a fatality in April 2011. On March 5, 2013, BSEE issued one INC to Nabors Offshore Corporation for failing to determine whether an electricity source was on or off, resulting in a serious injury. Finally, on March 5, 2013, BSEE issued four INCs to Ensco Drilling, including three related to drilling operations, for an inadvertent disconnect of the blowout preventer, failure to properly lock out/tag out, and failure to prevent a discharge into the Gulf of Mexico. This pattern suggests that BSEE believes it has the authority to issue INCs to contractors and will continue to use INCs as an enforcement strategy for both operators and contractors as long as the agency has authority to do so.

The drilling industry disputes BSEE's position that contractors are as accountable as operators. For example, the IADC opposed BSEE's use of a policy document to announce contractor liability, proclaiming that "BSEE's guidance is inconsistent with the industry model and creates a whole new area of ambiguity."[193]

3.3.1.2 Stakeholders Attempt to Fill Responsibility Gap with Voluntary Guidance

Despite industry pushback to BSEE oversight of contractors, the American Petroleum Institute attempted to fill safety management gaps with API Bulletin 97, *Well Construction Interface Document Guidelines.* API Bulletin 97 is voluntary industry guidance intended to help operators align their SEMS program with drilling contractors' safe work practices.[194] It envisions operators and drilling contractors creating bridging documents that delineate the operator's and contractor's responsibilities during well construction

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[188] *Island Operating Co., Inc.,* IBLA 2013-137 (September 25, 2015). https://www.oha.doi.gov/IBLA/Ibladecisions/186IBLA/186IBLA199%20.pdf (accessed December 22, 2015).

[189] 186 IBLA 207. Citing U.S.C. §§ 1332 and 1348(a) (2012).

[190] *Ibid.*

[191] 186 IBLA 213.

[192] The standard of review under the Administrative Procedures Act allows for reversal of the Board's decision only if it is found to be "arbitrary, capricious, an abuse of discretion…[or] in excess of statutory jurisdiction [or] authority…." 5 U.S.C. § 706(2).

[193] IADC. IADC criticizes BSEE policy for citing drilling contractors. August 17, 2012, http://www.iadc.org/news/iadc-criticizes-bsee-policy-for-citing-drilling-contractors/ (accessed March 26, 2016).

[194] API Bulletin 97, 1st ed., *Well Construction Interface Document Guidelines*, November 2013.

activities in light of the API RP-75/SEMS rule.[195] If followed, this bulletin could help operators and contractors better follow the spirit of the SEMS rule; however, it is still voluntary guidance that cannot impose any legal requirement. Furthermore, because the regulator was not involved in its development and will not review the bridging documents or assess their use, there is no reliable way to know how Bulletin 97 is being adopted or how many companies are actually using it. Finally, it does not solve the primary issue—that the owner of the offshore installation and (typically) the employer of a workforce majority can strongly influence how the major accident risks are controlled, but the regulator does not hold them directly accountable to demonstrate that those risks are effectively managed.

3.3.2 Other Regimes' Focus on Safety Responsibilities of Operator/Lessee and Drilling Contractor

Outside the US, the UK and Australia avoid the ambiguity of responsibility through statutory directives over an offshore duty holder (or controller of risk). Norway takes a different approach by acknowledging different parties can bear either individual responsibility or co-responsibility, but makes it is the operator's responsibility to ensure regulations are being adhered to by everyone on an offshore installation.

While placing safety and environmental duties on all entities that create or contribute to the control of the risks for a particular activity, [196] UK regulations place primary compliance responsibility on the duty holder. On production installations, this is the "operator," which may be either the entity appointed by the lessee to manage the installation functions, or the lessee itself. On non-production installations such as MODUs like the Deepwater Horizon, the duty holder is the rig "owner, which is the entity that controls the operation of that installation"[197] In either case, the duty holder is "in overall control of the installation and must co-ordinate the health and safety activities of all the companies and personnel present."[198]

The responsibilities of the principal duty holder go beyond the basic requirement to develop and implement a basic safety and environmental management program. They must also:[199]

- Submit safety case documentation to the regulator that demonstrates how the major hazards will be controlled and mitigated and risks are reduced to as low as reasonably practicable;

[195] *Ibid*., p 1.

[196] "The ultimate purpose of the enforcing authorities, [including the Offshore Division], is to ensure that duty holders manage and control risks effectively, thus preventing harm." This enforcement method is based in part on proportionality, or relating enforcement action to the risks. "Those whom the law protects and those on whom it places duties (duty holders) expect that action taken by enforcing authorities to achieve compliance or bring duty holders to account for non-compliance should be proportionate to any risks to health and safety, or to the seriousness of any breach, which includes any actual or potential harm arising from a breach of the law." UK HSE Enforcement Policy Statement, Pub. No. 41 (revised December 2009), http://www.hse.gov.uk/pubns/hse41.pdf (accessed March 26, 2016).

[197] Offshore Installations (Safety Case) Regulations 2005; Offshore Installations (Offshore Safety Directive)(Safety Case etc.), 2015, Interpretation, Regulation 2(1) "duty holder." http://www.legislation.gov.uk/uksi/2015/398/regulation/2/made (accessed March 26, 2016).

[198] UK HSE. *A guide to the Offshore Installations (Safety Case) Regulations 2005, 3rd ed.;* SCR 2005; 2006; http://www.hse.gov.uk/pubns/books/l30.htm (accessed March 26, 2016).

[199] Adapted from Offshore Safety Case Regulations: Duty Holder Relationships, presented to CSB by Ian Whewell, retired head of UK HSE OSD; July 2011.

- Submit appropriate revisions to the safety case documentation when the stipulated hazards management plan changes;
- Review the safety case documentation for accuracy and completeness every 5 years;
- Conform to the contents of the safety case documentation;
- Comply with the auditing requirements meant to verify conformance.

Thus, if the Macondo well were drilled in the North Sea, Transocean, as drilling contractor and owner of the rig, would be the designated duty holder, with primary legal responsibilities to ensure all operations on the rig were executed safely and that it conformed to all safety management practices and aspects of risk control as described within its safety case document.[200]

To be clear, in the UK arrangement, the leaseholder is not exempt from safety responsibility. BP, as the operator, would have primary responsibility to plan and design the well safely to ensure that "the well is so designed and constructed, and is maintained in such repair and condition, that (a) so far as reasonably practicable, there can be no unplanned escape of fluids from the well; and (b) risks to the health and safety of persons from it or anything in it, or in strata to which it is connected, are as low as reasonably practicable."[201] The leaseholder is legally required to communicate and cooperate fully with the rig owner to ensure safe execution of those plans,[202] and the leaseholder would be held liable for any of its actions found to be contributory to an incident. These shared legal requirements ensure that key participants are fully aware that they may be held liable in the event of an incident and that they cannot rely on legal responsibility falling on another party. As such, both the operator and owner have specific and explicit risk-reduction responsibilities, which are auditable by the regulator, to ensure that they safely conduct drilling and completion operations.

In Australia, NOPSEMA asserts the principle that "those who create the risk must manage it" and states that this is the "operator's job" because the operator of the facility "has the greatest in-depth knowledge of their installation."[203] NOPSEMA defines the operator as a person nominated by a facility owner or titleholder who has or will have the day-to-day management and control of the facility (or proposed facility) and the operations at that facility.[204] For a drilling and completion operation like Macondo, this would be the facility/installation owner, similar to the UK. The applicable offshore regulations stipulate that the operator with direct control of the facility identify the hazards and risks, describe how it controls those risks, and explain its safety management system to apply the controls effectively and

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[200] UK HSE. *A guide to the Offshore Installations (Safety Case) Regulations 2005, 3rd ed.;* SCR 2005; 2006; p 5, http://www.hse.gov.uk/pubns/books/l30.htm (accessed March 26, 2016).

[201] Offshore Installations (Offshore Safety Directive)(Safety Case etc.), 2015, Establishment of well examination scheme, Regulation 11, http://www.legislation.gov.uk/uksi/2015/398/regulation/11/made (accessed March 26, 2016).

[202] Oil & Gas UK. *Well Integrity Guidelines, Issue 1;* July, 2012; Section 2.

[203] NOPSEMA, What is a safety case, http://www.nopsema.gov.au/safety/safety-case/what-is-a-safety-case/ (accessed March 26, 2016).

[204] Offshore Petroleum and Greenhouse Gas Storage (Safety) Regulations 2009, Select Legislative Instrument No. 382, 2009 as amended, Chapter 2.3, https://www.legislation.gov.au/Details/F2013C00945 (accessed March 26, 2016).

consistently.[205] The titleholder (or leaseholder) also has specific safety responsibilities for the well. It must prepare a Well Operations Management Plan (WOMP) identifying all risks that can cause a loss of well integrity to adequately assess the control measures and performance standards.[206] Guidance provided by the regulator on the WOMP states, "The description and explanation should summarize the well management system goals, the well lifecycle integrity philosophy and process and provide a detailed risk assessment showing how these risks are reduced to as low as reasonably practicable. The content and level of detail must be sufficient for NOPSEMA to assess the well management system to be applied by the titleholder."[207]

Norwegian regulations state, "in reducing the risk, the responsible party shall choose the technical, operational or organisational solutions that, according to an individual and overall evaluation of the potential harm and present and future use, offer the best results, provided the costs are not significantly disproportionate to the risk reduction achieved."[208] They require the responsible party to "establish, follow up and further develop a management system designed to ensure compliance with requirements in the health, safety and environment legislation."[209]

Norwegian PSA regulations use the neutral phrases "responsible party" or "obligated party" to encompass the leaseholder, drilling contractor, and any other third-party contractors.[210] PSA guidance explains the use of a neutral term because several parties can be responsible for compliance at the same time, and an individual's responsibility will be limited to those tasks where the individual has control and instruction authority. The operator, however, has the duty to ensure that anyone working for it complies with the health, safety environmental regulations.[211] Therefore, if Macondo had happened in Norwegian waters, Transocean would have had to establish a safety management system and technical, organizational, and operational barriers for its activities at the well, but BP would have been ultimately held responsible for any failures to do so.

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[205] NOPSEMA, What is a safety case, http://www.nopsema.gov.au/safety/safety-case/what-is-a-safety-case/ (accessed March 26, 2016).

[206] NOPSEMA. *Guidance Note: Well operations management plan content and level of detail;* N-04600-GN1602, Rev. 0; December, 2015; http://www.nopsema.gov.au/assets/Guidance-notes/GN1602-Well-operations-management-plan-content-and-level-of-detail-Rev-0-December-2015.pdf (accessed March 26, 2016).

[207] *Ibid*., p 8.

[208] Petroleum Safety Authority Norway, Regulations Relating to Health, Safety and the Environment in the Petroleum Activities and at Certain Onshore Facilities (The Framework Regulations) (2013), Section 11, Risk reduction principles, http://www.psa.no/framework-hse/category403.html#_Toc357595238 (accessed March 26, 2016).

[209] *Ibid*., Section 17, Duty to establish, follow up and further develop a management system, http://www.psa.no/framework-hse/category403.html#_Toc357595245 (accessed March 26, 2016).

[210] Petroleum Safety Authority Norway, Guidelines Regarding the Framework Regulations, Re Section 7, Responsibilities pursuant to these regulations, http://www.ptil.no/framework-hse/category408.html#p7 (accessed March 26, 2016).

[211] Petroleum Safety Authority Norway, Regulations Relating to Health, Safety and the Environment in the Petroleum Activities and at Certain Onshore Facilities (The Framework Regulations) (2013), Section 7, Responsibilities pursuant to these regulations, http://www.psa.no/framework-hse/category403.html#_Toc357595233 (accessed March 26, 2016).

In these other regimes, the regulator would also have the authority to proactively assess the drilling contractor's performance, such as Transocean's management of hazards throughout the applicable phases of the lifecycle where it is recognized as the primary duty holder. For example, when the UK HSE became concerned about human and organizational factors aboard Transocean facilities, the regulator decided to audit five Transocean rigs in the North Sea to determine the extent of the problems.[212] Operators in this regulatory environment come to understand that safety is more than a checklist of completed required documents and tasks—that they must obey the rules and bear the burden of operating safely, acting "with confidence, knowing that they have a robust safety culture which can stand up to scrutiny, both externally and internally."[213]

3.3.3 Conclusion

Work conducted by contractors offshore directly impacts the risk of offshore operations. Sometimes personal safety risk is affected, but other times it plays a role in process safety risk that could increase the probability of multiple fatalities and large scale environmental damage, both consequences of the Macondo blowout. Risk management approaches for the latter are different from those intended to mitigate personal safety.[214] Just as the CSB argues that industry should approach personal and process safety differently, the CSB also sees value in the regulator having different approaches. To that end, the CSB sees the greatest potential to improve major accident prevention in US waters by explicitly focusing on the design and operation risks governed by the leaseholder/operators and drilling contractors for reasons. Ultimately, while this section describes the different approaches of several international regimes, the US needs to develop a more effective system for the oversight of key contractors' work such as the drilling contractor during offshore operations who create or control major accident risk.

3.4 Insufficient SEMS Worker Participation Provisions

Workers participate in virtually every safety activity, whether onshore or offshore.[215] At a minimum, management should encourage workers to participate in the following activities:

- Collaborating in hazard and management of change (MOC) reviews and job safety analyses;
- Investigating incidents and near-misses;
- Serving on health and safety committees;
- Conducting health and safety inspection/audits;
- Defining safe operating procedures and work practices for a task or job;

[212] Specialist Inspection Report, Transocean Offshore (North Sea) Ltd., by Martin Anderson, Specialist Inspector (Human and Organizational Factors), Offshore Division (inspections conducted over four months from July to October 2008).

[213] Shaw, S. *What's the Case for a US Version of the Safety Case?;* April 2, 2014; http://www.erm.com/en/news-events/platform/whats-the-case-for-a-us-version-of-the-safety-case/ (accessed March 26, 2016).

[214] See Volume 3, Section 3.1

[215] Center For Chemical Process Safety. *Guidelines for Risk Based Process Safety;* John Wiley & Sons: Hoboken, NJ, 2007; p 125.

- Reporting unsafe conditions, tools, equipment, and practices to management; and
- Providing safety feedback through defined mechanisms to other workers.[216]

Actively engaging the workforce, employees, and contracted personnel ensures all those involved with the hazardous work are participating in efforts to identify and manage safety risks. Enhanced workforce participation helps to create a strong safety culture and can lead to a safer workplace. The experience of companies in implementing enhanced efforts to engage and empower the workforce shows that efforts to increase workforce involvement greatly outweighs the costs of such programs.[217]

Inadequate worker involvement in policies, programs, and regulations limits a drilling crew's ability to help manage the hazards for major accident prevention. BP and Transocean used limited means to encourage and empower workers to be involved in managing major hazards. Efforts to include them in safety management primarily resided in company safety observation programs focused on occupational health and safety. As Volume 3 discussed in depth, occupational safety measures do not improve the process safety status of the organization. The CSB identified in previous investigation reports that effective process safety management and major accident prevention cannot be achieved without involving workers and their representatives. In its Chevron Regulatory Report, the CSB noted that the CCPS lists workforce involvement as one of 20 essential management components necessary to reduce process safety risks and prevent chemical accidents:[218]

> …workers are potentially the most knowledgeable people with respect to the day-to-day details of operating the process and maintaining the equipment and facilities and may be the sole source for some types of knowledge gained through their unique experiences. Workforce involvement provides management a mechanism for tapping into this valuable expertise.[219]

Worker participation in the offshore oil and gas industry is of critical importance. Workers aboard a rig can contribute keen insights into the daily workings of an operation that upper management might miss. As such, workers should be engaged in a wide range of safety management activities, including project planning, risk analysis, and incident investigations, and thus can play an integral role in preventing accidents. As Volumes 2 and 3 demonstrate, decisions that people on a rig make can impact the potential for a well kick, or strengthen or weaken a barrier. For example, "any problems that did occur during the TA [temporary abandonment] plan would be dealt with by employing the knowledge, experience and skills of the drilling team"[220] Therefore, if workers are not effectively engaged in the management of major hazards in these ways, a duty holder bypasses a key layer of insight and enhanced protection. Inclusion of workers also contributes significantly to creation of a positive safety culture, while omitting

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[216] American National Standards Institute/American Industrial Hygiene Association (ANSI/AIHA) Z10-2012, *Occupational Health and Safety Managment Systems*, 2012, p 34.

[217] Eves, D.; Gummer, J. *Questioning Performance: Essential Guide to Health, Safety and the Environment ;* IOSH Services Ltd: Wigston, United Kingdom, 2011, p 91.

[218] Center For Chemical Process Safety. *Guidelines for Risk Based Process Safety;* John Wiley & Sons: Hoboken, NJ, 2007; p liv.

[219] *Ibid.,* p 124.

[220] Volume 3, Section 1.8.2.

workers minimizes their contribution and weakens safety culture onboard a rig. A strong safety culture empowers individual workers and encourages them to be fully focused on safe working conditions. Thus, workforce engagement is vital to major accident prevention, and should be encouraged.

> *The purpose of employee participation is to utilize the employees' collective knowledge and experience to ensure that matters are sufficiently explored before decisions are made that concern health, safety, and the environment, and to provide the employees with the opportunity to exert influence on their own work situation.*
>
> — *Norwegian PSA Framework Legislation, Section 13, Facilitating Employee Participation,* http://www.ptil.no/framework/category408.html#p13.

At the time of the Macondo incident, there were no effective US offshore regulations that provided for worker participation in the management of process safety. While BSEE asserts that post-Macondo worker participation provisions within SEMS[221] provide "several key ways for personnel to help ensure safe performance of oil and gas activities on the OCS,"[222] these regulations could be substantially improved to enhance worker engagement in offshore safety management and major accident prevention efforts. Comparisons of the SEMS worker participation regulations with those of international offshore regimes and other high-hazard industries in the US illustrate opportunities for further improvement.

3.4.1 Post-Macondo/SEMS Worker Participation Provisions

In April 2013, several provisions were added to the SEMS regulations for worker participation,[223] but regulations do not guarantee that workers are effectively participating in managing offshore process safety. Effective worker participation requires active engaging workers in the designing, implementing, and improving an operation's safety management systems.[224] BSEE intends to meet this goal with the SEMS provisions:

1. Operators must have an Employee Participation Plan (EPP) for their employees. Under the rule, operators must consult with employees regarding the SEMS. Furthermore, operators must create a "written plan of action" showing how "appropriate employees" will contribute to the "development and implementation" of an operator's SEMS. Employees are also required to have access to any part of the SEMS that relates to their duties.[225]
2. Operators must include Stop-Work Authority (SWA) procedures in their SEMS program. Such procedures would authorize and require all employees and other personnel who witness an activity presenting an imminent risk or danger to the health or safety of an individual, the public,

[221] 30 C.F.R.250.1930-1932.

[222] Final Rule, Oil and Gas and Sulphur Operations in the Outer Continental Shelf—Revisions to Safety and Environmental Management Systems, 78 Fed. Reg. 20,423 (Apr. 5, 2013).

[223] *Ibid*.

[224] Center For Chemical Process Safety. *Guidelines for Risk Based Process Safety;* John Wiley & Sons: Hoboken, NJ, 2007; p 124.

[225] 30 C.F.R. § 250.1932.

or to the environment to stop the work creating the risk or danger. "Imminent risk or danger is defined as any condition, activity, or practice in the workplace that could reasonably be expected to cause:

- Death or serious physical harm; or
- Significant environmental harm …."[226]

3. Operators must define a process to designate an individual with Ultimate Work Authority (UWA) on each facility for operational and safety decision-making. After a Stop Work is initiated, work can resume upon determination by the UWA "that the imminent risk or danger …. no longer exists."[227]
4. Operators must provide all personnel with a system for reporting unsafe work conditions.[228]

These provisions are a marked improvement over the offshore safety regulations that existed at the time of the Macondo incident; however, the provisions are not adequate to ensure the workforce is engaged in creating and implementing a company's SEMS program.

3.4.2 Insufficient and Limited SEMS Worker Participation Provisions

In promulgating the Employee Participation Plans, BSEE sought to encourage an "environment that promotes participation by employees and management in order to eliminate or mitigate hazards on the OCS."[229] BSEE held that the rule would require "an operator who performs regulated activities on the OCS … to consult with its employees [workers] regarding the development, implementation, and modification of its SEMS program."[230] "Consult," however, is a vague term that does not ensure workers have a voice in process safety management matters. Consultation can be a one-way process, with operators simply telling their workers how the hazards will be managed without consideration of worker viewpoints or concerns. The purpose is to engage and empower the workforce throughout the entire SEMS lifecycle (development, implementation, and modification), incorporating the workforce's views, accepting those that are valid, and explaining why they are rejected when appropriate. But the SEMS regulations do not provide a framework for how that should occur. Furthermore, management selects the workers it deems "appropriate" and defines their level of involvement[231] in a way that makes the most sense for each company or operation, but the possibility exists for continued worker exclusion.

SEMS provisions that require worker participation are limited in scope. Additionally, other SEMS provisions that discuss aspects of worker involvement fail to require the level of active engagement that

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226 30 C.F.R. § 250.1930.

227 *Ibid*. The person with the ultimate work authority would be the person on the fixed, floating facilities or MODU with the final responsibility for making decisions. The operator's SEMS program must identify all persons that could have UWA, and the operator must designate those persons as such.

228 30 C.F.R. § 250.1933. Furthermore, on August 28, 2013 BSEE reports it has launched a confidential near-miss reporting system with the Department of Transportation and Statistics. The system will "provide important trend analysis and statistical data to BSEE." See BTS and BSEE to Develop Confidential Near-Miss Reporting System, http://www.rita.dot.gov/bts/bts_bsee (accessed March 26, 2016).

229 Final Rule, Oil and Gas and Sulphur Operations in the Outer Continental Shelf—Revisions to Safety and Environmental Management Systems, 78 Fed. Reg. 20,423 (Apr. 5, 2013).

230 *Ibid*.

231 30 C.F.R. § 250.1932(b).

would help to drive safety improvement. For instance, the SEMS Job Safety Analysis (JSA) provision requires “the immediate supervisor of the crew performing the job onsite [to] conduct the JSA, sign the JSA, and ensure that all personnel participating in the job understand and sign the JSA.”[232] Essentially, the supervisor must inform workers of risks associated with their respective jobs and have them sign off on the analysis, but the workers need not be involved in identifying, assessing, or mitigating such risks. By contrast, other offshore regimes provide specific requirements for including the workforce in safety management activities through worker-elected safety representatives.[233] Moreover, the SEMS Rule states, “Your SEMS program must establish and implement a training program so that all personnel are trained in accordance with their duties and responsibilities to work safely and are aware of potential environmental impacts.”[234] Thus, incorporating process safety concepts and effective practice should be part of the required training provided to the workers or their representatives.

The only other mechanism in SEMS directly addressing worker involvement besides EPP are the Stop-Work Authority (SWA) provisions;[235] however, SWA provisions are a weak substitute for worker involvement in major accident prevention offshore. A regulatory SWA provision will not be successful if the workforce is not aware of the specific safety risks of the work. For example, on the Deepwater Horizon, the majority of the frontline workers reported that they were “comfortable with identifying and understanding the hazards they were exposed to,”[236] but supervisors and rig leadership had concerns with hazard awareness amongst the crew. They noted that the crew did not always identify major hazards and appropriate controls in their THINK[237] plans.[238] As one person stated, “they don’t know what they don’t know.” The stop-work programs of BP and Transocean allowed for any employee to call for a stop work to intervene in hazardous operating conditions, but without clear understanding of the risks, the workforce is hindered from effectively identifying situations when major hazard risk barriers have been compromised and, thus, will be less likely to initiate a stop work.

[232] 30 C.F.R. § 250.1911(b)(2).

[233] See CSB Chevron Regulatory Report Section 4.4 for a detailed discussion of Active Workforce Participation in other jurisdictions; USCSB, 2013. *Regulatory Report: Chevron Richmond Refinery Pipe Rupture and Fire, Richmond, CA, August 6, 2012*, Report No. 2012-03-I-CA, April 2013, http://www.csb.gov/assets/1/19/Chevron_Regulatory_Report_11102014_FINAL_-_post.pdf (accessed January 25, 2016).

[234] 30 C.F.R. § 250.1915

[235] 30 C.F.R. §§ 250.1930, 250.1931.

[236] Internal Company Document, Transocean. Safety Management and Safety Culture/Climate: North America Division Summary Report, July 2, 2010, TRN-HCEC-00090521, see Exhibit 0929 http://www.mdl2179trialdocs.com/releases/release201304041200022/Bertone_Stephen-Depo_Bundle.zip (accessed October 7, 2015).

[237] THINK is a planning and risk management tool that begins with task development and the identification of associated task hazards. After hazards are identified, the THINK process requires management to communicate hazards to people and to put in place controls to mitigate them. The complexity of a task determines the depth of assessment and formality of the THINK plan; See Volume 3, Section 1.8.3 for more detail.

[238] Internal Company Document, Transocean. Safety Management and Safety Culture/Climate: North America Division Summary Report, July 2, 2010, TRN-HCEC-00090521, see Exhibit 0929 http://www.mdl2179trialdocs.com/releases/release201304041200022/Bertone_Stephen-Depo_Bundle.zip (accessed October 7, 2015).

3.4.3 No SEMS Provisions for Worker-Elected Safety Representatives

Safety representatives are spokespeople elected by the workforce onboard offshore drilling or production vehicles or other facilities to advocate for workers on “both day-to-day and strategic health and safety issues.”[239] Exact rules for using safety representative vary among jurisdictions. The UK initiated safety representatives post-Piper Alpha, resulting in stronger workforce commitment to implement safety management programs. Now frontline personnel encourage employees to share valuable input in identifying and controlling hazards.[240]

In many international regimes, the safety representative requirement is considered crucial to effectively implement worker participation measures.[241] The regulator-mandated safety representative motivates companies to include workers in safety management activities and promotes an essential dialogue among labor, the regulator, and the operator.[242] The explicit nature of the UK, Norwegian, and Australian regulations pertaining to worker-elected safety representatives demonstrate the recognized integral role workers play in robust safety management. Such regulation fosters an environment where workers can participate with industry and the regulator in managing safety. In addition, empowering workers to elect safety representatives through regulation is an important step in overcoming fears of management retaliation for reporting concerns.[243]

UK regulations grant worker safety representatives a variety of defined functions and powers, including:

- Investigating potential hazards and examining the causes of accidents;
- Investigating workforce complaints relating to health and safety;
- Inspecting installation equipment;
- Reporting findings from investigations to installation managers;
- Reporting unsafe activities to the regulator when, for instance, the installation management does not take immediate remedial actions after safety representatives bring the circumstances to their attention;
- Participating as a member of the installation’s safety committee; and

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[239] UK HSE. *A guide to the Offshore Installations (Safety Representatives and Safety Committees) Regulations 1989;* 2012; http://www.hse.gov.uk/pubns/priced/l110.pdf. (accessed March 26, 2016).

[240] *Ibid*., p 4.

[241] *See* The Offshore Installations (Safety Representatives and Safety Committees) Regulations 1989, 1989 No. 971, 18 Sept. 1989; Regulations Relating to Health, Safety and the Environment in the Petroleum Activities and at Certain Onshore Facilities (The Framework Regulations); Offshore Petroleum and Greenhouse Gas Storage Act 2006, Volume 3, Schedule 3, Part 3, http://www.comlaw.gov.au/Details/C2013C00071/Html/Volume_3#_Toc347403628; Working Environment Act, December 14, 2012; available at: http://www.arbeidstilsynet.no/binfil/download2.php?tid=92156; http://www.ptil.no/framework-hse/category403.html#_Toc357595234 (accessed March 26, 2016).

[242] UK HSE. *A guide to the Offshore Installations (Safety Representatives and Safety Committees) Regulations 1989;* 2012; p 7. http://www.hse.gov.uk/pubns/priced/l110.pdf. (accessed March 26, 2016).

[243] Efforts to enhance worker participation should not conflict with provisions established under the National Labor Relations Act.

- Consulting in the development of a safety case document.[244]

Worker-elected safety representatives formally accomplish the worker participation in safety management.[245] The UK captures the requirement that all workers participate in all phases of operation through the definition of the word "workforce" which "includes every person *who is for the time being working on or from an offshore installation*."[246] Worker-elected safety representatives in the UK are also permitted by regulation to participate in a wide range of safety matters aboard an offshore installation, ranging from investigations of accidents to general matters affecting the occupational health and safety of members of the workforce, and all without the loss of pay.[247]

Norway provides workers with an opportunity to follow up on safety matters.[248] For example, the working environment committee, which represents workers, "shall participate in planning safety and environmental work and shall follow up developments closely in [relation to] the safety, health and welfare of the employees [workers]."[249] This helps workers to know that management takes their concerns seriously. Similarly, Norway provides workers with the opportunity to participate in safety matters throughout the lifecycle of the operation.[250] Workers in Norway elect safety representatives called "safety delegates" to "see that work is carried out in such a manner that the safety, health and welfare of the employees [workers] are taken care of."[251] Through their elected representatives, workers are involved early in the safety management process.[252] Relevant regulations provide that worker participation "shall be ensured in all various phases of the [petroleum] activities," including the "establishment, follow-up

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244 The Offshore Installations (Safety Representatives and Safety Committees) Regulations 1989, http://www.legislation.gov.uk/uksi/1989/971/contents/made (accessed March 26, 2016).

245 UK HSE. *A guide to the Offshore Installations (Safety Representatives and Safety Committees) Regulations 1989;* 2012; http://www.hse.gov.uk/pubns/priced/l110.pdf. (accessed March 26, 2016).

246 The Offshore Installations (Safety Representative and Safety Committees) Regulations 1989, Interpretation, SI971 (1989), (emphasis added), available at: http://www.legislation.gov.uk/uksi/1989/971/regulation/2/made (accessed March 26, 2016).

247 UK HSE. *Safety representatives and safety committees on offshore installations: A brief guide for the workforce*, INDG199(rev1), 1999, http://www.hse.gov.uk/pubns/indg119.htm (accessed April 12, 2016).

248 Petroleum Safety Authority Norway, Regulations Relating to Health, Safety and the Environment in the Petroleum Activities and at Certain Onshore Facilities (The Framework Regulations) (2013), Section 17, Duty to establish, follow up and further develop a management system, and Section 13, Facilitating employee participation, http://www.psa.no/framework-hse/category403.html (accessed March 26, 2016).

249 Working Environment Act, December 14, 2012; Section 7-2, http://www.arbeidstilsynet.no/binfil/download2.php?tid=92156 (accessed March 26, 2016).

250 Petroleum Safety Authority Norway, Regulations Relating to Health, Safety and the Environment in the Petroleum Activities and at Certain Onshore Facilities (The Framework Regulations) (2013), Section 13, Facilitating employee participation, http://www.ptil.no/framework-hse/category403.html#_Toc357595240 (accessed March 26, 2016).

251 Ognedal, M. PSA, *Workforce Contribution*, June 11, 2011; http://www.hse.gov.uk/aboutus/meetings/iacs/oiac/wig/110609/psa.pdf, Slides 6-7. PSA. Guidelines Regarding the Framework Regulations, Re Section 13, Facilitating employee participation, http://www.ptil.no/framework/category408.html#_Toc407544828 (accessed March 26, 2016).

252 Petroleum Safety Authority Norway, Regulations Relating to Health, Safety and the Environment in the Petroleum Activities and at Certain Onshore Facilities (The Framework Regulations) (2013), Section 13, Facilitating employee participation, http://www.ptil.no/framework-hse/category403.html#_Toc357595240 (accessed March 26, 2016).

and further development of management systems."[253] Norway believes "the employees' experience and active participation is a significant precondition for a sound management system."[254] The Norwegian safety delegates also have duties and protections similar to those established in the UK.[255] PSA believes that this mandate provides workers with the opportunity to actually participate in and influence safety in day-to-day operations.[256]

Worker Participation in Mine Safety Regulation

In the US, the Mine Safety and Health Act of 1977 provides for two or more miners to designate a representative to advocate for their rights.[a] While the representative may be an employee, he or she does not necessarily have to be.[b] The miners' representative can request inspections,[c] participate in Mine Safety and Health Administration (MSHA) inspections,[d] and learn of and participate in enforcement proceedings.[e] Congress provided miners with worker participation rights because it believed the miners' knowledge of the operation could provide the MSHA with critical safety information.[f]

[a] *A Guide to Miners' Rights and Responsibilities: Under the Federal Mine Safety and Health Act of 1977;* pp 11-15. http://arlweb.msha.gov/s&hinfo/minersrights/minersrights.pdf (accessed March 26, 2016); 30 C.F.R 40.1.
[b] *Ibid.*, pp 10-11.
[c] Federal Mine Safety and Health Act of 1977 § 103(g).
[d] Federal Mine Safety and Health Act of 1977 § 103(f).
[e] Federal Mine Safety and Health Act of 1977 § 107(b).
[f] *A Guide to Miners' Rights and Responsibilities: Under the Federal Mine Safety and Health Act of 1977;* p 10. http://arlweb.msha.gov/s&hinfo/minersrights/minersrights.pdf (accessed March 26, 2016).

Australia's NOPSEMA requires that health and safety representatives be members of the workforce, which includes employees and contractors.[257] The representative is also selected by the workforce. By objective, this regulation intends to "ensure that expert advice is available on occupational health and

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[253] *Ibid*.

[254] PSA. Guidelines Regarding the Framework Regulations, Re Section 17, Duty to establish, follow up and further develop a management system http://www.ptil.no/framework/category408.html#_Toc407544828 (accessed March 26, 2016).

[255] PSA. Guidelines Regarding the Framework Regulations, Section 13, Facilitating employee participation, http://www.ptil.no/framework/category408.html#_Toc407544828; Working Environment Act, December 14, 2012; Chapter 6, http://www.arbeidstilsynet.no/binfil/download2.php?tid=92156 (accessed March 26, 2016).

[256] Guidelines Regarding the Framework Regulations, Re Section 13, Facilitating employee participation, http://www.ptil.no/framework/category408.html#_Toc407544828 (accessed March 26, 2016).

[257] Offshore Petroleum and Greenhouse Gas Storage Act 2006, Volume 3, Schedule 3, Part 3, and Volume 3, Schedule 3, Part 1.3 "member of the workforce," http://www.comlaw.gov.au/Details/C2013C00071/Html/Volume_3#_Toc347403628 (accessed March 26, 2016).

safety matters."[258] Such representation encourages a "consultative relationship between all relevant persons concerning the health, safety and welfare of members of the workforce at those facilities."[259]

3.4.4 No SEMS Requirement for Contractor Participation

SEMS does not directly apply to contractors. The EPP in SEMS, which requires the operator to "consult with its employees regarding the development, implementation, and modification of its SEMS program,"[260] does not encompass contractor employees, including the drilling contractor and other well service providers.[261] Yet, most crew members aboard these offshore facilities are contracted.[262] On the Deepwater Horizon, 118 of the 126 crew members were contractors,[263] including most of the individuals involved in the well operations activities leading up to the incident. Further, contractors performed 54% of BP's 373 million total work hours in 2013.[264]

Many production facilities also have high numbers of contractors conducting hazardous operations. In the November 16, 2012, multi-fatality hot work incident on a Black Elk Energy production platform, all 24 crew members present were employed by one of three contractor companies. A number of safety management system failures were identified as causal, including poor hot work procedures, inadequate assessment of the hazards, insufficient supervision, and lack of monitoring for flammable gas.[265] No Black Elk employees were working aboard the production platform at the time of the incident, and as a result, the contracting companies did not have to have a SEMS program, nor did the workers have a regulatory right to have an EPP and participate in the SEMS development process. Thus, no one aboard the Black Elk facility had a regulatory right to be involved in the safety management aspects of their work.

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[258] Offshore Petroleum and Greenhouse Gas Storage Act 2006, Volume 3, Schedule 3, Part 1.1, http://www.comlaw.gov.au/Details/C2013C00071/Html/Volume_3#_Toc347403590 (accessed March 26, 2016).

[259] Offshore Petroleum and Greenhouse Gas Storage Act 2006, Volume 3, Schedule 3, Part 1.1, http://www.comlaw.gov.au/Details/C2013C00071/Html/Volume_3#_Toc347403590 (accessed March 26, 2016).

[260] 30 C.F.R. § 250.1932; Oil and Gas and Sulphur Operations in the Outer Continental Shelf—Revisions to Safety and Environmental Management Systems, 78 Fed. Reg. 20423 (Final Rule, April 5, 2013).

[261] *Ibid*.

[262] MMS made this observation in 2003, and then it was reiterated after Macondo by the National Commission on the BP Deepwater Horizon Oil Sill and Offshore Drilling: Oil and Gas and Sulphur Operations in the Outer Continental Shelf—Incident Reporting Rule, 68 Fed. Reg. 40585 (Proposed Rule, July 8, 2003) and National Commission on the BP Deepwater Horizon Oil Spill and Offshore Drilling, *A Competent and Nimble Regulator: A New Approach to Risk Assessment and Management*, Staff Working Paper No. 21, p 7.

[263] Internal Company Document, Transocean. *Personnel On-Board as of 20 Apr 2010 17:09:15*, April 20, 2010, TRN-MDL-00030435, http://www.mdl2179trialdocs.com/releases/release201303071500008/TREX-00687.pdf (accessed March 26, 2016).

[264] BP. *Sustainability Review 2013*; Working with our contractors, suppliers and partners; p 27, http://www.bp.com/content/dam/bp/pdf/sustainability/group-reports/BP_Sustainability_Review_2013.pdf (accessed March 26, 2016).

[265] BSEE. *Investigation of November 16, 2012, Explosion, Fire and Fatalities at West Delta Block 32 Platform E;* BSEE Panel Report 2013-002; November 4, 2013; Gulf of Mexico Region, New Orleans Distric Lease No. OCS 00367; http://www.bsee.gov/uploadedFiles/BSEE/Enforcement/Accidents_and_Incidents/Panel_Investigation_Reports/Final%20BSEE%20Black%20Elk%20report.pdf (accessed March 26, 2016).

The failure of the SEMS rule to include contract workers who comprise the majority of the frontline workforce presents significant risks for offshore oil and gas operations. The UK, Norway, and Australia offshore regulations grant participation rights to both employed and contracted labor. In the UK, the Offshore Installations (Safety Representatives and Safety Committees) Regulations 1989 stipulate that "every person who is for the time being working on or from an offshore installation under a contract of service or a contract for services"[266] has the authority to nominate and elect safety representatives "to ensure that the whole workforce is formally involved in promoting health and safety."[267]

Similarly, Norwegian regulation provides that all workers elect a safety delegate, requiring each "individual employer" who carries out "simultaneous activities at the same workplace," meaning all employees, including contractors, to comply with this mandate.[268] In fact, PSA requires that the employer coordinate its selection of a safety delegate with a contractor's selection,[269] with the total number of representatives dependent on the operation size and the working conditions.[270]

Australia's NOPSEMA also requires that health and safety representatives be members of the workforce, including employees and contractors, and be selected by the workforce.[271] Such representation encourages a "consultative relationship between all relevant persons concerning the health, safety and welfare of members of the workforce at those facilities"[272] in order to "ensure that expert advice is available on occupational health and safety matters."[273]

3.4.5 SEMS Stop-Work Authority Impact on Worker Liability

The SEMS SWA provision does not sufficiently prohibit reprisal for stopping dangerous activities. It grants "all personnel the responsibility and authority, without fear of reprisal, to stop work or decline to perform an assigned task when an imminent risk or danger exists."[274] Since the SWA provision obligates workers to report unsafe operations, workers could be blamed for failing to stop the work if an incident occurs.

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[266] UK HSE. *A guide to the Offshore Installations (Safety Representatives and Safety Committees) Regulations 1989;* 2012; p 2. http://www.hse.gov.uk/pubns/priced/l110.pdf. (accessed March 26, 2016).

[267] *Ibid*., p 7.

[268] Petroleum Safety Authority Norway, Regulations Relating to Health, Safety and the Environment in the Petroleum Activities and at Certain Onshore Facilities (The Framework Regulations) (2013), Section 8, Employer's duties toward employees other than its own, http://www.ptil.no/framework-hse/category403.html#_Toc357595234 (accessed March 26, 2016).

[269] *Ibid*; Working Environment Act, December 14, 2012; Section 2-2, http://www.arbeidstilsynet.no/binfil/download2.php?tid=92156 (accessed March 26, 2016).

[270] *Ibid*; Working Environment Act, December 14, 2012; Section 6-1, http://www.arbeidstilsynet.no/binfil/download2.php?tid=92156 (accessed March 26, 2016).

[271] Offshore Petroleum and Greenhouse Gas Storage Act 2006, Volume 3, Schedule 3, Part 3, and Volume 3, Schedule 3, Part 1.3 "member of the workforce," http://www.comlaw.gov.au/Details/C2013C00071/Html/Volume_3#_Toc347403628 (accessed March 26, 2016).

[272] Offshore Petroleum and Greenhouse Gas Storage Act 2006, Volume 3, Schedule 3, Part 1.1, http://www.comlaw.gov.au/Details/C2013C00071/Html/Volume_3#_Toc347403590 (accessed March 26, 2016).

[273] *Ibid*.

[274] 30 C.F.R. § 250.1930.

Placing "the responsibility and authority" to halt dangerous activities on workers can create a culture of assigning blame to workers. The provision discusses that workers should not fear reprisal for initiating an SWA; however, the regulation does not speak to the protections granted to those who arguably failed to initiate an SWA when circumstances might have seemed to require it. If workers do not have a sufficient awareness of the hazards of an activity, they may be blamed or criticized after an incident for failing to initiate a stop work. Essentially, a worker is confronted with the dilemma of choosing between facing criticism (or worse) for stopping work or being blamed for failure to act.

The concept of imminent risk should not be a sole determinant for stop-work authority. Control of major hazards depends on defense-in-depth, or reliance on multiple barriers to prevent imminent danger because of barrier redundancy. Yet loss of a critical barrier should warrant a stop-work order even if risk is not imminent.

A poorly designed or supported SWA program may encourage workers to try to ignore certain activities in the hopes of avoiding fault in a potential stop-work situation – the antithesis of an engaged workforce. Thus, involving workers in these situations can have the unintended effect of reducing safety reporting, increasing defensive posturing by workers, and minimizing the benefits of a reporting system.[275]

In contrast, both the UK and Norway remove from the workforce any duty to stop work.[276] UK Safety Representative regulations state that "no function conferred on a [either the safety representative or the safety committee] by this regulation shall be construed as imposing a duty on [them]."[277] Legislation in Norway provides the safety representative with the opportunity to stop work, but the "representative is not liable for any loss suffered by the undertaking as a result of work being halted."[278] In both instances, removing potential sources of blame on the worker for stopping work is crucial to improving offshore safety.

3.4.6 Inadequate SEMS Requirements to Protect Workers from Retaliation

The SWA provision in SEMS is designed for use when work stoppage is most challenging. When the work is being performed, time and economic pressures are likely high, and the crew well understands the consequences of stopping work.[279] The CSB Tosco Avon Refinery investigation uncovered workers who stated they felt pressure to avoid using stop work because of economic implications and production pressures.[280] As such, they were greatly concerned about retaliation for initiating a stop work. Similarly,

[275] Dekker, S. *Just Culture: Balancing Safety and Accountability;* Ashgate Publishing Company: Hampshire, England, 2007; pp 20-27.

[276] Working Environment Act, December 14, 2012; Section 6-3, http://www.arbeidstilsynet.no/binfil/download2.php?tid=92156; The Offshore Installations (Safety Representatives and Safety Committees) Regulations 1989, No. 16 http://www.legislation.gov.uk/uksi/1989/971/contents/made (accessed March 26, 2016).

[277] The Offshore Installations (Safety Representatives and Safety Committees) Regulations 1989, No. 16 http://www.legislation.gov.uk/uksi/1989/971/contents/made (accessed March 26, 2016).

[278] Working Environment Act, December 14, 2012; Section 6-3, http://www.arbeidstilsynet.no/binfil/download2.php?tid=92156 (accessed March 26, 2016).

[279] USCSB, 2001, *Refinery Fire Incident, Martinez, CA, February 23, 1999,* Report No. 99-014-I-CA, March 2001, http://www.csb.gov/assets/1/19/Tosco_Final_Report.pdf (accessed March 25, 2016).

[280] *Ibid*.

in the GoM, the fear of retaliation for stopping work is described in BSEE's investigation of the 2012 Black Elk production platform explosion, where BSEE noted that contractors did not initiate a stop work because they feared losing their jobs for doing so.[281]

In many instances, simply requiring that companies have a stop-work program does not guarantee the workforce will actually use it. The workers must believe that using SWA will not result in disciplinary action. Indeed, the SEMS SWA provision creates the type of stop work programs already implemented by BP and Transocean at the time of the blowout, found to be lacking adequate worker protections. [282]

SEMS also requires that operators establish a program for reporting unsafe working conditions that protect "a person's identity to the extent authorized by law."[283] Initially, BSEE reported that it was developing a confidential near-miss reporting system with the Bureau of Transportation and Statistics."[284] This program has now been implemented.[285] According to the BSEE website, the program is both voluntary and anonymous.[286] At this time, the toll-free hotline line is operational but the BSEE website has not yet been modified to accept online reporting.[287] However, there are insufficient provisions within SEMS to protect workers from retaliatory action.

A bill that originated in 2010 in the House Committee on Education and the Workforce stated there was that no federal law that protects oil and gas workers if they are retaliated against after they blow the whistle on workplace health and safety violations on the Outer Continental Shelf.[288] The bill eventually

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[281] BSEE. *Investigation of November 16, 2012, Explosion, Fire and Fatalities at West Delta Block 32 Platform E;* BSEE Panel Report 2013-002; November 4, 2013; Gulf of Mexico Region, New Orleans Distric Lease No. OCS 00367; pp 3-4. http://www.bsee.gov/uploadedFiles/BSEE/Enforcement/Accidents_and_Incidents/Panel_Investigation_Reports/Final%20BSEE%20Black%20Elk%20report.pdf (accessed March 26, 2016).

[282] Bureau of Ocean Energy Management, Regulation, and Enforcement. *Report Regarding the Causes of the April 20, 2010, Macondo Well Blowout;* 2011; pp 189-190; OCEANA statement to BSEE, RE: Revisions to Safety and Environmental Management Systems (SEMS), 1010-AD73, November 14, 2011; p 3. http://www.bsee.gov/uploadedFiles/Oceana%2011-9-11.pdf (accessed March 26, 2016).

[283] 30 C.F.R. § 250.1933; 30 C.F.R. § 250.193.

[284] Notice of Voluntary Confidential NearMiss Reporting System Public Workshop, 79 Fed. Reg. 17563; See also BTS and BSEE to Develop Confidential Near-Miss Reporting System, http://www.rita.dot.gov/bts/bts_bsee (accessed March 26, 2016).

[285] This program was implemented on May 5, 2015 in SafeOCS. *See* Section 4.3.2.

[286] "SafeOCS is a voluntary and completely confidential system, in which the Bureau of Transportation Statistics (BTS) will collect and analyze near-miss reports submitted by individual OCS workers, companies, and others. The aggregated data will be shared with the general public through the BTS website, and used to identify safety trends and increase understanding of offshore risk;" http://www.bsee.gov/BSEE-Newsroom/Press-Releases/2015/BSEE-Director-Brian-Salerno-Announces-Key-Efforts-to-Reduce-Risk-Offshore/ (accessed March 26, 2016).

[287] The CSB has not identified an anonymous online reporting tool on the BSEE website. The Bureau of Transportation Statistics does have a functioning SafeOCS near-miss reporting system link which can be found here: https://near-miss.bts.gov/#contactUs (accessed March 31, 2016).

[288] 111 H.R. 5851. Offshore Oil and Gas Worker Whistleblower Protection Act of 2010. https://www.congress.gov/bill/111th-congress/house-bill/5851 (accessed January 7, 2016). The House also brought forward subsequent versions of this bill in 2011, and then again in 2015. See 112 H.R. 503, Offshore Oil and Gas Worker Whistleblower Protection Act of 2011; 114 H.R. 2824, Offshore Oil and Gas Worker Whistleblower Protection Act of 2015.

expired due to inaction during a previous Congress. Nevertheless, such legislation highlighted the regulatory gap in whistleblower protection that the SEMS program has not addressed.

BSEE itself, in its Safety Culture Policy Statement of May 9, 2013, identified an "Environment for Raising Concerns" as one of nine characteristics of a robust safety culture and that this meant that "A work environment is maintained where personnel feel free to raise safety and environmental concerns without fear of retaliation, intimidation, harassment, or discrimination."[289]

Some existing statutes have jurisdictional language that may apply offshore and the possibility exists that offshore workers may have some, albeit limited, measure of whistleblower protection. OSHA currently oversees enforcement of many different whistleblower protection laws arising in areas such as occupational, environmental, nuclear, transportation, consumer, and other categories.[290] Some of the most potentially applicable statutes that might help protect offshore workers tend towards environmental protection, are the Clean Air Act,[291] the Comprehensive Environmental Response, Compensation and Liability Act,[292] and the Federal Water Pollution Control Act (the Clean Water Act).[293]

In the UK, the workforce brings forward its safety concerns to its designated safety representatives who present these matters to the installation manager.[294] In effect, the workforce has a protective mechanism from retaliation. Norway and Australia take similar approaches.[295]

The Mining Safety and Health Administration, or MSHA, also provides protections for workers voicing safety concerns with mining operations. Neither a miner nor a miner's representative can be discharged or retaliated against for filing a complaint concerning safety related matters. Moreover, a miner or a miner's representative can seek legal relief if they believe they have been the subject of dismissal or harassment for filing such complaint.[296]

Effectively managed reporting programs provide the regulator a view of issues that may not otherwise be detected through inspections. To manage a reporting program effectively, the operator must remove

[289] BSEE, Safety Culture Policy, http://www.bsee.gov/Safety/Safety-Culture-Policy/ (accessed October 7, 2015).

[290] US Department of Labor. The Whistleblower Protection Programs, http://www.whistleblowers.gov/wb_filing_time_limits.html (accessed March 31, 2016).

[291] 42 U.S.C. § 7422.

[292] 42 U.S.C. § 9610.

[293] 33 U.S.C. § 1367.

[294] Malloy, J. Former Director, Regional Organizer, RMT Union Offshore Energy Branch, Personal communication, October 3, 2013; UK HSE. *Safety representatives and safety committees on offshore installations: A brief guide for the workforce,* INDG199(rev1), 1999, http://www.hse.gov.uk/pubns/indg119.htm.; The Offshore Installations (Safety Representatives and Safety Committees) Regulations 1989, http://www.legislation.gov.uk/uksi/1989/971/contents/made (accessed March 26, 2016).

[295] Working Environment Act, December 14, 2012; Section 6-2, http://www.arbeidstilsynet.no/binfil/download2.php?tid=92156.; Offshore Petroleum and Greenhouse Gas Storage Act 2006, Volume 3, Schedule 3, Part 3, Subdivision B, http://www.comlaw.gov.au/Details/C2013C00071/Html/Volume_3#_Toc347403653.

[296] 30 U.S.C. § 815(c).

penalties for reporting safety issues.[297] As long as SEMS and other potential sources of federal oversight fail to provide protection for whistleblowers or workers seeking to stop work in the offshore environment, offshore process safety suffers.

3.4.7 No SWA Worker-Requested Regulatory Provision in Regulation

The SEMS regulations do not contain a provision allowing the workforce to seek intervention by the regulator should they feel that management is not responding adequately to their call for a stop work. Rather, SEMS states, "Work may be resumed when the individual on the facility with Ultimate Work Authority (UWA) determines that the imminent risk or danger does not exist or no longer exists."[298] But management designates the individual with the UWA.[299] This creates the potential for resolving when to resume operations without adequate or impartial review. Workers may reasonably believe that operations still pose a significant risk if restarted. Therefore, SEMS should provide for regulatory intervention whenever management and workers disagree on whether work can be safely resumed.

UK law provides that if two or more safety representatives believe an "imminent risk" exists in any activity, they must inform the installation manager.[300] The installation manager then must inform an HSE inspector of the issue through a report as soon as is reasonably practicable.[301] The HSE may issue an enforcement notice either to prohibit the activity until matters have been corrected or to require some longer-term improvements, or in the worst case, to prosecute the responsible party.[302] The decision on when work can begin again is left to the regulator and is specified in the prohibition notice.[303]

In Norway, the safety representatives have the right to halt dangerous work. The danger must be immediate and cannot be averted by other means. If the safety representative determines these conditions to be the case, work may be halted until the labor inspection authority decides whether work may continue.[304]

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[297] Committee on Education and the Workforce. H.R. 503: Offshore Oil and Gas Worker Whistleblower Protection Act, http://democrats.edworkforce.house.gov/bill/hr-503-offshore-oil-and-gas-worker-whistleblower-protection-act (accessed March 26, 2016).

[298] 30 C.F.R. § 250.1930(c).

[299] 30 C.F.R. § 250.1931(a).

[300] The Offshore Installations (Safety Representatives and Safety Committees) Regulations 1989, http://www.legislation.gov.uk/uksi/1989/971/contents/made (accessed March 26, 2016).

[301] UK HSE, Safety Representatives and Safety Committees on Offshore Installations, http://www.hse.gov.uk/pubns/indg119.pdf (accessed March 26, 2016).

[302] UK HSE, HSE Public Register of Enforcement Notices, http://www.hse.gov.uk/notices/ (accessed March 26, 2016).

[303] Joomla!. UK Health and Safety Legal System: Appendix A – UK Health and Safety Legal System, Prohibition Notice, http://www.simplesensiblesafety.co.uk/index.php?option=com_content&view=article&id=22&catid=1&Itemid=82 (accessed March 26, 2016).

[304] Working Environment Act, December 14, 2012; Section 6-3, http://www.arbeidstilsynet.no/binfil/download2.php?tid=92156 (accessed March 26, 2016).

Australia requires safety representatives to report an imminent danger to the supervisor or, if no supervisors can be located, to stop work.[305] If supervisors can be located, then the supervisor is required to take actions that he or she believes will remove the danger. If the safety representatives believe imminent danger still exists, they may make a request to NOPSEMA to conduct an inspection of the activity. This option also exists for the supervisors if they disagree with the safety representatives. Only after the NOPSEMA inspection determines that the activity is safe can work resume.[306]

The SEMS failure to require regulatory intervention in a stop-work dispute between the workforce and management increases potential safety risk. Lack of regulatory participation in a stop-work situation can result in management's always making the ultimate decision. Management may order work to resume after a stop work before eliminating or sufficiently mitigating the hazard in the interest of averting costs, lost time, and other economic impacts caused by the stop work. Management may decide even with limited understanding of the risks due to distance from the worksite or unfamiliarity with the work, the requirements of its special tasks, or other unique circumstances. Regulatory intervention of the type discussed in the UK, Norway, and Australia thus provide an avenue for improving the SEMS regulation. The reality is, however, that the formality of involving the regulator in a stop work situation is only a backstop. Sound safety culture, with informed safety representatives and enhanced protection for workers who exercise stop work authority should resolve worker concerns about safety without frequent need for regulator involvement. Nevertheless, the right to involve the regulator is always available in those jurisdictions, and it remains a powerful driver to resolve issues. The US should emulate this important protection.

3.4.8 No SEMS Safety Committees or Tripartite Safety Forums Provision

A fundamental element in effective safety management for major accident prevention is active and equal participation from the regulator, industry, and labor. Each stakeholder provides unique and essential insights; removing the participation of any of them can result in losing a critical voice in safety management. While the regulator and industry management typically have the means to ensure that their voices are heard—they have the enforcement power on one hand and ownership or managerial authority on the other—the workers often lack similar means. Labor participation is vital as it gives workers the opportunity to provide management and the regulator with invaluable insights, and in many instances the workers are the only source of this information.[307] In other offshore regimes, workers are guaranteed rights to form safety committees, made up of both management and workforce members, to encourage dialogue on safety issues or concerns at each offshore facility. In contrast, SEMS lacks requirements for workforce-management safety committees that would promote dialogue on safety concerns between both entities.

The UK requires each offshore installation with more than one safety representative to establish a safety committee comprised of the installation manager, another person appointed by the installation manager,

[305] Offshore Petroleum and Greenhouse Gas Storage Act 2006, Volume 3, Schedule 3, Part 3, Division 5, 44, http://www.comlaw.gov.au/Details/C2013C00071/Html/Volume_3#_Toc347403653.

[306] Ibid., Division 5, 44 & 45.

[307] Center For Chemical Process Safety. *Guidelines for Risk Based Process Safety;* John Wiley & Sons: Hoboken, NJ, 2007; p 124.

and all of the safety representatives.[308] Through the committee, management and the workforce discuss health and safety matters with the goal of developing mutual cooperation and ensuring the safety of the workforce.[309]

In addition to these safety committees, many regimes have developed larger forums where regulator, industry, and workforce all have equal opportunities to directly interact and discuss safety matters. The regulator often hosts and supports these forums. Yet no such regulator-supported forum has been developed for US offshore worker representatives can openly discuss safety issues with industry management and the regulator.

The UK has a tripartite forum which is enabled through Step Change in Safety,[310] an organization established in 1997 when industry decided to require significant improvements in health and safety, and when collaboration among the parties became a priority.[311] Through the years, Step Change influenced greater cooperation among labor, industry, and the regulator.[312] The organization is led by a team of senior managers from industry, trade unions, trade associations, and the regulator. The workforce is specifically engaged through networks, including elected safety representatives, safety professionals, and site leaders. Regular meetings are held throughout the year to share safety information and to discuss safety issues. Through this framework, issues such as competence, leadership, workforce engagement, continual improvement, asset integrity, and communication are addressed to improve health and safety offshore.[313] Step Change supports a number of steering groups, including the Workforce Engagement Support Team (WEST), which aims to maximize the value of both safety representatives and workforce engagement survey tools that strengthen workers' role in safety management.[314] The UK HSE also chairs a more formal, higher level tripartite body, the Offshore Industry Advisory Committee (OIAC), which brings employer and worker representatives together with the regulator in another important forum to discuss offshore health and safety matters.[315]

Similarly, Norway's regulator established a number of tripartite bodies. A working environment committee is involved in planning safety issues such as construction work, work processes, and

[308] The Offshore Installations (Safety Representatives and Safety Committees) Regulations 1989, http://www.legislation.gov.uk/uksi/1989/971/contents/made (accessed March 26, 2016).

[309] UK HSE. *A guide to the Offshore Installations (Safety Representatives and Safety Committees) Regulations 1989;* 2012; p 2. http://www.hse.gov.uk/pubns/priced/l110.pdf. (accessed March 26, 2016); note, in the United States, safety committees are required by some state laws and often, in unionized workplaces, through the collective bargaining process.

[310] http://www.stepchangeinsafety.net/; UK HSE. Offshore Oil & Gas Sector Strategy, http://www.hse.gov.uk/offshore/priorities.htm (accessed March 26, 2016).

[311] Step Change in Safety, *Strategic Plan 2010-2015: Making the UK the safest place to work in the worldwide oil and gas industry*, 2010.

[312] *Ibid*.

[313] *Ibid*.

[314] Step Change in Safety, Workforce Engagement, https://www.stepchangeinsafety.net/about-step-change-safety/steering-groups/workforce-engagement (accessed March 26, 2016).

[315] UK HSE, Offshore Industry Advisory Committee (OIAC), http://www.hse.gov.uk/aboutus/meetings/iacs/oiac/ (accessed March 26, 2016).

preventive safety measures. The committee receives paid time off to attend training sessions.[316] A Regulatory Forum and the Safety Forum[317] also facilitates discussion of safety issues such as trends in risk management, practical implementation of regulatory requirements, and safety standards for use offshore.[318] PSA asserts that these forums are beneficial venues to raise awareness of safety issues and discuss potential solutions, especially for industry members who are less sophisticated.[319]

Australia's NOPSEMA uses its Offshore Petroleum Safety Tripartite Forum to actively engage all the stakeholders involved in the offshore petroleum industry.[320] NOPSEMA maintains that such engagement will improve safety by promoting "information sharing, learning and innovation across the offshore petroleum industry."[321]

The US lacks similar initiatives to encourage participation among the regulator, industry, and labor. This remains a missed opportunity.

3.4.9 Conclusion

The importance of worker participation in safety management cannot be overstated. Existing US offshore safety regulations addressing workforce participation are improved since Macondo; however, the regulations still suffer from significant gaps. The regulations fail to engage all members of the workforce; lack workforce-elected safety representatives and safety committees; rely heavily on SWA which is a weak form of worker involvement if not properly implemented or supported; and create potential opportunities for blaming the workforce without recourse to regulator intervention. These gaps diminish safety by discouraging workforce participation in managing offshore safety. The regulator should take additional steps to improve these regulatory provisions, provide for protection against retaliation for workforce participation in safety management activities, as well as play a lead role in establishing a tripartite forum to aid workers in having a larger voice in process safety management and major accident prevention.

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316 Working Environment Act, December 14, 2012; Section 7, http://www.arbeidstilsynet.no/binfil/download2.php?tid=92156 (accessed March 26, 2016).

317 Hauge , H., Okstad , E., Tinmannsvik , R., Lootz, E., Ovesen , M., Carlsen, I., Risk of Major Accidents: Causal Factors and Improvement Measures Related to Well Control in the Petroleum Industry, SPE Americas E&P Health, Safety, Security and Environmental Conference, Galveston, TX, March 18-20, 20132; SPE-163775-MS:

318 *Ibid*.; PSA, Regulatory Forum, 2014, http://www.ptil.no/regulations/regulatory-forum-article9524-216.html# (accessed March 26, 2016).

319 Sophistication refers to industry members who do not have the breadth and depth of offshore business experience as some of the oil majors, who have well-developed operational programs from decades of experience; CSB Norway trip notes, April 26 – May 1, 2012.

320 NOPSEMA. Offshore Petroleum Safety Tripartite Forum, http://www.nopsema.gov.au/safety/offshore-petroleum-safety-tripartite-forum/.

321 Offshore Petroleum Safety Tripartite Forum, Terms of Reference, Feb. 26, 2013, http://www.nopsema.gov.au/assets/document/Terms-of-Reference-Offshore-Petroleum-Safety-Tripartite-Forum-Rev-0-Feb-2013.pdf.

4.0 US Offshore Regulator Challenge in Effective Oversight

BSEE's goal of a SEMS program is "to promote safety and environmental protection."[322] To accomplish that goal, operators must "ensure [their] SEMS program identifies, addresses, and manages safety, environmental hazards …"[323] This language is weaker than the corporate policies BP and Transocean had at the time of Macondo to prevent incidents that harmed people and the environment and to apply ALARP principles in their operations.[324] Furthermore, BP and Transocean already had mandated internal safety management systems that would have satisfied post-Macondo SEMS requirements, including hazard analysis, management of change, operating procedures, and incident investigation.[325] The analysis presented in Volume 3 demonstrates that BP and Transocean's failures to effectively implement these systems were causal factors in the blowout. Thus, merely having a documented safety management program that complies with SEMS regulations is not sufficient. A fundamental question arises: Have enough changes occurred in the US to make safety management programs, like those which BP and Transocean already had in place, effective? This chapter answers the question by describing the value of major hazard documentation that identifies the major hazards and the barriers intended to prevent or mitigate them, as well as the influential role of the regulator in proactive review and verification of that documentation. The chapter also describes potential opportunities for BSEE to drive further industry safety improvements through the use of effective process safety indicators and transparency.

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[322] 30 C.F.R. § 250.1901.

[323] *Ibid*.

[324] BP's OMS Exploration and Production Drilling and Well Operations Practice (DWOP) states, "all risks shall be managed to a level which is as low as reasonably practical" or ALARP, Internal Company Document, BP. *GP 10-00 Drilling and Well Operations Practice*, Issue 1, October 2008, "This document contains the practices that have been agreed by BP management as current and relevant for drilling and well operations.", p A-8, BP-HZN-BLY00034518, http://www.mdl2179trialdocs.com/releases/release201304110900026/TREX-06121.pdf (accessed May 26, 2015). Transocean policies requires employees to manage risks to ALARP, which Transocean defines as "… requiring personnel to consider the various additional risk reduction measures (additional controls) and determine if the effort and cost of those measures justify the additional amount of risk reduction obtained" Internal Company Document, Transocean. *Health and Safety Policies and Procedures Manual*, Issue 03, Revision 07, HQS-HSE-PP-01, December 15, 2009, Section 4 (Safety Policies, Procedures and Documentation), p BP-HZN-2179MDL00132218, see Exhibit 4942, BP-HZN-2179MDL00132055, http://www.mdl2179trialdocs.com/releases/release201302281700004/Farr_Daniel-Depo_Bundle.zip (accessed October 7, 2015).

Internal Company Document, BP. *The BP Operating Management System Framework, Part 1, An Overview of OMS*, Issue 2, November 3, 2008, p 24, BP-HZN-2179MDL0033320, see Exhibit 2352 http://www.mdl2179trialdocs.com/releases/release201302281700004/Lynch_Richard-Depo_Bundle.zip (accessed October 7, 2015).

Internal Company Document, Transocean. *Health and Safety Policies and Procedures Manual*, Issue 03, Revision 07, HQS-HSE-PP-01, December 15, 2009, General, BP-HZN-2179MDL00132067, see Exhibit 4942 http://www.mdl2179trialdocs.com/releases/release201302281700004/Farr_Daniel-Depo_Bundle.zip (accessed October 7, 2015).

[325] 30 C.F.R. § 250.1902 and Volume 3.

In 2015 BSEE laid out two strategic goals:[326]

- Regulate, enforce, and respond to OCS development using the full range of authorities, policies, and tools to compel safety, emergency preparedness and environmental responsibility and appropriate development and conservation of the offshore oil and natural gas resources.
- Build and sustain the organizational, technical, and intellectual capacity within and across BSEE's key functions – capacity that keeps pace with OCS industry technological improvements, innovates in regulation and enforcement, and reduces risk through systemic assessment and regulatory and enforcement actions."

Yet despite these aims and the post-Macondo regulatory changes, BSEE still struggles with several limitations and untapped opportunities to more effectively regulate the offshore oil and gas industry:

- Limited proactive oversight mechanisms to drive industry to improve safety systems as evidenced by these shortfalls:
    - BSEE does not require documentation demonstrating control of major hazards before commencing the hazardous offshore operations;
    - Lack of sufficient direct involvement in SEMS audits, and the accompanying dialogue with the company that occurs as part of the auditing process, which minimizes BSEE's influence;
- Inadequate collection and use of safety performance indicator data to identify and analyze developing safety issues before they turn into more severe problems;
    - BSEE has not initiated industrywide or companywide audits to proactively assess safety trends;
- Historically inadequate levels of transparency in disseminating industry safety information and in the performance of oversight activities.

This chapter explores proactive mechanisms BSEE can use to counter this issues and more effectively oversee industry's efforts to manage major accident risk, while driving further safety improvements and promoting trust among members of industry, workforce, and the public.

4.1 No Required Review of Major Accident Hazard Documentation Before Hazardous Work Begins

Oil and gas companies operating in the US OCS are not required to provide major hazard documentation that: (1) identifies all major accident hazards, (2) implements the necessary barriers and controls to reduce risk to ALARP, and (3) describes an effective and operational safety management program to ensure that those barriers and controls will remain reliable and available as needed. [327] While point 3 could

[326] The US Department of the Interior. *Budget Justifications and Performance Information Fiscal Year 2015: Bureau of Safety and Environmental Enforcement;* http://www.bsee.gov/uploadedFiles/BSEE/About_BSEE/Budget/BSEE%20FY%202015%20Final%20Greenbook%20File.pdf (accessed March 25, 2015).

[327] See Chapter 4, Volume 2.

potentially be addressed by a SEMS program, points 1 and 2 go beyond current SEMS requirements.[328] BSEE could review major hazard documentation, and if necessary, challenge a company's assertions before and/or during hazardous activities. Furthermore, the assertions in major hazard documentation could become the foundation for BSEE to conduct more effective preventative audits and inspections and have meaningful dialogue with the duty holder about its specific risk management policies and practices.[329]

As described in Chapters 2.0 and 3.0, the development of a written case for safety is critical to the UK and Australian offshore regulatory regimes, and a similar "internal control" plan requirement exists for companies operating in Norwegian waters.[330] Originally only UK and Australian offshore regulators had to accept[331] a facility's written case for safety before it could commence operation, and as of June 28, 2013 that requirement now applies to all European Union members, [332] including over 1,000 facilities in the North Sea, Mediterranean Sea, and Black Sea with offshore drilling and production activities.[333] The regulator's acceptance of a written case for safety in any jurisdiction (called a Major Hazard Report under the EU directive) still does not license the facility or installation as "fit," nor does it shift the duty of risk control and reduction away from the facility owner or operator and onto the regulator. Rather, the duty of major accident prevention and risk-reduction to ALARP remains with the duty holder throughout the life of the facility. In fact, even in adopting the new directive, the EU noted that offshore safety remains primarily the obligation of the offshore operators and the individual countries in which they operate.[334] Following the regulator's acceptance of the safety case document, the duty holder must ensure that the installation is operated in accordance with the safety management system and other risk-reduction provisions described in the safety case.

The term "safety case" came about because in such a regime, the duty holder is expected to make a written case for safety to the regulator.[335] In their documentation, duty holders must explain the processes

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[328] As described in Section 6.1.1 of Volume 2, the hazard analysis requirement in SEMS (30 C.F.R. 250.1911) is not focused on targeted risk reduction of major accident events and the barriers intended to prevent or mitigate them.

[329] Section 4.2 for further discussion.

[330] See, Hopkins, A. *Explaining the Safety Case;* Working Paper 87; National Research Centre for OHS Regulation, Australian National University: April, 2012.

[331] This concept is discussed in the CSB's report on the Chevron Richmond Refinery. "Acceptance requires satisfaction with the duty holder's approach to identifying and meeting health and safety needs … HSE 'accepts' the validity of the described approach as being capable, if implemented as described, of achieving the necessary degree of risk control, but HSE does not confirm the outcomes of that approach." Therefore, "HSE will accept a safety case or a revision … when duty holders demonstrate and describe specified matters to HSE's satisfaction. Acceptance will be based on HSE's judgment that the arrangements and measures described in the safety case taken as a whole are **likely** to achieve compliance if implemented as described. To give acceptance HSE does not need to be satisfied that compliance **will** be achieved…." UK HSE. *A guide to the Offshore Installations (Safety Case) Regulations 2005, 3rd ed.;* SCR 2005; 2006; p 6, http://www.hse.gov.uk/pubns/books/l30.htm (accessed March 26, 2016).

[332] Http://ec.europa.eu/energy/en/topics/oil-gas-and-coal/offshore-oil-and-gas-safety.

[333] Safety of Offshore Oil and Gas Operations Directive, http://eur-lex.europa.eu/legal-content/EN/ALL/?uri=CELEX:32013L0030.

[334] European Commission, Offshore oil and gas safety, Http://ec.europa.eu/energy/en/topics/oil-gas-and-coal/offshore-oil-and-gas-safety (accessed January 26, 2016).

[335] *Ibid*., p 4.

they used to identify hazards and assess risks[336] and their rationale for choosing a particular method of controlling them.[337] The regulator reviews the case and accepts or rejects the document, which is a prerequisite to obtain a license to drill.[338] Once a rig has an accepted safety case, it can operate anywhere in that jurisdiction without resubmitting the case, assuming it addressed the full range of hazard options. This presentation and acceptance feature of the Australian and UK safety case process forms the basis of the legal agreement between the company and the regulator.

According to UK HSE guidance on the offshore Safety Case Regulations, safety case reports are "intended to be living documents, kept up to date and revised as necessary during the operational life of the installation."[339] Similarly, Australian regulators explain that if carried out properly, the process of developing the safety case will "improve safety of offshore activities by ensuring a systematic review of the hazards, their associated risks and the control measures that are applied at the facility to either eliminate the hazards or otherwise reduce the risks. Progress, in terms of risk-reduction, is achieved by applying the process both during initial development of the safety case and subsequently in the course of continual improvement."[340]

EU-wide safety standards

Under the Safety of Offshore Oil and Gas Operations Directive, the EU put in place a set of rules to help prevent accidents, as well as to respond promptly and efficiently should one occur before exploration or production begins. For their offshore installation, companies must prepare a Major Hazard Report, containing a risk assessment and an emergency response plan. They must keep resources at hand to put them into operation when necessary when granting licenses. EU countries must ensure that companies are well financed and have the necessary technical expertise and solutions critical for the safety of operators' installations. These must be independently verified by the regulator before the installation commences operation. National authorities must verify safety provisions, environmental protection measures, and the emergency preparedness of rigs and platforms. If companies do not respect the minimum standards, EU countries can impose sanctions, including halting production. Information on how companies and EU countries keep installations safe must be made available for citizens. Companies will be fully liable for environmental damages caused to protected marine species and natural habitats. For damage to marine habitats, the geographical zone will cover all EU marine waters including exclusive economic zones and continental shelves.

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336 *Ibid*., p 5.

337 *Ibid*., p 5.

338 Whewell, I. Former Director, UK HSE Offshore Division, Personal communication, July 6, 2011.

339 UK HSE. *A guide to the Offshore Installations (Safety Case) Regulations 2005, 3rd ed.;* SCR 2005; 2006; p 7. http://www.hse.gov.uk/pubns/books/l30.htm (accessed March 26, 2016).

340 NOPSEMA. *ALARP Guidance Note;* N-04300-GN0166, Rev 6; June, 2015; p 18. http://www.nopsema.gov.au/assets/Guidance-notes/N-04300-GN0166-ALARP.pdf (accessed March 26, 2016).

Internationally, both the UK HSE and NOPSEMA require acceptance of an operator's safety case before beginning activities.[341] This framework requires operators to demonstrate that all risks were reduced to ALARP.[342] Nevertheless, the safety case is "accepted" and not "approved," as the safety of the facility is not guaranteed by the regulator, nor does it mean the operation as a whole is fit.[343] Acceptance of the safety case indicates that the facility's approach is valid in terms of good practice; however, confirmation of compliance is based on post-acceptance programs, such as inspections and audits.[344] The requirement that the regulator accept an operator's safety case before beginning activities is beneficial because it allows for meaningful dialogue to begin at the early stages of development.[345]

In Norway, the PSA does not formally review and "accept" the management system documentation before permitting companies to drill, but it does require that management system documentation be prepared and be made available for the regulator's review at any time, such as during a facility audit. PSA then routinely reviews the documentation and discusses its contents with the operator to assess how the operator's SMS is working.[346] PSA does not require the facility to submit its safety management system for acceptance, and asserts that the benefits of this approach are: (1) it does not create the impression that the duty of ensuring safety has shifted to the regulator and (2) regulatory resources can focus on industry activities instead of the paperwork review.[347]

In the UK, Australia, and Norway, duty for assuring risks are reduced to ALARP remains with the entity responsible for creating or controlling the risk. The regulator checks that an operation is effectively reducing risk to ALARP through audits and inspections that verify the duty holder's adherence to its own

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[341] See The *Offshore Installations (Safety Case) Regulations 2005*, No. 3117, Regulation 7 & 8, http://www.legislation.gov.uk/uksi/2005/3117/contents/made (accessed March 26, 20160; Offshore Petroleum and Greenhouse Gas Storage (Safety) Regulations 2009, Division 2- Submission and acceptance of safety cases, https://www.legislation.gov.au/Details/F2013C00945 (accessed March 26, 2016).

[342] UK HSE. *A guide to the Offshore Installations (Safety Case) Regulations 2005, 3rd ed.;* SCR 2005; 2006; *Demonstration of 'as low as reasonably practicalbe,* p 13. http://www.hse.gov.uk/pubns/books/l30.htm (accessed March 26, 2016); Offshore Petroleum and Greenhouse Gas Storage (Safety) Regulations 2009, 1.4 Objects, https://www.legislation.gov.au/Details/F2013C00945 (accessed March 26, 2016).

[343] Pitblado, R.; Bjerager, P.; Andreassen, E. *An Effective US Offshore Safety Regime;* Det Norske Veritas: 22 2010, July; p 3. http://www.dnvusa.com/Binaries/1008-001%20Offshore%20Update_Key%20aspects_tcm153-430982.pdf (accessed March 16, 20106); Powell, T. *US Voluntary Semp Initiative: Holy Grail or Poisoned Chalice?*, Offshore Technology Conference, Housont, TX, May 8-9, 1996; OTC 8111.

[344] CSB Public Hearing: Regulatory Approaches to Offshore Oil and Gas Safety, Washington, DC, December 15, 2010; see, for example, pp 32-35. http://www.csb.gov/assets/1/19/Transcript_of_Public_Meeting_12_15_2010.pdf (accessed March 7, 2015).

[345] *Ibid.*

[346] Transportation Research Board of the National Academies. Evaluating the Effectiveness of Offshore Safety and Environmental Management Systems; Transportation Research Board Special Report 309; National Academy of Sciences: Washington, DC, 2012; pp 62-63. http://onlinepubs.trb.org/onlinepubs/sr/SR309.pdf (accessed March 31, 2016).

[347] Center for Stratetic & International Studies. *The International Regulatory Structures for Offshore Exploration;* November 8, 2010; p 2. http://csis.org/files/attachments/101108_Summary_International%20Practices.pdf (accessed March 26, 2016).

safety assertions.[348] The true strength of the regimes lie then in the regulators' abilities to test the validity of duty holder claims.[349]

Without such a review of the documentation detailing the planned risk reduction measures, a scenario could arise in which the operator assembles and executes a deficient safety management system and BSEE misses an opportunity to identify safety gaps. The permit-to-operate process that currently exists in the US OCS provides opportunities to evaluate aspects of a facility's management systems before certain design and operational phases of the well site. None, however, sufficiently address process safety concerns. For instance, in bidding on an OCS lease, BOEM can disqualify a potential lessee for various reasons, including unresolved or multiple incidents of noncompliance, civil penalties, or failure to adhere to lease obligations.[350] While civil penalties may touch upon aspects of process safety, disqualification largely depends on administrative or occupational safety matters.

Once a lease has been obtained, an operator must obtain approval from BSEE to drill by submitting information such as design criteria for the proposed well, drilling plans, and diverter and BOP system descriptions.[351] The information required by BSEE is a prescriptive-based series of technical specifications that does not contain a comprehensive list of best technical practices nor a comprehensive barrier-risk analysis that addresses both design and operational site specific risks.[352] Further, there is no performance based requirement to ensure the design risks of the well are and will remain reduced to a level such as ALARP throughout the lifecycle of the well.

For the US to effectively implement a more robust regulatory regime for its offshore oil and gas operations, BSEE must play a proactive role in risk-reduction. In the CSB's view, this includes not only active review and response to third-party audit results, but independent BSEE audits and initiatives on identified safety issues or at-risk facilities/companies, and the authority and to accept, reject, or require

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348 CSB Public Hearing: Regulatory Approaces to Offshore Oil and Gas Safety, Washington, DC, December 15, 2010; see, for example, p 95. http://www.csb.gov/assets/1/19/Transcript_of_Public_Meeting_12_15_2010.pdf (accessed March 7, 2015). UK HSE. *A guide to the Offshore Installations (Safety Case) Regulations 2005, 3rd ed.;* SCR 2005; 2006; *Demonstration of 'as low as reasonably practicalbe,* p 6. http://www.hse.gov.uk/pubns/books/l30.htm (accessed March 26, 2016).

349 "The fact is that the safety case is simply a series of 'claims' as to how an installation is being safely operated. The real strength in the regime is testing the validity of those claims through strategic intervention by competent regulators," Whewell, I. Former Director, UK HSE Offshore Division, Personal communication, August 23, 2013.

350 30 C.F.R. § 556.35; & 30 C.F.R. § 550.136; see also BSEE. Regional Leasing, http://www.boem.gov/Oil-and-Gas-Energy-Program/Leasing/Regional-Leasing/Index.aspx (accessed March 26, 2016).

351 §250.410; §250.400 indicates that those subject to Subpart D—Oil and Gas Drilling Operations under which the permitting requirements are described include lessees, operating rights owners, operators, and their contractors and subcontractors.

352 For example, the regulations for cementing require that the operator provide "A written description of how you evaluated the best practices included in API Standard 65—Part 2, Isolating Potential Flow Zones During Well Construction, Second Edition...Your written description must identify the mechanical barriers and cementing practices you will use for each casing string (reference API Standard 65—Part 2, Sections 4 and 5)." Sections 4 and 5 in API Standard 65 state, "This section [4] is not exhaustive, nor does it provide the reader with a comprehensive set of detailed recommendations for well construction. The intent is to highlight the salient aspects that should be considered and summarize the interrelationship between drilling operations and cementing success. All topics discussed are covered in detail in various API, ISO, and other industry publications. […] This [technical references] list is not all-inclusive. Other technical references are available in industry literature."

modifications to a company's major hazard risk management approach before or throughout the entirety of the offshore operation.

4.2 Regulatory Safety Oversight Audits and Initiatives

After BSEE's first audit of the SEMS program in 2013, it noted there was a significant variation in SEMS programs amongst operators.[353] As might be expected, for companies like BP and Transocean, BSEE observed that complying with the SEMS regulations entailed mapping their corporate policies to the SEMS elements listed in 30 C.F.R. 250 Subpart S.[354] BSEE noted that for other organizations, the SEMS rule "triggered a first effort to develop and implement a formal SEMS," and that for many organizations the focus was on compliance rather than "developing a tool to manage their respective operating health, safety, and environmental (HSE) risks."[355]

In a 2012 interview, former BSEE Director James Watson contended that BSEE did not "review and approve the safety and environmental management system programs and that's by design."[356] BSEE did not want to create a system in which industry relied on the government to management it.[357] 'Reviewing' a company's SEMS program and major hazard documentation, however, is an opportunity for the regulator to challenge 1) if hazards and risks have been assessed and 2) if controls and proposed safety management systems meant to ensure their effectiveness have been established. In this framework, "approving' a SEMS program or major hazard documentation can simply be acknowledgement by the regulator that all the elements it has deemed necessary to manage safety have been addressed. The effectiveness of a SEMS program though can only be assessed or audited after being tested under the demands of actual operations.

In 2012, BSEE (then BOEMRE) engaged the Transportation Research Board (TRB) to provide guidance on how to evaluate the effectiveness of the SEMS regulations. TRB observed:[358]

- If BSEE's goal is, as it should be, to encourage a culture of safety so that individuals know the safety aspects of their actions and are motivated to think about safety, then the agency will need to evolve an evaluation system for Safety and Environmental Management Systems (SEMS) that emphasizes the evaluation of attitudes and actions rather than documentation and paperwork.

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[353] BSEE. *SEMS Program Summary—First Audit Cycle (2011-2013);* July 23, 2014, http://www.bsee.gov/uploadedFiles/BSEE/Regulations_and_Guidance/Safety_and_Environmental_Management_Systems_-_SEMS/SEMS%20Program%20Summary%208132014.pdf (accessed March 29, 2016).

[354] *Ibid*.

[355] *Ibid*.

[356] Dlouhy, J. Offshore enforcement chief outlines approach to safety. *Fuel Fix from the Houston Chronicle*, December 18, 2012, http://fuelfix.com/blog/2012/12/18/offshore-enforcement-chief-outlines-approach-to-safety/ (accessed March 26, 2016).

[357] *Ibid.*

[358] Transportation Research Board of the National Academies. *Evlauating the Effectiveness of Offshore Safety and Environmental Managment Systems;* Transportation Research Board Special Report 309; National Academy of Sciences: Washington, DC, 2012; pp 31 and 91. http://onlinepubs.trb.org/onlinepubs/sr/SR309.pdf (accessed March 31, 2016).

- BSEE can encourage or hurt the development of a culture of safety by the way it measures and enforces SEMS. Forcing an operation to satisfy checklists that require specific forms of documentation and penalizing those operations that do not is likely to encourage a culture of compliance and discourage the development of a culture of safety.

BSEE's findings two years later in 2014 on the SEMS programs validated TRB's observations. BSEE noted that audit questions "were focused on assessing compliance rather than focusing on successfully reducing or managing risk" and that some reports were submitted "as nothing more than a completed checklist with little incorporated information or analysis." BSEE stated that compliance checklists "limit [its] ability to assess degrees of implementation or effectiveness [of SEMS programs]." TRB reviewed existing approaches for assessing safety management systems and BSEE's potential role in the process. TRB's report summarizes several auditor characteristics it observed in US and international regulatory agencies from a variety of industries (not all inclusive):[359]

- Specialized training for auditors to ensure a working knowledge of SMS elements, worker duties, and the industry
- A variety of tools for auditors to assess the implementation of SMSs including observing operations, verifying procedures, seeking evidence of corrective actions, and in the case of offshore, speaking to workers and managers, both at the offshore facilities and shore-based offices.
- Scheduled audits, in response to an incident or risk-based.
- Regulatory tools to stop work if companies cannot demonstrate adequate risk management of operations.

Specific to Norway, TRB noted that PSA replaced the term "inspection" with "supervision," and "approvals" with "consents." PSA believes that the terminology change was significant because it helped move audits beyond monitoring exercises and created a climate "in which PSA worked with the industry to improve safety instead of acting in the role of a compliance inspector and guarantor of the acceptability of company."[360] This sentiment was paralleled both in the US and the UK. In 1990, a Marine Board charged with exploring alternative inspection measures for the OCS told MMS that regulatory presence on offshore installations conveys a sense of oversight and provides impetus for safety improvement by marginal and inexperienced operators. [361] In the UK, following the 2005 Buncefield incident,[362] the HSE onshore regulator began emphasizing regulatory inspections and audits to ensure companies implement safety management systems to reduce risks to ALARP, as described in their safety case reports.

[359] *Ibid.*, Chapter 4.

[360] *Ibid.*, pp 60-61.

[361] Committee on Alternatives of Inspection of Outer Contineneta1 Shelf Operations, Marine Board, Commission on Engineering and Technical Systems National Reserach Council. *Alternatives for Inspecting Outer Continental Shelf Operations* [Online]; National Academy Press: Washington, 1990; p 81, http://www.nap.edu/download.php?record_id=1517 (accessed March 26, 2016).

[362] On December 11, 2005, a number of explosions occurred at Buncefield Oil Storage Depot in Hemel Hempstead, Hertfordshire, England, following the overfilling of a gasoline tank. There were no fatalities, 43 people were injured, and nearby commercial and residential property totaled $1.5 billion; Buncefield Major Incident Investigation Board. *The Buncefield Incident, 11 December 2005;* Volume 1; UK HSE: 2008; http://www.hse.gov.uk/comah/buncefield/miib-final-volume1.pdf (accessed March 26, 2016).

According to HSE, roughly 70 percent of an HSE onshore inspector's time is now spent inspecting.[363] In conversations with CSB investigators, HSE management and inspectors emphasized the importance of inspections and the "creative tension" created during dialogue between the inspector and the duty holder.[364]

4.2.1 Challenges of Relying on Third-Party Audits in the GoM

Third-party SEMS program audits are required by BSEE, [365] after which BSEE receives an audit report that then becomes its main source of information on the effectiveness of a SEMS program.[366] Third-party audit service providers (ASP) can play an important role in achieving safety, but solely relying on them creates a gap between BSEE and the companies it regulates. For instance, BSEE does not accredit the ASPs itself, instead relying on BSEE-approved Accreditation Bodies (AB).[367] Currently, the only AB BSEE has approved is the Center for Offshore Safety (COS), an industry sponsored organization.[368] Therefore if BSEE does not independently determine the quality and effectiveness of the third-party audits, the process could potentially devolve into ineffective industry self-regulation.

As part of the auditing process, the ASP must provide BSEE with an Audit Plan 30 days prior to conducting the audit, whereby BSEE reserves the right to modify the list of facilities identified for audit.[369] The auditor must provide BSEE a report of the audit findings and conclusions, including identified deficiencies, within 30 days of completion, and the company audited must provide a plan for addressing the deficiencies, the corrective actions that will be taken, and the person responsible for each.[370] BSEE has the legal authority to verify that the corrective actions have been taken.[371]

Yet, this approach has limitations and raises conflict-of-interest concerns. If BSEE does not conduct any of its own SEMS audits, it risks losing opportunities to: directly interact with the companies it regulates, gain familiarity with those offshore facilities and well operations/technologies/equipment, and dialogue directly with the workforce. These lost opportunities inhibit the development of that "creative tension" between the regulator and those regulated. Additionally, the manner in which third parties conduct BSEE audits is potentially problematic for several reasons:

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[363] Learned during CSB staff visit to the UK in March 2014.

[364] The UK HSE uses third-party audits to augment its own work, not supplant it. See Chapter 5.5, Volume 2.

[365] 30 C.F.R. § 250.1920(a) (2016). Prior to April 2013, BSEE also permitted "designated and qualified" personnel to complete the audits; 30 C.F.R. § 250.1920(a) (2012). With the introduction of SEMS II, BSEE removed this definition. Oil and Gas and Sulphur Operations in the Outer Continental Shelf—Revisions to Safety and Environmental Management Systems, 78 Fed. Reg. 20423 (Final Rule, April 5, 2013) (to be codified at 30 C.F.R. Part 250).

[366] BSEE communication to the CSB in 2016.

[367] 30 C.F.R. § 250.1921 and 1922.

[368] BSEE can recognize other accreditation bodies, but currently has only named COS an AB; BSEE. *Information to Lessees (ITL) and Operators of Federal Oil and Gas Leases on the Outer Continental Shelf (*OCS*);* June 18, 2015; http://www.bsee.gov/uploadedFiles/Information%20To%20Lessees-%20Accreditation%20Body.pdf (accessed March 26, 2016).

[369] 30 C.F.R. § 250.1920(b)(4)

[370] 30 C.F.R. § 250.1920(c) and (d)

[371] 30 C.F.R. § 250.1920(e)

- No law requires third-party auditors to behave independently and consistently, especially without regulator review of, and routine calibration with, all accredited auditors.
- SEMS does not require BSEE to send staff to attend audits, even though it does; thus, if these audit practices do not evolve, BSEE's own staff will not develop its own expertise.
- Problems with consistency are surfacing among accredited service providers. At a June 2015 Ocean Energy Safety Institute forum a presenter from DNV GL, an ASP, indicated inconsistent practices existed amongst ASPs.[372] For instance, DNV GL will not conduct an audit of a non-operating asset, but it has been informed that other ASPs are.[373]

On December 7, 2015, BSEE announced the launch of a pilot Risk-Based Inspection Program.[374] Industry data and BSEE reportable incident data indicates that four out of five incidents occur at just 20% of offshore facilities.[375] Consequently, BSEE wanted to efficiently and effectively manage the limited inspection and auditing resources of the agency by focusing on facilities that present a higher safety risk.[376] Such a program may prove to bridge the gap created by solely relying on third party audits, but as the pilot program is in its infancy, no conclusions concerning its effectiveness can be made at this time. Furthermore, lack of an accident does not guarantee no accidents in the future. Thus, BSEE must examine and follow-up on third-party audit results to proactively identify emerging safety issues at specific facilities/companies as well as industry-wide trends.

4.3 Regulatory Use of Safety Performance Indicator Data

One essential mechanism by which a regulator can check the pulse of industry and target major accident event risk is through comprehensive review of safety performance indicators. As the CSB learned in its July 2012 public hearing on Safety Performance Indicators[377] and then emphasized in its Chevron Interim and Regulatory Reports,[378] leading process safety indicators help drive continual safety improvements in

[372] Ilango, C. *Where has SEMS Been, an Auditors Perspective*, Taking SEMS to the Next Level Ensuring Continuous Improvement of Safety and Environmental Management Systems, Houston, TX, July 2015, 2015; http://oesi.tamu.edu/events/forum/ (accessed March 16, 2016).

[373] DNV also noted that initially, audit consistency was poor. While COS criteria has better defined audit expectations, new issues are emerging, for example "the minimum duration of audits allowing for wide variability in the depth of the audits – compliance vs. system audit;" *Ibid.*

[374] *Bureau of Safety and Environmental Enforcement to Launch Pilot Risk-Based Inspection Program for Offshore Facilities.* December 7, 2015. http://www.bsee.gov/BSEE-Newsroom/Press-Releases/2015/Bureau-of-Safety-and-Environmental-Enforcement-to-Launch-Pilot-Risk-Based-Inspection-Program-for-Offshore-Facilities/ (accessed December 21, 2015).

[375] BSEE. BSEE Blog: Risk-Based Inspection Pilot Program: What's in your facility?, http://www.bsee.gov/safety/bsee-blog/ (accessed March 16, 2016).

[376] *Ibid*.

[377] Described more fully in Section 3.4.1 of Volume 3; CSB Public Hearing: Safety Performance Indicators, Houston, TX, July 23-24, 2012; http://www.csb.gov/events/csb-public-hearing-safety-performance-indicators/ (accessed October 7, 2015). This information, including the agenda, the verbatim transcript of the proceedings, working papers submitted, slide presentations, and other materials from the proceedings, is available as part of the CSB's record pertaining to the Macondo investigation.

[378] USCSB, 2012 and 2014. *Regulatory and Intermim Reports: Chevron Richmond Refinery Pipe Rupture and Fire, Richmond, CA, August 6, 2012,* Report No. 2012-03-I-CA, http://www.csb.gov/assets/1/19/Chevron_Regulatory_Report_11102014_FINAL_-_post.pdf and

preventing major accidents, as long as regulators effectively use these indicators to focus inspections, audits, and investigations, and to share lessons learned throughout industry. Similarly, industry must simultaneously focus attention on indicators. Yet the indicators and other data BSEE collects do not adequately focus on process safety matters, especially relating to leading indicators. As such, BSEE's efforts are still insufficient in guiding industry concerning safety trends and deficiencies.

In contrast with the company-specific indicators tracked by individual companies, regulators can track more broad-based indicators, which they can then use to:

- Diagnose systemic problems in the safety management systems across industry;
- Develop and maintain industry benchmarks;
- Assess the effectiveness of their own regulations and policies to prevent major accidents;
- Measure the regulator's own performance with respect to core duties such as audits, inspection activities, and related regulatory initiatives; and
- Analyze macro trends to focus on big-picture issues and initiatives to improve industry safety performance.

4.3.1 Roadblocks to Regulatory Improvements in Data Collection and Analysis

Following the Piper Alpha incident in the UK in 1988, the US regulator received technical advice for improvement to its regulatory standards and practices. For example, a National Research Council Committee recommended that "MMS improve its collection, analysis, and use of safety-related data regarding offshore operations," since "improvements in safety performance derive in large part from past lessons."[379] The Committee explained:

> The committee recommends that MMS place its primary emphasis on detection of potential accident-producing situations—particularly those involving human factors, operational procedures, and modifications of equipment and facilities—rather than scattered instances of non-compliance with hardware specifications. … An important step is to extend the definition of a "mishap" to include near misses, i.e., drilling or production disruptions, and events that prompt the operator or an MMS inspector to shut down operations and require investigation of these less serious occurrences as well as events (accidents). [380]

Thirteen years after the Committee's study, in 2003, MMS proposed federal rulemaking to enhance reporting regulations.[381] At the time, MMS only required death or serious injury, fires, explosions, and blowouts be reported orally,[382] but the rule proposed expanding requirements to include written reports of

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http://www.csb.gov/assets/1/19/Chevron_Interim_Report_Final_2013-04-17.pdf, April 2013 and October 2015 (accessed October 7, 2015).

[379] Committee on Alternatives of Inspection of Outer Continenetal Shelf Operations, Marine Board, Commission on Engineering and technical Systms National Reserach Council. *Alternatives for Inspecting Outer Continental Shelf Operations* [Online]; National Academy Press: Washington, 1990; p 31, http://www.nap.edu/download.php?record_id=1517 (accessed March 26, 2016).

[380] *Ibid.*, p 831.

[381] Oil and Gas and Sulphur Operations in the Outer Continental Shelf—Incident Reporting Rule, 68 Fed. Reg. 40585 (Proposed Rule, July 8, 2003).

[382] 30 C.F.R. § 250.191 (2003)

the incidents listed in Table 4-1. MMS's intent was to capture those "near misses" that did not result in the accidents already being reported by industry. In proposing the rule, MMS noted that results from the voluntary SEMP program indicated there could be a marked increase in the number of incidents reported.[383] Tracking this data, MMS hoped to develop regulatory initiatives, conduct risk-based inspections, and work with industry to develop new standards, among other approaches, to address safety issues on the OCS. Additionally, MMS requested industry comments on whether it should collect the total number of hours worked by employees and the kind of information it should collect about contractors.[384] Without such data, MMS observed it could not normalize raw injury data and calculate injury rates or account for injury and illness cases that involved contractors, which MMS indicated made up 80% of the offshore workforce.[385]

Table 4-1. Abridged list of reportable incidents to BSEE from § 250.188.

1. All fatalities.
2. All injuries that require the evacuation of the injured person(s) from the facility to shore or to another offshore facility.
3. All losses of well control.
4. All fires and explosions.
5. All reportable releases of hydrogen sulfide (H2S) gas.
6. All collisions that result in property or equipment damage greater than $25,000.
7. All incidents involving structural damage to an OCS facility.
8. All incidents involving crane or personnel/material handling operations.
9. All incidents that damage or disable safety systems or equipment (including firefighting systems).
10. Any injuries that result in one or more days away from work or one or more days on restricted work or job transfer;
11. All gas releases that initiate equipment or process shutdown;
12. All incidents that require operations personnel on the facility to muster for evacuation for reasons not related to weather or drills;
13. All other incidents, not listed in paragraph (a) of this section, resulting in property or equipment damage greater than $25,000.

[383] MMS reported "injuries that required evacuation from the facility, and injuries that resulted in days away from work, restricted work, or job transfer) could require up to 291 additional injury reports." Incidents due to hydrogen sulfide and gas releases, collisions, damage, and cranes could result in an increase of 60 incidents reported per year; Oil and Gas and Sulphur Operations in the Outer Continental Shelf—Incident Reporting Rule, 68 Fed. Reg. 40585 (Proposed Rule, July 8, 2003).

[384] Oil and Gas and Sulphur Operations in the Outer Continental Shelf—Incident Reporting Rule, 68 Fed. Reg. 40585 (Proposed Rule, July 8, 2003).

[385] *Ibid*.

Numerous objections to the proposed rule were raised by industry groups, including the Offshore Operator's Committee (OOC) [386] the IADC, and the National Ocean Industries Association. [387] They objected because the proposed rule was overly prescriptive and burdensome and too complex.[388] One example the OOC gave was the proposed requirement to report "any unintentional release of gas at an OCS facility that could, without corrective action, raise hydrocarbon or other gas concentrations to the lower flammable (explosive) limit."[389] OOC explained that it would be difficult to determine when an unintentional release could have raised gas concentrations to explosive limits. OOC noted that gas detectors in some areas could result in system shut-ins, but reporting such incidents would be burdensome to MMS and the industry and "serve no purpose in improving safety on platforms." MMS disagreed:

> platforms have numerous sources of ignition, and there are many small fires reported on these facilities. Small fires have the potential to become major incidents that could cause serious injuries or deaths. By collecting the information on gas releases that result in equipment or process shut-in, we can track the trends, and possibly decrease the number of gas releases.[390]

With gas releases, MMS began to address the National Research Council's recommendation to extend the definition of "mishap" to include near-misses, but the CSB notes that due to the qualifiers on the definition of a gas release,[391] the data has limitations as to its usefulness. A review of previous years' data demonstrates that most of the companies operating in the OSC will likely not experience a qualifying gas release in a given year. In fact, there were never more than 17 gas releases that met the reporting criteria per year during any of the last six years. If BSEE had previously mandated that operators were to report all hydrocarbon releases, they would have reported more incidents, which could assist the regulator in at least three different functions:

- To alert the regulator about incidents or near-miss events that could warrant an immediate regulator response such as an urgent offshore visit to investigate;
- To help the regulator gather industrywide data at a macro scale for assessing overall industry performance and trends, and to help direct the regulator's priorities; and
- To benchmark and compare individual operators and companies.

At its most basic level, such data could alert the regulator to potentially dangerous trends that require initiating regulatory action or other industry improvements. This oversight role accords with the same industry methodology accepted and currently in use by other offshore regimes.

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[386] The Offshore Operator's Committee's comments to the proposed regulation were particularly strong citing "serious flaws" in "several areas" of the proposed regulation. Offshore Operator's Committee, letter referencing RIN 1010-AC57; NPRM Incident Reporting FR 68-40585, November 24, 2003, p 2.

[387] According to the group's website, "The National Ocean Industries Association (NOIA), founded in 1972 with 33 members, represents all facets of the domestic offshore energy and related industries. Today, over 300 member companies are dedicated to the safe development of offshore energy for the continued growth and security of the United States." http://www.noia.org/about/ (accessed March 26, 2016).

[388] Oil and Gas and Sulphur Operations in the Outer Continental Shelf—Incident Reporting Requirements, 71 Fed. Reg. 19640 (Final Rule, April 17, 2006).

[389] *Ibid*.

[390] *Ibid*.

[391] A 'gas release' must result in either equipment or process shutdown; 30 C.F.R § 250.188(b)(2).

BSEE could also track other types of near misses. An examination of loss of well control events illustrates this point. The 2006 reporting rule essentially defined loss of well control as the point when formation (or other fluids) leaves the well.[392] Analysis of the data collected from MMS's incident reporting rules since 2006 reveals that reported loss of well control events are infrequent. In fact they amounted to no more than eight events per year in the Gulf of Mexico over the last several years. [393] This is not a surprise as MMS predicted "a very minor increase in the number of loss of well control incidents (blowouts) reported due to this rule."[394]

A loss of well control is different from a well kick, which is the unintended flow of formation fluids into the wellbore. While not all well kicks evolve into serious events, Macondo demonstrates that unmanaged ones can lead to dangerous 'gas-in-riser' events and blowouts.[395] Therefore, variables related to kicks can produce trends to evaluate industry performance and create strategies to promote safety on the OCS. Ultimately, while the US offshore regulator recorded fewer than eight loss of well control events since 2006, internal Transocean kick data demonstrates that from 2006 to 2009 Transocean observed an increase in kicks in North America from 7 to 19, [396] and this is only from a single driller. By focusing on the more severe, but less frequent, loss of well control events, the utility of the metric is limited and does not lend itself to trending. Researchers funded by BSEE recently proposed key performance indicators related to kicks that "require special consideration and consistent tracking." [397] These include kick response time, kick volume, and the frequency of kicks during various drilling activities. In fact, the suggested key performance indicators echo kick indicators suggested by Transocean itself.[398]

MMS adopted the final reporting rule in 2006,[399] and required incident data (Table 4-1) for both operators and contractors.[400] The 2006 rule did not ultimately require that the total number of employee hours

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[392] The rule defined loss of well control as an (i) Uncontrolled flow of formation or other fluids. The flow may be to an exposed formation (an underground blowout) or at the surface (a surface blowout); (ii) Flow through a diverter; or (iii) Uncontrolled flow resulting from a failure of surface equipment or procedures; Oil and Gas and Sulphur Operations in the Outer Continental Shelf—Incident Reporting Requirements, 71 Fed. Reg. 19640 (Final Rule, April 17, 2006).

[393] BSEE, OCS Incidents/Spills by Category: 1996-2007, http://www.bsee.gov/Inspection-and-Enforcement/Accidents-and-Incidents/Spills-Archive-less-than/ and OCS Incidents/Spills by Category: CY 2008 - 2015 ytd, http://www.bsee.gov/Inspection-and-Enforcement/Accidents-and-Incidents/Listing-and-Status-of-Accident-Investigations/ (accessed March 26, 2016).

[394] Oil and Gas and Sulphur Operations in the Outer Continental Shelf—Incident Reporting Requirements, 71 Fed. Reg. 19640 (Final Rule, April 17, 2006).

[395] See Volume 3, Section 1.3.

[396] Volume 3, Section 3.5.1.1.; Internal Company Document, Transocean. *Well Control Events & Statistics 2005 to 2009*, TRN-INV-00760094, http://www.mdl2179trialdocs.com/releases/release201303211200016/TREX-05649.pdf (accessed June 24, 2015).

[397] Fraser, D.; Lindley, R.; Moore, D.; Staak, V. Early Kick Detection Methods and Technologies, SPE Annual Technical Conference and Exhibition, Amsterdam, The Netherlands, October 27-29, 2014; SPE-170756-MS.

[398] See Volume 3, Section 3.5.1.1.

[399] Oil and Gas and Sulphur Operations in the Outer Continental Shelf—Incident Reporting Requirements, 71 Fed. Reg. 19640 (Final Rule, April 17, 2006).

[400] 30 C.F.R. § 250.189-190 (2016).

worked to be reported, despite MMS's initial indication that it would like them.[401] This did not change until 2011 when BSEE made a voluntary MMS Form-131 mandatory (renamed "BSEE-0131"[402]).[403] This form collects personal safety statistics and infrequent lagging metrics listed in, such as recordable illness injuries, Days Away, Restrictions and Transfers (DART), injury/illness rate, notices of EPA noncompliance, and the total number of oil spills suffered over a specified period of time in a standardized written format not previously required.[404] The report format and reportable incidents mirrors that found in Appendix E of API 75. BSEE-0131 remains substantively similar to its predecessor.

At best, the regulator and the company reporting the information can use data from BSEE-0131 and Table 4-1 only to react to the circumstances giving rise to the incidents reported after the fact. It is good that a regulator would be responsive to data of any type, including personal safety matters and lagging indicators, but BSEE cannot effectively use the data on this form to shape audits or inspections because of its inherent limitations. It also is less useful in identifying precursor events that present warning signs, which could allow for the company's immediate responsive action, or even the regulator's own urgent attention. The result of this narrow data-gathering process is a small data set that does not lend itself to trending or other potentially helpful analysis because only serious incidents are reported.

BSEE continues to miss a critical opportunity to use performance safety indicators more proactively because it collects mostly infrequent lagging indicator data and does not use the data to inform its own performance in terms of special areas of focus, audit and inspection activities, and other targeted activities.

4.3.2 Inadequate Use of Safety Performance Indicators

One essential mechanism by which a regulator can check the pulse of industry and target major accident event risk is through comprehensive review of safety performance indicators. Neither MMS before Macondo, nor BSEE currently, had (has) direct indicator data that provides information on the effectiveness of the barriers and safety management systems meant to keep offshore operations safe (e.g., maintenance issues, audit results, failures of equipment during routine testing).[405] These are the Tier 3 and Tier 4 indicators described in Volume 3.[406] Instead, the original desire of MSS to use indicator data to influence safety strategies on the OCS remain limited by the type of data collected.

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[401] Oil and Gas and Sulphur Operations in the Outer Continental Shelf—Incident Reporting Rule, 68 Fed. Reg. 40585 (Proposed Rule, July 8, 2003).

[402] BSEE. *BSEE-0131, Performance Measures Data;* http://www.bsee.gov/uploadedFiles/BSEE/About_BSEE/Doing_Business_with_BSEE/OCS_Forms_New/Form%200131%20for%20exp%202018.pdf (accessed March 29, 2016).

[403] Reorganization of Title 30: Bureaus of Safety and Environmental Encorcement and Ocean Energy Management, 76 Fed. Reg. 64432 (Final Rule, October 18, 2011).

[404] See BSEE Form 131, http://www.bsee.gov/About-BSEE/Procurement-Business-Opportunities/BSEE-OCS-Operation-Forms/BSEE-OCS-Operation-Forms.aspx (accessed January 21, 2016).

[405] See Volume 3, Chapter 3, particularly Sections 3.4.1-3.4.2.

[406] Section 3.4.2, as defined by API 754, Tier 3 indicators include challenges to a safety systems, which results when exceeding defined process limits and a safety system is initiated to bring the system back to an accepted safe state (e.g., the activation of a shutdown system or a pressure relief device); Tier 4 indicators include performance of

As the CSB has emphasized,[407] leading process safety indicators help drive continual safety improvements in the area of major accident prevention, as long as regulators effectively utilize these indicators to focus inspections, audits, and investigations, and to share lessons learned throughout industry.

Global Indicator Data Sharing

The International Regulators' Forum (IRF) on Global Offshore Safety Performance Measurement Project was created to establish a framework based on a common set of indicators definitions and criteria. The IRF annually complies indicators, such as numbers of fatalities and injuries, losses of well control, mass hydrocarbon releases, collisions, and fires, for each IRF member country and makes them publicly available on the IRF website.[†] *The focus is on higher consequence lagging and personal safety data, and the IRF is still working on reporting consistency among members. But, as this global sharing network continues to improve, it should allow for even greater improved opportunities to uncover emerging safety risks.*

[†] IRF, IRF Performance Measurement Project, http://www.irfoffshoresafety.com/country/performance/scope.aspx (accessed December 21, 2015).

To date, BSEE does not have SEMS performance indicators, though it has reported sponsoring efforts to quantify such indicators.[408] As such, BSEE's efforts are insufficient in guiding industry with respect to safety trends and deficiencies. In the meantime, indirect, lagging measures of a SEMS program could be gleaned from the reporting of the incidents listed in Table 4-1; presumably, an effective SEMS program would reduce the occurrence of fatalities, injuries, loss of well control, etc. On May 5, 2015, BSEE

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barriers and management system components, such as management of change (MOC) compliance, inspections, or timely training schedules.

[407] Volume 3, Chapter 3.

CSB Public Hearing: Safety Performance Indicators, Houston, TX, July 23-24, 2012; http://www.csb.gov/events/csb-public-hearing-safety-performance-indicators/ (accessed October 7, 2015). (including the agenda, the verbatim transcript of the proceedings, working papers submitted, and PowerPoint presentations and other materials from the proceedings are all available and included as part of the CSB's record pertaining to the Macondo investigation).;

[407] USCSB, 2012 and 2014. *Regulatory and Intermim Reports: Chevron Richmond Refinery Pipe Rupture and Fire, Richmond, CA, August 6, 2012,* Report No. 2012-03-I-CA, http://www.csb.gov/assets/1/19/Chevron_Regulatory_Report_11102014_FINAL_-_post.pdf and http://www.csb.gov/assets/1/19/Chevron_Interim_Report_Final_2013-04-17.pdf, April 2013 and October 2015 (accessed October 7, 2015).

[408] For example, there is an April 2016 SPE/BSEE Summit: Assessing the Processes, Tools, and Value of Sharing & Learning from Offshore E&P Safety Related Data, http://www.spe.org/events/smsr/2016/ (accesses April 1, 2015).

announced its intention to initiate a new program called SafeOCS.[409] In addition to providing a voluntary and anonymous reporting channel for offshore workers, BSEE designed this program as a way to collect leading and lagging safety indicator data that could made publicly available and inform prevention and mitigation efforts.[410] Although a positive step, BSEE currently has limited SafeOCS reports.[411] Several companies have verbally indicated they will participate in the near future,[412] but BSEE will need more time to determine the success of the voluntary program. Anonymous reporting and key performance indicators though are two different systems, and while they complement one another, they do not replace one another.

BSEE publishes incident statistics and summaries of the data received on incidents listed in Table 4-1 on its website,[413] and could use this data to drive industry initiatives as observed in other oil-producing jurisdictions around the world. In the UK, the offshore regulator HSE uses focused Key Programme Initiatives (Key Programmes or KPs), which are multi-year efforts to collect data and assess trends to drive improvement in offshore areas of significant concern, such as hydrocarbon releases, deck and drilling operations, asset integrity, and aging facilities.[414] The Key Programmes are not limited to data collection and trend assessments, but are detailed and coordinated programs covering other regulatory activities including inspecting sites, raising awareness, and facilitating the development of standards, all requiring some level of data gathering activity.

HSE launched these Key Programmes to formulate and share good practices with industry.[415] During the first Key Programme (KP1), between 2000 and 2004, among other notable regulatory activities, the regulator worked with industry and unions to collect relevant data to reduce reportable hydrocarbon releases by 50 percent in four years. For KP1, gas releases were categorized as minor, significant, or major using release size, rate, and duration criteria developed with industry.[416] While the number of major releases was reduced by 33%, the regulator noted a 50% increase in the number or reported minor releases.[417] This was attributed to an increased awareness of the need to report minor releases, and demonstrates that regulator participation can lead to more robust data collection.

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[409] BSEE. BSEE Director Brian Salerno Announces Key Efforts to Reduce Risk Offshore, http://www.bsee.gov/BSEE-Newsroom/Press-Releases/2015/BSEE-Director-Brian-Salerno-Announces-Key-Efforts-to-Reduce-Risk-Offshore/ (accessed March 26, 2016).

[410] BSEE, 2014 Annual Report; p 9, http://www.bsee.gov/uploadedFiles/BSEE/BSEE_Newsroom/Publications_Library/Annual_Report/BSEE%202014%20Annual%20Report.pdf (accessed December 21, 2015).

[411] BSEE communication to the CSB.

[412] *Ibid.*

[413] BSEE. Incident Statistics and Summaries, http://www.bsee.gov/Inspection-and-Enforcement/Accidents-and-Incidents/Other-Incidents/ (accessed March 29, 2016).

[414] UK HSE, Key Programme final reports, http://www.hse.gov.uk/offshore/programmereports.htm (accessed March 26, 2016).

[415] UK HSE. *OSD hydrocarbon release reduction campaign, Report on the hydrocarbon release incident investigation project -1/4/2000 to 31/3/2001;* 2001; p 1. http://www.hse.gov.uk/research/otopdf/2001/oto01055.pdf (accessed March 26, 2016).

[416] *Ibid*., p 2.

[417] *Ibid*., p iii.

In 2010, the UK HSE initiated KP4 to address the issue of aging equipment offshore and the operation of installations beyond their design life.[418] That same year, the HSE published *Managing Aging Plant: A Summary Guide*,[419] to aid industry in preventing major accidents. The report provides an overview of plant and equipment failure due to age related mechanisms, their management, and suggested leading and lagging indicators to monitor them. It also presents analysis on how aging plant equipment may be a factor in loss of containment incidents. According to Jake Malloy, Regional Organizer of the National Union of Rail, Maritime and Transport Workers Union (UK), "it is our firm belief that the most influential and effective schemes using indicators to measure improvements and major accident prevention are those initiatives generated by our regulator, the Health and Safety Executive."[420]

The Norwegian offshore regulator, PSA, runs a multi-year program to track indicators data. The program, *Trends in Risk Level in the Petroleum Activity* (RNNP), focuses on identifying trends in leading and lagging indicators such as near-miss incidents, barrier performance, chemical exposure, well control incidents, and maintenance management.[421] PSA chose these indicators for its trends program because it noticed industry was relying on indicators such as lost-time incidents, which alone are unable to present a full picture of safety.[422] PSA states, "RNNP has become an important management tool for all participants in the petroleum sector. Its findings are valuable for our planning of supervision activities and development of the regulations."[423] Furthermore, PSA indicates, "with solid facts on the table, employers and unions can drop time consuming discussions [on whether the industry is "safe"] and concentrate instead on achieving improvement."[424]

If BSEE were to take the lead in establishing a robust system of safety performance indicators that includes information on barriers and safety management systems and use that information to target audits, inspections, enhanced rule-making, and other regulatory activity aimed at major offshore accident prevention, the risk of incidents like Macondo can be reduced. Ultimately, six years after the catastrophe, regulatory requirements are still needed for developing and implementing safety performance indicators to prevent major accidents.

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[418] UK HSE. *Key Programme 4 (KP4): Ageing and life extension*, http://www.hse.gov.uk/offshore/ageing/kp4-report.pdf (accessed December 8, 2014).

[419] UK HSE. *Managing Ageing Plant, A Summary Guide*, http://www.hse.gov.uk/research/rrpdf/rr823-summary-guide.pdf (accessed November, 1, 2013).

[420] CSB Public Hearing: Safety Performance Indicators, Houston, TX, July 23-24, 2012; testimony of Jake Malloy, *Safety Performance Indicators—The Workforce Perspective*, p 139, http://www.csb.gov/assets/1/19/CSB_20Public_20Hearing.pdf (accessed October 7, 2015).

[421] Numerous reports available, PSA. Trends in risk level, http://www.psa.no/risk-level/category876.html (accessed March 26, 2016).

[422] PSA. *Summary Report 2012—Norwegian Continental Shelf, Trends in Risk Level in the Petroleum Activity*, p 1, http://www.ptil.no/getfile.php/PDF/RNNP_2012/Trends%20in%20risk%20level_2012.pdf (accessed March 26, 2016).

[423] PSA, Trends in risk level in the petroleum activity (RNNP), http://www.psa.no/about-rnnp/category911.html (accessed March 26, 2016).

[424] See video at http://www.psa.no/about-rnnp/category911.html (accessed March 26, 2016).

> *Safety performance indicators (SPIs) should be used as an aid to communication. They are not the entire message. . . . All stakeholders need to remember SPIs do not measure the level of safety. SPIs indicate how the measures to achieve safe operation are performing. SPIs offer a chance to improve transparency and communication between operators and inspectors. It is up to senior management to decide whether they wish to implement these tools. Government policy makers need to realize the potential and provide suitable training and resources to allow inspectors to be competent partners in the use of SPIs and thus enable the necessary dialogue to take place.* [†]
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> [†] Jennings, K.; Hailwood, M. OECD Guidance on Safety Performance Indicators - An International Approach to Assessing the Success of Industry, Public Authorities and Communities in Managing Major Accident Hazards; *IChem E Loss Prevention Bulletin* **2010,** *212*, p 10.

4.4 Transparency of Offshore Safety

Public disclosure of offshore safety information encourages accountability, risk-reduction, effective enforcement, and sharing of lessons learned. Public disclosure of this type of information could also promote trust among workers, operators, and the regulator, and even help to provide a mechanism for members of the public to satisfy themselves about the safety of offshore operations and the adequacy of regulatory action. Historically, the US offshore safety regulator did not promote safety improvements through transparency.[425] That may now be starting to change, however, as BSEE initiated an annual report, which is publicly available and published on the agency's website. The report contains industry safety performance indicator data, acknowledges operational and organizational BSEE deficiencies, and provides strategic goals and objectives for the agency. The report notes that BSEE is working to create a Data Stewardship team, with the primary responsibility of improving the overall quality, management, and use of offshore data.[426] In addition, BSEE issues safety alerts and publishes them on its website to help share lessons learned from investigations of incidents.[427] BSEE also makes available on its website a listing of "Incident Statistics and Summaries" which includes data covering a variety of topics back to 2008, with additional incident archive data back to 1996. [428] BSEE notes in its 2014 annual report that lessons learned from investigations in the Pacific Region triggered two safety alerts in 2014.[429] Currently,

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[425] Steffy, L. Dearth of data leaves Gulf safety record in the dark. *Fuel Fix from the Houston Chronicle*, December 7, 2012, http://fuelfix.com/blog/2012/12/07/steffy-dearth-of-data-leaves-gulf-safety-record-in-the-dark/ (accessed March 26, 2016).

[426] BSEE. *2014 Annual Report.* May 5, 2015; p 12. http://www.bsee.gov/uploadedFiles/BSEE/BSEE_Newsroom/Publications_Library/Annual_Report/BSEE%202014%20Annual%20Report.pdf (accessed December 21, 2015).

[427] BSEE. Current Safety Alerts, http://www.bsee.gov/Regulations-and-Guidance/Safety-Alerts/Safety-Alerts/ (accessed March 26, 2016).

[428] BSEE. Incident Statistics and Summaries, http://www.bsee.gov/Inspection-and-Enforcement/Accidents-and-Incidents/Listing-and-Status-of-Accident-Investigations/ (accessed March 26, 2016).

[429] BSEE. *2014 Annual Report.* May 5, 2015; p 17. http://www.bsee.gov/uploadedFiles/BSEE/BSEE_Newsroom/Publications_Library/Annual_Report/BSEE%202014%20Annual%20Report.pdf (accessed December 21, 2015).

operators and drilling contractors are not required to provide public access to safety-related documentation or statistics. Some enforcement data and statistics on lagging indicators are available publicly,[430] but insufficient dialogue about these issues remains among industry, the regulator, and the public.

4.4.1 Regulatory Approaches to Transparency

Transparency can be achieved through publishing enforcement actions, safety case documentation, and annual reports of safety statistics. In Norway, the PSA disseminates offshore process safety data through its website, forums, and archives.[431] The PSA website provides statistics, an annual Risk Assessment Report, and information on recent major accidents in Norwegian waters.[432] PSA also uses numerous indicators to uncover trends and determine the overall process safety health offshore, which are published in an annual Risk Assessment Report. The agency then bases it priorities for the year on PSA data analysis and establishes forums in which it participates with industry and workers to engage in open discussion on how to improve safety.[433] The PSA asserts this approach is necessary to reduce risks.[434]

Although the UK does not make public an operator's safety case documentation,[435] it does publish guidance for compliance with ALARP, enforcement decision processes for the safety case, and aggregation of process safety indicators.[436] The Seveso III Directive, enacted in UK law in June 2015 through Control of Major Accident Hazards (COMAH) regulations, requires active public disclosure of major accident risks at any operation.[437] The UK HSE provides public access to its enforcement decisions regarding safety case violations.[438] The UK HSE also publishes its safety case assessment process online

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[430] 30 C.F.R. § 250.1929; and BSEE. Incidents of Noncompliance, http://www.bsee.gov/Inspection-and-Enforcement/Enforcement-Programs/Incidents-of-Non-Compliance/.

[431] PSA. Transparency: Open and honest, http://www.ptil.no/news/transparency-open-and-honest-article7627-878.html (accessed March 26, 2016); CSB Public Hearing: Regulatory Approaces to Offshore Oil and Gas Safety, Washington, DC, December 15, 2010; see, for example, pp 70-71. http://www.csb.gov/assets/1/19/Transcript_of_Public_Meeting_12_15_2010.pdf (accessed March 7, 2015).

[432] See PSA. Safety Stats and signals, http://www.ptil.no/?lang=en_US; Report following the audit of Exxon Mobil's use of quantitative risk analyses, http://www.ptil.no/news/report-following-the-audit-of-exxon-mobil-s-use-of-quantitative-risk-analyses-article6019-878.html; and Notification of orders to BP after investigation of Valhall PC fire, http://www.ptil.no/risk-management/notification-of-orders-to-bp-after-investigation-of-valhall-pcp-fire-article8233-1029.html; and Risk Level, http://www.ptil.no/rnnp/category876.html (accessed March 7, 2015)..

[433] CSB Public Hearing: Regulatory Approaces to Offshore Oil and Gas Safety, Washington, DC, December 15, 2010; see, for example, pp 70-71. http://www.csb.gov/assets/1/19/Transcript_of_Public_Meeting_12_15_2010.pdf (accessed March 7, 2015).

[434] PSA. Transparency: Open and honest, http://www.ptil.no/news/transparency-open-and-honest-article7627-878.html (accessed March 26, 2016);

[435] The CSB Investigations staff learned in its March 2014 trip to the UK that before 9/11, the UK HSE made safety case report summary documents publicly available; however, for security reasons, the UK ceased to make these documents available under a Secretary of State order.

[436] Learned during CSB staff visit to the UK in March 2014.

[437] UK HSE, Public Information, http://www.hse.gov.uk/seveso/public.htm (accessed March 26, 2016).

[438] UK HSE, HSE Public Register of Enforcement Notices, http://www.hse.gov.uk/notices/ (accessed March 26, 2016).

along with annual offshore safety statistics, safety alerts, and reports of key intervention programmes.[439] According to Ian Travers, the UK HSE Head of Chemical Industries Strategy Unit, Hazardous Installations Directorate, transparency revolutionized the offshore industry. For example, Travers explained that although UK HSE operates a hotline for confidential whistle-blowing, it is "rarely used" and tends to be used only in situations where companies operating offshore lack a good safety culture, which Travers attributed to an atmosphere of "transparency" in the North Sea.[440] Travers also explained that the role of the regulator in terms of its relationship with industry, along with the unique place indicators play in that relationship:

> The essential role of the regulator for major hazards is to provide public assurance that those whose activities give rise to risks to people and the environment are adequately controlling those risks. Industry in turn should ensure that there is transparency and openness in how well those risks are being controlled. KPIs are an essential ingredient in that dialogue between the regulator and the regulated in, for example, setting and agreeing on programmes for operators' major hazard improvement and the regulator's intervention strategies and plans.[441]

Travers's testimony was corroborated by Bob Lauder, former Health and Safety Policy Manager of Oil & Gas UK, the industry trade association that serves as "the voice of the offshore industry" in the North Sea. Lauder testified this openness did not always exist:

> There was significant reluctance on the part of lots of companies … in the UK to go as public as we've now gone with our statistics. … So, what we do now is … we get this information directly back from the Health and Safety Executive from their managed database. And, on a quarterly basis, we put it on our website so it's publicly available. … And, on a quarterly basis, we—I hate to use the phraseology, but it has been called naming and shaming …. You can see that we named the duty-holder, we named the installation, and then we give some indication of the nature and scale of the release. So, that's out there. It's [visible to] anybody who wants to see it. A point I might want to make here is you'll see some very familiar names on there. … So, I think that really was a big deal for us to [become] as transparent as we now are with that and it didn't happen overnight and it didn't happen without some resistance.[442]

Mr. Lauder left unstated, however, that industry players in the UK are now working in a more mature regulatory environment that values disclosure of this type of safety information. Rather than viewing it as harmful to their respective competitive positions or to their standing within the industry, the operators came together through their trade association and formalized an arrangement to provide for openness about hydrocarbon releases. This intentional strategy is an important source of potential learning for the

[439] UK HSE, Key Programme final reports, http://www.hse.gov.uk/offshore/programmereports.htm (accessed March 26, 2016);

[440] CSB Public Hearing: Safety Performance Indicators, Houston, TX, July 23-24, 2012; testimony of Ian Travers, Overview of Leading Indicator and Usage, p 157, http://www.csb.gov/assets/1/19/CSB_20Public_20Hearing.pdf (accessed October 7, 2015).

[441] CSB Public Hearing: Safety Performance Indicators, Houston, TX, July 23-24, 2012; written testimony of Ian Travers, The Implementation of Effective Key Performance Indicators for Major Hazard Enterprises, p 3, http://www.csb.gov/UserFiles/file/Travers%20%28HSE%29%20-%20Testimony%20-%20printed.pdf (accessed October 7, 2015).

[442] CSB Public Hearing: Safety Performance Indicators, Houston, TX, July 23-24, 2012; testimony of Bob Lauder, Major Hazard (Asset Integrity) Key Performance Indicators in Use in the UK Offshore Oil and Gas Industry, pp 175-176, http://www.csb.gov/assets/1/19/CSB_20Public_20Hearing.pdf (accessed October 7, 2015).

entire industry, and it can actually help to promote public and political trust and confidence in offshore operators.

In his testimony to the CSB at the agency's performance safety indicators event on July 24, 2012, Jake Malloy, Regional Organizer of the National Union of Rail, Maritime and Transport Workers Union (UK), further corroborated the transparency of the UK's offshore regulator, explaining the benefits of open, public and transparent safety information that he has observed over the course of his career in the UK offshore industry since the HSE initiated "Key Programmes." Malloy explained that Key Programme 1 (KP1), "Reducing Hydrocarbon Releases," was accompanied by publicly available results and other information relative to actions by North Sea operators and the regulator. Malloy noted that "since KP1 was launched the industry has been pro-active in setting its own targets for leak reduction." In addition, industry publishes details of the leaks, including volumes, locations, and operators as part of their own initiative to reduce leaks still further through sharing and learnings."[443] Malloy attributed this improved performance to the general availability of the information explaining, "KP1 was launched publicly, meaning workers and moreover the press had the ability to report and monitor performance. In short, it is transparent and subject to public and governmental scrutiny."[444]

Some of Australia's safety regulators provide the public with summaries of safety case documentation produced by the duty holders.[445] NOPSEMA, Australia's federal safety regulator, offers public access to a host of safety-related information, including monthly newsletters containing data on inspections and incidents, aggregated safety statistics, drilling guidance, and brochures on process safety.[446] For instance, NOPSEMA publishes guidance on elements of a safety case report, including hazard identification with assistance on selecting a hazard identification technique.[447]

The Nuclear Regulatory Commission provides a positive example of using transparency to drive safety improvement. Testifying before the CSB, John Lubinski, Director of the Division of Inspection and Regional Support, Office of Nuclear Reactor Regulation, explained:

> Yes, we believe [public reporting] does [influence safety] as far as impacting the performance. Under the old system … [w]hen we had findings or we had people that were outside of a key performance indicator, we could take enforcement action issuing citations, issuing monetary civil

[443] CSB Public Hearing: Safety Performance Indicators, Houston, TX, July 23-24, 2012; testimony of Jake Malloy, *Safety Performance Indicators, The Workforce Perspective;* 2012; http://www.csb.gov/UserFiles/file/Molloy%20%28RMT%29%20Testimony.pdf (accessed March 26, 2016).

[444] *Ibid*.

[445] See WorkSafe Victoria, *Guidance Note: Overview of the Safety Case regime for a Major Hazard Facility*; p 14. "The local community must be provided with certain information, including a summary of the Safety Case," http://www.worksafe.vic.gov.au/__data/assets/pdf_file/0015/12381/50712_WS_3_Safety_Case_OV_5HR.pdf, (accessed March 26, 2016). Examples Safety Case Summaries can be found at: http://www.exxonmobil.com/Australia-English/PA/Files/publication_safetycase_altonaref.pdf; and http://www.exxonmobil.com/Australia-English/PA/Files/publication_Longford_Safety_Case_2013.pdf (accessed March 26, 2016).

[446] IRF. Member Country Profile—Australia, http://www.irfoffshoresafety.com/country/Australia.aspx (accessed March 26, 2016).

[447] NOPSEMA. *Guidance Note: Hazard Identification;* N- 04300-GN0107, Rev. 5; December, 2012; http://www.nopsema.gov.au/assets/Guidance-notes/N-04300-GN0107-Hazard-Identification.pdf (accessed March 26, 2016).

> penalties. What we found is this is actually a more risk informed and also a benefit from the standpoint of moving forward to increasing performance. Number one is it focuses the licensee's effort and the NRC inspection efforts in the correct area. But, number two is because all of the information is made public, not just when a bad event occurs at a plant, all the information. It requires all the licensees to look at it and say "how are we being publicized on the NRC website?" The performance indicators are not a report card; however, they are information. And we think that information being available, not only does it have the licensees more accountable for safety but it also has us as the regulator more accountable. When the public is looking at this website and saying how can you have a plant that has white performance indicators, yellow findings and you're still letting them operate, what is your technical basis for doing that? So it holds us accountable in being able to describe what the safety performance is of that plant. So, that's where we see the benefits to making all this information available to the public. The final [reason] is just the fact that from our standpoint we believe in open and transparent regulation and we want the people in the community to understand what the hazards are associated with the plant and what the safety implications are of any activities that are occurring. [448]

In addition to boosting public goodwill for a high-hazard industry, transparency provides a tangible safety benefit: deterrence. Public scrutiny can be a significant deterrent against bad practices in offshore operations through publications, discussions, and political pressure.[449] The Environmental Protection Agency (EPA) enforces anti-pollution laws and makes them public. Former EPA Administrator William Reilly recently noted, "I see no reason not to publicize these violations," Reilly explained during his investigation of the Macondo incident for a Presidential Commission.[450]

Further elaborating on the desirability of publicly available safety information, Lois Epstein, Engineer and Arctic Program Director for The Wilderness Society, explained, "the public interest community strongly supports making operator-specific data publicly available with shielding of company names kept to a minimum and only with a very strong justification. Sunshine[451] improves the quality and increases the learning opportunities associated with accident prevention data. Potential litigation should not be a reason to withhold data, as litigation will occur regardless."[452]

Complete transparency is not necessary. For instance, the UK does not require that an operation's safety case be made publicly available.[453] In contrast, certain states and territories of Australia make safety case

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[448] CSB Public Hearing: Safety Performance Indicators, Houston, TX, July 23-24, 2012; testimony of John W. Lubinski, Questions & Answers by CSB Board, Staff and Public, p 94, http://www.csb.gov/assets/1/19/CSB_20Public_20Hearing.pdf (accessed October 7, 2015).

[449] CSB Public Hearing: Safety Performance Indicators, Houston, TX, July 23-24, 2012; testimony of Jake Malloy, *Safety Performance Indicators, The Workforce Perspective*, pp 139-40, http://www.csb.gov/assets/1/19/CSB_20Public_20Hearing.pdf (accessed October 7, 2015).

[450] Dlouhy, J. After spill, offshore enforcement remains murky. *Fuel Fix from the Houston Chronicle*, December 12, 2012, http://fuelfix.com/blog/2012/12/12/after-spill-offshore-enforcement-remains-murky / (accessed March 26, 2016).

[451] "Sunshine" refers to openness or transparency in matters of public importance, relating back to a famous quote from former US Supreme Court Justice Brandeis. "Publicity is justly commended as a remedy for social and industrial diseases. Sunlight is said to be the best of disinfectants; electric light the most efficient policeman."

[452] CSB Public Hearing: Safety Performance Indicators, Houston, TX, July 23-24, 2012; testimony of Lois N. Epstein, *Safety Performance Indicators*, p 152, http://www.csb.gov/assets/1/19/CSB_20Public_20Hearing.pdf (accessed October 7, 2015).

[453] CSB UK trip notes, March 6 & 7, 2014.

summaries publicly available. There are also limits on disclosing some information due to commercial sensitivity (e.g., trade secrets, confidential business information) that provides a competitive advantage in a challenging sector of the economy, as well as physical security issues, among other concerns. Companies must strike a balance between disclosing all relevant information and protecting information not appropriate for disclosure. Yet global experience suggests that an effective offshore regulatory regime will seek opportunities to use transparency to drive continual safety improvements.

5.0 Insufficient and Inadequate Staff for Appropriate Oversight

BSEE's ability to regulate safety is contingent upon adequate numbers of staff with multifaceted competencies in not only technical disciplines, but human and organizational factors, communication and interpersonal skills such as negotiation, persuasion and advocacy, and process safety, among others. These skill sets provide inspectors with the tools to conduct effective preventive audits and inspections, and to regularly engage with duty holders. To date, the staffing changes in BSEE have not fully met these requirements. Congress has not appropriated sufficient funding on an ongoing and consistent basis for BSEE to meet such staffing needs, and along with these constraints, continuing conflicts between political and legislative priorities are structural impediments to BSEE's ability to fulfill its difficult mission. The Department of Interior has confronted this issue recently, noting that continuing resolutions and a sequester of 5 percent in fiscal years 2013 and 2014 significantly impacted the Department's agencies, requiring a hiring freeze and reducing funding for staffing and oil and gas activities.[454]

To ensure that companies are managing major hazard risks and employing the best available standards and technology effectively, the regulator must hire and retain knowledgeable and skilled staff who can critically assess company safety practices. The CSB discusses in the Chevron Regulatory Report the importance of having a well-funded, technically competent regulator that has the ability to conduct proactive, preventive inspections. To operate a robust performance-based regulatory regime in which the regulator directly oversees and evaluates total safety performance of the industry, BSEE's enhanced recruiting, hiring, and retention efforts must continue and must include senior specialists with experience in areas such as petroleum engineering, process safety, human factors, and organizational performance.

5.1 Models for Building a Competent Regulator

The UK and other US safety regulators, particularly in the nuclear sector, use effective methods for recruiting, training, and retaining highly proficient staff that could help inform BSEE efforts.

5.1.1 UK Offshore Safety Directive Regulator

The UK Offshore Safety Directive Regulator (OSDR) is part of the UK Health and Safety Executive (HSE). It provides detailed guidance for companies, inspectors, and the public on how the regulator assesses companies' plans to reduce major accident hazards.[455] It published pamphlets and handbooks, geared toward duty holders, on offshore topics ranging from corrosion to human factors to process integrity. The "Assessment Principles for Offshore Safety Cases" is an agreed framework for inspector conduct during the offshore assessment process.[456] Those principles emerge from the definitive, 300+

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[454] US Government Accountability Office. *Report to Congressional Requesters. Oil and Gas: Interior Has Begun to Address Hiring and Retention Challenges but Needs to Do More*; US Government Accountability Office: January, 2014; p 77; http://www.gao.gov/assets/670/661025.pdf (accessed March 26, 2016).

[455] UK HSE, Guidance, http://www.hse.gov.uk/offshore/safetycases.htm (accessed March 26, 2016).

[456] UK HSE. *Assessment Principles for Offshore Safety Cases (APOSC);* March, 2006; http://www.hse.gov.uk/offshore/aposc190306.pdf (accessed March 26, 2016).

page inspector's manual, Guidance for the Topic Assessment of the Major Accident Hazard Aspects of Safety Cases (GASCET).[457]

The OSDR can hire competent personnel to develop guidance and perform safety case reviews because it is authorized to pay offshore staff higher specialist salaries. Offshore assessor work involves time away from family in uncomfortable conditions. To incentivize it, most mid-level OSDR technical staff were paid between £67,213 and £77,499 in 2012, the equivalent of $109,241 to $125,959.[458] Specialist staff in Aberdeen receive a location enhancement on top of these "standard" pay scales that enables HSE to recruit to that location and compete with the oil industry. The enhancement is currently £10,000 (approximately $15,600). These salaries are significantly higher than their onshore inspector counterparts, whose mid-level salaries ranged from £37,303 to £46,937 in 2012, the equivalent of $60,628 to $76,286.

Former UK Offshore regulatory staff reported that the OSDR looks for new recruits with good communication skills in addition to relevant education, licensure, and experience because their job requires getting companies to aspire to make safety improvements that the companies may not want to do.[459] Once on board, new recruits directly from industry undertake a rigorous regulator training program during their first two years, including significant on-the-job training.[460] They are required to take a series of courses and related assessments, and they may be fired if they do not pass the assessments.[461] At the same time, new inspectors receive training by working alongside more experienced inspectors on safety case procedures, technical assessment procedures (such as electrical and mechanical safety), audit and regulatory intervention activities.[462] For inspectors who have a primary interface role with offshore companies, OSDR aims to rotate them to different companies every two to three years to avoid the inspectors becoming too comfortable with their surroundings.[463] One message that UK offshore industry and regulatory staff repeated to CSB investigators is that the industry believes having proficient regulatory staff adds significant value to their business.[464] Professional proficiency, as well as technical and risk management acumen, allow regulatory staff the wherewithal to pushback against industry claims, should that be necessary.[465] This competence is also essential for companies' confidence in the accuracy of the regulatory staff's advice, inspections, and citations.

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[457] HSE. (http://webcommunities.hse.gov.uk/connect.ti/gascet/view?objectId=62036 (accessed March 2, 2016).

[458] In contrast, BSEE pays mid-level petroleum engineers somewhere between $62,000 and $84,000 per year. https://www.usajobs.gov/GetJob/ViewDetails/341573400 (accessed March 26, 2016).

[459] Whewell, I. Former Director, UK HSE Offshore Division, and Wilkinson, P. principal "architect" for the development of Australia's National Offshore Petroleum Safety Authority, (NOPSA), Personal communication, July 11, 2011.

[460] *Ibid.*

[461] *Ibid.*

[462] *Ibid.*

[463] *Ibid.*

[464] *Ibid.*

[465] Wilkinson, P. *Australia Department of Industry, Tourism and Resources, Presentation to the National Research Centre for Occupational Health and Safety;* May 15, 2002.

5.1.2 US Government Incentives to Build Competent Staff

The federal government has used extensive resources to retain the best available talent to focus on health and safety oversight of US commercial and defense nuclear facilities.[466] Many nonsupervisory technical staff at the US Nuclear Regulatory Commission (NRC)[467] and the Defense Nuclear Facilities Safety Board (DNFSB) are paid at the top of the General Schedule.[468] Virtually all technical staff at the DNFSB hold technical master's degrees, and approximately 25 percent hold doctorates.[469]

The US government has a unique category of non-executive positions, Scientific or Professional,[470] which involve high-level research and development in the physical, biological, medical, or engineering sciences, or a closely related field.[471] These positions are classified above the highest general schedule pay level. These special salary authorizations contribute to the ability of technical agencies to compete with private industry in recruiting and retaining highly proficient staff.

The NRC's extensive training programs also help attract and retain competent technical staff. For new inspection staff, the NRC requires a series of courses, assessments, and simulations, all of which take approximately two years to complete.[472] Inspectors must have a bachelor's degree in engineering or a degree in a relevant scientific field and Professional Engineer certification.[473] The agency operates a technical training center in Chattanooga, Tennessee, with various control room simulators that mirror licensees' facilities. NRC staff are expected to understand how this equipment operates so that they can conduct audits and investigations.[474] Before they are deemed qualified to inspect, inspector candidates must be recommended by the NRC inspector qualification board and certified by the regional administrator or division director.[475]

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[466] *FY 2013 Budget Request to the Congress*; Defense Nuclear Factilities Safety Board: 2012; pp 1-3; http://www.dnfsb.gov/sites/default/files/About/Budget%20Requests/2013/FY%202013_CONG%20BUDGET_FINAL.PDF (accessed March 26, 2016).

[467] Presentation by NRC Executive Director Bill Borchardt to CSB, January 2011.

[468] $123,758 to $155,500 per year in 2012 in Washington, DC.; OPM. Pay & Leave, Salaries & Wages, https://www.opm.gov/oca/12tables/html/dcb.asp (accessed March 26, 2016).

[469] *FY 2013 Budget Request to the Congress*; Defense Nuclear Factilities Safety Board: 2012; p 7; http://www.dnfsb.gov/sites/default/files/About/Budget%20Requests/2013/FY%202013_CONG%20BUDGET_FINAL.PDF (accessed March 26, 2016).

[470] See, e.g., 5 C.F.R. § 319.103. This category covers non-executive positions classified above the GS-15 level. *See* https://www.opm.gov/policy-data-oversight/senior-executive-service/scientific-senior-level-positions/ (accessed January 7, 2016).

[471] OPM. Senior Executive Service, http://www.opm.gov/ses/recruitment/stpositions.asp (accessed March 26, 2016).

[472] NRC. *NRC Inspection Manual, Qualification Program for Operating Reactor Programs (Ch. 1245)*; 2011; p 4; http://pbadupws.nrc.gov/docs/ML1110/ML11105A153.pdf (accessed March 26, 2016).

[473] NRC Reactor Inspector Job Posting No. R-I/DRS-2013-0001.

[474] See, e.g., IAEA. NS Tutorial, http://www.iaea.org/ns/tutorials/regcontrol/regbody/reg2124.htm (accessed March 26, 2016).

[475] NRC. *NRC Inspection Manual, Qualification Program for Operating Reactor Programs (Ch. 1245)*; 2011; ; http://pbadupws.nrc.gov/docs/ML1110/ML11105A153.pdf (accessed March 26, 2016).

5.2 Disproportionate Regulator Resources for Gulf of Mexico Offshore Activity

Historically, the number of MMS employees working on permitting, permit modifications, and inspections did not increase proportionally to the increase in production—in fact, those staff numbers decreased by 36 percent between 1983 and 2010.[476] Meanwhile, MMS found that OCS leasing experienced a 200 percent increase, and oil production increased by 185 percent between 1982 and 2007.[477] In addition, an internal MMS report issued a few months after the Macondo incident put it more bluntly: the Gulf of Mexico district offices did not have enough engineers to conduct permit reviews, and they had only about 55 inspectors for 3,000 facilities.[478]

Following these reports and associated recommendations to increase hiring,[479] BSEE stated that it intended to triple the number of inspectors in the Gulf of Mexico,[480] but hiring efforts initially focused on recent graduates, who lacked relevant professional experience. Former-Director [of BOEMRE] Bromwich began the hiring effort by visiting several universities with petroleum engineering departments to entice new graduates to work for the offshore regulator.[481] The agency also sought recently retired petroleum engineers to work temporarily until permanent hires could join, but several potential applicants lost interest when they saw that the starting salaries were significantly lower than what industry offered for similar work.[482] In March 2012, former BSEE Director Watson stated to Congress that the agency increased inspector hiring by 50 percent since April 2010, but engineers hiring had only increased by ten percent.[483] Watson later explained that BSEE intended to hire another 200 people to conduct permit and spill response plan reviews, inspect offshore facilities, and ensure environmental compliance.[484] He added

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[476] Lewis, W.; Kendall, M.; Suh, R. *U.S. Department of the Interior Outer Continental Shelf Safety Oversight Board Report to the Secretary of the Interior Ken Salazar* ; US Department of the Interior: September 1, 2010; p 6 and 13; http://www.noia.org/wp-content/uploads/2015/12/DOI-OCS-Safety-Oversight-Board-Report.pdf (accessed March 26, 2016).

[477] *Ibid*., p 13.

[478] The report highlighted a 71% increase in permit modification applications in the New Orleans District in 2009; *Ibid*., p 6.

[479] See, e.g., National Commission on the BP Deepwater Horizon Oil Spill and Offshore Drilling. *Deepwater: The Gulf Oil Disaster and the Future of Offshore Drilling - Report to the President;* Janurary, 2011; p 256, Recommendation A5.

[480] *Budget Justifications and Performance Information Fiscal Year 2013*; US Department of the Interior: 2012; p 30; http://www.bsee.gov/About-BSEE/Budget/FY2013BudgetJustification/ (accessed March 26, 2016).

[481] Snow, N. BOEMRE seeks recently retired petroleum engineers, Bromwich says. *Oil & Gas Journal*, April 22, 2011, http://www.ogj.com/articles/2011/04/boemre-seeks-recently.html (accessed March 26, 2016).

[482] *Ibid.*

[483] Watson, J. *Statement of James Watson, Director Bureau of Safety and Environmental Enforcement United States Department of the Interior Committee on Appropriations Subcommittee on Interior, Environment and Related Agencies House of Representatives;* March 7, 2012; http://www.bsee.gov/uploadedFiles/BSEE/Newsroom/Congressional_Testimony/Congressional%20Testimony%2020120307.pdf (accessed March 26, 2013).

[484] Dittrick, P. OTC: BSEE director calls for industry to promote safety culture. *Oil & Gas Journal*, May 1, 2012, http://www.ogj.com/articles/2012/05/otc-bsee-director-calls-for-industry-to-promote-safety-culture.html (accessed March 26, 2016).

there was "still a considerable amount of positions yet to be filled, including additional inspectors, engineers, regulatory specialists, environmental specialists, and other critical disciplines."[485]

BSEE stated in its 2014 annual report that the Bureau hired 88 personnel in 2014, a net gain of 9 full-time-equivalent employees, and 56 of the 88 newly hired personnel were from critical scientific, inspection, and engineering fields. [486] BSEE noted in the report that it will maintain its long-term focus on growing its workforce by attracting the top talent available to fill the agency's ranks.[487] In April 2015, BSEE reported that the number of inspectors in the Gulf of Mexico OCS region increased from 55 in April 2010 to 92 (as of April 20, 2015).[488] Additionally, the number of engineers in the BSEE workforce increased from 106 in October 2011 to 129 in April 2015.[489] Despite the challenges, BSEE made progress.

In 2015, BSEE received authorization to offer new recruits a salary incentive of 25% above base pay.[490] The purpose of this authorization was to help BSEE better compete with the private sector, which is not bound by the federal government's salary and retention rules;[491] however, the authorization brought entry-level starting salaries up to only approximately $40,000, nowhere near equivalent to private industry offerings for equivalent jobs, which average $80,849.[492] Also, this authorization focused exclusively on geophysicists, geologists and petroleum engineering positions, but did not incentivize hiring specialists with other critical professional backgrounds such as environmental science, human factors, psychology, toxicology, or other complementary engineering disciplines relevant to offshore exploration, drilling and production. More remains to be done to help BSEE attract and retain the staff needed to execute its important mission.

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[485] Watson, J. *Statement of James Watson, Director Bureau of Safety and Environmental Enforcement United States Department of the Interior Committee on Appropriations Subcommittee on Interior, Environment and Related Agencies House of Representatives*; March 7, 2012; http://www.bsee.gov/uploadedFiles/BSEE/Newsroom/Congressional_Testimony/Congressional%20Testimony%2020120307.pdf (accessed March 26, 2013).

[486] BSEE. *2014 Annual Report.* May 5, 2015; p 13. http://www.bsee.gov/uploadedFiles/BSEE/BSEE_Newsroom/Publications_Library/Annual_Report/BSEE%202014%20Annual%20Report.pdf (accessed December 21, 2015).

[487] *Ibid.*, p 3.

[488] BSEE and BOEM. *Reforms since the Deepwater Horizon Tragedy*; http://www.eenews.net/assets/2015/04/16/document_gw_03.pdf (accessed March 26, 2016).

[489] *Ibid*.

[490] BSEE. *Understanding the Special Salary Rate for Certain Geologist, Geophysicist, and Petroleum Engineer Positions in the BSEE and BOEM Gulf of Mexico Region*; p 1. http://www.boem.gov/uploadedFiles/BOEM/About_BOEM/Jobs/FAQs_BOEM-PayTables.pdf (accessed December 21, 2015).

[491] BSEE. Director's Corner, August 27, 2014, http://www.bsee.gov/safety/directorscorner/ (accessed March 26, 2015).

[492] BSEE starting salaries for entry level petroleum engineers range from $35,657.00 to $56,859.00. See BSEE position announcement for Petroleum Engineer, GS-0881-05/07, https://www.usajobs.gov/GetJob/ViewDetails/331348800. Meanwhile, the median salary for a highly recruited petroleum engineer in the private sector is $127,970, with average starting salaries around $80,000. See, e.g., http://www.reuters.com/article/2012/01/18/us-energy-jobs-idUSTRE80H1GQ20120118; http://www.forbes.com/pictures/efkk45eghj/1-petroleum-engineering/ (accessed March 26, 2015).

The BSEE salary incentive allows for only 25% more than a new hire's base pay, not above the locality pay. Locality pay is a supplemental pay amount added to account for regional differences in cost of living, among other factors.[a] *The specific duty locations that can offer this special pay rate in the Gulf of Mexico Region are Jefferson, Lafayette, Lake Charles, and Houma, Louisiana.*[b] *Although the Lake Jackson, Texas, District Office is part of the Gulf of Mexico Region, its basic pay plus locality pay is higher than the 25 percent allotted by Congress, so employees of that office cannot receive this supplemental pay.*[c]

For instance, a new graduate hired for a petroleum engineer position at general schedule Grade 7, step 5 in Jefferson County, Louisiana would receive a base salary of $38,511 per year in 2012.[d] *Even without the special authority, he or she would automatically receive the locality pay increase for that area, which means the salary would actually be $43,964 per year.*[e] *BSEE's incentive authority would permit an increase of up to 25 percent of base salary, or $9,628, for a total salary of $48,138 per year. If the engineer were hired for the Lake Jackson, Texas, District Office, he or she would not get the bonus pay, because the locality-adjusted salary of $49,568 per year*[f] *is already more than the 25 percent bonus. In effect, this special pay authority is able to bring only the other Gulf of Mexico district office salaries for geophysicists, geologists, and petroleum engineers closer to their peers' salaries in Lake Jackson.*

[a] OPM. Pay & Leave, Salaries & Wages, http://www.opm.gov/oca/payrates/LPA.asp (accessed March 26, 2015).
[b] BSEE. *Understanding the Special Salary Rate for Certain Geologist, Geophysicist, and Petroleum Engineer Positions in the BSEE and BOEM Gulf of Mexico Region*; p 1. http://www.boem.gov/uploadedFiles/BOEM/About_BOEM/Jobs/FAQs_BOEM-PayTables.pdf (accessed December 21, 2015).
[c] *Ibid.*
[d] For an example, see BSEE position announcement for Petroleum Engineer, GS-0881-05/07, https://www.usajobs.gov/GetJob/ViewDetails/331348800 http://www.opm.gov/oca/payrates/LPA.asp; OPM. Pay & Leave, Salaries & Wages, http://www.opm.gov/oca/payrates/LPA.asp (accessed March 26, 2015).
[e] OPM. Pay & Leave, Salaries & Wages, http://www.opm.gov/oca/payrates/LPA.asp (accessed March 26, 2015).
[f] *Ibid*.

Unfortunately, a 2014 report published by the US Government Accountability Office (GAO) found that the actual pay increase provided to support BSEE's hiring initiative was lower than the 25 percent target envisioned because the increase did not include locality pay.[493] The report also found that US Department of Interior oil and gas departments, such as BSEE and BOEM, continue to struggle hiring and retaining

[493] US Government Accountability Office. *Report to Congressional Requesters. Oil and Gas: Interior Has Begun to Address Hiring and Retention Challenges but Needs to Do More*; US Government Accountability Office: January, 2014; pp 22-23; http://www.gao.gov/assets/670/661025.pdf (accessed March 26, 2016).

key oil and gas oversight positions, including inspectors and petroleum engineers.[494] The report attributes this difficulty to competitive oil and gas industry salaries and signing bonuses for new hires,[495] although low oil and natural gas prices in recent quarters started to impact this dynamic. The report also stated that these challenges have resulted in less time available for oil and gas oversight activities, including inspections. Surveys conducted by GAO showed that the number and thoroughness of inspections were "somewhat or greatly reduced because of … vacancies."[496] To compound the problem, the report noted that a "high proportion of staff in key oil and gas positions … will be eligible to retire within a few years."[497] GAO analysis found that roughly 35 percent of BSEE's petroleum engineers would be eligible to retire by 2017 compared with a government-side average of 27.5 percent for all federal employees during the same period.[498]

BSEE staff has to cover three geographical regions (Alaska, GoM, and the Pacific), and the GoM alone has 2,481 active platforms, with 329 new wells drilled during 2014, and 133 designated operators.[499] Thus, total staffing resources leveraged against the current GoM assets and accompanying drilling and production activity, supports the agency's human capital aspirations "to meet the consistent challenge of recruiting and retaining top talent."[500] With its efforts in place, BSEE may be able to take advantage of macroeconomic conditions and the current low prices of oil and natural gas which are driving down GoM activity and job cuts in the industry.[501] It is only a matter of time, however, before the trend reverses, therefore BSEE needs to remain ready for these cycles.

5.3 The Deficit in Regulator Technical Competency and Credibility

Earlier reports on the Macondo incident, such as the Presidential Oil Spill Commission Report[502] and MMS's own report,[503] explained MMS permit reviewers and inspectors historically lack technical competency, noting that it struggled to retain competent staff. In the version of the proposed SEMS rule

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494 *Ibid.,* p 14.

495 *Ibid.*, p 19.

496 *Ibid.*, pp 31-32.

497 *Ibid.* p 17.

498 *Ibid.*, p 17

499 BSEE. *2014 Annual Report.* May 5, 2015; p 8. http://www.bsee.gov/uploadedFiles/BSEE/BSEE_Newsroom/Publications_Library/Annual_Report/BSEE%202014%20Annual%20Report.pdf (accessed December 21, 2015).

500 *Ibid*., p 13.

501 As of April 1, 2016, the total number of active rigs in the US dropped by 545; Baker Hughes. Rig Count Overview & Summary Count, http://phx.corporate-ir.net/phoenix.zhtml?c=79687&p=irol-rigcountsoverview; and Reed, S. Stung by Low Oil Prices, BP Will Cut 4,000 Jobs. January 12, 2016, http://www.nytimes.com/2016/01/13/business/energy-environment/bp-jobs-oil-prices.html (accessed March 26, 2016).

502 See e.g., National Commission on the BP Deepwater Horizon Oil Spill and Offshore Drilling. *Deepwater: The Gulf Oil Disaster and the Future of Offshore Drilling - Report to the President;* Janurary, 2011; p 74.

503 Lewis, W.; Kendall, M.; Suh, R. *U.S. Department of the Interior Outer Continental Shelf Safety Oversight Board Report to the Secretary of the Interior Ken Salazar* ; US Department of the Interior: September 1, 2010; pp 13-16; http://www.noia.org/wp-content/uploads/2015/12/DOI-OCS-Safety-Oversight-Board-Report.pdf (accessed March 26, 2016).

issued the year before the Macondo incident, MMS noted that most comments received in response to the 2006 advanced notice of proposed rulemaking expressed that API RP 75 provided excellent guidance, but that MMS should not approve SEMS plans, "rather, a third party should determine or certify whether a SEMS plan is viable, because MMS may not have the resources and expertise to approve a minimum of one plan for each OCS operator."[504] MMS's inadequate budget and conflicting missions resulted in serious management deficiencies and a pervasive culture of deference to the offshore industry for guidance on reviews and inspections at the time of the Macondo incident.[505]

5.4 Post-Macondo Efforts to Improve Competency

BSEE has been working to correct many of the deficiencies in MMS's recruitment and training programs for offshore inspectors and investigators. In March 2010, it issued an internal handbook to improve the conduct of internal investigations, but it did not significantly change the basic protocol or management responsibilities outlined in an earlier manual.[506] More importantly, it did not provide special procedures for conducting catastrophic or serious accident investigations, nor did it contain a protocol for evidence gathering.[507]

To improve training at the agency, BSEE opened its virtual National Offshore Training Center in 2011.[508] According to BSEE, agency staff logged more than 10,000 hours of technical and safety training in FY 2012,[509] and 38 staff attended a two-week boot camp in petroleum geology, drilling engineering, production engineering and permitting, with lectures by college professors complemented by hands-on exposure to equipment in August 2012.[510] Additionally, BSEE Director Salerno recently stated that the National Offshore Training Program grew in FY 2014, offering 79 technical courses, an increase of 29 courses over FY 2013.[511] The BSEE 2014 Annual Report noted the agency remains committed to employee development and that in calendar year 2014, BSEE offered 105 training courses with 145

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504 Safety and Environmental Management Systems for Outer Continental Shelf Oil and Gas Operations, 74 Fed. Reg. 28639 (Proposed, June 17, 2009).

505 Forty-two percent of inspectors interviewed for the Safety Oversight Board's Report to Secretary Salazar stated that "headquarters management does not provide sufficient direction and support;" Lewis, W.; Kendall, M.; Suh, R. *U.S. Department of the Interior Outer Continental Shelf Safety Oversight Board Report to the Secretary of the Interior Ken Salazar* ; US Department of the Interior: September 1, 2010; p 15; http://www.noia.org/wp-content/uploads/2015/12/DOI-OCS-Safety-Oversight-Board-Report.pdf (accessed March 26, 2016).

506 *Ibid*., p 22.

507 *Ibid*., p 22.

508 BSEE. BSEE Director Delivers Remarks at the International Regulators Forum 2011 Global Offshore Safety Summit Conference. October 4, 2011, http://www.bsee.gov/BSEE-Newsroom/Press-Releases/2011/BSEE-Director-Delivers-Remarks-at-the-International-Regulators-Forum-2011-Global-Offshore-Safety-Summit-Conference/ (accessed March 26, 2016).

509 Dlouhy, J. Tougher offshore scrutiny? Not yet. *Fuel Fix from the Houston Chronicle*, December 13, 2012, http://fuelfix.com/blog/2012/12/13/tougher-offshore-scrutiny-not-yet/ (accessed March 26, 2016).

510 *Ibid*.

511 BSEE. The National Offshore Training Program Shows Continued Growth in 2014: Remains a Priority for BSEE Moving Forward. October 28, 2014, http://www.bsee.gov/BSEE-Newsroom/BSEE-News-Briefs/2014/The-National-Offshore-Training-Program-Shows-Continued-Growth-in-2014/ (accessed December 9, 2014).

engineers attending an average of three classes each, and 124 inspectors attending an average of approximately four classes each, for a total of 24,486 training hours conducted.[512]

Additional insights into BSEE's intentions to equip its staff with needed skills appear in the 2014 US Department of the Interior Office of Inspector General (IG) *Report on Offshore Oil and Gas Permitting*.[513] According to the report, BSEE issued an internal policy document in spring 2013, *Training Requirements for Engineers*, which requires all engineers to complete at least 32 hours of approved technical training annually and newly hired engineers with fewer than 3 years of oil and gas engineering experience to complete BSEE's engineering boot camp or a similar program.[514] The report found that BSEE did not "effectively or efficiently" implement that policy, and "did not ensure that all employees were aware of the new requirement."[515] As a result, the IG recommended that BSEE "document that all permitting employees are aware of IPD [Interim Policy Document] requirements; and monitor and track all training to ensure that training requirements, including training hours, are met and that all training is recorded."[516] BSEE stated in its response that in April 2014, it finalized a mandatory online training awareness module, that by August 29, 2014, "more than 94 percent of BSEE engineers had completed their fiscal year 2014 training requirements … [and that] by January 1, 2015, BSEE will ensure that all technical courses offered in FY15 will have the training hours listed on the engineer's transcript, as well as the class completion certificate."[517]

In addition to needing technical competency, inspectors must have excellent communication, advocacy, and negotiation skills. Hiring and developing regulatory personnel with a full range of skill sets is essential to help build a knowledgeable, credible regulator who can recognize deficiencies and engage with operators to develop appropriate risk-reduction strategies and persuade them to make changes when necessary.[518]

5.5 Insufficient Regulatory Funding Mechanism for Securing Staff

At the time of the Macondo incident, the US offshore safety regulator did not have sufficient, sustainable funding to manage major accident prevention activities. To drive continual improvement in the offshore industry and hire and retain sufficient competent staff, the offshore regulator needs adequate and sustainable funding. Insufficient funding is often cited as the main reason that MMS was unable to hire

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[512] BSEE. *2014 Annual Report.* May 5, 2015; p 13. http://www.bsee.gov/uploadedFiles/BSEE/BSEE_Newsroom/Publications_Library/Annual_Report/BSEE%202014%20Annual%20Report.pdf (accessed December 21, 2015).

[513] IG. *Offshore Oil and Gas Permitting US Department of the Interior;* Report No. CR-EV-BSEE-0006-2013; September, 2014; https://www.doioig.gov/sites/doioig.gov/files/CR-EV-BSEE-0006-2013Public.pdf (accessed March 26, 2016).

[514] *Ibid.*, p 12.

[515] *Ibid.*, p 1.

[516] *Ibid.*, p 13.

[517] *Ibid.*, p 18.

[518] Wilkinson, P. *Creating a New Offshore Petroleum Safety Regulator*, Presentation to IADC, Australian Petroleum Production & Exploration Association Conference, March 25, 2003; p 6 http://www.nopsema.gov.au/assets/document/IADC-Annual-General-Meeting.pdf (accessed March 26, 2016).

and retain sufficient staff or to adequately oversee deepwater drilling.[519] Beginning in 2011, BSEE received a sizeable budget increase; however, this funding is by congressional appropriations that may (and likely will) vary from year to year. Other offshore regimes ensure the regulator is funded at variable but appropriate levels through an industry self-funding or "cost recovery" mechanism. As offshore activities increase or decrease, so too does the regulator funding to ensure adequate resources for regulatory oversight.

5.5.1 Ineffectual Funding Appropriations for Offshore Activity

As offshore drilling activities increase and expand into deeper and riskier waters, the need for a stronger, more effective offshore regulator becomes greater.[520] Adequate and sustainable funding is a necessary attribute of a competent regulator.[521] One way to ensure consistent funding in the appropriation process is to provide agencies with an independent funding mechanism.[522] An independent funding mechanism based on the number and type of active offshore sites renders a straightforward means of ensuring sufficient funding. When offshore operations decline, the overall level of risk that the industry assumes declines, and so too would the funding.

As a component of the Department of the Interior, MMS was, and BSEE is, appropriated funding by Congress through the General Fund.[523] Each year, the agency sends a budget justification and request to its appropriators in Congress, whose jurisdiction extends to the rest of the Department of the Interior, the Environmental Protection Agency, and several smaller independent agencies.[524] The appropriators then determine the size of each agency's annual budget. In March 2012, former BSEE Director Watson attributed recent regulatory action and increased hiring of inspectors partly to the budget increase that Congress provided.[525] By spring 2012, however, Interior officials expressed concern to the Government Accountability Office that current and future budgetary constraints may prevent BSEE from fully implementing reforms as planned, and that this would handicap BSEE's ability to manage oil and gas

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[519] MMS's inability to keep up with technological advances was made more problematic because its level of funding and technical staffing remained static or decreased as industry's offshore drilling activity increased; National Commission on the BP Deepwater Horizon Oil Spill and Offshore Drilling. *Deepwater: The Gulf Oil Disaster and the Future of Offshore Drilling - Report to the President;* Janurary, 2011; p 72.

[520] "Interior's capacity to identify and evaluate risk remains limited, raising questions about the effectiveness with which it allocates its oversight resources;" US Government Accountability Office. *Oil and Gas Management: Interior's Reorganization Complete, but Challenges Remain in Implementing New Requirements;* GAO-12-423; July 30, 2012; p 106. http://www.gao.gov/assets/600/593110.pdf (accessed March 26, 2016).

[521] National Commission on the BP Deepwater Horizon Oil Spill and Offshore Drilling, *A Competent and Nimble Regulator: A New Approach to Risk Assessment and Management*, Staff Working Paper No. 21.

[522] Barkow, R. Insulating agencies: avoiding capture through institutional design, *Texas Law Review, 89*, 2010, p 15, 44. 146-47. http://papers.ssrn.com/sol3/papers.cfm?abstract_id=1717037.

[523] The General Fund is the US Treasury account that appropriates funds to most federal agencies.

[524] US House of Representative Committee on Appropriations. Interior Subcommittee Jurisdiction, http://appropriations.house.gov/about/jurisdiction/interiorenvironment.htm (accessed March 26, 2016).

[525] Watson, J. *Statement of James Watson, Director Bureau of Safety and Environmental Enforcement United States Department of the Interior Committee on Appropriations Subcommittee on Interior, Environment and Related Agencies House of Representatives*; March 7, 2012; http://www.bsee.gov/uploadedFiles/BSEE/Newsroom/Congressional_Testimony/Congressional%20Testimony%2020120307.pdf (accessed March 26, 2013).

activities in the Gulf of Mexico.[526] BSEE officials from the Gulf of Mexico regional office said that they could not reliably anticipate budget increases for new hiring and helicopter operating costs.[527] This budget uncertainty, the officials explained, hindered BSEE's ability to review permits and conduct inspections.[528]

The fiscal year 2012 appropriations bill, passed in March 2012, included a line item for inspection fees of $62 million,[529] which BSEE officials agreed would cover most of the resources needed to increase BSEE's inspection and permitting capacity for that year.[530] In a given year, fees for inspections and additional offsetting collections can comprise a portion of BSEE's operating costs, and they are subtracted from the appropriated budget.[531] Despite the increase for fiscal year 2012, BSEE officials expressed concern that public and congressional attention to oversight of offshore oil and gas drilling may diminish over time and that future appropriations may decrease, which would endanger their ability to provide effective safety oversight offshore.[532] Despite these concerns, BSEE total appropriations have not drastically changed since 2012. BSEE total appropriations were $182.4 million in FY 2012,[533] $200.8 million in FY 2013,[534] $202.6 million in FY 2014,[535] and $204.6 million in FY 2015.[536]

The Mine Safety and Health Administration (MSHA) provides a particularly compelling example of how appropriations funding can decrease over time. MSHA was formed in 1977, following a slew of mining

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[526] US Government Accountability Office. *Oil and Gas Management: Interior's Reorganization Complete, but Challenges Remain in Implementing New Requirements;* GAO-12-423; July 30, 2012; p 101. http://www.gao.gov/assets/600/593110.pdf (accessed March 26, 2016).

[527] *Ibid*., p 101.

[528] *Ibid*., p 101.

[529] For FY 2015, the BSEE budget requested $204.6 million, which includes $50.4 million from offsetting rental collections, $8.2 million from cost recovery fees, and $65.0 million inspection fees; The US Department of the Interior. *Budget Justifications and Performance Information Fiscal Year 2015: Bureau of Safety and Environmental Enforcement;* http://www.bsee.gov/uploadedFiles/BSEE/About_BSEE/Budget/BSEE%20FY%202015%20Final%20Greenbook%20File.pdf (accessed March 25, 2015).

[530] US Government Accountability Office. *Oil and Gas Management: Interior's Reorganization Complete, but Challenges Remain in Implementing New Requirements;* GAO-12-423; July 30, 2012; p 101. http://www.gao.gov/assets/600/593110.pdf (accessed March 26, 2016).

[531] For example, in FY2013, BSEE anticipated receiving half of its appropriation from fees and offsetting collections. The portion has varied significantly, but it has typically been 25% or less of the total appropriation; *Budget Justifications and Performance Information Fiscal Year 2013*; US Department of the Interior: 2012; p 6, Table 1; http://www.bsee.gov/About-BSEE/Budget/FY2013BudgetJustification/ (accessed March 26, 2016).

[532] US Government Accountability Office. *Oil and Gas Management: Interior's Reorganization Complete, but Challenges Remain in Implementing New Requirements;* GAO-12-423; July 30, 2012; p 101. http://www.gao.gov/assets/600/593110.pdf (accessed March 26, 2016).

[533] *Budget Justifications and Performance Information Fiscal Year 2013*; US Department of the Interior: 2012; p 3; http://www.bsee.gov/About-BSEE/Budget/FY2013BudgetJustification/ (accessed March 26, 2016).

[534] *Budget Justifications and Performance Information Fiscal Year 2014*; US Department of the Interior: 2013; p 3; http://www.doi.gov/budget/appropriations/2014/upload/FY2014_BSEE_Greenbook.pdf (accessed March 26, 2016).

[535] *Budget Justifications and Performance Information Fiscal Year 2016*; US Department of the Interior: 2015; p 3; http://www.doi.gov/budget/appropriations/2016/upload/FY2016_BSEE_Greenbook.pdf (accessed March 26, 2016).

[536] *Ibid*., p 3.

disasters when Congress and the public realized that the predecessor agency, the Mining Enforcement and Safety Administration, had prioritized revenue generation over safety.[537] Congress recognized that the increased enforcement, legal, and administrative responsibilities for MSHA would require additional funds for hiring and support services. Yet it did not create a special mechanism to ensure increased funding was available year after year. Instead, Congress expected that MSHA's funds "can be provided through the normal appropriation process as necessary."[538] So in 1979, the year it became a fully operational agency, MSHA's budget peaked at an inflation-adjusted $355 million. By 2007, despite some increases in spending, the budget dropped 15 percent.[539] The President recommended to Congress that MSHA receive a budget of $395 million in 2016.[540] The MSHA experience is a powerful reminder that the source of an agency's funding is critical to achieving its mission.

If it is to avoid repeating MSHA's good intentions and budget woes, a renewable, sustainable funding structure is the best way to ensure that BSEE will have adequate funding to regulate environmental and safety activity on the OCS in future years. One argument against an industry-funded regulator is that it can become "captured" by the industry that funds it. [541] Conversely, interest groups can exert pressure on Congress to control an agency's activities through its budget, which is just another type of agency capture. [542] Yet other federal safety regulators transitioned to industry-funded appropriations precisely to avoid the inadequacies and lack of a consistent budget. The Nuclear Regulatory Commission (NRC) was reorganized in response to the Three Mile Island incident in 1979. As part of the regulatory overhaul in the 1980s and 1990s, the NRC transitioned to a fee-for-service model of regulating. Now, Congress sets the agency's budget, but the NRC is required by law to recover at least 90% of its funding through licensing and inspection fees.[543] For instance, each year the agency determines and publishes fee amounts for new reactor license applications ($17,800), amendments to licenses ($9,600), and inspections ($273

[537] Senate Report 95-181 at 3405 (95th Congress), May 16, 1977 http://arlweb.msha.gov/SOLICITOR/COALACT/leghist2.htm (accessed March 26, 2016).

[538] *Ibid*.

[539] OMB Watch. *Coal Mine Safety Shortchanged by Years of Budget Cuts;* OMB Watch: Washington, D.C., 2008; http://miningquiz.com/pdf/NEC/US_Coal_Mine_Safety_Shortchanged_by_Years_of_Budget_Cuts.pdf (accessed March 26, 2016); meanwhile, mining production had increased significantly since the 1970s. In 1973, the U.S. Department of Energy, Energy Information Administration reported 591 million short tons of coal produced in the U.S. By 2007, production increased to 1.147 billion short tons; The American Resource, Trends in U.S. Coal Mining 1923-2001, http://www.nma.org/pdf/c_trends_mining.pdf. (accessed March 26, 2016).

[540] US Department of Labor. Budget request for FY 2016 outlines priorities for future, http://www.msha.gov/fromthedesk/2015/0203.asp (accessed March 26, 2016).

[541] Rachel E. Barkow, *Insulating Agencies: Avoiding Capture Through Institutional Design*, 89 TEX. L. REV. 15, 42 n. 146-47 (2010); *see also* Steven A. Ramirez, Depoliticizing Financial Regulation, 41 WM. & MARY L. REV. 503, 517 (2000) (noting with surprise that most proposals for offshore regulatory reform have not focused on agency financing).

[542] Capture of a federal agency can be defined as strong responsiveness to the desires of the industry or groups being regulated. See Rachel E. Barkow, *Insulating Agencies: Avoiding Capture Through Institutional Design*, 89 TEX. L. REV. 15, p 21 (2010); Roger G. Noll, REFORMING REGULATION 99-100 (1971). This document explains that capture happens most often when an agency assigns undue weight to the interests of the regulated industries as opposed to public interests.

[543] Section 6101 "NRC User Fees and Annual Charges," Omnibus Budget Reconciliation Act, Pub. L. 103-66. 107 Stat. 312 (Aug. 10, 1993).

per hour).[544] This funding mechanism ensures that the agency's budget adequately covers the regulatory activities it performs, but no more. It also simplifies the agency's budget planning. Because fees directly correspond to the actions the NRC performs, the agency does not worry about potential budget shortfalls from year to year. BSEE could use this same approach to fund additional hires. Offshore revenue from existing drilling and production activities could cover necessary inspection staff. Salaries could then be calculated at a rate comparable to a private third-party auditor in the GoM, making the structure more cost effective.

The Pipeline and Hazardous Materials Safety Administration (PHMSA) within the Department of Transportation provides another example of an industry-supported federal safety regulator. PHMSA is authorized to assess and collect pipeline user fees to fund its pipeline safety activities.[545] The pipeline safety statute that authorized PHMSA recognized a need for consistent funding for the pipeline regulator's safety oversight. It reflected Congress's intention that the total costs of administering certain federal pipeline safety programs be recovered through charges to the industry.[546] PHMSA assesses operators of interstate and intrastate natural gas and hazardous liquid transmission pipelines so that the operators each pay a share of the total federal pipeline safety program costs in proportion to the number of miles of pipeline they have in service at the end of a calendar year.[547]

At least one county safety regulator is industry funded. In Contra Costa County, California, the California Accidental Release Prevention Program (CalARP) works to prevent catastrophic accidental releases of highly toxic or flammable chemicals through its Risk Management Program.[548] CalARP engineers review industry risk-management program plans, conduct regular audits of sites, and follow up with action items to verify compliance.[549] The county uses a Certified Unified Program Agency (CUPA) single-fee system, which assesses fees to users of all CUPA programs, including CalARP.[550] Under this system, a single invoice is issued annually to each of the regulated business sites for review and audit services that CalARP performs. The collected fees cover salaries and benefits, services and supplies, and overhead costs of the CUPA programs.[551]

5.5.2 Industry Funding of International Offshore Regulators

In contrast to the US offshore regulator's hybrid fee and congressional appropriation scheme, the North Sea and Australian offshore regimes use a cost-recovery model. Since 1999, the UK offshore regulator

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[544] 10 C.F.R. § 170.21.

[545] 49 U.S.C. § 60301.

[546] Skinner v. Mid-America Pipeline Co., 490 U.S. 212 (1989).

[547] The 2010 fee assessed on liquid pipelines was offset by $18.8 million, roughly half of the total program allocated, from the Oil Spill Liability Trust Fund. Letter from Cynthia Quarterman, Administrator, Pipeline and Hazardous Materials Safety Administration, to Senator Daniel K. Inouye, Chairman, Committee on Appropriations (April 5, 2010).

[548] Contra Costa Health Services, California Accidental Release Prevention (CalARP) Program, http://cchealth.org/groups/hazmat/california_accidental_release_prevention.php (accessed March 26, 2016).

[549] *Ibid*.

[550] http://cchealth.org/groups/hazmat/pdf/cupa/fee-exhibits.pdf.

[551] Contra Costa Health Hazardous Materials. *List of Exhibits: To Staff Report on the Determination and Apportionment of CUPA Fees;* http://cchealth.org/hazmat/pdf/cupa/fee-exhibits.pdf (accessed March 26, 2016).

aimed to recover its costs entirely through fees or "charges" to duty holders.[552] The UK government wanted to ensure appropriate funding for the offshore safety and health program, so it decided the industry benefiting from the regulator's services should support that program. It instituted a per-hour cost recovery rate for offshore regulatory activities, such as safety case document review and inspections.[553]

Not long after the fee schedule was established, an independent consulting firm authored a report for UK HSE examining the potential effects on UK HSE charging industry in this manner. Relying on extensive interviews with duty holders, unions, UK HSE staff, document review, and statistical analysis,[554] the report explained that the majority of the industry respondents interviewed indicated their relationship with the regulator had not been "negatively affected", and they observed no change in regulatory performance or in efficiency on the part of the regulator.[555]

Although there were some faults in the program in terms of implementation, including some negative feedback concerning administrative issues (primarily proper invoicing and difficulties for duty holders with anticipated budgeting based on anticipated inspector activity at particular locations),[556] cost did not turn out to be an issue. Only half of the companies surveyed claimed to have incurred additional costs after the UK transitioned to this system, most of which were less than £3,000 (approximately $4,516).[557]

The single most important focus in terms of statistical analysis covered by the report was to determine if any change in outcomes on health and safety resulted across the population of duty holders.[558] The study concluded that it was impossible to prove statistically whether the new system affected health and safety issues due to the low probability of events, resulting in a relative paucity of data from which to try to draw such conclusions.[559] The study documented, however, a significant statistical increase in documented activity across all regulatory areas by inspectors, including increased issuance of improvement notices, prohibition notices, enforcement notices, and prosecutions.[560] The total number of safety cases presented, and accepted, also increased significantly from 1996-2001, but the percentage of safety cases accepted remained relatively constant.[561]

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[552] *Offshore Oil and Gas in the UK—An Independent Review of the Regulatory Regime;* https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/48252/3875-offshore-oil-gas-uk-ind-rev.pdf (accessed March 26, 2016). "The Panel comprised three independent appointees, including myself, all with an element of experience and knowledge relevant to the industry, alongside a senior representative of each of the three national regulatory bodies with responsibilities for the offshore oil & gas sector, namely: the Department of Energy and Climate Change (DECC), the Health and Safety Executive (HSE) and the Maritime and Coastguard Agency (MCA);" *Ibid*., p 1.

[553] Since April 2016, the charge is £266 per inspector hour. http://www.hse.gov.uk/charging/offshore/chgoffsh.htm for information on the UK HSE's charging process (accessed March 26, 2016).

[554] *Ibid*., § 1.2.

[555] *Ibid*., e.g., §§ 1.6-1.7, 1.10, 1.16-1.17.

[556] *Ibid*., § 1.12.

[557] *Ibid*., § 1.2.

[558] *Ibid*., § 3.2.

[559] *Ibid*., § 4.1.

[560] *Ibid*., § 4.1-4.4.

[561] *Ibid*., § 4.5-4.6.

Australia's offshore safety regulator, NOPSEMA, is also industry-funded, but in a slightly different way than the UK OSDR.[562] Much like the UK, NOPSEMA collects funds through safety case levies on the offshore industry, which it determines by individual activity levels.[563] Rather than hourly rates, levies paid by the duty holders are flat fees based on the facility in use.[564] This arrangement ensures that each operator is well aware of the cost it will incur for regulatory services. Also, the regulator is aware of its budget for the year, and it does not cause industry any misgivings over the need for additional inspections or audits. In addition, this funding scheme helps regulatory staff build healthy and appropriate relationships with industry.

While BSEE's most recent budget suggests that it is well-funded, an industry funding mechanism guarantees that future funding is always commensurate with industry activity offshore, regardless of cyclical movements of oil and gas prices, which can impact the industry, along with changing political will in terms of the desirability of an enhanced regulatory presence versus production pressures during times of peak energy demand.

5.6 The Importance of an Independent Regulator

To ensure that safety is a priority offshore, the regulator must maintain its independence from the economic aspects of offshore drilling activities. Independence is an essential feature of an effective safety regulator for major hazard facilities because offshore leasing and revenue generation goals are often in conflict with safety and environmental protection. In mining and nuclear safety, Congress recognized that an independent safety regulator requires full isolation of the safety mission from the government agency tasked with production and revenue management. A regulator must be regarded as independent from stakeholder community it regulates while still maintaining appropriate levels of engagement. UK HSE communications with the CSB corroborate this, noting that even the perception of a conflict of interest with industry in the UK would undermine that regulator's effectiveness.

BSEE has taken steps to establish and maintain independence, but evidence suggests it has yet to achieve full independence, and the appearance of a conflict of interest may remain. Reorganization of offshore safety regulator in the Department of Interior fails to reflect the lessons from previous congressional safety reforms and the experiences of other international offshore regulatory regimes.

5.6.1 The Minerals Management: The Safety Versus Revenue Conflict

The Minerals Management Service (MMS) regulated offshore safety from 1982 until its reorganization following Macondo in 2010. Through the Secretary of the Interior, MMS used the Outer Continental

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[562] Australian Petroleum (Submerged Lands) Act Section 138 specifies industry payment of fees to the regulator.

[563] NOPSEMA, Cost Recovery and Levies, http://www.nopsema.gov.au/about/cost-recovery-and-levies/ (accessed March 26, 2016).

[564] NOPSEMA. *Guideline: Safety Case Levies;* December 19, 2013; http://www.nopsema.gov.au/assets/Guidelines/N-11000-GL0238-Safety-Case-Levies.pdf (accessed March 26, 2016); *Ibid*.

Shelf Lands Act to promulgate regulations outlining leasing, revenue collection, environmental compliance, and safety requirements for activities on the outer continental shelf (OCS).[565]

MMS was created in 1982, during a period of rising inflation and market uncertainty about oil prices.[566] Then-Secretary of the Interior James Watt, expressing concern about offshore revenue, attempted to expand offshore federal leasing to promote drilling and oil production. Soon after, an administration blue ribbon commission issued a report that exposed ineffective revenue management for energy production on federal lands, describing it as "a failure for more than 20 years."[567]

To expand leasing and revenue-promotion goals, Secretary Watt used his discretion under the Outer Continental Shelf Lands Act to transition the authority for revenue collection from the Bureau of Land Management and for regulatory oversight of offshore activity from the US Geological Survey. These functions, previously separated, were now vested in one agency, the new Minerals Management Service.[568] This created an inherent conflict of interest within one agency because through the fall of 2010, the MMS would oversee both regulatory and revenue functions for offshore drilling operations on the OCS. In many ways, Secretary Watt's actions were reinforcing the purpose of the Outer Continental Shelf Lands Act of "expeditious and orderly development [of OCS resources], subject to environmental safeguards, in a manner which is consistent with the maintenance of competition and other national needs."[569] Nevertheless, the inherent conflict remained, with the desire for enhanced revenue generation potentially pitted against the drive for offshore safety.

One of Watt's first actions were to streamline the OCS leasing process and to encourage drilling with an ambitious five-year leasing plan for up to five billion acres of the US Outer Continental Shelf.[570] Though it succeeded in invigorating lease sales, the 1982-1987 five-year plan was dampened by a longstanding congressional leasing moratorium,[571] which was followed by a series of executive offshore leasing moratoria, the first issued by President George H. W. Bush in 1990.[572] The western Gulf of Mexico,

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[565] See 30 C.F.R. Part. 250.

[566] Bernanke, B.; Gertler, M.; Watson, M.; Sims, F.; Friedman, B. Systematic Monetary Policy and the Effects of Oil Price Shocks; *Brookings Papers on Economic Activity* **1997 (1),** *1997*, pp 91-157; see also International Monetary Fund. Global Economy Learns to Absorb Oil Price Hikes, http://www.imf.org/external/pubs/ft/survey/so/2012/num052512a.htm (accessed March 26, 2016); *Ibid.*

[567] Commission on Fiscal Accountability of the Nation's Energy Resources. *Fiscal Accountability of the Nation's Energy Resources;* January, 1982; http://www.onrr.gov/laws_R_D/FRNotices/PDFDocs/linowesrpt1-5.pdf (accessed March 26, 2016).

[568] Secretarial Order No. 3071 (Jan. 19, 1982).

[569] 43 U.S.C. § 1332(3).

[570] Department of the Interior Notice, Tentative Proposed Final 5-Year OCS Oil and Gas Leasing Program, 47 Fed. Reg. 11980 (March 19, 1982).

[571] Over Secretary Watt's objections, Congress reined in his proposal to offer almost all of the US coastline for offshore oil and gas development by 1987. The 1984 Interior appropriations bill banned drilling along most of California and Cape Cod. See e.g., Russakoff, D. Watt's Adversaries Would Almost Hate To See Him Resign. *The Washington Post*, October 7, 1983, https://www.washingtonpost.com/archive/politics/1983/10/07/watts-adversaries-would-almost-hate-to-see-him-resign/f324ed56-31d7-4b59-ae52-2b756cf53e91/ ; and Vann, A. *Offshore Oil and Gas Development: Legal Framework*; RL33404 2-3; Congressional Research Service: 2011.

[572] *President George Bush: Statement on Outer Continental Shelf Oil and Gas Development;* June 26, 1990; http://www.presidency.ucsb.edu/ws/?pid=18638 (accessed March 26, 2016).

however, was not part of the leasing and drilling moratoria, and the lease sales and resulting revenue became the second largest revenue source for the federal treasury.[573] An assessment of the scope of MMS activities from that time through the date of the Macondo incident shows the agency's emphasis on maximizing revenue generation as compared to safety and environmental regulation.[574]

5.6.2 BSEE Organizational Structure

Changes in the Department of the Interior post-Macondo are in line with the September 2010 US Department of Interior Outer Continental Shelf Safety Oversight Board's *Report to Secretary of the Interior Ken Salazar,* which recommends "In future institutional structures implemented through the ongoing BOEMRE reorganization, separate the management of environmental functions from the leasing and development to ensure that environmental concerns are given appropriate weight and consideration."[575] They are also consistent with the Presidential Commission's recommendation to create "an independent agency within the Department of the Interior with enforcement authority to oversee all aspects of offshore drilling safety."[576] The recommendation did not resolve the inherent problems with the Secretary of Interior's continued responsibility for simultaneous missions that often conflict. The Department of the Interior retains offshore production and revenue collection authority.

The various bureaus and services composing the Interior Department are not independent agencies; each is one part of a strict, hierarchical structure with the Secretary at the top of the pyramid.[577] These line bureaus operate only on delegated authority because the statutes they implement do not even mention the bureau. Instead, final powers of decision remain with the Secretary of the Interior.[578] The following organizational charts for the Department of the Interior illustrate the similarities between MMS and BSEE's positions within the Department. Both agencies report to the Assistant Secretary for Land and Minerals Management, who reports to the Deputy Secretary of the Interior, who reports to the Secretary. The Director of BSEE is three levels of authority below the Secretary of the Interior, as was the MMS Director. The agency branch responsible for safety follows the same hierarchical structure as before the Macondo blowout.

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[573] National Commission on the BP Deepwater Horizon Oil Spill and Offshore Drilling. *Deepwater: The Gulf Oil Disaster and the Future of Offshore Drilling - Report to the President;* Janurary, 2011; p 63.

[574] House Committee on Energy and Commerce, JIT hearing, July 20, 2010, statement of Rep. Sutton, http://www.gpo.gov/fdsys/pkg/CHRG-111hhrg77922/html/CHRG-111hhrg77922.htm.

[575] Lewis, W.; Kendall, M.; Suh, R. *U.S. Department of the Interior Outer Continental Shelf Safety Oversight Board Report to the Secretary of the Interior Ken Salazar* ; US Department of the Interior: September 1, 2010; p 33; http://www.noia.org/wp-content/uploads/2015/12/DOI-OCS-Safety-Oversight-Board-Report.pdf (accessed March 26, 2016).

[576] National Commission on the BP Deepwater Horizon Oil Spill and Offshore Drilling. *Deepwater: The Gulf Oil Disaster and the Future of Offshore Drilling - Report to the President;* Janurary, 2011; p 26, Recommendation A4.

[577] George Cameron Coggins and Doris K. Nagel, Nothing Beside Remains: *The Legal Legacy of James G. Watt's Tenure as Secretary of the Interior on Federal Land Law and Policy*, 17 B.C. ENVTL. AFF. L. REV. 473, 482 (1990).

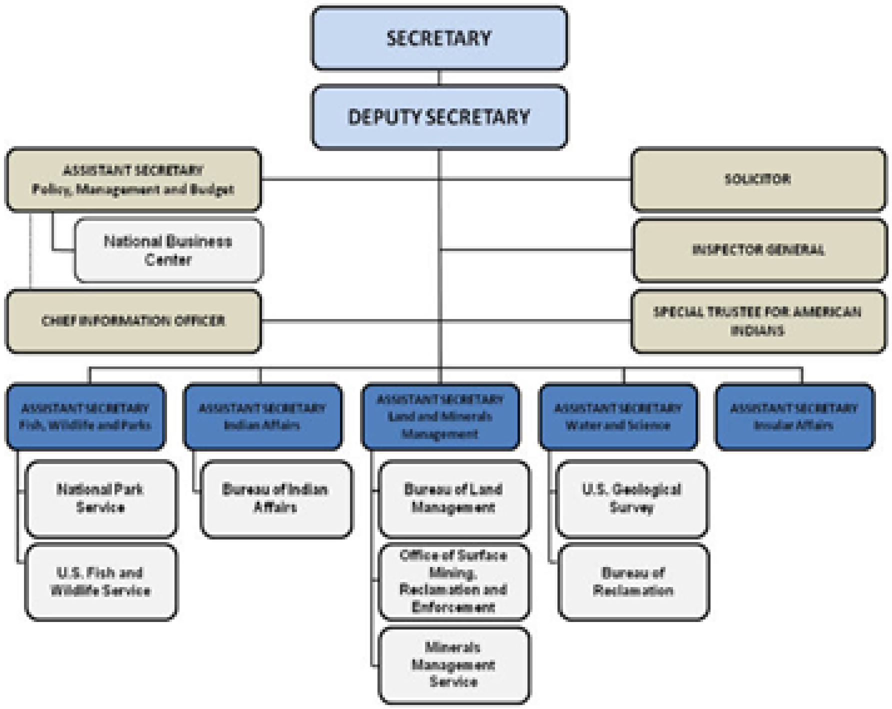
[578] *Ibid*.

Other agencies with competing missions exist in the federal government.[579] The federal administrative agencies and bureaus that manage public lands, like the former MMS, the Bureau of Land Management, and the US Forest Service, probably have the most diverse and sweeping range of goals, including production, environmental protection, public use, and worker and public safety, all of which are difficult to address equally.[580] Each of these agencies has either admitted to or been accused of emphasizing one or more of their missions, typically the economic or production-related ones, over others such as safety.[581] There are signs that BSEE may continue to emphasize the economic or production-related aspects of DOI's mission, particularly for permitting offshore operations.

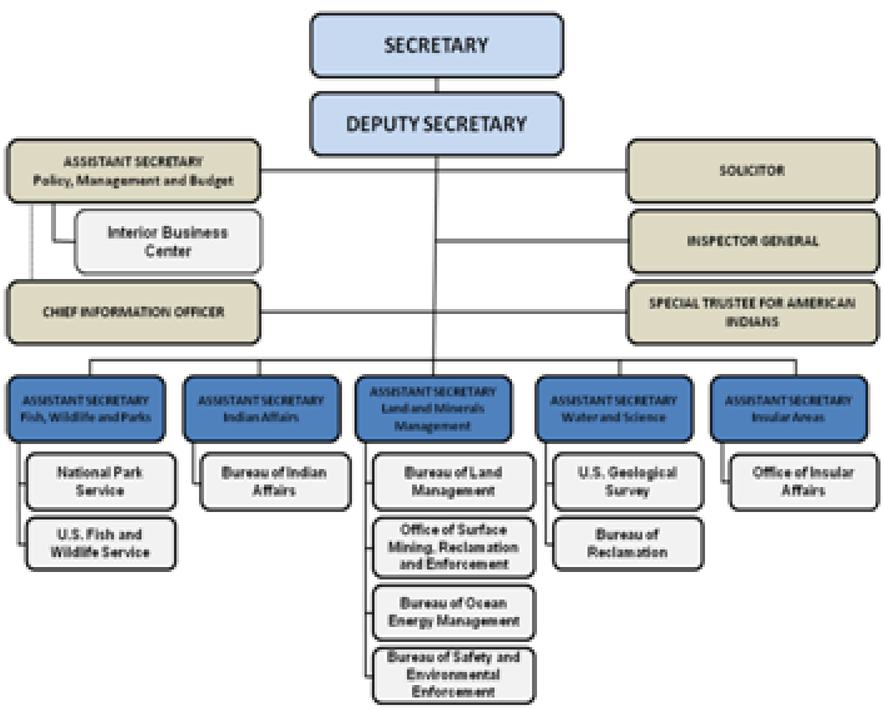
[579] In addition to the Department of the Interior, they include the Federal Bureau of Investigation, the US Forest Service, and the Department of Homeland Security, among others. *See, e.g.*, Eric Biber, Too Many Things To Do: How to Deal With the Dysfunctions of Multiple-Goal Agencies, 33 HARV. ENVT'L. L. REV. 1 (2009).

[580] For an example, see Eric Biber, Too Many Things to Do: How to Deal With the Dysfunctions of Multiple-Goal Agencies, 33 HARV. ENVT'L. L. REV. 1, 2 (2009).

[581] *Ibid*.



Structure at the time of the Macondo Incident



Structure Post-Macondo

Figure 4-1. Department of Interior organization chart: at the time of the April 20, 2010, Macondo incident and currently.

5.6.3 Critical BSEE Drilling Permit Concerns

Post-Macondo, there has been a resurgence of pressure for BSEE to approve drilling permits. In more than one committee hearing that purported to explore other topics, the focus of questioning shifted to Gulf-area congressional representatives' concerns about oil production and the pace of drilling permit review. In an October 2011 House Natural Resources committee hearing about the results of the Joint Investigation Team,[582] committee members chided then-Director Bromwich for not focusing enough on speeding up drilling permit reviews and production.[583] A few months later, after testimony before the House and Senate appropriations subcommittees in 2012, members repeatedly questioned former Director Watson about BSEE's slow pace of drilling permit approvals.[584] In episodes reminiscent of early MMS OCS subcommittee discussions, congressional representatives expressed concern about a decrease in drilling permits and about rigs "leaving our shores and going to Brazil" because the country needs to "get [offshore] production going up and prices at the pump going down."[585] Less than two years following the incident, congressional attention to safety reform was nearly eclipsed by a seeming preoccupation with the potential effects of a drilling moratorium that had been in place while the Macondo well was still leaking oil into the Gulf. Thus, the inherent conflict between production and safety remains on the shoulders of the DOI Assistant Secretary, Deputy Secretary, and Secretary, all whom also face economic development and production pressures. By remaining under the DOI umbrella, the offshore safety regulator is not truly independent from these pressures, potentially compromising major accident prevention initiatives.

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[582] As offshore safety regulators in the US, BOEMRE and USCG formed a Joint Investigation Team to investigate the Deepwater Horizon disaster. BOEMRE and the USCG published separate reports addressing their respective areas of safety responsibility; USCG, *Report of the Investigation into the Circumstances Surrounding the Explosion, Fire, Sinking and Loss of Eleven Crew Members Aboard the Mobile Offshore Drilling Unit Deepwater Horizon in the Gulf of Mexico, April 20-22, 2010*, Volume 1, MISLE Activity Number 3721503; p 127. http://www.uscg.mil/hq/cg5/cg545/dw/exhib/DWH%20ROI%20-%20USCG%20-%20April%2022,%202011.pdf (Accessed March 26, 2016).

[583] Full Committee Oversight Hearing on the BOEMRE/U.S. Coast Guard Joint Investigation Team Report, U.S. House of Representatives Committee on Natural Resources, October 13, 2011, see e.g., p 3 https://www.gpo.gov/fdsys/pkg/CHRG-112hhrg70720/pdf/CHRG-112hhrg70720.pdf (accessed March 26, 2016).

[584] House Natural Resources Subcommittee on Energy and Mineral Resources Hearing on President Obama's Fiscal 2013 Budget Proposal for the Bureau of Ocean Energy Management and Bureau of Safety and Environmental Enforcement, March 8, 2012 http://naturalresources.house.gov/calendar/eventsingle.aspx?EventID=282268 and Senate Appropriations Subcommittee on Interior, Environment and Related Agencies Hearing on the Proposed 2013 Appropriations for the Interior Department's Onshore and Offshore Energy Development Programs, March 14, 2012 http://www.appropriations.senate.gov/imo/media/doc/hearings/03_14_12%20Interior%20&%20Environment%20On&Off%20Shore%20energy%20GPO%20Record.pdf (accessed March 26, 2016).

[585] House Natural Resources Subcommittee on Energy and Mineral Resources Hearing on President Obama's Fiscal 2013 Budget Proposal for the Bureau of Ocean Energy Management and Bureau of Safety and Environmental Enforcement, March 8, 2012 http://naturalresources.house.gov/calendar/eventsingle.aspx?EventID=282268 (accessed March 26, 2016).

5.6.4 Historical Recognition for Separating Safety Oversight from Resource Development

Congress can rely on several precedents for separating safety and environmental oversight from a predecessor agency to an independent regulator. Some of the most analogous situations that resulted in legislative actions to separate safety oversight were prompted by a catastrophic incident much like Macondo. As it has done with mining and nuclear safety, Congress would need to take action to move offshore safety regulation into an independent agency separate from the Department of Interior.

5.6.4.1 Creation of the Mine Safety and Health Administration

The current Mine Safety and Health Administration (MSHA) was once the Mining Enforcement and Safety Administration (MESA), a subcomponent of the Department of the Interior. After a string of serious mining disasters in the 1970s (including Sunshine Silver, Buffalo Creek, Blacksville, and Scotia), Congress reviewed MESA's enforcement record, finding the fatality and injury numbers unacceptably high.[586] Congress determined that a conflict existed between MESA, which was responsible for enforcing and administering the mine safety and health laws, and the Department of Interior, which "pursued the goal of maximizing production."[587] Congress reasoned that separating the mine safety and health regulator from revenue-related activities would solve the problem of conflicting missions.[588] MSHA was moved to the Department of Labor because its primary mission is to keep workers safe.[589] Congress enacted the Federal Mine Safety and Health Amendments Act of 1977 to formalize MSHA's authority.[590]

5.6.4.2 Creation of the Nuclear Regulatory Commission

Just as the reorganization of MESA was prompted by a catastrophic accident, nuclear safety regulatory structures were reformed again after the Three Mile Island nuclear incident in 1979. The original Atomic Energy Commission (AEC) had three conflicting goals: managing the atomic weapons program, promoting the peaceful use of atomic power, and protecting public health and safety.[591] The AEC came under attack for its focus on developing nuclear technology and a cozy relationship with industry. Critics complained that it was "like letting the fox guard the henhouse."[592] In response, Congress split the AEC, assigning safety regulation to the new Nuclear Regulatory Commission (NRC) and placing the development and research in what is now the Department of Energy.[593] But the NRC's Reorganization

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[586] Senate Report 95-181 at 3405 (95th Congress), May 16, 1977 http://arlweb.msha.gov/SOLICITOR/COALACT/leghist2.htm (accessed March 26, 2016).

[587] *Ibid*.

[588] *Ibid*.

[589] *Ibid*.

[590] *Ibid*.

[591] Mazuzan, G.; Walker, S. *Controlling the Atom: The Beginnings of Nuclear Regulation, 1946-1962,* 1st ed.; University of California Press: 1984.

[592] *Ibid*.

[593] Energy Reorganization Act of 1974, Pub. L. No. 93-438, 88 Stat. 1233; *see also* Alice L. Buck, U.S. Dep't of Energy, A History of the Atomic Energy Commission 8 (1983) (describing history of conflict); *see also* Eric Biber, Too Many Things To Do: How to Deal With the Dysfunctions of Multiple-Goal Agencies, 33 HARV. ENV'TL. L. REV. 1, 33 (2009).

Plan No. 1 of 1980, a major overhaul of the agency, was the direct result of Three Mile Island accident. The 1980 plan established a program to integrate NRC findings about licensee performance into a public report, expanded performance-oriented and safety-oriented inspections and risk assessment, and strengthened and reorganized a separate, independent NRC enforcement office.[594]

5.6.4.3 Creation of the UK HSE Offshore Division

In the UK, the offshore regulator was initially organized within the Department of Energy—Petroleum Engineering Division. This division held responsibility for developing and enforcing health and safety regulations in addition to licensing and resource development.[595] Although the conflict between these missions was apparent before then, a 1972 inquiry identified fundamental flaws in this arrangement.[596] In 1988, the Piper Alpha disaster confirmed that a complete reorganization of offshore safety regulation was necessary.[597]

A major recommendation of the Lord Cullen report was to transfer the responsibility for offshore safety regulation from the Department of Energy to the UK's HSE. In response, the UK HSE Offshore Division was created in 1991, with sole responsibility for offshore safety oversight.[598] This separation of responsibility for regulating offshore safety from licensing and revenue collection continued in the UK ever since, despite various subsequent organizational changes. Following the recent implementation of the EU Offshore Safety Directive by the UK, the offshore regulator is now the Offshore Safety Directive Regulator (OSDR). In the US, a similar structure without inherent conflicts would strengthen BSEE in its regulatory function.

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[594] See, e.g., NRC. Backgrounder on the Three Mile Island Accident, http://www.nrc.gov/reading-rm/doc-collections/fact-sheets/3mile-isle.html#impact; Nuclear Regulatory Legislation: 113th Congress; 2nd Session (Volume 1, Number 11), http://www.nrc.gov/reading-rm/doc-collections/nuregs/staff/sr0980/v1/sr0980v1.pdf, (accessed March 26, 2016).

[595] T. Hunter and J. Paterson, Offshore Petroleum Facility Integrity in Australia and the United Kingdom: A Comparative Study of Two Countries Utilising the Safety Case Regime, Oil, Gas & Energy Law Intelligence (October 2011), p 7.

[596] *Ibid*.

[597] *Ibid*.

[598] UK HSE, Who we are, http://www.hse.gov.uk/offshore/who.htm (accessed March 26, 2016).

6.0 Conclusion

This final volume on the Macondo blowout focuses on several key attributes of more robust process safety management regulatory regimes that the CSB believes would enhance existing US offshore regulations. Many of the attributes of an effective goal-setting, risk-reduction regime focused on major accident prevention were not present pre-Macondo, and recent changes to the US offshore regulator's organization and regulations, particularly the establishment of SEMS, do not go far enough to ensure effective industry management and control of major hazards or prevent possible future Macondo-type incidents. Specifically, the US offshore regulatory regime does not adequately put the onus on industry to minimize risk and empower the regulator proactively to ensure effective industry management and control of major hazards.

The CSB finds that more robust US and international regimes focus on major accident prevention and continual improvement and they identify gaps and weaknesses that were causal to the Macondo incident. When taken together:

- Foster continual improvement by requiring companies to reduce their risks through goal-setting risk reduction techniques such as ALARP;
- Cultivate more adaptability;
- Clarify safety responsibility to focus accountability on key parties such as leaseholder/operator and drilling contractor that create or control major accident risks;
- Create opportunities for active workforce participation;
- Require written safety documentation by duty holders;
- Require proactive regulatory assessment and verification;
- Establish and use helpful process safety indicators to drive performance;
- Employ appropriately trained and experienced regulatory staff; and
- Feature a transparent, independent, and well-resourced regulator.

Collectively, these attributes provide the foundation for a more robust goal-setting risk-reduction regulatory model for US offshore drilling and production operations. Based upon its analysis of other high-hazard industries that use similar performance-based regulations, as well as other offshore regimes, the CSB concludes that augmenting the current US offshore regulatory model will better ensure major accident risk reduction.

7.0 Recommendations

The CSB issues four recommendations to the US Department of Interior for additional improvements in offshore safety.

CSB2010-10-I-OS-R11 Recommends Revision to the Offshore Safety Regulations to Establish a Regulatory Framework with a Specific Goal Of Preventing Major Accidents Based on the Attributes Described in CSB Macondo Investigation Report Volume 4.

United States Department of Interior

Revise and augment the offshore safety regulations, including the SEMS Rule (C.F.R. 250 subpart S), and issue guidance as it relates to those revisions/augmentations, to:

a. Establish clear and consistent safety and environmental management responsibilities to prevent major accidents for the companies having primary control over the hazardous activities being undertaken (e.g., the owner/drilling contractor for a non-production installation and the leaseholder/operator for the production installation);
b. Require all responsible parties as defined in R11(a) to develop documentation for each hazardous operation/facility it maintains primary control over, where the documentation demonstrates the party's systematic analysis that risks posed by all identifiable major accident hazards are reduced to As Low As Reasonably Practicable (ALARP) or similar risk-reduction target. The documentation shall include:
    1. Identification of major hazards and the barriers and safety management systems controls (including augmented SEMS elements) that will be used to reduce risk to ALARP or similar risk reduction target;
    2. Use of the hierarchy of controls to the greatest extent feasible in establishing safety barriers and controls;
    3. Identification of safety critical elements and tasks to establish and maintain safety barriers and controls, in fulfillment of R1 (See Volume 2);
    4. Demonstrate use of established qualitative, quantitative and semi-quantitative methods in determining (1) the barriers and safety management systems necessary to achieve ALARP risk reduction levels and (2) the performance requirements of those barriers and controls (e.g., reliability, functionality, and availability) to ensure their effectiveness;
    5. Identification of all US and international standards that have been applied, or will be applied, in relation to the facility, hazardous operation, or equipment used on/in connection with the operation for which required documentation is submitted. Should the responsible party wish to use standards other than well-recognized US or international consensus safety standards developed by a representative committee of diverse stakeholders, a detailed technical justification that those standards achieve risk-reduction to ALARP must accompany submitted documentation. The regulator may challenge or reject the technical justification. Remove from the US offshore safety regulatory scheme

the provisions that allow companies to substitute requirements to use the best available and safest technology with a showing of compliance with BSEE regulations.

c. Require responsible parties as defined by R11(a) to fully implement all aspects of the documentation stipulated in R11(b) and establish a documented process to verify that all methods to manage, reduce, and control those hazards are effectively maintained throughout the lifecycle of the operation/facility.

CSB2010-10-I-OS-R12 Recommends Strengthening Preventative Oversight by the Offshore Safety Regulator

United States Department of Interior

Augment the capabilities and functioning of BSEE to incorporate the following proactive oversight mechanisms:

a. Review of the documentation required to be submitted under CSB 2010-I-OS-R11(b) by technically qualified regulatory personnel who have the capability and authority to require modifications and improvements to the major hazards report as necessary, either before an acceptance process and commencement of the major hazards operation(s) or during periodic proactive review by the regulator;
b. Establish a program for preventive, comprehensive inspections and audits with technically qualified staff as described in R13(a) to ensure that the responsible party as defined in R11(a) can demonstrate the risk reduction commitments stipulated in its major hazards report.

CSB2010-10-I-OS-R13 Recommends Continued Efforts to Develop a Sufficiently Resourced, Technically Qualified, and Diverse Staff

United States Department of Interior

Further enhance the qualifications, professional competency, and diversity of BSEE staff to implement major accident prevention programs by:

a. Continuing efforts to enhance recruiting and retention of sufficient staff with a diversity of expertise, professional backgrounds and skill sets, such that BSEE has staff competencies in a variety of safety-critical and technical areas, including petroleum, chemical, and mechanical engineering; human and organizational factors; well design and control; and process safety, as well as those with industry experience to perform an even more expanded mission as envisioned in this report;
b. Retaining the services of a human resources consulting firm to complement BSEE's efforts to date on human capital management and workforce planning issues, in light of documented difficulties in recruiting and retaining necessary staff, including the development of a plan with respect to large numbers of retirements facing the agency in the coming decade, as well as a compensation analysis (and a plan for subsequent periodic market analyses and benchmarking) to ensure BSEE remains competitive with other employers in the offshore industry. Augment the agency's compensation system as necessary to enable BSEE to attract and retain the level of staffing needed to perform BSEE's mission.

c. Continuing to assess, expand, and improve ongoing BSEE training programs for new hires to provide all employees with robust skill sets, including appropriate technical training as well as interpersonal skills such as communications, negotiation and advocacy.

If funding, legislative authority, or other approvals are required to implement the recommended regulatory provisions in Recommendation R11 – R13, the Secretary of the Interior shall seek such authority from Congress or expedited hiring authority from the Office of Personnel Management.

CSB2010-10-I-OS-R14 Recommends Improving the Regulatory Reporting Program to Drive Continual Safety Improvement of Industry

United States Department of Interior

Expand the offshore safety regulatory program that collects, tracks, and analyzes safety performance indicators from industry to further influence industry efforts in reducing major accident risks to ALARP. At a minimum, this program shall:

a. Require the reporting of safety indicator data by all responsible parties, as defined in R11(a);
b. Emphasize the greater preventive value of using leading indicators to actively monitor the health and performance of major accident safety barriers and the management systems meant to ensure their effectiveness, and work with industry to develop leading indicators that are measurable, actionable, normalized across industry, and that occur with sufficient frequency to allow for meaningful trending and analysis at the facility and corporate levels;
c. Augment current reporting requirements to include leading safety performance indicators;
d. Use the safety performance indicator data to:
    1. identify industrywide, companywide, and facility-specific safety trends and deficiencies;
    2. set annual process safety goals or targets for the industry, company and/or facility, as appropriate, based upon those identified safety trends and deficiencies;
    3. issue, at a minimum, annual reports that publicly communicate those trends, deficiencies, targets, and goals; and
    4. determine future appropriate allocations of BSEE resources and the prioritization of BSEE inspections;
e. Include use of significant lagging indicators data (including those already mandated by 30 C.F.R. 250.188(a) and (b), such as major events like explosions, fires, gas releases, fatalities, INCs) as qualification criteria in the lease-approval and permit-to-drill decision-making processes by the regulator.

CSB2010-10-I-OS-R15 Recommends Strengthening Regulatory Requirements for Worker Engagement in the Management of Safety

United States Department of Interior

Issue participation regulations and training requirements for workers and their representatives that include the following:

a. Worker-elected safety representatives and safety committees for each staffed offshore facility chosen under procedures overseen by the regulator; these safety representatives will have the authority to interact with employers (such as operators and drillers) and regulators on issues of worker health and safety risks and the development and implementation of the major hazard report documentation;

b. The elected worker representative has the right to issue an enforceable stop-work order if an operation or task is perceived as unsafe; all efforts should be made to resolve the issue at the workplace level, but if the issue remains unresolved, BSEE shall establish mechanisms such that the worker representative has the right and ability to seek regulator intervention to resolve the issue, and the regulator must respond in a timely fashion;
c. The regulator will host an annual tripartite forum for workforce representatives, industry management, and the regulator to promote opportunities for interaction by all three entities on safety matters and to advance initiatives for major accident prevention.
d. Protections for workers participating in safety activities with a specific and effective process that workers can use to seek redress from retaliatory action with the goal to provide a workplace free from fear that encourages discussion and resolution of safety issues and concerns. Protected activities include, but are not limited to reporting unsafe working conditions, near misses, and situations where stop work authority is used.

CSB2010-10-I-OS-R16 Recommends Incorporating API 75 by Reference upon Revision in Response to CSB Recommendation R11

United States Department of Interior

Incorporate by reference into the offshore safety regulations the revised version of Recommended Practice 75, *Development of a Safety and Environmental Management Program for Offshore Operations and Facilities, 3rd Ed.*, May 2004 (reaffirmed May 2008) upon the inclusion of the CSB recommendations in R11 by API.

Appendix A: International Offshore Incidents and the US Response

Alexander Kielland and Regulatory Change in Norway

On March 27, 1980, the Alexander L. Kielland installation capsized in the North Sea, killing 123 of the 212 people on board.[599] The incident had a dramatic impact on the offshore industry and the Norwegian regulator, which was called the Norwegian Petroleum Directorate.[600] The day after the incident, a Commission was appointed to determine the causes of the accident and recommend actions to prevent similar incidents.[601] The Commission's final report identified weaknesses in Norwegian inspection routines, safety training, and technical expertise in rescue equipment.[602] It also recommended centralizing regulatory authority and finalizing the Petroleum Activities Act, which licensed internal controls for offshore operations and implemented risk-analysis requirements.[603]

By the mid- to late-1980s, dramatic changes took place for the regulator and the overall management of major accident risk. New regulations and requirements were established for companies operating offshore to develop and implement internal control plans for safety management, which required regulatory approval.[604] The aim of these regulatory changes was to shift from adherence to prescriptive requirements to a more comprehensive understanding of risk.[605] In addition to centralizing regulatory authority, new concepts were introduced, including a "compliance responsibility" whereby companies were required to verify acceptable risk management.[606]

The Norwegian government began to consider its role as supervisor instead of inspector of the offshore industry.[607] The regulator began interacting with industry professional associations and studies, adding to

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599 Norwegian Public Reports, Presented to Ministry of Justice and Police (March 1981), NOU 1981: 11 "The Alexander L. Kielland accident" p 9.

600 Melberg , E. Determined to learn from history. August 13, 2010, http://www.npd.no/en/publications/norwegian-continental-shelf/no1-2010/determined-to-learn-from-history/ (accessed 31 2013, October).

601 Norwegian Public Reports, Presented to Ministry of Justice and Police (March 1981), NOU 1981: 11 "The Alexander L. Kielland accident" pp 1-2.

602 PSA. From prescription to performance in petroleum supervision. March 12, 2010, http://www.ptil.no/news/from-prescription-to-performance-in-petroleum-supervision-article6696-878.html (accessed October 31, 2013).

603 *Ibid.*

604 Committee on Alternatives of Inspection of Outer Continenetal Shelf Operations, Marine Board, Commission on Engineering and technical Systms National Reserach Council. *Alternatives for Inspecting Outer Continental Shelf Operations* [Online]; National Academy Press: Washington, 1990; p 111, http://www.nap.edu/download.php?record_id=1517 (accessed March 26, 2016).

605 Melberg , E. Determined to learn from history. August 13, 2010, http://www.npd.no/en/publications/norwegian-continental-shelf/no1-2010/determined-to-learn-from-history/ (accessed 31 2013, October).

606 PSA. From prescription to performance in petroleum supervision. March 12, 2010, http://www.ptil.no/news/from-prescription-to-performance-in-petroleum-supervision-article6696-878.html (accessed October 31, 2013).

607 *Ibid*.

its audit, verification, investigation and consideration responsibilities.[608] Additionally, it began issuing "consents" to operate in lieu of "approvals."[609] These shifts helped the Norwegian offshore regulator transform from a compliance-based regime that shifted some of the responsibility for safety from the regulator into a goal-based regime that allowed industry to determine how best to meet those goals.[610]

Ocean Ranger and Regulatory Change in Canada

The *Ocean Ranger* drilling rig capsized off the Canadian coastal region of Newfoundland during a severe storm with hurricane-force winds, ending 84 lives.[611] A Royal Commission on the Ocean Ranger Marine Disaster formed to investigate the incident found the prescriptive offshore regulatory regime overly complex and inadequately enforced. Recommendations from the Commission's resulting two reports involved consolidation of regulatory powers under a single body.[612] At the time of the incident, the Canada Oil and Gas Lands Administration, Newfoundland Labrador Petroleum Directorate, and the US Coast Guard all held some regulatory authority over the Ocean Ranger's drilling operation.[613] In 1985, the Canada-Newfoundland Offshore Petroleum Board was formed to centralize regulatory authority.[614] As offshore development continued to grow into more complex and challenging geographical locations, the offshore safety regulators for Canada's eastern provinces, the Nova Scotia and Newfoundland Labrador Offshore Petroleum Boards, worked with the Norwegians to implement changes they considered necessary to safely develop their resources.[615] They have replaced many of their prescriptive offshore regulations for goal-based rules, moving much of their prescription to guidance documents. The boards recognized that this fundamental change allowed for the regulator not only to keep step with industry advances, but also to demand continual safety improvement from industry without rule-making.[616]

[608] *Ibid*.

[609] *Ibid*.

[610] Melberg , E. Determined to learn from history. August 13, 2010, http://www.npd.no/en/publications/norwegian-continental-shelf/no1-2010/determined-to-learn-from-history/ (accessed 31 2013, October).

[611] Higgins, J. Response to the Ocean Ranger Disaster. *Newfoundland and Labrador Heritage*, 2012, http://www.heritage.nf.ca/articles/politics/ocean-ranger-disaster-response.php (accessed December 17, 2014).

[612] *Ibid*. This regulatory body is now known as the Canada-Newfoundland and Labrador Offshore Petroleum Board. There is also a Canada-Nova Scotia Offshore Petroleum Board which regulates offshore oil and gas industry safety for the Nova Scotia and frontier lands and a National Energy Board, which regulates offshore areas not otherwise covered by provincial or federal management systems. http://www.neb-one.gc.ca/clf-nsi/rthnb/whwrndrgvrnnc/nbfctsht-eng.html (accessed January 26, 2016).

[613] The Ocean Ranger was owned by Ocean Drilling and Exploration Company, an American corporation that had been contracted by Mobil Oil to drill; Higgins, J. Response to the Ocean Ranger Disaster. *Newfoundland and Labrador Heritage*, 2012, http://www.heritage.nf.ca/articles/politics/ocean-ranger-disaster-response.php (accessed December 17, 2014).

[614] *Ibid*.

[615] Trip notes from CSB meeting with the Canada Newfoundland and Labrador Offshore Petroleum Board (CNLOOPB), St. John's, Newfoundland, Canada (March 7, 2011).

[616] *Ibid*.

Piper Alpha and Regulatory Change in the United Kingdom

On July 6, 1988, an explosion occurred aboard the Piper Alpha oil production platform 120 miles off the coast of Scotland in the North Sea.[617] A series of explosions and fire killed 167 workers and almost completely destroyed the platform. This accident is the deadliest in the history of the offshore operations.[618] Multiple systemic, organizational, and regulatory deficiencies caused the incident.[619]

The UK government conducted an inquiry that called into question the adequacy of the detailed prescriptive regulatory regime that existed at the time of the incident.[620] Lord Cullen, the judge leading the inquiry, listed 106 recommendations to revamp offshore safety regulation in the UK, which included a recommendation for the responsible party providing a written case for safety identifying the hazards and demonstrating the adequacy of the safety management systems in place to control for each hazard at every offshore site.[621]

The intent of the safety case was to shift the responsibility for identifying and mitigating hazards and risks from the regulator to the duty holder.[622,623] Lord Cullen reasoned that "a regulator cannot be expected to assume direct responsibility for the on-going management of safety. … this is and remains in the hands of the operator."[624] The UK government accepted all of the 106 recommendations,[625] ushering in new goal-setting regulations to replace the existing prescriptive ones.[626] The Offshore Installations (Safety Case) Regulations came into force in 1992. By November 1993, a safety case for every installation had been submitted to the HSE, and by November 1995, all had had their safety case accepted by the HSE.

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617 Department of Energy. *The Public Inquiry into the Piper Alpha Disaster; Presented to Parliament by the Secretary of State for Energy by Command of her Majesty*. November, 1990.

618 John M.T. Balmer, The BP Deepwater Debacle and Corporate Brand Exuberance, 18 J. Brand Mgmt. 97, 100 (2010).

619 Department of Energy. *The Public Inquiry into the Piper Alpha Disaster; Presented to Parliament by the Secretary of State for Energy by Command of her Majesty*. November, 1990; pp 121-22.; John Paterson, The Significance of Regulatory Orientation in Occupational Health and Safety Offshore, 38 B.C. Envtl. Aff. L. Rev. 369 (2011), http://lawdigitalcommons.bc.edu/ealr/vol38/iss2/8 (accessed March 26, 2016).

620 T. Hunter; J. Paterson; "Offshore Petroleum Facility Integrity in Australia and the United Kingdom: A Comparative Study of Two Countries Utilising the Safety Case Regime" OGEL 6 (2011); p 9.

621 *Ibid*.

622 Duty holders are considered to be "those who create and/or have the greatest control of the risks associated with a particular activity. Those who create the risks at the workplace are responsible for controlling them." HSE. *Planning to do business in the UK offshore oil and gas industry? What you should know about health and safety;* October 2011; p 2. These entities may include operators, contractors, and subcontractors. http://www.hse.gov.uk/offshore/guidance/entrants.pdf (accessed June 5, 2013).

623 T. Hunter; J. Paterson; "Offshore Petroleum Facility Integrity in Australia and the United Kingdom: A Comparative Study of Two Countries Utilising the Safety Case Regime" OGEL 6 (2011); p 9-10.

624 *Ibid*.

625 180 Parl. Deb., H.C. (6th ser.) (1990) 329-45; John Paterson, The Significance of Regulatory Orientation in Occupational Health and Safety Offshore, 38 B.C. Envtl. Aff. L. Rev. 369 (2011), http://lawdigitalcommons.bc.edu/ealr/vol38/iss2/8 (accessed March 26, 2016).

626 John Paterson, The Significance of Regulatory Orientation in Occupational Health and Safety Offshore, 38 B.C. Envtl. Aff. L. Rev. 369 (2011), http://lawdigitalcommons.bc.edu/ealr/vol38/iss2/8 (accessed March 26, 2016).

The Safety Case Regulations require the duty holder of every installation operating in UK waters to submit a safety case to HSE for acceptance. The safety case must fully explain the duty holder's plans for managing health and safety and controlling major accident hazards on the installation.[627] It must demonstrate that the company has established safety management systems, identified risks and reduced them to as low as reasonably practicable, introduced management controls, provided a temporary safe refuge on the installation, and provided for safe evacuation and rescue.[628] Duty holders are required to revise and update their safety cases as needed throughout the life cycle of their installation.

Outside the UK, other regulators also heeded the Cullen Report recommendations. A few months after the incident, Australia formed the Consultative Committee on Safety in the Offshore Petroleum Industry to advise the Minister for Resources on safety issues related to Australia.[629] The Committee recommended that the key outcomes of the UK Piper Alpha inquiry be implemented in Australia, and regulatory reform ensued that made the safety case a requirement for offshore.[630] The UK Safety Case Regulations were revised in 2005 to improve their effectiveness and reduce the burden of three yearly resubmissions.

Montara and Regulatory Change in Australia

On August 21, 2009, approximately six months prior to the Macondo incident, the Montara Wellhead Platform suffered a blowout in the Timor Sea off the coast of Australia.[631] The Montara rig caught fire and a well leaked tens of thousands of barrels of oil over two-and-a-half months before it was shut down.[632] Although it was similar to the Macondo event in many ways, including well capping and misunderstandings about cement,[633] this blowout did not result in any fatalities. At the time of the Montara incident, Australia was already using a goal-setting regulation that required operating companies to set their own standards based on the hazards and risks posed by their activities, and then follow through on their commitment.[634] The duty holder on the Montara platform failed to comply with its own well construction standards (WCS) in numerous ways, including (1) failure to test the cemented casing shoe and subsequent reliance on this untested barrier, (2) reliance on pressure containing corrosion caps (PCCCs) as a well barrier when these are not approved in the WCS, (3) failure to install sufficient barriers to meet the requirements for long-term suspension of the well, and (4) failure to monitor completion fluid

[627] Oil & Gas UK. *Piper Alpha Lessons Learnt;* 2008; p 5. http://oilandgasuk.co.uk/wp-content/uploads/2015/05/HS048.pdf (accessed 26 2016, March).

[628] *Ibid*.

[629] Patrick Brazil and Peter Wilkinson, The Establishment of a National Offshore Petroleum Safety Authority (2005) 24 Australian Resources and Energy Law Journal 87, pp 88-89.

[630] T. Hunter; J. Paterson; "Offshore Petroleum Facility Integrity in Australia and the United Kingdom: A Comparative Study of Two Countries Utilising the Safety Case Regime" OGEL 6 (2011); pp 15-16.

[631] Montara Commission of Inquiry. *Report of the Montara Commission of Inquiry;* Commonwealth of Australia 2010: June, 2010; http://www.iadc.org/wp-content/uploads/2016/02/201011-Montara-Report.pdf (accessed March 26, 2016).

[632] *Ibid*., p 38.

[633] Hayes, J. Operator competence and capacity – Lessons from the Montara blowout; *Safety Science* **2012,** *50*, pp 563-574.

[634] *Ibid.*

parameters to ensure overbalance and subsequent reliance on this unmonitored barrier during temporary suspension.[635]

As a result of the accident, the Australian government organized an inquiry to identify the likely causes of the release, including regulatory failures.[636] The Australian government report confirmed that the blowout was immediately caused by the failure of the primary well control barrier—the cement casing shoe.[637] In addition, the report also criticized the operator's reliance on improper secondary well control barriers, inadequate well management plans, improper pressure testing, and inexperienced personnel.[638] The Montara blowout was the worst of its kind in Australia's offshore industry history.[639] The inquiry helped the Australian government realize that the provincial regulation of offshore safety was inadequate for preventing major accident. In other words, no problem was uncovered concerning the quality of the well-integrity regulations, but a failure of the provincial regulator (the Northern Territory) to adequately enforce the existing regulations, primarily based on the authority being too trusting of industry. It has since implemented changes to bring offshore operations under the purview of NOPSEMA, a national agency with the necessary resources to enforce existing regulations more effectively.

History of Regulatory Change in the US

The lessons learned from major industrial accidents helped shape the major hazard regulatory regimes around the world, both on and offshore. In most cases, post-accident regulatory changes involved replacing compliance-based regulations with performance-based, goal-setting risk-reduction models that support adaptability and continued risk-reduction to as low as reasonably practicable (ALARP) or some roughly equivalent standard, while providing the regulator with the needed resources and tools to drive continual improvement among major hazard facilities.

For example, the international offshore energy industry experienced several catastrophic accidents in the 1980s, including the *Alexander Kielland* in Norway in 1980, the *Ocean Ranger* in Canada in 1982 and *Piper Alpha* in the UK in 1988. These accidents prompted significant shifts in the offshore regulatory structures of Norway, Canada, the UK, and Australia from prescriptive compliance-based regulation to performance-based goal-setting models. The CSB's Chevron Regulatory Report also provides a helpful discussion of the accidents that spurred global development of the safety case regulatory regime for onshore and offshore major hazards.[640]

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[635] *Ibid.*

[636] Peter Wilkinson presentation on Montara to CSB, July 2011 (slide 14).

[637] Montara Commission of Inquiry. *Report of the Montara Commission of Inquiry;* Commonwealth of Australia 2010: June, 2010; p 7. http://www.iadc.org/wp-content/uploads/2016/02/201011-Montara-Report.pdf (accessed March 26, 2016).

[638] *Ibid*., pp 7-11.

[639] *Ibid*., p 5.

[640] USCSB, 2013. *Regulatory Report: Chevron Richmond Refinery Pipe Rupture and Fire, Richmond, CA, August 6, 2012*, Report No. 2012-03-I-CA, April 2013, http://www.csb.gov/assets/1/19/Chevron_Regulatory_Report_11102014_FINAL_-_post.pdf (accessed January 25, 2016). See Chapter 3 for a helpful discussion of the accidents that spurred global development of the safety case regulatory regime for onshore and offshore major hazards.

At the time of the Alexander Keilland accident in 1980, the US GoM OCS region still consisted of shallow-water (defined here as less than 1,000 feet) exploration, drilling, and production operations, though some offshore drilling operations reached depths of approximately 1,500 feet in the California OCS as early as 1975, which were considered "deepwater" drilling operations at the time.[641] The GoM also enjoys more hospitable weather, as well as calmer seas, minus the occasional hurricane, and warmer temperatures than the North Sea. Thus, it is perhaps not surprising that lessons learned overseas in foreign offshore oil-producing jurisdictions did not result in full-scale changes to the US offshore regulatory regime, especially with an accident such as the Alexander Keilland which was not a drilling platform or vessel but an accommodations vessel. Drilling and production regulations in the US thus remained prescriptive and focused heavily on equipment rather than on hazard assessments and safety management systems.

Yet a decade later, regulatory changes did not keep pace with changes in the field, as the US GoM OCS industry began exploring deeper waters, encountering ever more complex subsea geology and higher pressures during more dangerous drilling operations.[642] Approximately one year after the Piper Alpha incident, when the US experienced its own major offshore event—a 1989 explosion at the ARCO platform in the Gulf of Mexico resulting in 7 fatalities[643]—MMS commissioned a task force to review its regulatory program. It also requested that the Marine Board of the National Research Council recommend improvements in MMS's operational safety and environmental protection inspection practices.[644]

The National Research Council Marine Board, referencing Piper Alpha, recommended adopting a more systems-based risk analysis focused on human factors, operational procedures, and modifications of equipment and facilities rather than adding equipment-specific prescriptive regulations.[645] The Marine Board report identified that MMS's prescriptive approach to regulating offshore operations actually forced industry into a compliance mentality that did not promote effective risk identification or comprehensive accident mitigation.[646] The Board highlighted its long-held belief that the offshore regulatory regime should itself evolve by exploring different inspection, enforcement, and compliance

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[641] National Commission on the BP Deepwater Horizon Oil Spill. *A Brief History of Offshore Oil Drilling;* Staff Working Paper No. 1; August, 2010; http://cybercemetery.unt.edu/archive/oilspill/20121211011815/http:/www.oilspillcommission.gov/sites/default/files/documents/A%20Brief%20History%20of%20Offshore%20Drilling%20Working%20Paper%208%2023%2010.pdf (accessed March 26, 2016).

[642] Hopkins, A. *Disastrous Decisions;* CCH Australia: Australia, 2012; p 138.

[643] E.P. Danenberger et al., Investigation of March 19, 1989 Fire, South Pass Block 60 Platform B, Lease OCS-G 1608, OCS Report MMS 90-0016 (New Orleans: U.S. Dept of the Interior, MMS, April 1990), p 15, as cited in National Commission on the BP Deepwater Horizon Oil Spill and Offshore Drilling. *Deep Water: The Gulf Oil Disaster and the Future of Offshore Drilling*; 2011; p 70. It is important to note that the ARCO incident involved shallow-water drilling at approximately 200 feet below sea level. See http://incidentnews.noaa.gov/incident/6687 (accessed March 26, 2016).

[644] Committee on Alternatives of Inspection of Outer Continenetal Shelf Operations, Marine Board, Commission on Engineering and technical Systms National Reserach Council. *Alternatives for Inspecting Outer Continental Shelf Operations* [Online]; National Academy Press: Washington, 1990; p v, http://www.nap.edu/download.php?record_id=1517 (accessed March 26, 2016).

[645] *Ibid*., p 83.

[646] *Ibid*.

approaches.[647] For example, the Board found that MMS's program at the time "incorporates no mechanism or analytical basis for systematically upgrading safety requirements for OCS operations."[648] Specifically, the Board found that MMS failed to:

- analyze data to identify safety trends;
- collect data consistently across operators and facilities that would permit such analyses;
- document operator safety histories; or
- cross-reference PINCs (potential incidents of non-compliance) and incidents of noncompliance (INCs) to events (accidents).[649]

The Board recommended that MMS enhance its collection and analysis of safety-related data to "permit systematic targeting of spot inspections, and … to support a variety of continuing safety analysis to be used to improve safety and environmental protection on the OCS."[650] The Board noted these activities were "essential to an ongoing 'risk assessment and management' program."[651] It recommended that MMS emphasize "detection of potential accident-producing situations—particularly those involving human factors, operational procedures and modifications of equipment and facilities—rather than scattered instances of non-compliance and hardware specifications."[652]MMS was not slow to act on the Board's recommendations, perhaps because, along with the US Coast Guard, it was preoccupied with the effects of the Exxon Valdez oil spill, in March 1989.[653]

Two years later, in 1991, MMS introduced a regulatory model for offshore safety management, the Safety and Environmental Management Program (SEMP).[654] Industry pushback led to SEMP stagnating and it became a voluntary program whereby MMS asked offshore operators[655] to adopt active safety and environmental management approaches in their operations.[656]

Before the Macondo incident, MMS maintained an insular view of learning from international accidents. In particular, eight months prior to the Macondo incident, MMS largely disregarded the causes of a blowout in Australian waters from the Montara Wellhead Platform.[657] Especially concerning about this

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[647] *Ibid*., p v.

[648] *Ibid*., p 81.

[649] *Ibid*., p 81.

[650] *Ibid*., p 75.

[651] *Ibid*., p 75.

[652] *Ibid*, p 83.

[653] On March 24, 1989, the tanker *Exxon Valdez* grounded on Bligh Reef in Alaska's Prince William Sound, rupturing spilling nearly 11 million gallons of Prudhoe Bay crude oil into the Sound. Before the 2010 *Deepwater Horizon* oil spill, it was the largest single oil spill in US coastal waters.

[654] Oil and Gas and Sulphur Operations in the Outer Continental Shelf, 56 Fed. Reg. 30400 (Notice, July 2, 1991).

[655] "Operators" as referenced in US offshore regulations refer explicitly to the leaseholders of the well; this term does not include drilling contractors or other well service providers.

[656] Oil and Gas and Sulphur in the Outer Continental Shelf (OCS)—Safety and Environmental Management Systems, 71 Fed. Reg. 29278 (Advanced Notice of Proposed Rulemaking, May 22, 2006).

[657] U.S. Chemical Safety and Hazard Investigation Board interview of former MMS Director, April 5, 2011; Montara Commission of Inquiry. *Report of the Montara Commission of Inquiry;* Commonwealth of Australia 2010: June, 2010; p 7. http://www.iadc.org/wp-content/uploads/2016/02/201011-Montara-Report.pdf (accessed March 26, 2016).

Offshore Operators Historically Opposed SEMP Due to Its Prescriptive Nature

Industry opposition to SEMP's incorporation as regulation, as documented in public comment (excerpted below) submitted during consideration of the issue, revealed industry's concerns about the limiting and compliance-based nature of a prescriptive regime. These concerns could be ameliorated by supplementing the existing regulatory structure with the attributes identified in this volume...

"As MMS has noted, most industrial accidents and spill result from human error or organizational errors, not device or equipment failures and we agree. So, the question is, How do we overcome human error? It is difficult for us to see how a mandatory, highly prescriptive program proposed in the rulemaking will overcome human error." — Offshore Operators Committee, OOC/API Comments on Proposed Subpart S-SEMS, RIN 1010-AD 15; FR Vol. 74, No. 115, (June 17, 2009).

"While BP is supportive of companies having a system in place to reduce injuries, risks, accidents and spills, we are not supportive of the extensive, prescriptive regulations proposed in this rule." — BP America[a]

"The proposed rule takes the approach of incorporating API RP 75 into the regulation and then rewords the requirements. Complicating these proven processes with additional prescriptive requirements may be detrimental to the overall implementation and will take away from the key elements of an integrity management system." — Exxon Mobil[b]

[a] Comment on Proposed Rule (74 Fed. Reg. 1010-AD15), from Richard Morrison, BP, to MMS, (September 19, 2009).
[b] Comment on Proposed Rule (74 Fed. Reg. 1010-AD15) from Jonathan Armstrong, Exxon, to MMS (September 14, 2009).

situation were the similarities between that incident and Macondo,[658] and despite differences in the regulatory framework between the two countries, and some differences in the operations, sufficient similarities between Montara and Macondo blowouts made Montara a missed learning opportunity for MMS. For example, the failure of the cement to seal in the well, improper pressure testing, and reliance on limited and compromised (or missing) barriers all presented MMS with opportunities to study a major offshore accident. This could have aided MMS in identifying potential deficiencies in the US regulatory system, or in sharing some lessons learned with industry to enhance major accident prevention in US waters.

MMS might have learned lessons from Montara if it had mechanisms for assessing major incidents and implementing needed changes from the lessons learned. But MMS lacked those mechanisms. Despite the enormous concern in Australia about the Montara incident, the Director of MMS at the time said, "what had happened in Australia was not going to happen here."[659] She also reported the US had little to learn

[658] National Commission on the BP Deepwater Horizon Oil Spill and Offshore Drilling. *Deep Water: The Gulf Oil Disaster and the Future of Offshore Drilling*; 2011; p 125 and 327.

[659] U.S. Chemical Safety and Hazard Investigation Board interview of former MMS director, April 5, 2011.

from the event because Australia's offshore regulatory standards were not as strong as those in the US.[660] The CSB observed that such statements from MMS offshore regulatory personnel made during interviews reflected an agency that was not attuned to learning best-practice lessons from other jurisdictions and lacked a broader continual learning philosophy aimed at major accident prevention and continued improvement. Rather, at the time of the Montara incident, MMS appeared to focus more on issues such as offshore production and oil and gas royalty revenue collection than on major accident prevention.[661] Thus, notwithstanding Montara, it took the Macondo disaster to spur increased dialogue regarding safety management offshore in the US.

History demonstrates that the broad lessons of Macondo were not new. While other regimes made drastic changes to their regulatory frameworks after major offshore accidents, it was not until the US had an accident in its own waters that change was spurred. In a break from the past, and in an effort to prevent similar incidents, the US offshore regulatory regime reorganized and introduced new safety regulations beginning in 2010 in the aftermath of Macondo.

Two months after the Macondo incident, MMS was renamed the Bureau of Ocean Energy Management, Regulation and Enforcement (BOEMRE). On October 1, 2010, the revenue collection arm of the former MMS moved to its own office, the Office of Natural Resources Revenue.[662] In October 2011, then-Department of Interior Secretary Salazar created the Bureau of Ocean Energy Management (BOEM) and BSEE from the former BOEMRE.[663] BOEM, with leasing responsibilities, and BSEE, with environmental and safety responsibilities,[664] both report to the same Assistant Secretary for Land and Minerals Management, and the heads of these two bureaus still report to Secretary of the Interior.[665] According to communications from former Secretary Salazar and the Department of the Interior, however, this restructuring had been intended to eliminate conflicts associated with the differing missions of promoting resource development, enforcing safety regulations, and maximizing revenue from offshore oil and gas development.[666]

The reorganization was in line with the Presidential Oil Spill Commission's recommendation to create "an independent agency within the Department of the Interior with enforcement authority to oversee all aspects of offshore drilling safety."[667] The Presidential Commission's recommendation did not resolve the

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[660] *Ibid*.

[661] U.S. Chemical Safety and Hazard Investigation Board interview of former MMS director, April 5, 2011. Issues included (1) an offshore renewable energy program, (2) five-year plans for offshore oil and gas production under the OCSLA, (3) environmental sensitivity analysis for the current five-year plan, and (4) ongoing issues about oil and gas royalty revenue collection.

[662] Fact Sheet, BSEE and BOEM Separation: An Independent Safety, Enforcement and Oversight Mission (January 19, 2011). http://www.bsee.gov/uploadedFiles/BOEMRE%20Reorganization%20Fact%20Sheet(1).pdf (accessed March 26, 2016).

[663] *Ibid*.

[664] The US Coast Guard shares responsibility with BSEE for regulating safety and the environment offshore.

[665] Secretarial Order No. 3299 (May 19, 2010).

[666] BSEE. *The Reorganization of the Former MMS.* http://www.bsee.gov/About-BSEE/BSEE-History/Reorganization/Reorganization/ (accessed March 26, 2016).

[667] National Commission on the BP Deepwater Horizon Oil Spill and Offshore Drilling. *Deep Water: The Gulf Oil Disaster and the Future of Offshore Drilling*; 2011; Recommendation A4; p 256. Both the US Coast Guard (regulates safety of navigation and environmental protection on OCS units and vessels) and BSEE have shared

inherent problems associated with the Secretary of Interior's continued responsibility for missions that often conflict with one another. The Department of the Interior retains offshore production and revenue collection authority. In addition, the various bureaus and services that compose the Interior Department are not independent agencies; each is part of a strict, hierarchical structure with the Secretary at the top of the pyramid.[668] These line bureaus also operate only on delegated authority because the statutes they implement do not even mention the bureaus.[669] Instead, final decision authority remains with the Secretary.[670]

Once BSEE was created, the agency made an effort to increase its staffing and hire additional inspectors. According to former BSEE Director James Watson, between April 2010 and March 2012, BSEE increased its number of inspectors by 50 percent and its number of engineers by nearly 10 percent.[671] In conjunction with changes to the regulatory body, new safety regulations were also established. The Safety and Environmental Management Systems (SEMS) rule is the new regulation through which BSEE oversees oil and gas offshore safety. Its stated purpose is to ensure safe operations on the OCS. In promulgating this regulation, BSEE stated that "requiring operators to implement SEMS will reduce the risk and number of accidents, injuries, and spills during OCS activities."[672] The final rule, issued in October 2010, incorporated by reference and made mandatory API RP 75(3rd edition). As a result, SEMS established requirements pertaining to 13 specific safety management elements, including hazard analysis, management of change, operating procedures, and training, among others.[673] Any permissive language found in API RP 75 was also amended in the final version of the rule and made mandatory.

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responsibilities for safety regulation on the OCS. The two entities have a Memorandum of Agreement to establish a process for the identifying offshore safety and environmental management requirements within the jurisdiction of both agencies and to spur joint development of policies and guidance. *See* http://www.bsee.gov/uploadedFiles/BSEE/Newsroom/Publications_Library/BSEE-USCG%20MOA_FINAL%20SIGNED%2004-30-13.pdf (accessed January 6, 2016).

[668] George Cameron Coggins and Doris K. Nagel, *Nothing Beside Remains: The Legal Legacy of James G. Watt's Tenure as Secretary of the Interior on Federal Land Law and Policy*, 17 B.C. ENV'TL. AFF. L. REV. 473, 482 (1990).

[669] Since the Secretary of the Interior created each bureau without presidential or congressional direction, the bureaus are operating through authority delegated to the Secretary, not to the head of the bureaus. Thus, the bureaus are purely creations of the Secretary of the Interior.

[670] George Cameron Coggins and Doris K. Nagel, *Nothing Beside Remains: The Legal Legacy of James G. Watt's Tenure as Secretary of the Interior on Federal Land Law and Policy*, 17 B.C. ENV'TL. AFF. L. REV. 473, 482 (1990).

[671] Watson, J. *Statement of James Watson, Director Bureau of Safety and Environmental Enforcement United States Department of the Interior Committee on Appropriations Subcommittee on Interior, Environment and Related Agencies House of Representatives*; March 7, 2012; http://www.bsee.gov/uploadedFiles/BSEE/Newsroom/Congressional_Testimony/Congressional%20Testimony%2020120307.pdf (accessed March 26, 2013). Director Watson noted that there was still a considerable number of positions to be filled, including additional inspectors, engineers, regulatory specialists, and other disciplines.

[672] Oil and Gas and Sulphur Operations in the Outer Continental Shelf, 75 Fed. Reg. 63609 (Final Rule, October 15, 2010) (to be codified at 30 C.F.R. Part 250).

[673] 30 C.F.R. § 250, Subpart S (2011).

In April 2013, BSEE published additional safety provisions as amendments to SEMS. Informally called "SEMS II,"[674] it provided additional requirements for stop-work authority and ultimate work authority, employee participation in developing and implementing SEMS programs, reporting unsafe working conditions, conducting independent third-party audits of operators' SEMS programs, and performing job safety analyses (JSAs) for activities identified in an operator's SEMS program.

[674] Oil and Gas and Sulphur Operations in the Outer Continental Shelf—Revisions to Safety and Environmental Management Systems, 78 Fed. Reg. 20423 (Final Rule, April 5, 2013) (to be codified at 30 C.F.R. Part 250).

By the

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U.S. CHEMICAL SAFETY AND HAZARD INVESTIGATION BOARD

INVESTIGATIVE STUDY

Final Report

PUBLIC SAFETY AT OIL AND GAS STORAGE FACILITIES

MULTIPLE SITES

(44 FATALITIES, 25 INJURED)

26 INCIDENTS FROM

1983-2010

KEY ISSUES:

- OIL AND GAS EXPLORATION AND PRODUCTION FACILITIES PRESENT HAZARDS TO MEMBERS OF THE PUBLIC INCLUDING CHILDREN
- SECURITY MEASURES ARE INSUFFICIENT AT EXPLORATION AND PRODUCTION FACILITIES
- REGULATIONS AND INDUSTRY STANDARDS DO NOT PROVIDE UNIFORM, EFFECTIVE GUIDANCE

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Abbreviations

API	American Petroleum Institute
bbl	Barrel (42 U.S. gallons)
CSB	U.S. Chemical Safety Board
E&P	Exploration and Production
EIA	U.S. Energy Information Administration
EPA	U.S. Environmental Protection Agency
GOR	Gas Oil Ratio
MSO&GB	Mississippi Oil and Gas Board
NFPA	National Fire Protection Association
OCC	Oklahoma Corporation Commission
OSHA	U.S. Occupational Safety and Health Administration
psig	Pounds per square inch gauge
RRC	Railroad Commission of Texas

1.0 Executive Summary

1.1 Oil and Gas Storage Sites Present a Hazard in Rural Areas

On October 31, 2009, two teenagers, aged 16 and 18, were killed when a petroleum storage tank exploded in a rural oil field in Carnes, Mississippi. Six months later a group of youths were exploring a similar tank site in Weleetka, Oklahoma, when an explosion and fire fatally injured one individual. Two weeks later, a 25-year-old man and a 24-year-old woman were on top of an oil tank in rural New London, Texas, when the tank exploded, killing the woman and seriously injuring the man. In April 2010, the U.S. Chemical Safety Board (CSB) initiated an investigation into the root causes of these tragic incidents. All three incidents involved rural unmanned oil and gas storage sites that lacked fencing and signs warning of the hazards, which might have otherwise deterred members of the public from using them as places to gather.

Oil and gas storage sites are part of the landscape in many rural American communities and an important component of the country's vast system of oil and gas exploration and production. Over 800,000 crude oil and natural gas producing facilities are distributed across the U.S., often located in wooded clearings or other isolated locations.

However, in many states, these sites can be placed as close as 150 to 300 feet from existing residences, schools, churches and other structures. Only in a few large cities where these sites exist – Houston, Oklahoma City, and Los Angeles – are constraints placed on the location of the facilities within the city limits.[1]

In most cases, however, these sites are away from public view, often unfenced, unsupervised, and lacking warning signs. They have proven to be a tempting venue for young people looking for a place to gather,

[1] New Jersey Petroleum Council and The American Petroleum Institute. Oil and Natural Gas Industry Security Assessment and Guidance. 2002. <http://www.nj.gov/dep/rpp/brp/security/downloads/NJ%20Best%20Practices%20Petroleum%20Sector.pdf>

and socialize. Activities where an ignition source is introduced into the tank, or even the presence of static electricity or lightning, can cause hydrocarbon vapors in the tanks to ignite and explode.

1.2 CSB Study

To prevent future deaths and injuries, the CSB investigated the root causes of the three incidents and conducted an analysis of the regulatory framework that contributed to the prevalence of this type of event. The CSB examined federal, state, and local regulations; inherently safer designs of tanks; and industry standards and practices recommended by the American Petroleum Institute (API) and the National Fire Protection Association (NFPA). The CSB also administered a survey to gauge the public's view of these sites and the issues arising from their presence in the community. Among 190 survey recipients in a rural Mississippi community, 11 percent of respondents stated they had "hung out at oil sites." When asked about the type of activity engaged in at oil sites, 14 percent stated they socialized; 19 percent said that they rode four-wheelers at oil sites; and 11.5 percent stated that they hunted.

This CSB study provides recommendations to strengthen security at exploration and production (E&P) sites to include fencing, warning signage, locking of all hatches and using inherently safer tank features to prevent future incidents.

1.3 Findings from Oil and Gas Site Incidents

The CSB found the three explosions in Mississippi, Oklahoma, and Texas could have been prevented or made less likely by restricting access to the facilities, by providing warning signage, by securing the hatches on the tanks or utilizing inherently safer tank design at these facilities. The growing number of oil and gas facilities nationally, their accessibility to members of the public, and the lack of awareness among the public about the hazards posed by the tanks suggest a potential for similar incidents. The CSB makes the following key findings:

1. Members of the public, most often children and young adults, commonly visit oil and gas production sites without authorization for recreational purposes.

2. Members of the public gain access to production tanks via attached unsecured ladders and catwalks, and may come into contact with flammable vapors from tank vents or unsecured tank hatches.

3. Members of the public, unaware of the explosion and fire hazards associated with the tanks, unintentionally introduce ignition sources for the flammable vapor, leading to explosions.

4. The CSB identified 26 similar incidents between 1983 and 2010, which resulted in a total of 44 fatalities and 25 injuries. All the victims were 25 years of age or less.

5. The three incidents investigated by the CSB in 2009-2010 occurred in isolated, rural wooded areas at production sites that were unfenced, did not have clear or legible warning signs, as required under OSHA's Hazard Communication Standard, and did not have hatch locks to prevent access to the flammable hydrocarbons inside the tanks.

6. The storage tanks did not include inherently safer design features to prevent tank explosions. Safer design features used in the downstream, refining sector would likely prevent tank explosions at E&P sites. These include the use of vents fitted with pressure-vacuum devices, flame arrestors, vapor recovery systems, floating roofs or an equivalent alternative.

7. E&P storage tanks are exempt from the security requirements of the Clean Water Act and from the risk management requirements of the Clean Air Act.

8. Industry guidance from the American Petroleum Institute recommends specific security measures for storage tanks of refined petroleum products but not for storage tanks at upstream E&P sites, and the National Fire Protection Association standards do not adequately define security expectations where these deadly incidents occurred.

9. Some states, including California and Ohio, and some localities have mandated security (including fencing, locked or sealed tank hatches, and warning signs) for E&P sites, particularly in urban areas. As a result, despite its large role as an oil producing state with many of these types of facilities, none of the 26 incidents occurred in California. However, many other large oil and gas producing states have no such requirements (except for certain E&P sites where toxic hydrogen sulfide gas is present).

1.4 Recommendations

As a result of the findings from this study, the CSB makes recommendations to the following recipients:

- U.S. Environmental Protection Agency (EPA)
- Mississippi Oil and Gas Board
- Oklahoma Compact Commission
- Texas Railroad Commission
- American Petroleum Institute (API)
- National Fire Protection Association (NFPA)

2.0 Hazard at Oil and Gas Production Facilities

Between October 2009 and April 2010, four teenagers and young adults lost their lives from explosions at three different oil and gas production sites in rural Mississippi, Oklahoma, and Texas. The CSB first became aware of this hazard in 2003 when a similar explosion in Palestine, Texas, fatally injured four teenagers. In 2010, the CSB initiated an investigation to further examine the issue. The CSB found 26 similar incidents involving explosions and fires at oil and gas production sites.

2.1 CSB Outreach

After the CSB's initial deployment to a tank explosion in Carnes, Mississippi, the agency created a safety video targeting individuals under the age of 25 to increase awareness of the hazards posed by oil and gas sites. The safety video, "No Place to Hang Out: The Danger of Oil Sites," incorporates the experiences of the victims' friends, families, and community leaders in Carnes, and is intended to be integrated into high school and middle school curricula. The CSB distributed this video to school superintendents across Mississippi and continues to work with safety advocates in an effort to reach young people who live in oil and gas producing communities.

2.2 Study Methodology

To further understand why these incidents were occurring across the country, the CSB deployed to and investigated the three oil and gas tank explosions discussed above and collected information on 23 similar explosions across the country. Investigators interviewed key witnesses and first responders at each of the three incident sites and gathered exploration and production (E&P) site records from each state oil and gas regulator. Incident reports for the 23 additional incidents were requested from local responders. A survey of high school students and community members in Carnes, Mississippi, was administered to understand the use of and hazard awareness at oil and gas facilities. The CSB then analyzed safety and security regulations at the local, state, and federal level as well as relevant industry standards in order to identify systemic gaps and formulate recommendations aimed at preventing future incidents.

3.0 Characteristics of Oil and Gas Storage Facilities

3.1 Process Overview

At typical E&P sites, crude oil and natural gas are pumped from underground hydrocarbon reservoirs to the surface. The well stream is connected to a piping system that transports hydrocarbons to an oil-gas separator where gas and water are removed from crude oil. The oil is then transferred to storage tanks in a tank battery[2] until it is pumped into a transport truck for eventual sale (Figure 3-1).

In states where vapor recovery systems[3] are not mandated,[4] oil tanks are usually equipped with a tank hatch[5] and an atmospheric vent on the surface (Figure 3-1). Oil field workers regularly check liquid levels through the hatch, which is accessible by a walkway or catwalk.[6] The oil-gas separator also contains an atmospheric vent that releases hydrocarbon vapors. 210-barrel capacity atmospheric storage tanks – which were involved in two of the three explosions investigated by the CSB – are commonly used to store crude oil and condensate at E&P facilities throughout the U.S. These tanks are rated for petroleum liquids with a vapor pressure of less than 0.5 psig[7] and are selected "based on vapor pressure, flash point, potential for explosion, temperature and specific gravity."[8] If circumstances change inside the tank and

---

[2] A tank battery is an installation of several tanks at E&P facilities.

[3] A vapor recovery system consists of a sealed vapor gathering system capable of collecting the hydrocarbon vapors and gases discharged and a vapor disposal system capable of processing such hydrocarbon vapors and gases so as to prevent their emission into the atmosphere.

[4] California state law requires oil and gas sites located in non-attainment (non-compliant) air pollution areas to capture all hydrocarbon vapors produced in a stock tank and cycle them through a vapor recovery system.

[5] A tank hatch is a covered opening on the surface of a tank.

[6] A catwalk is the stair or ladder leading to and providing access to the top of a tank or vessel.

[7] Myers, P.E. Aboveground Storage Tanks. 1997. NY: McGraw-Hill, p. 25.

[8] *Ibid.*

the internal pressure increases significantly above its pressure rating, the tank loses its structural integrity and fails.

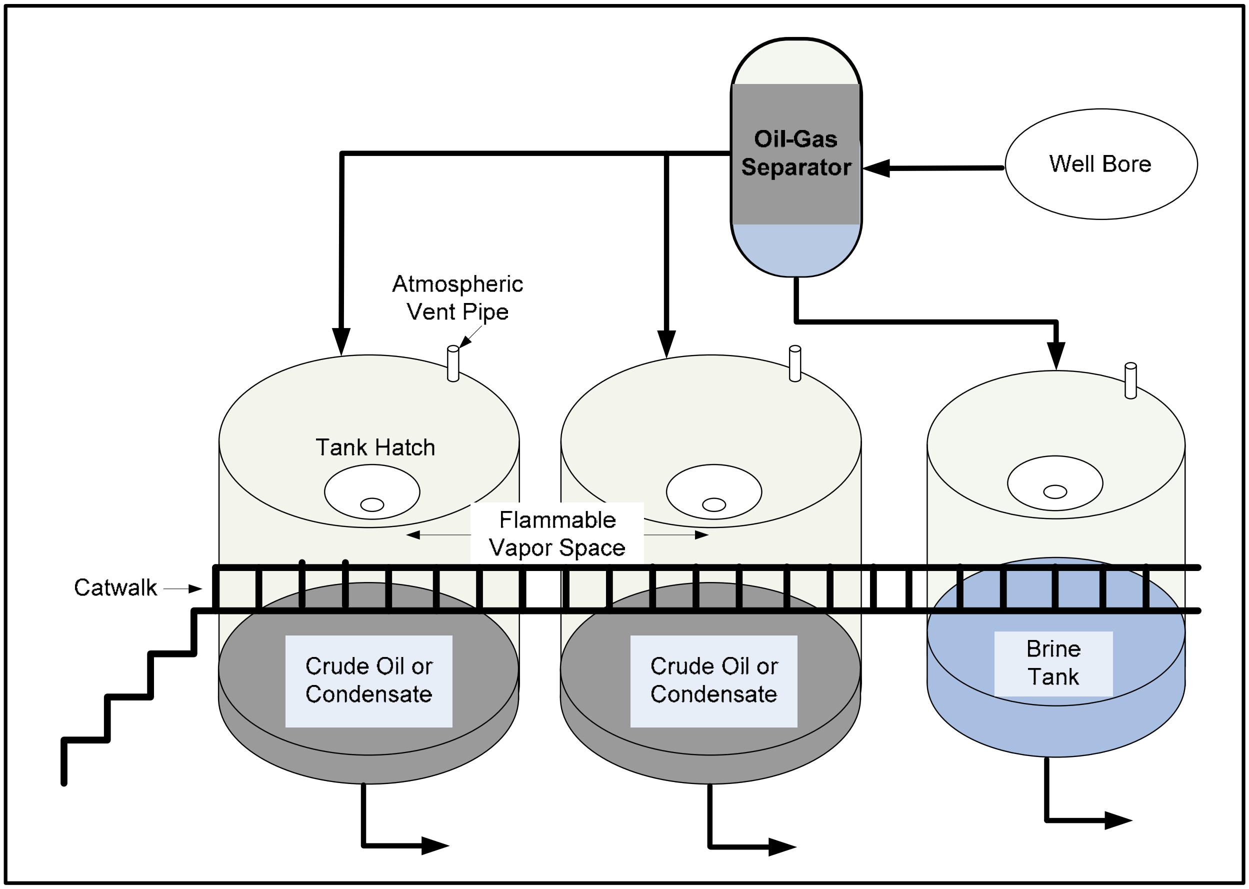

Figure 3-1: Basic schematic of oil and gas production facility.

3.1.1 Measuring Flammability Properties at Oil and Gas Facilities

The flammability of the product at E&P facilities varies depending on the geology of the formation and can change over time. The flammability of crude oil and condensate may be characterized by specific gravity (weight per volume), American Petroleum Institute (API) gravity, and the gas oil ratio (GOR). The higher the API gravity, the lighter and more flammable the compound; materials below an API gravity value of 35 are characterized as crude oil, while those above 45 are considered condensate. Light crudes generally exceed 38 degrees API and heavy crudes have an API gravity of 22 degrees or below.

Intermediate crudes fall in the range of 22 degrees to 38 degrees API gravity. API gravity is measured using stock oil taken from the storage tanks and is often reported to state oil and gas boards upon initial production from a well. The Gas Oil Ratio (GOR) measures the dissolved natural gas remaining in a well stream at a specific pressure and temperature and is a ratio of the gas produced for each barrel of stock oil in standard cubic feet per barrel (scf/bbl).

In addition to being flammable, crude oil and associated produced water (also referred to as brine) may contain varying levels of hydrogen sulfide[9] depending on the geology of the hydrocarbon reservoir. Crude oil storage sites containing hydrogen sulfide are typically subjected to stronger regulatory requirements.

3.2 Close Proximity of Oil and Gas Facilities to Residents

In most states oil and gas leases are divided into a mineral[10] and surface estate[11]. In the past, both the surface and mineral estates were transferred when a property was sold. It is now common for mineral estates and surface estates to be severed and sold separately. However, federal and state laws allow dominance of mineral estate rights over the rights of the surface estate. This supremacy allows mineral estate owners to lease their rights to oil and gas operators, who utilize the surface estate to access the minerals beneath the surface.[12] Although requirements vary across states, surface estate owners can refuse access to the minerals estate owners or charge a fee for access. While some states may institute “accommodation” statutes that enable a surface estate owner to reduce the impact of the exploration activities to the surface, such an agreement is not required by an operator who has leased the mineral

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[9] Hydrogen sulfide is hazardous and deadly at low concentrations with an Immediately Dangerous to Life and Health concentration of 100 parts per million-(ppm) in air.

[10] Mineral estate refers to the ownership of mineral rights or “mineral interest”-- all unusual organic and inorganic substances in the soil giving it value on a property.

[11] Surface estate refers to the ownership of the surface of a property above the mineral estate.

[12] Texas Rail Road Commission. Oil & Gas Exploration and Surface Ownership.
< http://www.rrc.state.tx.us/about/faqs/SurfaceOwnerInfo.pdf>

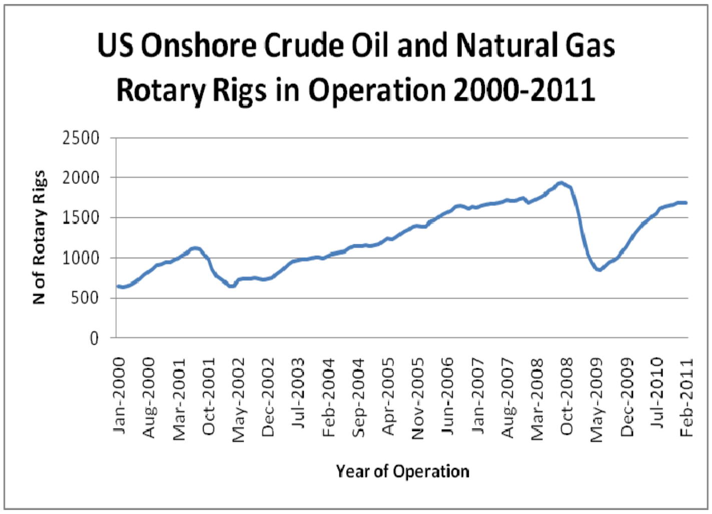
estate from its owner.[13] Additionally, once an oil or gas operator obtains a mineral lease, drilling operations can occur in close proximity to existing residences, without notifying the surface owner.

In both urban and rural areas, drilling may occur within a few hundred feet of residences. For example, in many states, minimum requirements for the placement of oil sites and tank storage facilities range from 150 to 300 feet from existing residences, schools, churches, and other structures.[14] CSB investigators observed that a number of oil and gas production facilities in Mississippi, Oklahoma, and Texas are unsecured and located within rural communities and in close proximity to residences. The CSB also learned that although the mineral estate can be leased to an oil or gas operator, unless stipulated otherwise in the leasing agreement, the surface estate owner can concurrently lease the surface rights of the same property as part of hunting leases or for other uses.

[13] Court of Appeals of Mississippi. No. 2003-CA-01572-COA. *MS: Turner vs EOG Resources.* <http://caselaw.findlaw.com/ms-court-of-appeals/1243004.html>

[14] Colorado Law Institute. Comparison of State Oil and Gas Regulations and Local Ordinances Regarding Setbacks for the Intermountain West. 2009. <http://www.oilandgasbmps.org/laws/setback.standards.comparison.10.8.09.pdf>

4.0 Increase in Oil and Gas Storage Sites Poses Increased Risk



4-1: EIA U.S. Onshore Crude Oil and Natural Gas Rotary Rigs in Operation

As the number of oil production sites and the population density increase, so does the likelihood that young people will access oil sites as places to "hang out." In 2009, the Energy Information Administration (EIA) reported that there were at least 363,459 active oil and 461,388 active gas well sites throughout the U.S.[15] Approximately 85 percent of oil and gas wells are small producers generating 15 barrels of oil equivalent per day (BOE/day)[16] or less.[17]

The EIA data demonstrate a general increase in drilling activity over the past decade (Figure 4-1). In addition, drilling in shale for natural gas exploration and development has nearly doubled from 2009 to 2010 and active wells increased from 11,657 to 20,388.[18] The increase in oil and gas drilling activity for crude oil and natural gas exploration creates an increase in the number of oil and gas production sites, likely increasing the risk to members of the public.

[15] The Energy Information Administration. United States Total 2009, Distribution of Wells by Production Rate Bracket. < http://www.eia.gov/pub/oil_gas/petrosystem/us_table.html>

[16] Barrels of Oil Equivalent per day is used in the production or distribution of oil. One barrel of oil has the same amount of energy content as 6,000 cubic feet of natural gas.

[17] The Energy Information Administration. United States Total 2009, Distribution of Wells by Production Rate Bracket. <http://www.eia.gov/pub/oil_gas/petrosystem/us_table.html>

[18] The Energy Information Administration. Annual Energy Outlook 2011. <http://www.eia.gov/forecasts/aeo/pdf/0383(2011).pdf>

5.0 Oil and Gas Tank Explosions in the U.S. from 1983 to 2010

Through media searches, the CSB identified 26 similar incidents that occurred from 1983 to 2010 at oil and gas production sites in 10 different states (Figure 5-1). These incidents resulted in 44 fatalities and 25 injuries to members of the public under 25 years of age (Appendix A). The majority of these incidents occurred in rural areas, where the sites lacked security and safety measures such as fencing, warning signs, or locks on tank hatches. The CSB collected investigation reports from oil and gas boards, local fire departments, and/or state environmental agencies detailing the circumstances and consequences of these incidents (Appendix A). The reports illustrate the explosion hazard to members of the public who wander into these sites for recreational purposes. The data are limited to accidents covered in the media, since a central database for tracking incidents involving members of the public does not exist. For this reason, a background rate of the frequency of these incidents could not be obtained. However, the CSB found these incidents are occurring consistently, although the data were not sufficient to demonstrate a meaningful trend.

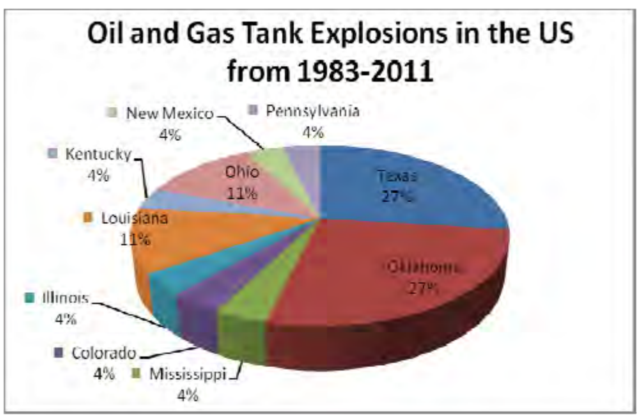


Figure 5-1: Oil and Gas Storage Tank Explosions across 10 states, 1983-2011

Of the incidents reviewed, the CSB concluded that 82 percent of the fatally injured victims were teenagers and 18 percent were young adults between the ages of 20-25. Sixty-nine percent of the incidents involved multiple injuries or fatalities.

The majority of the 26 incidents occurred in Texas (27 percent) and Oklahoma (27 percent); however the remaining 46 percent of incidents occurred in oil and gas production states throughout the country (Figure 5-2). The CSB discovered approximately 84 percent of the 26 incidents occurred in areas that did not have any state or local zoning ordinances that required security fencing, signs, or hatch locks to discourage site access. Only 16 percent of the incidents occurred in areas where zoning ordinances appeared to require fencing for sites in urban locations. (See Appendix A for more details on incidents).

Figure 5-2: Map of oil and gas production facility explosions from 1983-2010 that killed or injured members of the public.

6.0 CSB Investigations, 2009-2010

The CSB investigated the three recent incidents described in this section to develop a more thorough understanding of why tank explosions continue to occur at E&P sites.

6.1 Delphi Oil, Carnes, Mississippi

Figure 6-1: Delphi Oil gas production site, Carnes, Mississippi

6.1.1 Incident Details

On October 31, 2009, two teens from Carnes, Mississippi, were fatally injured when a tank of gas distillate exploded at a rural oil and gas storage site located near several residences. The two teenagers, 18 and 16, arrived at the home of one of the victims at approximately 11:00 p.m. on October 30, 2009. Between midnight and 4 a.m., the victims drove to the adjoining gas well site located approximately 150 yards from the home in a nearby clearing in the woods. At approximately 4:00 a.m. a violent explosion occurred inside one of the site's two storage tanks.

Figure 6-2: A) Remnants of exploding tank
B) Tank hatch located approximately 300ft from berm
C) Bottom of tank found 60 feet from berm in adjacent wooded area

The force of the explosion propelled the upper part of the tank approximately 225 feet while the bottom of the tank was thrown about 60 feet in the opposite direction. The tank's vent pipe and hatch detached from the tank top and landed over 300 feet away (Figure 6-2B). The exploding tank lost all its contents, triggering a large fire up to 200 feet high that persisted for about four hours. The fire prevented first responders from accessing the sign containing Delphi Oil's emergency contact information, which was located at the well head within the fire zone (Figure 6-3). Both teenagers were killed instantly; their bodies were found approximately 120 feet from the original location of the tank. Forrest County Sheriff photographs taken immediately following the incident demonstrate the two victims were thrown from the catwalk. Although a cigarette lighter was found at the site there was no evidence that it was the ignition source.[19] CSB staff traveled to

Figure 6-3: Delphi Oil gas production site identification sign

[19] Ignition sources may include matches, lighters, cigarettes, lightning, static electricity, and in some cases pyrophoric iron sulfide.

the incident site in November 2009 and January 2010 and interviewed emergency responders, neighbors, family members, and friends of the victims.

6.1.2 Incident Site

Figure 6-4: Delphi Oil gas production site surrounded by woods

The explosion and fire occurred at an active natural gas well site leased by Delphi Oil, an oil and gas producer based in Baton Rouge, Louisiana. Delphi Oil began exploring and developing the site in November 2006, when it obtained the mineral leases to a number of lots in Forrest County. Delphi Oil leased approximately 400 acres of mineral rights for the Delphi Oil 5-18 No. 1 gas production well. The site produced natural gas and gas condensate,[20] a mixture of light hydrocarbons, which was stored in a 210-barrel[21] capacity tank interconnected to an adjacent 210-barrel tank that stored brine. Each tank had a six-inch diameter hatch and a vent pipe located on the roof that was open to the atmosphere.

Figure 6-5: Oil and gas production site in Carnes, Mississippi with elevated catwalk

6.1.3 Flammability

At the time of the incident, the exploding tank contained approximately 14 barrels of condensate. According to records from the Mississippi Oil and Gas Board (MSO&GB), the distillate from the well had an API gravity of 50 degrees, indicating the presence of a highly volatile hydrocarbon mixture.

[20] Condensate: A flammable natural gas liquid recovered from gas wells using separation equipment.

[21] A barrel is a unit of volume equal to 42 U.S. gallons.

6.1.4 Access, Fencing, Warning Signs, and Security

This particular gas well site is located in a rural clearing surrounded by woods (Figures 6-1 and 6-4) approximately 500 feet from an adjacent residential property. It is readily accessible from a number of foot trails in the woods and an unsecured dirt access road. At the time of the explosion, the site did not have signage to warn of the hazardous contents of the tanks, hatch locks, perimeter or equipment fencing to deter public access, nor were the tanks designed to avoid an internal vapor explosion.

6.1.5 Recognition of Oil and Gas Site Hazards

Rural oil and gas tank production sites are often in remote locations that are cleared for the installation of extraction and storage equipment. Residents and friends of the victims told CSB investigators that prior to the incident, they did not view oil and gas production sites as dangerous, as they were part of the landscape. Many had grown up in close proximity to oil rigs and tank storage sites and used them as common gathering locations for recreational purposes such as socializing, hunting, and driving all-terrain vehicles. The CSB learned that a number of hunting leases in the area incorporate oil and gas sites and their storage facilities, and some residents described using the sites' elevated catwalks (Figure 6-5) and the tanks as platforms for hunting.

6.2 Three MG Family, Weleetka, Oklahoma

Figure 6-6: Weleetka, OK, oil and gas well site indicating Tank 4-22, which exploded

6.2.1 Incident Details

On April 14, 2010, a 210-barrel capacity tank exploded at an oil and gas production site in rural Weleetka, Oklahoma, fatally injuring a 21-year-old male and causing second-degree burns to a 26-year-old male. At the time of the explosion, a group of six young adults and teenagers, ages 18 to 32, were socializing at the oil and gas site. They were on their way to an isolated location along the North Canadian River in Oklahoma, when they turned off onto a rural dirt road, which also provided access to the oil and gas site. According to witness testimony, rather than continue directly to the riverbank, the group stopped at the oil and gas site about a half mile from their intended destination at approximately 8:30 p.m. Shortly thereafter, witnesses said the victim ascended stairs to the catwalk that accessed the three oil storage tanks belonging to Three MG Family, Inc. Witnesses said that the victim looked into the hatch of tank 4-22, possibly while smoking; at the same time another friend was walking behind him in the dark and struck his lighter to see. Vapors from the tank ignited and an explosion ensued.

A fireball engulfed the victim, causing third degree burns covering up to 95 percent of his body. The Weleetka Fire Department received a 9-1-1 call at 9:06 p.m. and, upon arrival at the scene, observed a

Figure 6-7: A) Gate at entrance to dirt road leading to Weleetka oil and gas well site B) Cattle gate on dirt road leading to oil and gas well. C) Sign identifying gas pipeline at Weleetka oil and gas site

raging fire. The victim was airlifted to a Tulsa burn center but succumbed to his injuries the next day. The exploding tank (Tank 4-22) contained approximately 155 barrels of crude oil; the adjacent tank had approximately 10 barrels of crude oil and the tank closest to the oil separator was half-full of brine (Figure 6-6). Three Enterprise Oil tanks on the opposite side of the oil-gas separators were unaffected by the explosion and ensuing fire. As a result of the explosion and fire, oil spilled around the tanks and fire spread about 15 feet onto the surrounding brush area behind the affected tanks. The site did not have a berm or dike to contain the oil released from the exploding tank when it lost its contents.

6.2.2 Incident Site

The oil and gas site was leased by Three MG Family, ScissorTail Energy, LLC, and Enterprise Energy. The site contained six 210-barrel capacity storage tanks, two oil separators, and two gas separators. One set of oil and gas separators was connected to three adjacent interconnected storage tanks belonging to Three MG Family, Inc.; the other set provided oil and gas to three interconnected storage tanks belonging to Enterprise Oil (Figure 6-6).

6.2.3 Flammability

Three MG Family, Inc. sales records show that the three interconnected tanks were emptied on April 10, 2010, four days before the explosion and fire, leaving a significant vapor space above the remaining contents in the tank. According to company transport documents, the crude oil in the exploding tanks had an API gravity rating of approximately 39.0, falling between the range of crude oil and condensate. A transport receipt dated March 4, 2010, identified the contents of the affected tanks as Petroleum Crude Oil, 3 UN 1267. A material safety data sheet (MSDS) for this type of oil describes the material as "easily ignited by heat, sparks or flames." Section 4 of the MSDS, "Fire and Explosion Hazards," states that "vapor/gas will spread along the ground [and] collect in low or confined areas (sewers, basements, tanks). [Vapors] may also travel to a source of ignition and flash back. Containers may explode when heated."[22]

6.2.4 Access, Fencing, Warning Signs, and Security

The oil tank site involved in this incident is located in a wooded clearing less than a mile from the main road and half a mile from the banks of the Northern Canadian River. The dirt road leading to the site is unlit and secured by a typically unlocked iron cattle gate located where the dirt road intersects the main road (Figure 6-7A, B). The gate is approximately 4 feet high and 12 feet long and is the only means of discouraging access to the site (Figure 6-7B). The site lacks a perimeter fence, warning signs identifying hazards of the flammable materials inside the tanks, or hatch locks. The design of the failed tank did not prevent an internal explosion. There was one warning sign identifying the location of a gas pipeline on site (Figure 6-7C). The site is unmanned except for a well tender who checks the oil levels in the tanks

[22] Irving Oil. MSDS Crude Oil.
<http://www.irvingoil.com/dloads/refinery/03050%20CRUDE%20OIL%20MSDS.pdf.>

each morning. The CSB determined from witness testimony that the gate to the dirt road leading to the oil tank storage site was often left unlocked and on the day of the incident was likely unlocked.

6.3 MC Production, New London, Texas

Figure 6-8: MC Production Oil tank site, New London, Texas

6.3.1 Incident Details

At approximately 1:00 a.m. on April 26, 2010, an oil tank exploded in New London, Texas, fatally injuring a 24-year-old woman and seriously injuring a 25-year-old man. The exploding tank was propelled 48 feet away from its original location; the top of the tank was found 35 feet from its original location. The CSB learned that two individuals were climbing the stairway of the catwalk when one victim asked the other to light a cigarette. Witness testimony revealed that when the second victim lit the cigarette, an explosion ensued.

6.3.2 Incident Site and Flammability

The oil and gas site was leased by MC Production. At the time of the explosion, there were three interconnected 1000-barrel capacity tanks at the facility. The exploding tank contained a small amount of hydrocarbons and another adjacent tank had a hole. The oil site has been in operation for at least 80 years. According to well records obtained from the Texas Railroad Commission (RRC), the oil lease was active at the time of the explosion producing 185 barrels of oil and selling 369 barrels during the month of the incident. However, testimony from the well tender indicates the oil tank involved in the explosion

Figure 6-9: A) Open cattle gate leading to storage site B) Access road leading to tank storage site C) Woods surrounding oil tank site

had not stored product for at least one-and–a-half years prior to the explosion. The CSB also learned that MC Production reported the oil from the site had an API gravity of 37.4, characteristic of an intermediate crude oil that can produce flammable hydrocarbons.

6.3.3 Access, Fencing, Warning Signs, and Security

Figure 6-10: M-C Production tank site with warning sign

The MC Production oil field is located at the end of an isolated road in the middle of a clearing surrounded by woods (Figure 6-9C). According to Rusk County Fire Department officials and the Rusk County Sheriff’s office, at the time of the explosion the oil site had no fences or hatch locks nor were the tanks designed to reduce the potential of an internal explosion. A cattle gate marked the entrance to a dirt road that led to the tank battery site over 200 feet away (Figure 6-9A). The site did have one warning sign covered by graffiti; however, its exact location at the time of the incident is unclear. Witness testimony revealed the sign may have been moved three to four times the day after the explosion. Although the “No” on the sign was blurred from graffiti, it warned against smoking, matches or open lights (Figure 6-10).

Figure 6-11: A) Exploding Tank at MC Production oil site B) Children's bicycle found on M-C Production tank site on the day of the explosion.

Incident photos also revealed the tank site contained graffiti tags from local gangs (Figure 6-10). In addition, on the night of the explosion, a pink children's bicycle was found at the tank site (Figure 6-11). Both the presence of the graffiti and the children's bicycle indicate the tank site was visited by various members of the public. Two days after the fatal accident, Rusk County investigators returned to the accident scene to find a new steel gate with locks and signs at the entry to the access road.

6.4 Recreational Use of Oil and Gas Sites

6.4.1 Survey Methods

The three tank storage sites investigated by the CSB were located in rural areas in close proximity to residential communities. To further assess public understanding of oil and gas site hazards, the CSB conducted a survey of students at Forrest County Agricultural High School, where the victims of the October 2009 explosion were enrolled, and other members of the Carnes, Mississippi, community. The survey was conducted during the spring of 2010, several months after the explosion. The surveys were administered by Forrest County Agricultural High School personnel. Participants were asked to provide age and gender information but no other personal identifiers. A total of 190 surveys were completed; participants had a median age of 16. The survey results are summarized below.

6.4.2 Survey Results

Similar to CSB interviews of community members, the survey results reveal that many local residents (especially children and young adults) view oil and gas sites as convenient places to gather and participate in recreational activities, made easier by relatively unhindered access. Respondents to the survey stated overwhelmingly that they would avoid these sites if hazard signs were present or if access were made more difficult with perimeter fencing and locks.

In the survey, 11 percent of respondents stated they previously "hung out at oil sites." When asked about the activity engaged in at an oil or gas production site, 14 percent stated they spent time with friends; 19 percent said that they rode four-wheelers; and 11.5 percent stated that they fished or hunted. Seven respondents said they had climbed onto the catwalk at an oil site, while six stated they consumed alcoholic beverages and four stated that they smoked cigarettes or cigars at oil sites.

Of the 190 respondents, 11 indicated they visited oil sites once a year and 21 said they did so less than once a year. Five respondents stated that they had lifted the hatch of an oil storage tank; and seven stated they used a lighter or a match while at an oil well site.

7.0 Inherently Safer Tank Design

Inherently safer tank design could have prevented the formation of a flammable atmosphere inside the tanks and likely prevented the three incidents investigated by the CSB, as well as the 23 other similar tank explosions that were identified. The following are examples of tank design features that can be used at E&P facilities to isolate and contain the flammable vapors in order to prevent a vapor space explosion.

An internal floating roof is a design feature where a roof floats on top of a flammable liquid, reducing the hydrocarbon vapor to low concentrations well below the flammable limit. In the past, smaller diameter tanks (e.g. less than 30 feet diameter) could not practically use floating roofs because of stability issues. Today, due to API 650 relaxed buoyancy requirements for small tanks and the development of new composite floating roof materials, floating roofs can be installed in new or existing tanks as small as 8-10 feet in diameter. Currently, most E&P storage tanks have fixed roofs—a less costly alternative to an internal floating roof.

A second inherently safer design feature is the use of pressure vacuum (PV) relief valves. Pressure vacuum relief valves are commonly used on fixed roof tanks to minimize evaporation losses. However, they effectively isolate ignition sources, essentially acting as flame arrestors, so that external ignition sources nearby will not flash back to the vapor space, causing a tank explosion. The valves are designed to prevent the accumulation of pressure or vacuum which could compromise the tank integrity. However, most existing E&P oil storage tanks use open vents when storing flammable liquids. Only those tanks located in areas with strict air pollution rules (e.g. in California) avoid the use of open atmospheric vents. The likelihood of a flash back can be significantly reduced by the use of PV relief valves.

A third design option (one which is recommended for tanks located in urban areas of Ohio) is the use of an actual flame arrestor—a device that extinguishes a developing flame outside a tank, preventing it from entering the vapor space. The flame arrestor forces a flame front through narrow channels that inhibit the propagation of the flame. Both flame arrestors and pressure vacuum valves are similar in function in that they act as barriers to flame propagation from outside the tank into the vapor space.

A final option is the use of a vapor recovery system—a closed system that keeps flammable vapors inside the tank. This system requires the entire tank (tank hatches, atmospheric vents and all tank orifices) to be sealed and isolated from the atmosphere, thus preventing external ignition sources from entering the vapor space. The internal vapors are either recovered for future use or routed to a flare system. Vapor recovery systems are required for tanks located in poor air quality zones in California.

8.0 Oversight of Security at Oil and Gas Storage Facilities

The CSB reviewed federal, state, and local regulations as well as industry standards and guidance to evaluate the existing safety and security requirements for preventing public access to oil and gas production sites.

8.1 Mississippi Oil and Gas Rules

8.1.1 County Rules: Oil and Gas Well Sites in Forrest County, Mississippi

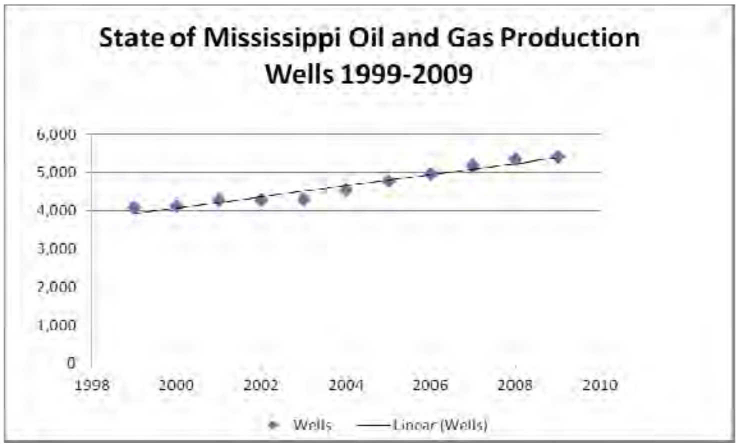


Figure 8-1: Oil and gas production wells in Mississippi (Source: Mississippi Oil and Gas Board)

The Delphi Oil gas site involved in the October 31, 2009, explosion is located in the Pistol Ridge oil field. Delphi Oil leases 15 of the producing wells and their associated tank storage sites in the area. In 2010, following the incident, the Forrest County Emergency Management District (FCEMD) conducted an analysis and reported 119 oil and gas production and storage sites in Forrest County, which includes the rural community of Carnes. Of the 119 oil and gas sites, only 15 were fenced at the time of the FCEMD report.[23] At the time of the incident, Forrest County had no local zoning ordinances requiring oil and gas facilities to be fenced or marked by warning signs. Following the FCEMD report, county supervisors required new measures to improve security at these facilities (see Section 8.1.7).

[23] Forrest County Oil and Gas Well Report. July 2010. The Emergency Management District.

8.1.2 State of Mississippi Regulations

Since 1999, there has been an increase in the number of oil and gas production wells in the state of Mississippi (Figure 8-1).[24] In 2009 there were 5,417 producing oil and gas wells, which were all regulated by the Mississippi Oil and Gas Board (MSO&GB).[25] This is the largest number of wells present since 1951. Multiple wells may feed into a single tank site. The MSO&GB does not collect information on the number of tank batteries in the state. Since 1932, the MSO&GB has regulated the drilling, completion, recompletion and/or operation of oil and gas wells and related facilities throughout Mississippi. The MSO&GB has "sole and exclusive" authority to regulate oil and gas conservation in the state and has "jurisdiction and authority over all persons and property necessary" to enforce all laws requiring the conservation of oil and gas.[26] The MSO&GB has seven inspectors who are responsible for inspecting over 5,000 wells throughout the state.

At the time of the incident, oil field rules promulgated by the MSO&GB did not require fencing, signage, or locks to prevent unauthorized entry to oil and gas sites, apart from those that contain hydrogen sulfide. The MSO&GB does not require inherently safer tank design features be utilized to prevent internal vapor explosions. Rule 6 of the MSO&GB Statewide Rules and Regulations required producers to post a site identification sign with company emergency contact information at tank sites, but did not state where the sign should be located. Additional rules require wells to be located 330 feet from every exterior boundary of the drilling unit;[27] [28] no requirements exist for spacing tanks from existing structures such as residences or public places**.**

[24] MSO&GB Annual Production Report. < http://www.ogb.state.ms.us/annprod.php>

[25] The Mississippi Oil and Gas Board. Annual Production Report. Retrieved from <http://www.ogb.state.ms.us/annprod.php. >

[26] The Mississippi Oil and Gas Board. MSO&GB. 53-1-17. Powers of Board. (g)

[27] Drilling unit is the maximum area in a pool which may be assigned to one well to produce recoverable oil or gas.

8.1.3 Communication with the Mississippi Oil and Gas Board

The CSB found the MSO&GB had numerous interactions and communications with personnel from Delphi Oil during the permitting process and the commissioning of drilling operations at the gas well site. There were at least 14 separate communications with Delphi Oil and two site inspections. These inspections did not consider security measures since they were not required in state regulations at the time.

8.1.4 Tanks with Hydrogen Sulfide

The MSO&GB has a site security rule for oil tanks containing hydrogen sulfide in excess of 20 parts per million. Since July 1, 1971, MSO&GB Rule 62 on "Storage Tanks and Sour Crude Oil" has required that oil and gas wells be adequately marked to alert the public and well site workers if a well contains hydrogen sulfide.[29] Additionally, Section A requires that "all access hatches to the tanks capable of being readily operable shall be kept closed securely at all times except when necessary for such hatches to be open for inspection and gauging." The same rule also requires that "all fumes and vapor in such tank or tanks be suitably recovered in a vapor recovery unit or flared to the atmosphere [and] all storage tanks and the nearby surrounding areas be conspicuously marked and posted in a manner advising of the presence of potentially lethal fumes and vapors."

The Safety Practices section of the Mississippi Oil and Gas Statutes, "Operations Involving Hydrogen Sulfide," requires that "safety precaution signs be displayed and unauthorized personnel kept out of the storage area." The CSB determined that similar requirements, if extended to all aboveground production sites storing flammables (with or without hydrogen sulfide hazards), would significantly discourage public access to the sites, preventing possible fires and explosions.

[28] MSO&GB. Statutes, Rules of Procedure. Statewide Rules and Regulations. April 3, 2009. Rule 62: Storage Tanks, Sour Crude Oil Pg 88.

[29] *ibid.*

8.1.5 Role of Local Municipalities

At the time of the October 2009 explosion, Forrest County had no zoning ordinances that required fencing, locked hatches, or posting of hazard warning signs at oil and gas sites. However, the City of Laurel, in an adjacent county, had implemented stricter ordinances since 1988 that require fencing and signage at oil and gas sites within the city limits for public safety.[30] In Laurel, fences must be at least six feet high with double stranded barbed wire enclosing all tanks and related equipment.

8.1.6 Forrest County Local Ordinance

As a result of the October 2009 incident, in 2010 the Forrest County Board of Supervisors adopted a local ordinance that requires fencing and warning signs at oil and gas sites that are outside corporate city limits. The measure requires continuous perimeter fencing at least five feet high with one or more strands of barbed wire, locks on gates, and warning and identification signs within five feet of any access point.[31] The ordinance also requires that well operators employ a locking mechanism to “restrict unauthorized use of an exterior gate, door, hatch, ladder, stairway, stairwell or similar device controlling access.”

8.1.7 New Tank Storage Site Security Measures: Mississippi Oil and Gas Board

In the aftermath of October 2009 incident in Carnes, in January 2011 the MSO&GB amended Rule 6 of the Mississippi code to require the following at production sites:

- A hazard sign posted at the entrance of well locations in “reasonably large and clear lettering” stating, “Danger,” “No Trespassing,” and “Authorized Personnel Only.”

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[30] City of Laurel, Mississippi. Code of Ordinance, Ch. 16: Section 75.

[31] Forrest County Board of Supervisors. Ordinance of the Forrest County Board of Supervisors Requiring Certain Safety Measures at Oil and Gas Facilities. July 13, 2010.

- A gate affixed to stairways leading to storage tanks accompanied by a sign reading "Danger (white lettering on red background)," "No Trespassing," and "Authorized Personnel Only."
- The placement of identification signs at site entrances during drilling operations, at the wellbore after well completion, and on the tank battery if it is remote from the wellbore.
- An around-the-clock telephone number posted for reporting incidents at unmanned facilities.
- A sign identifying all wells providing oil or natural gas to a tank battery.

8.2 State of Oklahoma Oil and Gas Rules

8.2.1 Oklahoma Lacks Oil and Gas Sites Security Requirements

The Oklahoma Corporation Commission (OCC) regulates oil and gas site safety for the state. OCC oil field rules do not require a perimeter berm or fencing of oil and gas sites, hazard signs, or hatch locks on oil storage tanks not containing hydrogen sulfide.[32] The OCC does not have any requirements for using inherently safer tank design features. Of the 26 similar incidents identified by the CSB, seven occurred in Oklahoma. Oklahoma reported approximately 41,000 gas wells and 83,000 oil wells in 2009.

8.2.2 Tanks with Hydrogen Sulfide

Similar to Mississippi, the State of Oklahoma requires more public protection measures if oil tanks contain vapor concentrations of hydrogen sulfide. When these conditions are present, OCC rules require warning signs and wind indicators on atmospheric storage tanks. The rules specify language warning about the presence of poisonous hydrogen sulfide. Signage is required within 50 feet of the facility, to be readable from the entrance and of "sufficient size." The OCC also requires fencing when storage tanks containing hydrogen sulfide above 500 ppm are located inside populated limits of a township or city "where conditions cause the storage tanks to be exposed to the public."

[32] Oklahoma Corporation Commission. Chapter 10: Oil and Gas Conservation, July 11, 2009, p. 49.

8.2.3 Tank Hatch Security

The State of Oklahoma changed its security requirements after a fatal accident in 1993 where a 12-year-old boy was asphyxiated upon putting his head into a large hatch of an oil storage tank. On January 1, 1995, Oklahoma state law was amended to require crude oil producers to adopt one of the following security measures:

- Install and maintain a sealing device on the hatch of a tank,
- Reduce the opening of the hatch to less than six inches in diameter or affix, or
- Maintain a sign on or near the hatch no smaller than 40 square inches that warns against opening the hatch and the danger within the storage tank.

The CSB determined that the tanks involved in the April 14, 2010, explosion were equipped with six-inch diameter hatches, but they were not locked.

The OCC also has stronger requirements for certain aboveground flammable storage tanks;[33] however, the rules do not cover the approximately 120,000 oil and gas wells and their associated tanks involved in upstream exploration and production (E&P) activities.[34] Tanks covered under the aboveground storage tank provision are required to be enclosed within a 6-foot high chain link fence, be separated from the fence by at least 10 feet, and have a gate to secure against unauthorized entry.[35] This provision also requires "conspicuously posted" signs with the words "Warning" and "No Smoking" and grounding instructions. CSB investigators determined that the incident in Weleetka would have been less likely to occur if the site were required to follow the fencing and/or warning provisions for either aboveground storage tanks or production sites with hydrogen sulfide hazards.

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[33] Aboveground storage tanks under OCC Ch 26-1-21 include tanks used in wholesale or bulk distribution activities.

[34] Oklahoma Corporation Commission (2009). Energy, Transportation and Utilities. Annual Report Snapshot FY 2009.

[35] Oklahoma Corporation Commission. Chapter 26: Aboveground Storage Tanks, July 1, 2009. p 27.

8.3 Texas Oil and Gas Rules

8.3.1 Texas lacks oil and gas security requirements

In September 2011, there were over 261,400 producing oil and gas wells in Texas, which were regulated by the Railroad Commission of Texas (RRC). Title 16, Chapter 3, Rule § 3.3, *Identification of Properties, Wells, and Tanks*, requires all oil and gas production facilities to post identification signs displaying the name of the property (as shown on RRC records), the name of the operator, and related information, but does not require fencing, warning signs, or locked tank hatches for tanks without hydrogen sulfide.[36] The RRC does not have requirements for using inherently safer tank design to prevent an internal vapor explosion.

8.3.2 Hydrogen Sulfide Storage Tanks

As in Mississippi and Oklahoma, the RRC has stronger requirements for oil and gas production and storage sites where hydrogen sulfide is present. Under Texas Administrative Code Title 16, Chapter 3, Rule § 3.36, oil and gas production wells with hydrogen sulfide are required to post a warning sign 50 feet from the facility to warn of the dangers.[37] Fencing is also required as a security measure if the oil and gas well site is located inside the limits of a township or city. If the concentration of hydrogen sulfide gas exceeds 100 ppm and the radius of exposure exceeds 50 feet, warning signs must be posted on access roads or public streets. If the concentration of hydrogen sulfide is less than 100 ppm, the lease is not subject to the RRC's hydrogen sulfide rule and lease access and warnings to the public are determined by the operator.

[36] Railroad Commission of Texas; Ch. 3, Oil and Gas Division; Rule 3.36, Gas or Geothermal Resources Operations in Hydrogen Sulfide Areas.

[37] Texas Administrative Code Title 16, Economic Regulation; Part 1, Railroad Commission of Texas; Ch. 3, Oil and Gas Division; Rule 3.36, Gas or Geothermal Resources Operations in Hydrogen Sulfide Areas.

8.3.3 State/Municipal Storage Tank Site Security Policies

The CSB reviewed state and local regulations in states with active oil and gas extraction operations, focusing on areas with a high production volume and areas where oil tank explosions have occurred affecting members of the public.

The CSB found a lack of consistent state or municipal regulations for perimeter fencing, hatch locks, and warning signage. The 26 incidents identified by the CSB occurred in ten states. The CSB reviewed the regulations in these states and determined that there is a wide disparity in requirements from state to state. Ohio and California appeared to have the most extensive regulations related to tank security, while some states had no requirements at all. Table 1 summarizes the findings of the analysis.

Table 1: Summary of Oil and Gas Rules in Urban and Rural Areas

Summary of Oil and Gas Rules in Urban (U) and Rural (R) Areas											
Jurisdiction	Fences		Hatch Locks		Warning Signs		Gates		Flame Arrestors		Comments
	U	R	U	R	U	R	U	R	U	R	
California	Y	Y	N*	N*	N	N	N	N	N	N	*Bolted hatches (air emission requirement)
Colorado	Y	N	N*	N	Y**	Y**	Y	Y	N	N	*Gauge hatches to be closed **Prohibit smoking near flammables
Kentucky	N	N	N	N	N	N	N	N	N	N	
Louisiana	N*	N	N	N	N	N	N	N	N	N	*Requires dike/ firewall around tanks in urban areas
Mississippi	N	N	N	N	N	N	N	N	N	N	H_2S sites require fencing, signs and secured hatches
New Mexico	Y	N*	N	N	N	N	N	N*	N	N	*Fencing and gates required for low grade tanks/pits
Ohio	Y	N	Y	N	Y	N	Y	N	Y	N	
Oklahoma	N	N	N	N	N	N	N	N	N	N	
Texas	N	N	N	N	Y	Y	N	N	N	N	Warning signs specific to tank batteries
Los Angeles	Y	Y	N/A*	N/A*	N	N	Y	Y	Y	Y	*Req vapor recovery system and bolted hatches by state
Forrest County, Mississippi	N/A	Y	N	N	N/A	Y*	N/A	Y*	N	N	*Operators restrict use with locking mechanism
City of Laurel, Mississippi	Y	N/A	N	N/A	Y	N/A	Y	N/A	N	N/A	

8.4 Other State Oil and Gas Rules

8.4.1 Ohio Oil and Gas Rules

The Ohio Department of Mineral Resources Management has stronger requirements for tank storage facilities within city limits than in rural areas. Prior to 2004, oil and gas drilling was not permitted in urban areas. However, State House Bill 278 (The Urban Drilling Law) allowed drilling in areas with a population of 5,000 or more people and developed rules to adequately protect the public from the hazards. In urban areas, the law requires oil and gas producers to erect eight-foot-high chain-link fences with three strands of barbed wire around storage tanks, separators, and associated production equipment.[38] The rules require tanks to have spark or lightning arrestors and hatches that are secured at all times. Sites are required to have signs warning against entry and prohibiting smoking. In rural areas, lesser requirements apply.

Figure 8-2: Tank battery in Los Angeles, California

8.4.2 California Oil and Gas Rules

There are over 53,800 producing oil and gas wells in California regulated by the California Department of Conservation, Division of Oil, Gas and Geothermal Resources.[39] However, none of the 26 incidents identified by the CSB occurred in California. The CSB found California was the only state to require some type of fencing in both urban and rural areas for E&P facilities. Title 14 of the California

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[38] Ohio Department of Mineral Management. 1501:9-9-05 Producing operations.

[39] California Department of Conservation, Division of Oil, Gas and Geothermal Resources. 2009 Annual Report of the State Oil & Gas Supervisor. < ftp://ftp.consrv.ca.gov/pub/oil/annual_reports/2009/PR06_Annual_2009.pdf.>

Code of Regulations requires that all oil and gas equipment located in urban areas be fenced with chain-link perimeter fencing extending a minimum of five feet high with three strands of barbed wire. In rural areas, oil and gas producers can choose whether to install a five-foot chain-link fence as required in the urban areas or a fence constructed of barbed wire or commercial livestock wire netting extending at least four feet high.[40] The rules require identification signs but not warning signs. As a result of more stringent air pollution rules in California, oil and gas storage tanks in air pollution non-attainment areas do not have an atmospheric vent pipe and the hatch is bolted to the top of the tank. Under California clean air requirements enforced by local air resource boards, tank vapors are routed to vapor recovery systems (Figure 8-2). These systems make it virtually impossible to ignite the flammable vapors inside the tank because the atmosphere is too rich to burn.

8.5 Federal Regulations

8.5.1 Federal OSHA Regulations

The federal regulatory framework for E&P facilities includes measures to protect workers onsite and other measures to protect the health and safety of members of the public offsite. The Federal Occupational Safety and Health Administration (OSHA) has regulatory standards that are designed solely to protect workers while the Environmental Protection Agency (EPA) and the Department of Homeland Security (DHS)[41] have regulations intended to protect members of the public outside of facilities. The CSB found no current federal regulatory standards to protect members of the public, including children and young adults, who enter unattended oil sites without authorization.

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[40] California Code of Regulations, Title 14: Natural Resources, Article 3: 1778. Enclosure Specifications. California Environmental Protection Agency. Air Resources Board. Vapor Recovery Health and Safety Code Statutes. <http://www.arb.ca.gov/regact/2011/evr11/gdfhapp3.pdf>

[41] The Department of Homeland Security promulgated the Chemical Facility Anti-Terrorism Standards to protect U.S. chemical facilities from acts of terrorism. Covered facilities must submit a performance based security plan. DHS does not consider E&P facilities to be a significant risk for acts of terrorism; therefore they do not submit a security plan.

The CSB noted that OSHA has promulgated several standards that include protections for employees working at oil production sites that may also provide a certain degree of protection for members of the public. The most relevant are the storage tank provisions in the Hazard Communication Standard (29 CFR 1910.1200) and the Flammable and Combustible Liquids Standard (1926.152).

8.5.2 The Hazard Communication Standard (29 CFR 1910.1200)

The OSHA Hazard Communication Standard requires employers to ensure that each container of hazardous chemicals in the workplace is labeled, tagged, or marked with the identity of the hazardous chemicals and an appropriate hazard warning.[42] Contrary to the Hazard Communication Standard, many of the oil and gas production sites examined by CSB investigators did not identify the hazardous chemicals contained in storage tanks or provide appropriate hazard warnings.[43] Moreover, OSHA permits employers to use labeling systems with various codes, symbols, and/or numeric ratings that may not be understood by the public. The oil and gas storage sites visited by the CSB did not contain such symbols or numeric ratings.

8.5.3 Flammable and Combustible Liquids Standard (29 CFR 1910.106)

OSHA's Flammable and Combustible Liquids Standard is another occupational regulation that may offer overlapping protections to members of the public. Although the standard is outdated, based on the 1969 version of NFPA 30, it does address many safety issues for aboveground storage tanks including design, construction and installation, corrosion protection, instrumentation, normal vent and emergency relief devices, fire protection, and controlling sources of ignition. However, the OSHA standard has no

[42] Occupational Health and Safety Administration. 29 CFR 1910.1200(f)(5)(i)-(ii).

[43] For a detailed discussion and analysis of this issue, see Section 5.3 of the CSB Investigation Report on the Vapor Cloud Deflagration and Fire that occurred at the BLSR Operating Ltd in Rosharon, Texas on January 13, 2003. (Report No. 2003-06-I-TX).

requirements for security or fencing. The standard also exempts crude oil tanks at E&P facilities from requirements for venting valves and flame arrestors.

8.6 Environmental Protection Agency (EPA)

In contrast to OSHA, the EPA has jurisdiction to regulate oil and gas storage sites for the protection of human health and the environment. Accordingly, the agency administers a number of environmental statutes relevant to oil and gas production, including the Clean Air Act (CAA); the Clean Water Act (CWA); the Comprehensive Environmental Response, Compensation, and Liability Act (CERCLA or Superfund); the Resource Conservation and Recovery Act (RCRA); and the Toxic Substances Control Act (TSCA). However, many of these statutes contain various exemptions applicable to oil and gas well sites.

8.6.1 Clean Water Act (CWA)

The Federal Water Pollution Control Act of 1972, as amended, or CWA, is the principal federal statute for protecting navigable waters, adjoining shorelines, and the waters of the contiguous zone from pollution. Section 311 addresses the control of oil and hazardous substance discharges and provides the authority for a program to prevent, prepare for, and respond to such discharges. Specifically, §311(j)(1)(C) mandates regulations establishing procedures, methods, equipment, and other requirements to prevent and contain discharges of oil[44] from facilities and vessels.

8.6.1.1 Spill Prevention Control and Countermeasure (SPCC) Rule

The SPCC regulation promulgated by EPA under the CWA, has been in effect since January 10, 1974 (38 FR 34164). The 1974 SPCC Rule established oil discharge prevention procedures, methods, and

[44] Under CWA §311(a)(1), "oil" means "oil of any kind or in any form."

equipment requirements for non-transportation-related facilities with an aboveground oil storage capacity greater than 1,320 gallons (or greater than 660 gallons in a single aboveground tank) or a buried underground oil storage capacity greater than 42,000 gallons. Regulated facilities were also limited to those that, because of their location, could reasonably be expected to discharge oil into the navigable waters of the U.S. or adjoining shorelines. Subparagraph (e)(5)(iii) contains specific requirements for bulk storage tanks at onshore oil production facilities, which are defined in subparagraph (e)(5)(i) as including "all wells, flowlines, separation equipment, storage facilities, gathering lines, and auxiliary non-transportation-related equipment and facilities in a single geographical oil or gas field operated by a single operator."[45]

These requirements address the need for storage tank construction to be compatible with the oil being stored, secondary containment to catch spills, periodic inspection and maintenance, and installation of fail-safe devices to prevent overflow and collapse. Under the security provisions for unattended SPCC facilities, "All plants handling, processing, and storing oil should be fully fenced, and entrance gates should be locked and/or guarded when the plant is not in production or is unattended." However, oil production facilities (see subparagraph (e)(9)(i)), were specifically excluded from compliance with these requirements.[46]

8.6.2 Clean Air Act Amendments

Following a series of chemical accidents in the U.S. and overseas, Congress enacted the Clean Air Act Amendments (CAAA) of 1990. Under 42 U.S.C. § 7412 (r), owners and operators of stationary sources[47]

[45] The US Environmental Protection Agency. SPCC Guidance for Regional Inspectors, US EPA, Version 1.1, 3/14/2006 p. 1-2.

[46] 38 FR 34168-70.

[47] Stationary source means any buildings, structures, equipment, installations, or substance-emitting stationary activities that belong to the same industrial group, which are located on one or more contiguous properties and under the control of the same person (or persons under common control), and from which an accidental release may occur (63 FR 645).

must identify hazards, prevent, and minimize the effect of accidental releases whenever extremely hazardous substances are present at their facility.[48]

This section of the CAAA required the EPA to promulgate an initial list of at least 100 substances that, in the event of an accidental release, "are known to cause or may reasonably be anticipated to cause death, injury, or serious adverse effects to human health or the environment." Stationary sources that have more than a threshold quantity of a regulated substance are subject to accident prevention regulations, including the requirement to develop a risk management plan (RMP).[49]

E&P facilities were originally considered for coverage under the RMP rule. However, in 1995, the American Petroleum Institute (API) submitted an analysis[50] to the EPA docket that argued for removing the facilities from the scope of the rule asserting that the facilities did not pose a significant flammable or toxic hazard offsite. In January 1998, the EPA agreed to an exemption, stating the "EPA believes regulated flammable substances in naturally occurring hydrocarbon mixtures, [51] such as crude oil, that contain many non-volatile components, are unlikely to form large vapor clouds and therefore, generally have low potential for vapor cloud explosions. EPA considers vapor cloud explosions the consequence of greatest concern for flammable substances." EPA further stated that "the general duty clause of section 112(r)(1) would apply when site-specific factors make an unlisted chemical extremely hazardous." [52]

[48] *Guidance for the Implementation of the General Duty Clause of the Clean Air Act, Section 112(r)(1)*, US EPA, Publication No. EPA 550-B00-002, May 2000, page 2.

[49] 63 FR 640, 640 (January 6, 1998).

[50] Hazard Assessment of Exploration and Production Facilities Potentially Subject to the Environmental Protection Agency's Risk Management Program regulations (API, January 20, 1995).

[51] EPA defines naturally occurring hydrocarbon mixtures as any or all combination of the following: natural gas condensate, crude oil, field gas, and produced water.

[52] 63 FR 642.

8.6.2.1 The General Duty Clause

The Clean Air Act Amendments include a "general duty clause" which holds owners and operators responsible for preventing chemical accidents involving extremely hazardous substances. The clause states that:

> *It shall be the objective of the regulations and programs authorized under this subsection to prevent the accidental release and to minimize the consequences of any such release of any substance listed pursuant to paragraph (3) or any other extremely hazardous substance. The owners and operators of stationary sources producing, processing, handling or storing such substances have a general duty, in the same manner and to the same extent as section 654, title 29 of the United States Code, to identify hazards which may result from such releases using appropriate hazard assessment techniques, to design and maintain a safe facility taking such steps as are necessary to prevent releases, and to minimize the consequences of accidental releases which do occur.*

As part of their responsibility, industries have developed standards and generally accepted safe practices to address the risks posed by extremely hazardous substances.[53] The EPA recommends that owners and operators handling extremely hazardous substances "adhere to a recognized industry standard and practices (as well as government regulations)" to comply with the general duty clause. The EPA advises that when site specific conditions create "unique circumstances" that render some standards "inapplicable," the Agency "may exercise its authority to require an owner or operator to implement additional measures to address the hazard."

To advise the regulated community of its general duty clause obligations, the EPA has published a number of Chemical Safety Alerts. Alerts have addressed a variety of subjects including pressure vessel hazards, lightning hazards to facilities handling flammables, and the catastrophic failure of storage tanks. Security guidance similar to the "Chemical Accident Prevention: Site Security" and "Anhydrous

[53] Although there is no definition for extremely hazardous substances, the legislative history of the 1990 Clean Air Act Amendments suggests criteria which EPA may use to determine if a substance is extremely hazardous. The Senate Report stated the intent that the term "extremely hazardous substance" would include any agent "which may or may not be listed or otherwise identified by any Government agency which may as the result of short-term exposures associated with releases to the air cause death, injury or property damage due to its toxicity, reactivity, flammability, volatility, or corrosivity" (Senate Committee on Environment and Public Works, Clean Air Act Amendments of 1989, Senate Report No. 228, 101st Congress, 1st Session 211 (1989).

Ammonia Theft" safety alerts published under the general duty clause would alert operators to the security precautions necessary to prohibit members of the public from entering oil and gas storage facilities. Based on flammability, hydrocarbons stored at E&P facilities would meet the definition of extremely hazardous substances and thus be subject to the CAAA general duty clause.

8.7 Industry Standards and Guidance

The CSB determined that there are currently no comprehensive, specific industry standards or guidance addressing the safety of members of the public at oil and gas sites. The CSB noted some provisions in existing API and NFPA guidance documents that provide limited protections.

8.7.1 American Petroleum Institute (API)

API is a national trade association that represents the oil and natural gas industry and also develops industry standards, recommended practices, and codes.[54] Although they are voluntary, API standards are widely utilized by the energy industry. API standards that are relevant to E&P storage tanks include API 2610 and API 74.

8.7.2 API Standard 2610

API Standard 2610, Design, Construction, Operation, Maintenance and Inspection of Terminal & Tank Facilities (2nd ed.), issued in May 2005, applies to downstream facilities that store refined petroleum products. Section 13.3.6 of API 2610 discusses security measures such as fencing, perimeter lighting, and preventing tank access.[55] The standard recommends that covered facilities be fenced to "maintain facility security and prevent product loss and vandalism," and that "barriers can be added to tank external ladders or stairways to restrict access." The EPA lists API 2610 as a standard that can assist owners and

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[54] The American Petroleum Institute. About API. <www.api.org/aboutapi>.

[55] The American Petroleum Institute. API 2610, Second Edition, May 2005.

operators of SPCC-covered facilities with security plans. However, the scope of API 2610 specifically excludes "[t]anks that are part of oil and gas production, natural gas processing plants, or offshore operations." Nonetheless, the incidents involving public fatalities and injuries at E&P sites demonstrate that these facilities are subject to similar fire and explosion hazards as storage sites in the downstream or refining sector.

8.7.3 API Recommended Practice 74

API Recommended Practice 74, Occupational Safety for Onshore Oil and Gas Production Operation, was developed in response to a CSB safety recommendation that resulted from a 1998 explosion that killed four workers at a Louisiana oil and gas production facility. It includes safety guidance for fire prevention and protection, such as designating areas where there are fire hazards, prohibiting smoking and ignition sources within those areas, posting conspicuous warning signs, and properly labeling tanks that contain flammable liquids. Appendix A of API 74 includes a checklist of questions for periodically assessing safety at oil production facilities.[56] Some questions, for example, suggest that operators verify the posting of "No Smoking," "No Trespassing," and/or "Authorized Personnel Only" signs at oil site entrances. Other checklist questions ask whether "ladders are caged when over 20 feet," if the "access opening to the ladders [is] provided with a swinging gate or chain closure," and whether "tank thief hatches seal or are in good repair."

Beyond these appendix questions, however, the main sections of API 74 include no guidance on requirements for fencing, physical barriers, or security gates to prevent access to tank catwalks and tank hatches; hatch locking mechanisms; or specific tank explosion warning signs to prevent fatal incidents due to unauthorized entry. As currently written, API 74 primarily focuses on occupational safety requirements, containing only limited recommendations for public protection.

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[56] The American Petroleum Institute. API RP 74, Appendix A, p. 17.

8.7.4 API Oil and Natural Gas Industry Security Assessment and Guidance

Following the 9/11 attacks, the API assessed the E&P sector for security vulnerabilities. The API assessment found most E&P facilities produce low quantities of product; over 75 percent of U.S. oil wells are "stripper" wells that produce fewer than 10 barrels of oil daily. Most are located in rural areas. To provide safety and security, the API suggested the use of the following standards:

- Recommended Practice 49, Drilling and Well Servicing Operations Involving Hydrogen Sulfide
- Recommended Practice 54, Occupational Safety for Oil and Gas Well Drilling and Servicing Operations
- Recommended Practice 74, Occupational Safety for Onshore Oil and Gas Production Operations
- Publication 761, Model Risk Management Plan for E&P Facilities

Of these standards, only API 54 recommends labeling of tanks "to denote their flammable contents" (API 54 Section 8.4.4).

8.7.5 National Fire Protection Association (NFPA)

The NFPA is a non-profit organization that develops and advocates consensus codes and standards for fire protection and prevention. The codes and standards are voluntary unless adopted by law or regulation. The codes are used as good-practice guidance by industry, insurance companies, engineers, and safety professionals. There are three NFPA codes that address security measures for various sectors, but these are not specific to E&P facilities. These codes include NFPA 30, Flammable and Combustible Liquids Code (2008); NFPA 30A, Code for Motor Fuel Dispensing Facilities and Repair Garages (2008); and NFPA 730, Guide for Premises Security (2008).[57]

[57] The National Fire Protection Administration. Codes and Standards. Retrieved from <www.nfpa.org/assets/files/PDF/CodesStandards/Directory/NFPADirectory2010.pdf>

8.7.6 NFPA 30

NFPA 30, the Flammable and Combustible Liquids Code (2008), applies to the storage, handling, and use of flammable and combustible liquids, including waste liquids. Section 21 requires the use of flame arrestors when storing certain flammable liquids (Class 1B and IC) and Annex A suggests their use to stop the propagation of a flame inside a tank. Section 22 has requirements for storing liquids in aboveground tanks including location and installation, normal and emergency venting, fire protection, spill control, collision protection, and maintenance. In the 1990 edition, the NFPA added subsection 2-9.3 which states that “unsupervised, isolated aboveground storage tanks shall be secured and marked in such a manner as to identify the fire hazards of the tank and its contents to the general public.” The 2008 edition further states “where necessary, to protect the tank from tampering or trespassing, the area where the tank is located shall be secured.” The NFPA justified the provision based on “several recent tank explosions caused by youngsters who have trespassed in and on tanks.” However, the code has no specific requirements for security or fencing. The CSB learned that 44 states[58] have adopted a version of NFPA 30 (ranging from the 1990 to 2008 editions).

8.7.7 NFPA 30A

NFPA 30A, the Code for Motor Fuel Dispensing Facilities and Repair Garages (2008), provides guidance to reduce hazards of motor fuels from marine/motor fuel-dispensing facilities located inside buildings, at fleet vehicle motor fuel facilities, farms, isolated construction sites, and motor vehicle repair garages. Section 4.3.7 contains requirements to physically protect aboveground tanks. If tanks are not enclosed in a vault, or if the property lacks a perimeter security fence, the code requires a secured gate and a chain link fence, at least 1.8 meters (6 feet) high and separated from the tanks by at least 3 meters (10 feet). Section 13.3 includes requirements for marking tanks and containers: they must be “conspicuously marked” with the name of the product and “FLAMMABLE – KEEP FIRE AND FLAME AWAY.” The EPA lists this

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[58] The National Fire Protection Association. Editions Currently Adopted. <NFPA.org>.

standard as a guideline for security for SPCC-covered facilities. However, NFPA 30A does not apply to E&P facilities.

8.7.8 NFPA 730

NFPA 730, Guide for Premises Security (2008), describes construction, protection, occupancy features, and practices intended to reduce security vulnerabilities to life and property. As a guide, this NFPA document is advisory and informational and contains only non-mandatory provisions; the NFPA does not deem the document, as a whole, to be suitable for adoption into law. Chapter 6 discusses requirements for exterior security devices and systems for perimeter protection of facilities and lists detailed specifications for chain link fencing, including design, location of the fence line, signs, height, posts, bracing, top guards, entrances and locks, lighting, and maintenance. Although Chapters 11 through 22 contain specific requirements for different types of facilities (e.g., restaurants, shopping centers, industrial facilities, etc.), there are no specific requirements for oil production sites. However, assuming that such sites can be considered industrial facilities, the guide recommends that access to critical assets be restricted by establishing a secure perimeter accessible only to employees, authorized vendors and contractors, and escorted visitors. Moreover, the guide recommends the following:

> *All industrial companies, big and small, should have site security programs in place to minimize security vulnerabilities and to protect company assets. This is especially true for facilities that handle extremely hazardous substances.*

9.0 CSB Findings

The CSB found that the three incidents in Mississippi, Oklahoma, and Texas, could likely have been prevented by restricting access to the oil and gas production facilities and providing appropriate warning signage, hatch locks, or other appropriate security alternatives; or utilizing inherently safer tank design alternatives. The ease of accessibility and a lack of awareness of the hazards associated with the storage tanks, coupled with the number of oil and gas facilities nationally, demonstrate a potential for similar incidents to occur. The CSB makes the following key findings:

1. Members of the public, most often children and young adults, commonly visit oil and gas production sites without authorization for recreational purposes.

2. Members of the public gain access to production tanks via attached unsecured ladders and catwalks, and may come into contact with flammable vapors from tank vents or unsecured tank hatches.

3. Members of the public, unaware of the explosion and fire hazards associated with the tanks, unintentionally introduce ignition sources for the flammable vapor, leading to explosions.

4. The CSB identified 26 similar incidents between 1983 and 2010, which resulted in a total of 44 fatalities and 25 injuries. All the victims were 25 years of age or less.

5. The three incidents investigated by the CSB in 2009-2010 occurred in isolated, rural wooded areas at production sites that were unfenced, did not have clear or legible warning signs, as required under OSHA's Hazard Communication Standard, and did not have hatch locks to prevent access to the flammable hydrocarbons inside the tanks.

6. The storage tanks did not include inherently safer design features to prevent tank explosions. Safer design features used in the downstream, refining sector would likely prevent tank explosions at E&P sites. These include the use of vents fitted with pressure-vacuum devices, flame arrestors, vapor recovery systems, floating roofs or an equivalent alternative.

7. E&P storage tanks are exempt from the security requirements of the Clean Water Act and from the risk management requirements of the Clean Air Act.

8. Industry guidance from the American Petroleum Institute recommends specific security measures for storage tanks of refined petroleum products but not for storage tanks at upstream E&P sites, and the National Fire Protection Association standards do not adequately define security expectations where these deadly incidents occurred.

9. Some states, including California and Ohio, and some localities have mandated security (including fencing, locked or sealed tank hatches, and warning signs) for E&P sites, particularly in urban areas. As a result, despite its large role as an oil producing state with many of these types of facilities, none of the 26 incidents occurred in California. However, many other large oil and gas producing states have no such requirements (except for certain E&P sites where toxic hydrogen sulfide gas is present).

10.0 Recommendations

The CSB makes the following recommendations:

The Environmental Protection Agency

2011-H-1-R01

Publish a safety alert directed to owners and operators of exploration and production facilities with flammable storage tanks, advising them of their general duty clause responsibilities for accident prevention under the Clean Air Act. At a minimum, the safety alert should:

a) Warn that storage tanks at unmanned facilities may be subject to tampering or introduction of ignition sources by members of the public, which could result in a tank explosion or other accidental release to the environment

b) Recommend the use of inherently safer storage tank design features to reduce the likelihood of explosions, including restrictions on the use of open vents for flammable hydrocarbons, flame arrestors, pressure vacuum vent valves, floating roofs, vapor recovery systems or an equivalent alternative.

c) Describe sufficient security measures to prevent non-employee access to flammable storage tanks, including such measures as a full fence surrounding the tank with locked gate, hatch locks on tank manways, and barriers securely attached to tank external ladders or stairways

d) Recommend that hazard signs or placards be displayed on or near tanks to identify the fire and explosion hazards using words and symbols recognizable by the general public

The Mississippi Oil and Gas Board

2011-H-1-R02

Amend state oil and gas regulations to require the use of inherently safer tank design features such as flame arrestors, pressure vacuum vents, floating roofs, vapor recovery systems or an equivalent alternative, to prevent the ignition of a flammable atmosphere inside the tank.

Oklahoma Corporation Commission

2011-H-1-R03

Amend state oil and gas regulations to:

a) Protect storage tanks at exploration and production sites from public access by requiring sufficient security measures, such as full fencing with a locked gate, hatch locks on tank manways, and barriers securely attached to tank external ladders and stairways.

b) Require hazards signs or placards on or near tanks that identify the fire and explosion hazards using words and symbols recognizable by the general public.

c) Require the use of inherently safer tank design features such as flame arrestors, pressure vacuum vents, floating roofs, vapor recovery systems or an equivalent alternative, to prevent the ignition of a flammable atmosphere inside the tank.

The Texas Railroad Commission (RRC)

2011-H-1-R04

Amend state oil and gas regulations to:

a) Protect storage tanks at exploration and production sites from public access by requiring sufficient security measures, such as full fencing with a locked gate, hatch locks on tank manways, and barriers securely attached to tank external ladders and stairways.

b) Require hazards signs or placards on or near tanks that identify the fire and explosion hazards using words and symbols recognizable to the general public.

c) Require the use of inherently safer tank design features such as flame arrestors, pressure vacuum vents, floating roofs, vapor recovery systems or an equivalent alternative to prevent the ignition of a flammable atmosphere inside the tank.

American Petroleum Institute

2011-H-1-R05

Create a new standard or amend existing standards covering exploration and production facilities to:

a) Warn that storage tanks at unmanned facilities may be subject to tampering or introduction of ignition sources by members of the public, which could result in a tank explosion or other accidental release to the environment.

b) Recommend the use inherently safer storage tank design features to reduce the likelihood of explosions, including restrictions on the use of open vents for flammable hydrocarbons, flame arrestors, pressure vacuum vent valves, floating roofs, vapor recovery systems or an equivalent alternative.

c) Require security measures at least as protective as API 2610 to prevent non-employee access to flammable storage tanks at upstream E&P sites, including such measures as a full fence surrounding the tank(s) with a locked gate, hatch locks on tank manways, and barriers securely attached to tank external ladders or stairways.

d) Require that hazard signs or placards be displayed on or near tanks to identify the fire and explosion hazards using words and symbols recognizable by the general public.

e) Recommend that new or revised mineral leasing agreements include security and signage requirements as described above.

The National Fire Protection Association

2011-H-1-R06

Amend NFPA 30, "Storage of Liquids in Tanks—Requirements for all Storage Tanks" as follows:

a) Remove the term "isolated" from the current wording of the standard and replace it with a more descriptive term, such as "normally unoccupied"

a) Remove the words "Where necessary" from Security for Unsupervised Storage Tanks, Chapter 21.7.2.2.

b) Add a reference to a relevant security standard that offers specifications on fencing, locks and other site security measures.

c) Add a definition of security encompassing requirements such as fencing, locked gates, hatch locks, and barriers.

By the

U.S. Chemical Safety and Hazard Investigation Board

The Honorable Rafael Moure Eraso

Chair

The Honorable John S. Bresland

Member

The Honorable Mark Griffon

Member

Date of Board Approval

11.0 Appendix A: Previous Incidents

Rio Blanco County, Colorado, June 24, 2007: 2 Teen Fatalities[59]

On June 24, 2007, in Rio Blanco County, Colorado, a tank exploded when a group of 15 to 20 teens and young adults were socializing near an oil tank storage site. The site was located along an access road on public land leased from the National Forest Service. The production site had two 400-barrel capacity tanks with atmospheric vent pipes; one contained 60 barrels and the other contained 120 barrels of oil. The youths had built a campfire approximately 50 to 60 yards from a group of oil tanks and two or three individuals and a dog climbed onto the tanks. Witnesses indicated that these individuals were jumping on the tanks when the witnesses heard a hissing coming from the tanks. Approximately 10 minutes later, an explosion propelled the bottom of one tank 80 to 100 yards away from its original location. The force of the explosion killed the two teens jumping on the tanks. The oil site was located in an isolated area and the embankment surrounding the tanks had a steel construction type pipe fence around it, intended to restrict cattle. The Colorado Bureau of Investigations (CBI) determined a lighter to be the likely ignition source and recommended that fencing be placed around the pumping unit and pit area.

Mercedes, Texas, May 17, 2007: 3 Teen Fatalities[60]

A tank explosion on May 17, 2007, in Mercedes, Texas, killed three teens. Shoe prints were found on top of the tank, indicating that the teens were likely on top of the tank prior to the explosion; a cigarette lighter was also found. The tank was easily accessible and was a regular hangout for the teens.

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[59] Colorado Bureau of Investigations

[60] Hidalgo County Fire Marshal's Office

Long Lake, Texas, April 11, 2003: 4 Teen Fatalities[61]

A tank explosion on April 11, 2003, in Anderson County, Texas, killed three teens instantly; another died later of his injuries. Five teens had gathered at a remote oil site to socialize. They climbed the catwalk that accessed several tanks. They climbed to the top of the tank when one teenager climbed back down to the catwalk, opened an access hatch to one of the tanks, and looked inside. He returned to his spot on top of one of the tanks while one of his friends climbed down to look inside the tank, using a lighter to see the contents more clearly. The tank exploded fatally injuring three, seriously injuring one teen and leaving one with minor injuries. The site had no fences or warning signs.

Heflin, Louisiana, May 26, 2001: 1 Teen Fatality [62]

An oil tank incident on May 26, 2001, in Heflin, Louisiana, killed one teen, severely burned another, and left a third with minor burns. Six teens gathered at an oil site at approximately 5:00 a.m., when three of the six climbed the catwalk of a tank, which allowed access to the tops of three oil tanks. One teen climbed the center tank; another joined him, but became frightened while on the tank and climbed back down to the catwalk. The teen on top of the tank was smoking a cigarette, which likely ignited flammable fumes venting from the tank, causing the explosion. The force from the explosion threw the teen approximately 96 feet from the tank, killing him. Another teen on the catwalk was doused in burning liquid and severely burned. The third received minor burns.

[61] Anderson County Sheriff Department
[62] Webster Parish Sheriff's Office

Oil and Gas Storage Site Explosions, 1983-2010							
	Date	**City**	**State**	**Fatality**	**Injury**	**Incident Summary**	**Fencing Required**
1	4/2/1983	Center	TX	2	0	Explosions blew apart two storage tanks of gas distillate killing two fourteen-year-old girls playing nearby; four other youths escaped uninjured.	No
2	6/24/1985	Centralia	IL	1	4	Firecrackers tossed into a 10-ft oil tank triggered an explosion and killed one teenager and injured four, including the father of a victim. The blast sprayed crude oil on homes nearly 100 yards away.	No
3	5/16/1990	Beggs	OK	3	0	An oil storage tank exploded, killing three men in their early 20s when one of the men attempted to light a cigarette.	No
4	8/19/1990	Logansport	LA	4	0	Four people, including two teenage sisters, were killed when a storage tank exploded. The victims appeared to be climbing a ladder to the top of the tank when the explosion happened.	No
5	6/19/1991	Oklahoma City	OK	1	0	A 13-year-old boy playing atop an oil field salt water tank was killed by an explosion triggered when he apparently struck a match. His body was thrown 60 yards by the blast.	Yes (Urban)
6	10/28/1991	Tyler County	TX	0	2	An adult and a teenager were injured when an oil storage tank exploded, igniting four other tanks when one of the victims lit a cigarette lighter near the storage tank's open hatch.	No
7	9/22/1992	Sherman	TX	1	4	A tank explosion killed a teenager and injured four others at a tank farm where seven teenagers were partying after four teens climbed a tank and lit a match to see inside.	Yes (Urban)

	Date	City	State	Fatality	Injury	Incident Summary	Fencing Required
8	7/2/1993	Providence	KY	4	5	Four teenagers were killed and five others injured in a crude oil storage tank explosion triggered by a cigarette at a party. The victims were sitting on top the tank when it exploded.	No
9	4/23/1995	Duncan	OK	3	0	An oil field blast killed three 13-year-old boys while playing near two remote oil field storage tanks.	No
10	11/28/1995	Bradford	PA	2	0	A lit cigarette was blamed for an oil tank explosion that killed two 14-year-old boys playing on the tanks.	No
11	6/22/1997	Konawa	OK	2	0	Two teenagers, 15 and 13, died when they climbed a 20,000-gallon oil tank and lit fireworks, triggering an explosion.	No
12	7/29/1997	Chandlersville	OH	2	0	Two teenagers, 17 and 15, died when a 15-ft oil tank exploded, throwing their bodies more than 200 feet. The teens appeared to have been climbing the tank at the time of the explosion.	No
13	8/14/1998	Logan	OH	1	1	One young man was killed and a 16-year-old girl was seriously injured when an oil storage tank exploded, throwing their bodies about 100 feet. The oil tanks were not in use at the time of the explosion.	No
14	1/29/2000	Flora Vista	NM	1	1	A gas tank explosion killed one teenager and critically injured another when one of the boys apparently threw a lighter into the 12,000-gallon tank.	No
15	5/26/2001	Sibley	LA	1	1	One teenager was killed and another critically burned when an oil tank in an oil field exploded. Two of the five teens were sitting on the tank, and one was smoking a cigarette at the time of the explosion.	No

	Date	City	State	Fatality	Injury	Incident Summary	Fencing Required
16	11/30/2001	Duson	LA	0	1	An explosion in a crude oil storage tank threw a 14-year-old boy more than 100 feet as he was reportedly walking his dog in the surrounding fields.	No
17	4/11/2003	Long Lake (Palestine)	TX	4	0	Four teenagers died in an oil storage tank explosion when five teens climbed the tank and one opened the hatch. A cigarette lighter triggered the blast and the victims were thrown nearly 75 yards.	No
18	9/6/2003	Blue Rock	OH	0	2	Four individuals were socializing at an oil tank site when a tank exploded causing head injuries to two of the men. One of the men apparently lit a cigarette after climbing atop the tank.	No
19	5/14/2005	Ripley	OK	2	0	Two men ages 19 and 20 died from third-degree burns over 90 percent of their bodies after an oil storage tank exploded while they and two others were drinking at the site.	No
20	12/18/2006	Springtown	TX	1	1	Two teenagers, 16 and 14, at a tank battery dropped a burning paper into an unlocked tank hatch located inside a 5-ft high unlocked cattle fence. One victim was killed and the other injured.	No* (cattle fence)
21	3/12/2007	Oklahoma City	OK	0	1	A 15-year-old boy was critically injured after an explosion and fire at an oil tank battery burned more than 45 percent of his body. The cause of the explosion was unclear.	Yes (Urban)
22	5/18/2007	Mercedes	TX	3	0	Three teenagers were killed when a liquid storage tank exploded in a field after one of the teens apparently climbed onto the abandoned tank and opened the hatch.	No

	Date	City	State	Fatality	Injury	Incident Summary	Fencing Required
23	6/23/2007	Oak Creek	CO	2	0	A group of 15-20 teens partying at an oil storage site triggered a tank explosion killing two teens as they jumped on and smoked near the oil tanks.	Yes (Wildlife)
24	10/31/2009	Carnes	MS	2	0	Two teenagers socializing at a tank site were killed when an oil tank exploded in a wooded clearing approximately 150 yards from one of the victims' homes.	No
25	4/14/2010	Weleetka	OK	1	1	A group of 6 teenagers and young adults were socializing at an oil storage site when a tank exploded, fatally injuring one and causing second degree burns to another.	No
26	4/26/2010	New London	TX	1	1	Two young adults were socializing at an oil tank site when an explosion killed one and critically injured the other.	No

Sources: 1) Associated Press; 2) Chicago Tribune; 3) USA Today; 4) Washington Post; 5) Daily Oklahoman; 6) San Antonio Daily Express; 7) New York Times; 8) Associated Press/CSB Documents; 9) Daily Oklahoman; 10) Pittsburgh Gazette; 11) Associated Press; 12) Columbus Dispatch; 13) Associated Press/CSB Documents; 14) Albuquerque Tribune; 15) Associated Press/CSB Documents; 16) Daily Advertiser; 17) Associated Press; 18) Associated Press/CSB Documents; 19) Associated Press; 20) CSB Documents; 21) Daily Oklahoman; 22) Associated Press; 23) CSB Documents; 24) CSB Investigation; 25) CSB Investigation; 26) CSB Investigation

U.S. CHEMICAL SAFETY AND HAZARD INVESTIGATION BOARD

INVESTIGATION REPORT

CATASTROPHIC RUPTURE OF HEAT EXCHANGER (SEVEN FATALITIES)

TESORO ANACORTES REFINERY

ANACORTES, WASHINGTON
APRIL 2, 2010

KEY ISSUES

- INHERENTLY SAFER DESIGN
- TESORO PROCESS SAFETY CULTURE
- CONTROL OF NONROUTINE WORK
- MECHANICAL INTEGRITY INDUSTRY STANDARD DEFICIENCIES
- REGULATORY OVERSIGHT OF PETROLEUM REFINERIES

REPORT 2010-08-I-WA
MAY 2014

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Dedication

This report is dedicated to the two women and five men who lost their lives as a result of the Tesoro Anacortes Refinery incident on April 2, 2010.

Daniel Aldridge

Matthew Bowen

Matthew Gumbel

Darrin Hoines

Lew Janz

Kathryn Powell

Donna Van Dreumel

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Acronyms and Abbreviations

°F	degrees Fahrenheit
AcciMap	Accident Map
ALARP	As Low As Reasonably Practicable
AIHA	American Industrial Hygiene Association
ANSI	American National Standards Institute
API	American Petroleum Institute
API RP 571	API RP 571—Damage Mechanisms Affecting Fixed Equipment in the Refining Industry
API RP 580	API RP 580—Risk-Based Inspection
API RP 581	API RP 581—Risk-Based Inspection Technology
API RP 941	API RP 941—Steels for Hydrogen Service at Elevated Temperatures and Pressures in Petroleum Refineries and Petrochemical Plants
API RP[1]	API Recommended Practices. API standards that communicate recognized industry practices. Recommended practices (RPs) may include both mandatory and non-mandatory requirements. *Shall:* As used in a standard, "shall" denotes a minimum requirement in order to conform to the standard. *Should:* As used in a standard, "should" denotes a recommendation or that which is advised but not required in order to conform to the standard.
API Standard[2]	API Standards include Specifications, Recommended Practices, Standards, and Codes. Standards combine elements of both specifications and recommended practices. "Standard" is also a broad term covering all API documents that have been developed in accordance with API procedures for standards development.
API TR 941	API Technical Report 941—The Technical Basis Document for API RP 941
APOSC	Assessment Principles for Offshore Safety Cases
ASNT	American Society for Nondestructive Testing
AUBT	Advanced Ultrasonic Backscatter Technique
bpd	Barrels Per Day
CAA	Clean Air Act

1 http://www.api.org/publications-standards-and-statistics/~/media/Files/Publications/FAQ/2011-Procedures-Final.ashx *API Procedures for Standards Development.* 2011; p 3.

2 *Ibid* at pp 2-3.

Cal/OSHA	California Occupational Safety and Health Administration
CCPS	Center for Chemical Process Safety (American Institute of Chemical Engineers)
CFR	Code of Federal Regulations
CSB	U.S. Chemical Safety and Hazard Investigation Board
CSHO	Compliance Safety and Health Officer
DCS	Distributed Control System
DOSH	Division of Occupational Safety and Health (within Washington L&I)
DMHR	Damage Mechanism Hazard Review (also known as a corrosion review)
EPA	U.S. Environmental Protection Agency
HAZ	Heat Affected Zone
HSE	Health and Safety Executive
HTHA	High Temperature Hydrogen Attack
IOW	Integrity Operating Window
IST	Inherently Safer Technology
L&I	Washington State Department of Labor & Industries
MOC	Management of Change
MOOC	Management of Organizational Change
MSDS	Material Safety Data Sheet
NDE	Nondestructive Examination
NDT	Nondestructive Testing
NEJAC	National Environmental Justice Advisory Council
NEP	OSHA Petroleum Refinery Process Safety Management National Emphasis Program
NHT	Catalytic Reformer / Naphtha Hydrotreater Unit
NIST	National Institute of Standards and Technology
OSHA	U.S. Occupational Safety and Health Administration
OSHAct	Occupational Safety and Health Act of 1970, 29 U.S.C. 667
PHA	Process Hazard Analysis
PQV	PSM Program Quality Verification Inspection—referenced in OSHA's 1994 PSM Compliance Directive[3]
PSIA	Pounds Per Square Inch Absolute

[3] OSHA Instruction CPL 2-2.45A CH-1 September 13, 1994 Directorate of Compliance Programs, 29 CFR 1910.119, Process Safety Management of Highly Hazardous Chemicals -- Compliance Guidelines and Enforcement Procedures. https://www.osha.gov/pls/oshaweb/owadisp.show_document?p_table=DIRECTIVES&p_id=1559 (accessed December 28, 2013).

PSIG	Pounds Per Square Inch Gauge
PSM	Process Safety Management
PSM Standard	OSHA Process Safety Management of Highly Hazardous Chemicals Standard, 29 CFR §1910.119
PWHT	Post-Weld Heat Treatment
RAGAGEP	Recognized and Generally Accepted Good Engineering Practice
RBI	Risk-Based Inspection
RMP	Risk Management Plan (EPA), as defined in U.S.C. Section 42, Chapter 85, Subchapter I, Part A, Section 7412(r)
RP	Recommended Practice (API)
S-Scan	Sectorial Scan
SS	Stainless Steel
TOP	Triangle of Prevention
UK	United Kingdom
USW	United Steelworkers Union
UT	Ultrasonic Technique
WAC	Washington Administrative Code
WFMT	Wet Fluorescent Magnetic Particle Testing

1.0 Executive Summary

1.1 Incident Summary

On April 2, 2010, the Tesoro Refining and Marketing Company LLC ("Tesoro") petroleum refinery[4] in Anacortes, Washington ("the Tesoro Anacortes Refinery"), experienced a catastrophic rupture of a heat exchanger in the Catalytic Reformer / Naphtha Hydrotreater unit ("the NHT unit"). The heat exchanger, known as E-6600E ("the E heat exchanger"), catastrophically ruptured because of High Temperature Hydrogen Attack (HTHA).[5] Highly flammable hydrogen and naphtha at more than 500 degrees Fahrenheit (ºF) were released from the ruptured heat exchanger and ignited,[6] causing an explosion and an intense fire that burned for more than three hours. The rupture fatally injured seven Tesoro employees (one shift supervisor and six operators) who were working in the immediate vicinity of the heat exchanger at the time of the incident. To date this is the largest fatal incident at a US petroleum refinery since the BP Texas City accident in March 2005.[7]

The NHT unit at the Tesoro Anacortes Refinery contained two parallel groups, or banks, of three heat exchangers (A/B/C and D/E/F) used to preheat process fluid before it entered a reactor, where impurities were treated for subsequent removal. The E heat exchanger was constructed of carbon steel.[8] A schematic of the six heat exchangers is illustrated in Figure 1.

At the time of the release, the Tesoro workers were in the final stages of a startup activity to put the A/B/C bank of heat exchangers back in service following cleaning. The D/E/F heat exchangers remained in service during this operation. Because of the refinery's long history of frequent leaks and occasional fires during this startup activity, the CSB considers this work to be hazardous and nonroutine.[9] While the operations staff was performing the startup operations, the E heat exchanger in the middle of the operating D/E/F bank catastrophically ruptured.

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4 Tesoro purchased all of the Shell Oil Company's stock in the Shell Anacortes Refining Company in 1998. Approximately 350 employees are at the Anacortes refinery and 185 of them are operations and maintenance workers who are represented by the United Steelworkers union (USW).

5 HTHA is a damage mechanism that results in fissures and cracking and occurs when carbon steel equipment is exposed to hydrogen at high temperatures and pressures.

6 The autoignition temperature of a material is defined as the temperature at which it will ignite spontaneously on contact with oxygen, without spark or flame. The Tesoro Material Safety Data Sheet (MSDS) for naphtha listed autoignition temperature as 437 ºF. As the process temperature was more than 500 ºF, autoignition was likely.

7 The 2005 BP Texas City incident resulted in 15 fatalities and 180 injuries.

8 The portion of the E heat exchanger that failed was constructed of carbon steel. The details of the exchanger materials are addressed in Section 4.2.1, NHT Heat Exchanger Construction.

9 Nonroutine does not refer to the frequency at which the activity occurs. Nonroutine refers to whether the activity is part of the normal sequence of converting raw materials to finished products. Startup is considered a nonroutine activity. Center for Chemical Process Safety (CCPS), *Guidelines for Risk Based Process Safety*. 2007; p 286.

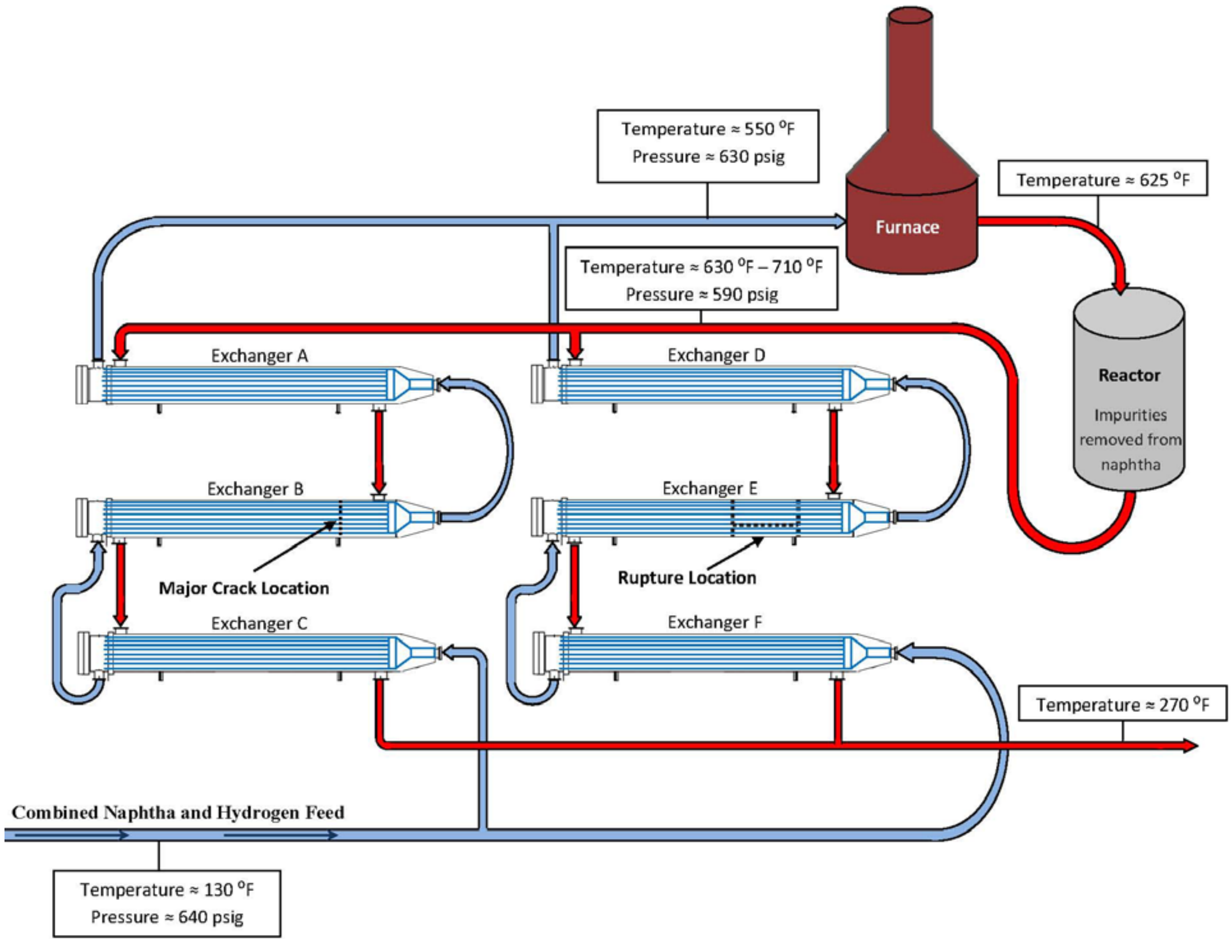

Figure 1. Schematic of the Tesoro Anacortes Refinery NHT Unit Heat Exchangers. There are two banks of three heat exchangers: A/B/C bank and D/E/F bank. The E heat exchanger catastrophically ruptured on April 2, 2010.

1.2 Key Findings

1.2.1 Technical Findings

1. The rupture of the E heat exchanger was the result of the carbon steel heat exchanger being severely weakened by a damage mechanism known as HTHA. The B heat exchanger did not fail, but was constructed with the same materials and operated under the same conditions as the E heat exchanger. The B heat exchanger was also severely weakened by HTHA damage. HTHA is a damage mechanism that results in fissures and cracking and occurs when carbon steel equipment

is exposed to hydrogen at high temperatures and pressures.[10] The resulting damage severely degrades the mechanical properties of the steel.[11] (Section 4.1)

2. HTHA can accumulate in high-stress areas in carbon steel, such as non-post-weld heat-treated welds. The welds of the B and E carbon steel heat exchangers were not post-weld heat-treated. The high stress areas near the welds of these heat exchangers were found to contain HTHA damage. The rupture location of the E heat exchanger was along these high-stress weld regions and was attributable to cracks caused by HTHA. (Sections 4.1.2 and 4.2.1)

3. In 1970, the American Petroleum Institute (API) published API Recommended Practice (RP) 941 *Steels for Hydrogen Service at Elevated Temperatures and Pressures in Petroleum Refineries and Petrochemical Plants*. This document provides Nelson curves to predict the occurrence of HTHA in various materials of construction as a function of temperature and hydrogen partial pressure.[12] The Nelson curves are predicated on past equipment failure incidents and are plotted based on self-reported process conditions that are ill-defined and lack consistency. (Section 4.4.1.1)

4. The CSB performed computer reconstruction[13] of the process conditions within the NHT heat exchangers. The results of the computer reconstruction show that the portion of the carbon steel E heat exchanger that ruptured was estimated to have operated below the applicable Nelson curve. This was considered the safe region of operation where HTHA could not occur. Therefore, the carbon steel Nelson curve methodology is inaccurate, cannot be depended on to prevent HTHA equipment failures, and cannot be reliably used to predict the occurrence of HTHA equipment damage. (Section 4.4.1.1)

5. The hottest portion of the B and E heat exchangers was clad with stainless steel, which improved resistance to HTHA. On the basis of CSB computer reconstruction of the process conditions in the heat exchangers, the CSB estimates that this stainless steel-clad portion of the heat exchangers operated at process conditions that were at times above the carbon steel Nelson curve. However, the unclad portion where the rupture of the E heat exchanger occurred, and where HTHA existed in the B and E heat exchangers, was estimated to have operated below the Nelson curve. (Sections 4.2.1 and 4.4.1.2)

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[10] McIntyre, Vogelsange, *Progress in Corrosion- The First 50 Years of the EFC;* Maney Publishing 2009*;* Section 12.5.1.

[11] Shih, H.M. and Johnson, H.H. A *Model Calculation of the Nelson Curves for Hydrogen Attack;* Acta Metallurgica, Volume 30. 1982; pp 537-545.

[12] Hydrogen partial pressure is a calculated parameter. It is the pressure that would be exerted by a single component of a gas mixture. For example, the hydrogen partial pressure of a 500 psia gas mixture in a vessel that contains 50 mol% hydrogen and 50 mol% propane equals 250 psia.

[13] The CSB modeled the exchanger process conditions using Aspen HYSYS® and Aspen Exchanger Design and Rating. The model required the use of several assumptions, such as fouling distribution, because of a lack of both process and fouling data gathered by Tesoro. As a result, all model results are estimates. Due to limitations in historical data, modeling estimates were limited to 2007-2010. See Appendix C for a detailed description of the modeling assumptions and results.

6. It is very difficult to inspect for HTHA because the damage might not be detected; it can be microscopic and may be present only in small localized areas of equipment. In addition, equipment must already be damaged by HTHA for equipment inspection to identify HTHA. Successful identification of HTHA is highly dependent on the specific techniques employed and the skill of the inspector, and there are few inspectors who have this expertise. Inspection is therefore not sufficiently reliable to ensure mechanical integrity and prevent HTHA equipment damage. (Section 4.1.4)

7. Equipment inspections and post-weld heat treating rely on procedures and human implementation, which are low on the hierarchy of controls[14] and thus are weaker safeguards to prevent HTHA failures than the use of materials that are less susceptible to HTHA damage. (Section 4.1.2)

8. Inherently safer design is a better approach to prevent HTHA. API has identified high chromium steels that are significantly more resistant to HTHA than carbon steel. The B and E heat exchangers were not constructed from these inherently safer materials. (Sections 4.1.3 and 4.1.4)

1.2.2 Organizational Findings

9. The startup of the NHT heat exchangers was hazardous nonroutine work. Leaks routinely developed that presented hazards to workers conducting the startup activities. Process Hazard Analyses (PHAs) [15] at the refinery repeatedly failed to ensure that these hazards were controlled and that the number of workers exposed to these hazards was minimized. (Section 5.2.3)

10. The Shell Anacortes Refining Company was owned and operated by the Shell Oil Company ("Shell Oil") prior to 1998. The 1996 Shell Oil NHT unit PHA simply cited ineffective, non-specific, judgment-based, qualitative safeguards to prevent equipment failure from HTHA. However, the effectiveness of these safeguards was neither evaluated nor documented; instead the PHA merely listed general safeguards. Had the adequacy of the safeguards been verified, improved safeguards intended to protect against HTHA failure could have been recommended. The 2001 and 2006 Tesoro PHA revalidations did not address or modify the analysis performed

[14] An effectiveness ranking of techniques used to control hazards and the risk they represent can be described as a hierarchy of controls – the higher up (further left) on the hierarchy, the more effective the risk reduction achieved (Figure 17).

[15] A PHA is a hazard evaluation to identify, evaluate, and control the hazards of a process. Facilities that process a threshold quantity of hazardous materials, such as the Tesoro Anacortes Refinery, are required to conduct a PHA per the Washington Administrative Code (WAC) Title 296 Chapter 67, Safety standards for process safety management of highly hazardous chemicals (1992). *See:* http://apps.leg.wa.gov/wac/default.aspx?cite=296-67 (accessed September 29, 2013) PHAs are also required by the federal EPA Risk Management Program.

in the 1996 Shell Oil PHA. The Tesoro 2010 NHT unit PHA failed to identify HTHA as a hazard for the shell of the B and E heat exchangers.[16] (Sections 5.3.4.1, 5.3, and Appendix D)

11. For the 15 years before the April 2010 incident, assumptions used by PHA teams at the Anacortes refinery contributed to ineffective safeguards, ineffective hazard identification, and ineffective control of hazards to prevent equipment failures from HTHA damage, such as the E heat exchanger in the NHT unit.[17] (Section 5.3.4.1 and Appendix D)

12. Shell Oil completed a PHA in 1995 related to process modifications that could increase the hydrogen partial pressure in the NHT heat exchangers. However, when managing this change no consideration, evaluation, or recommendations were made to address the potential for HTHA damage to the NHT heat exchangers. (Section 5.3.4 and Appendix D)

13. Shell Oil and Tesoro periodically performed damage mechanism hazard reviews (DMHRs), called corrosion reviews. However, these reviews did not identify HTHA as a credible failure mechanism for the B and E heat exchangers. These reviews were weakened by primarily relying on design operating parameters for these heat exchangers rather than data from actual process operating conditions.[18] (Section 5.3.3 and Appendix D)

14. Tesoro did not monitor actual operating conditions of the B and E heat exchangers within the NHT heat exchanger banks, even though it would have been technically feasible to do so. Rather, corrosion experts hired by Tesoro primarily relied on design operating conditions that when evaluated using the Nelson curve indicated lower susceptibility to HTHA damage than the operating conditions estimated by CSB models.[19] The use of the design temperatures contributed to the incorrect conclusion that the heat exchangers were not susceptible to damage from HTHA. As a result, Tesoro was not aware that the hottest section of the B and E heat exchangers (Can

[16] The term “shell” in this context refers to the pressure containing carbon steel wall of the heat exchanger. The 2010 Tesoro NHT unit PHA did identify HTHA as a possible hazard for the tube side of the B and E exchangers. Heat exchangers of this design have process flow through two sides, separated by mechanical design. Heat is transferred from one side to the other to exchange heat. Flow on the inside of the tubes through the heat exchanger is commonly referred to as “tube-side,” while flow on the outside of the tubes is called “shell-side.” The B and E exchangers had HTHA damage to the pressure containing portion on the shell-side. The 2010 Tesoro NHT unit PHA did not identify HTHA as a hazard where HTHA occurred on the shell-side of the exchanger.

[17] Tesoro issued a new PHA procedure in 2012 that removed the list of assumptions that had previously limited the PHA teams’ analyses. Now, the PHA procedure requires that all assumptions can and should be challenged at any point in the PHA process. Furthermore, if a credible challenge is made, the assumption is eliminated for the duration of the study. This change to Tesoro’s PHA procedure should help ensure that process safety hazards and proposed safeguards are more effectively evaluated in the future.

[18] Design operating conditions include estimated and calculated conditions used to design the exchangers and the thermal profile developed.

[19] Tesoro hired corrosion experts to evaluate damage mechanisms at the Anacortes refinery. These external experts were not Tesoro employees.

4)[20] at times likely operated above the carbon steel Nelson curve. If Tesoro had measured or otherwise technically evaluated the actual operating conditions of these heat exchangers, existing company procedures required HTHA inspection.[21] Although HTHA may have been identified, inspection for HTHA is not sufficiently reliable. (Sections 5.3.3.1, 4.1.4, and Appendix D)

15. Tesoro procedures did not prohibit or effectively limit the use of additional personnel during the nonroutine hazardous startup of the NHT heat exchangers. The heat exchanger startup procedure specifies the use of only one outside operator to perform startup operations of the NHT heat exchanger banks. However on the day of the incident, a supervisor requested five additional operators to assist with the startup of the A/B/C heat exchanger bank. (Section 5.2.3)

16. The NHT heat exchangers frequently leaked flammable hydrocarbons during startup, sometimes resulting in fires. Tesoro management had been complacent about these hazardous leaks and did not always investigate the cause of the leaks. Tesoro did take some actions to prevent the leaks, but these actions did not effectively prevent the leaks before the April 2010 incident. Additional operators, such as those present during the April 2010 heat exchanger startup, were frequently needed during startup of the NHT heat exchanger banks to respond to potential hydrocarbon leaks or fires. This past practice contributed to the presence of the six additional workers in the unit during the April 2010 incident. (Sections 5.1 and 5.2)

17. The NHT heat exchanger banks were designed with large, difficult-to-manipulate manual block valves on different levels of the NHT heat exchanger structure. These valves were used to start up the NHT heat exchanger banks and typically required numerous adjustments to maintain temperature specifications. The difficulties with valve operation during startup typically resulted in the need for additional operator assistance. This past practice contributed to the presence of some of the six additional workers in the NHT unit during the April 2010 incident.[22] (Section 5.2.3)

18. The CSB found several indications of process safety culture deficiencies at the Tesoro Anacortes Refinery. Refinery management had normalized the occurrences of hazardous conditions, including frequent leaks from the NHT heat exchangers, by using steam to mitigate leaks, ineffectively identifying methods to prevent leaks from the heat exchanger flanges and gaskets,

[20] The general construction of each heat exchanger shell consisted of a series of four steel sections, called “Cans” welded to form a cylinder (exchanger shell). This construction required a longitudinal weld to form each “Can” or section, and three circumferential welds to join the four sections end to end. The temperature profile is such that Can 1 is the coolest and temperature increase towards the hottest section at Can 4.

[21] Tesoro’s inspection procedure would have required HTHA inspection if operating conditions were found to be within 25 pounds per square inch absolute (psia) or 25 ºF of the Nelson curve.

[22] The new design of the NHT heat exchangers has eliminated the need to clean the exchangers while the unit is operating. Post-incident, Tesoro performed a study to evaluate hazardous equipment that is cycled more frequently than the unit. This study took two months to complete and resulted in 53 recommendations. One of the recommendations is intended to ensure that a hazard review is conducted before cycling equipment that was not included in this study.

commonly requiring additional operators during NHT heat exchanger startups, and exceeding the staffing levels that procedures specified. (Section 5.0)

19. The refinery process safety culture required proof of danger rather than proof of effective safety implementation. For years, technical experts used design parameters to evaluate the B and E heat exchangers for HTHA susceptibility. Data for actual operating conditions were not readily available, and these technical experts were not required to prove safety effectiveness in reaching their conclusion that the B and E heat exchangers were not susceptible to HTHA damage. (Section 5.0)

1.2.3 Industry Codes and Standards Findings

20. *API RP 941 - Steels for Hydrogen Service at Elevated Temperatures and Pressures in Petroleum Refineries and Petrochemical Plants* is written permissively such that there are no minimum requirements to prevent HTHA failures. Currently API RP 941 uses the term "should" 27 times and the word "shall" only once. As used in a standard, "shall" denotes a minimum requirement to conform to the standard, while "should" denotes a recommendation that is advised but not required to conform to the standard. API RP 941 does not require users to verify actual operating conditions when establishing operating limits or to confirm that the selection of construction materials will prevent HTHA. (Section 6.1.1)

21. API RP 941 provides industry guidance to predict the occurrence of HTHA in various materials of construction by using the Nelson curves. The Nelson curves are predicated on past equipment failure incidents and are plotted based on self-reported process conditions that are ill-defined and lack consistency. The API Technical Report 941 notes, "The concept of a simple boundary between safe and unsafe operating conditions in hydrogen for common alloys, of the type depicted by the Nelson curves should not be expected."[23] (Sections 4.1.1 and 6.1.3)

22. The CSB has learned of at least eight recent refinery incidents where HTHA reportedly occurred below the carbon steel Nelson curve. In 2011, API issued an industry alert on HTHA in refinery service.[24] The API alert noted multiple incidents of carbon steel equipment at operating conditions where carbon steel was previously thought to be resistant to HTHA. These refinery incidents and the subsequent API response strongly suggest an industry-wide problem with the carbon steel Nelson curve. (Section 6.1.4.2)

23. The CSB found that the carbon steel Nelson curve is inaccurate and cannot be relied on to prevent HTHA equipment failures or accurately predict HTHA equipment damage. (Section 6.1.4)

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[23] API Technical Report 941. *The Technical Basis Document for API RP 941*. 2008; p 47.

[24] *See*: http://www.api.org/publications-standards-and-statistics/hidden-pages/industry-alert (accessed January 19, 2014).

24. API RP 941 does not require industry to use inherently safer materials to prevent HTHA failures. (Section 6.1.1)

25. API RP 581*: Risk-Based Inspection Technology* allows users to calculate a damage factor to determine the HTHA susceptibility of various materials of construction. Tesoro hired damage mechanism experts to help ensure that damage mechanism hazards were properly identified. API RP 581 does not require users to verify actual operating conditions when determining applicable damage mechanisms. The calculation for carbon steel using the design conditions applied in damage mechanism reviews results in the conclusion that the B and E heat exchangers had a "Low Susceptibility" to HTHA. The API RP 581 calculation is therefore unreliable for preventing HTHA failure or predicting the probability of HTHA damage in carbon steel equipment. (Section 6.2)

26. API RP 581*: Risk-Based Inspection Technology* is written permissively, so that there are no minimum requirements to prevent HTHA failures. There are 19 uses of "shall" in RP 581, but none is substantive—nearly all the uses of "shall" are in formulas or requirements for damage factor or inspection effectiveness calculations that are themselves non-mandatory. There are three uses of "shall" in the HTHA section, but they are again used for calculations that are not required, preceded by language such as "the following procedure may be used" or if HTHA is detected, "fitness for service should be performed." An instructive example of the permissiveness of API RP 581 is the important guidance that the document provides for conditions that would make equipment susceptible to HTHA damage. However, if the equipment is identified as meeting the criteria that would indicate HTHA is a credible damage mechanism, according to API RP 581 guidance, the equipment "should" be evaluated for HTHA susceptibility.[25] (Section 6.2)

1.2.4 Regulatory Findings

27. Despite the fact that the nation's roughly 150 petroleum refineries represent only a small fraction of the thousands of chemical processing facilities throughout the United States, the CSB has noted a considerable frequency of significant and deadly incidents at refineries over the last decade. In 2012 alone, the CSB tracked 125 significant incidents at US petroleum refineries.[26] (Section 7.1)

28. The draft CSB Chevron Regulatory Report recommends that the state of California improve the oversight of petroleum refineries by supplementing the existing process safety management regulations with more rigorous features such as requiring companies to reduce risks to as low as reasonably practicable, or ALARP; requiring the effective implementation of safeguards and the

[25] API RP 581, *Risk-Based Inspection Technology*. 2008; pp 252-258.

[26] These incidents were reported to the Department of Energy or the National Response Center and were examined by the CSB Incident Screening Department. The CSB has concluded that incidents that result in disruptions to the national energy supply, produce serious injuries, or receive high levels of media attention are all significant.

use of the hierarchy of controls; and providing for the development of a more well-funded, technically competent regulator. In the draft Chevron Regulatory Report, the CSB concluded that the existing regulatory regimes for onshore petroleum refineries in the United States and California: (Appendix F)

a. Rely on a safety and environmental management system framework that is primarily activity-based rather than goal-based risk reduction to as low as reasonably practicable (ALARP) or equivalent.

b. Are static, unable to adapt to innovation and advances in the management of major hazard risks.

c. Place the burden on the regulator to verify compliance with the regulations rather than shifting the burden to industries by requiring duty holders to effectively manage the risks they create and also ensure regulator acceptance of their plans for controlling those risks.

d. Do not effectively incorporate lessons learned from major accidents; nor do they have the regulatory authority to require duty holders to address newly-identified safety issues resulting from such incidents.

e. Do not effectively collect or promote industry use of major accident performance indicators to drive industry to reduce risks to ALARP.

f. Do not require the use or implementation of inherently safer systems analysis or hierarchy of controls.

g. Do not effectively involve the workforce in hazard analysis and prevention of major accidents.

h. Do not provide the regulator with the authority to accept or reject a company's hazard analysis, risk assessment, or proposed safeguards; and

i. Do not employ the requisite number of staff members with the technical skills, knowledge, and experience necessary to provide sufficient direct safety oversight of petroleum refineries.

29. The Washington State Department of Labor and Industries (L&I), which oversees workplace safety in the state, does not have sufficient personnel resources to verify that process safety management (PSM) requirements are being implemented adequately. L&I enforces state PSM requirements that are based on the federal OSHA PSM standard for hazardous chemical facilities. However, the state of Washington has only four PSM specialists in its compliance section to regulate and inspect nearly 270 PSM-covered facilities, including five petroleum refineries. Of these four specialists only one has a technical background. (Section 7.2)

30. Washington L&I completed an audit of the Tesoro NHT unit under the refinery National Emphasis Program (NEP) in March 2009, one year before the incident. The Tesoro Anacortes NEP audit is noteworthy, as it was the only audit conducted pursuant to the federal OSHA NEP that focused on a unit that subsequently experienced a catastrophic accident that the CSB has investigated. The heat exchanger that failed, the E heat exchanger, was a fundamental component

of the Tesoro NEP audit. However, no citable mechanical integrity or other process safety management deficiencies related to the heat exchanger were found. (Section 7.3.3.1)

31. Shell Oil and Tesoro PHAs conducted on the NHT unit cited non-specific, judgment-based qualitative safeguards that in light of the April 2010 incident were not effective. Following the April 2010 incident the L&I Division of Occupational Safety and Health (DOSH) issued citations to Tesoro relating to its PHA program, but they were not associated with evaluating the effectiveness of safeguards such as the robustness of the HTHA prevention program. If the Washington PSM standard had required an evaluation and documentation of safeguard effectiveness, Shell Oil and Tesoro would have been obligated to conduct such an analysis. (Section 7.4)

32. In the 2006 Tesoro NHT unit PHA, Tesoro discontinued a review of its corrosion control program and a specific mechanical integrity checklist associated with the corrosion program after concluding that they were "not a legal requirement." The state of Washington PSM regulation did not require this review. Tesoro conducted the optional review ineffectively and then terminated it when the company determined that it was not strictly required. An enhanced regulatory system with goal-setting attributes would require continual risk reduction and performance of an effective DMHR. This review is not just an activity but must meet the goal of preventing equipment failures. (Sections 5.3.4 and 7.2.1)

33. Under the existing US and Washington regulatory systems, including the PSM standard and the U.S. Environmental Protection Agency (EPA) Risk Management Program (RMP), there is no requirement to reduce risks to a specific risk target such as ALARP. While the Clean Air Act (CAA) directed the EPA to promulgate the RMP regulations "to provide, to the greatest extent practicable, for the prevention and detection of accidental releases of regulated substances,"[27] there is no RMP ALARP requirement. Under both the PSM and RMP regulations, an employer must "control" hazards when conducting a PHA of a covered process. However, there is no requirement to address the effectiveness of the controls or to use the hierarchy of controls. Thus, a PHA can satisfy the regulatory requirements even though it might inadequately identify or control major hazards. In addition, there is no requirement to submit PHAs to the regulator, and the regulator is not responsible for assessing the quality of the PHA or the effectiveness of proposed safeguards, resulting in a regulatory system that is often reactive and frequently becomes involved in examining the details of process safety programs only after a major process accident. (Section 7.4)

[27] 42 U.S.C. §7412(r)(7)(B)(i) (1990).

1.2.5 Similar Findings in CSB Investigations of the Tesoro Anacortes and Chevron Richmond Refinery Incidents

34. The CSB conducted an investigation of the August 6, 2012, Chevron Richmond Refinery incident. That incident was also the result of a metallurgical failure caused by a well-known damage mechanism called sulfidation corrosion, and Chevron process safety programs failed to effectively control the hazard before the major incident that endangered the lives of 19 Chevron employees. The CSB identified a number of similar causal findings common to both the April 2010 Tesoro Anacortes Refinery incident and the August 2012 Chevron Richmond Refinery incident. (Section 7.7)

35. Mechanical integrity programs at both Tesoro and Chevron emphasized inspection strategies rather than the use of inherently safer design to control the damage mechanisms that ultimately caused the major process safety incidents. These inspections were unreliable and failed to prevent the incidents. Since the Richmond and Anacortes incidents, both Chevron and Tesoro have upgraded the materials of construction for the equipment that failed, using inherently safer design that significantly reduced the risk of the applicable damage mechanism hazards. (Section 7.7.1)

36. Both Tesoro and Chevron PHAs were ineffective in identifying the significant hazards of HTHA and sulfidation corrosion, respectively. Rather than performing rigorous analyses of damage mechanisms during the PHA process, both companies simply cited non-specific, judgment-based qualitative safeguards to reduce the risk of damage mechanisms. The effectiveness of these safeguards was neither evaluated nor documented; instead, the PHA merely listed general safeguards. (Section 7.7.2)

37. The Anacortes and Richmond refineries relied on API standards to assist in the selection of construction materials for the Tesoro NHT heat exchangers and the Chevron piping circuit, specifically API RP 941 and API RP 939-C *Guidelines for Avoiding Sulfidation (Sulfidic) Corrosion Failures in Oil Refineries*. The documents provide guidance on how to avoid HTHA and sulfidation corrosion failures, respectively, but neither document establishes minimum requirements to evaluate and minimize the risks of equipment failure from the damage mechanism hazard. (Section 7.7.3)

38. Neither the Washington nor the California process safety regulations were successful in preventing major process safety incidents. Neither set of regulations required DMHRs, reduction of risk to ALARP, evaluation of effectiveness of controls, or use of the hierarchy of controls. In addition, there is no requirement to submit PHAs to the regulator, and the regulator is not responsible for assessing the quality of the PHA or the proposed safeguards. Furthermore, neither Washington nor California required the use of inherently safer design to the greatest extent practicable. A regulatory system that contains more robust goal-setting attributes would help to ensure that all of the refineries in these states rigorously apply process safety concepts that focus

more effectively on prevention. The new regulatory framework would also emphasize the implementation of inherently safer designs and the hierarchy of controls to prevent major process safety incidents. (Section 7.7.4)

39. Both Washington and California have significant weaknesses in the staffing of PSM inspectors. Both Washington L&I (the Washington PSM regulator) and the California Occupational Safety and Health Administration (Cal/OSHA) (the California PSM regulator) lack sufficient technically experienced and qualified staff members to verify that PSM requirements are being implemented adequately. It is essential that regulators of high-hazard facilities are independent, well funded, well staffed, and technically qualified. These individuals must be able to communicate effectively with refinery personnel and to monitor the adequacy of refinery process safety practices. (Section 7.7.4)

40. Both the Chevron and Tesoro incidents could have been prevented if inherently safer equipment construction materials had been used. Although inherently safer technology (IST) is the most effective major accident prevention approach in the hierarchy of controls it is not enforced by the EPA through the General Duty Clause or other provisions of the Clean Air Act. The EPA has the authority to require the application of IST through the General Duty Clause. Furthermore, the Clean Air Act provides the authority for the EPA to develop and implement new regulations requiring the use of inherently safer systems analysis and the hierarchy of controls to establish more effective safeguards for identified process hazards to prevent major accidents. (Section 7.8)

1.3 Recommendations

As a result of the findings and conclusions of this report, the CSB makes recommendations, summarized below, to the following recipients:

The U.S. Environmental Protection Agency

Revise the Chemical Accident Prevention Provisions under 40 CFR Part 68 to require the documented use of inherently safer systems analysis and the hierarchy of controls to the greatest extent feasible in establishing safeguards for identified process hazards. Until this revision is in effect, enforce through the Clean Air Act's General Duty Clause the use of inherently safer systems analysis and the hierarchy of controls to the greatest extent feasible when facilities are establishing safeguards for identified process hazards. In addition, effectively participate in the oversight of the process safety culture program at the Tesoro Anacortes Refinery.

Washington State Legislature, Governor of Washington

Augment the existing process safety management regulatory framework with the more rigorous safety management attributes identified in this report for petroleum refineries in the state of Washington.

Washington State Division of Occupational Safety and Health – Labor and Industries

Perform verifications at all Washington petroleum refineries to ensure prevention of equipment failure because of HTHA and that effective programs are in place to manage hazardous nonroutine work. In addition, effectively participate in the oversight of the process safety culture program at the Tesoro Anacortes Refinery.

American Petroleum Institute

Revise API RP 941 and API RP 581 to prohibit the use of carbon steel equipment in HTHA-susceptible service and require verification of actual operating conditions. Make additional revisions to API RP 941 to establish minimum requirements to prevent HTHA failures and to require the use of inherently safer design.

Tesoro Refining & Marketing Company LLC

Participate with API in the API RP 941 revisions to establish minimum requirements to prevent HTHA failures and to require the use of inherently safer design. Following the API RP 941 revisions, develop and implement a plan to meet the new API RP 941 requirements. Improve process safety management programs for damage mechanism hazards to require the hierarchy of controls and the use of inherently safer design.

Tesoro Anacortes Refinery

Implement a process safety culture program that will assess and continually improve any identified process safety culture issues at the Tesoro Anacortes Refinery.

United Steelworkers Local 12-591

Effectively participate in the process safety oversight committee to continually improve any identified process safety culture issues at the Tesoro Anacortes Refinery.

Section 8.0 details the recommendations.

2.0 Tesoro Refining & Marketing Company LLC

Tesoro Corporation was founded in 1968 as a petroleum exploration and production company. In 1969, Tesoro began operating its first refinery near Kenai, Alaska. A Fortune 100 company, Tesoro now operates six refineries in the western United States. These refineries have a combined capacity of approximately 850,000 barrels per day (bpd).[28]

2.1 Anacortes Refinery

Tesoro purchased the Anacortes refinery from Shell Oil Company in August 1998. Located approximately 70 miles north of Seattle (Figure 2 and Figure 3), the Tesoro Anacortes refinery has a total crude-oil capacity of 120,000 bpd. The refinery has been in operation since 1955.[29]

The Anacortes refinery primarily supplies gasoline, jet fuel, and diesel to markets in Washington and Oregon. It also manufactures heavy fuel oils, liquefied petroleum gas, and asphalt. Approximately 350 employees and 50 contractors work at the refinery.[30]

Figure 2. Tesoro Anacortes Refinery

[28] *See* http://tsocorp.com/about-tesoro/locations/ and http://tsocorp.com/about-tesoro/company-history/ (accessed January 4, 2014).

[29] Statement of Basis for the Final Air Operating Permit – Final, July 26, 2010, p 6.

[30] The United Steelworkers (USW) represents approximately 185 of the operations and maintenance workers at the refinery. *See* http://www.usw.org/media_center/releases_advisories?id=0521, (accessed November 9, 2013).

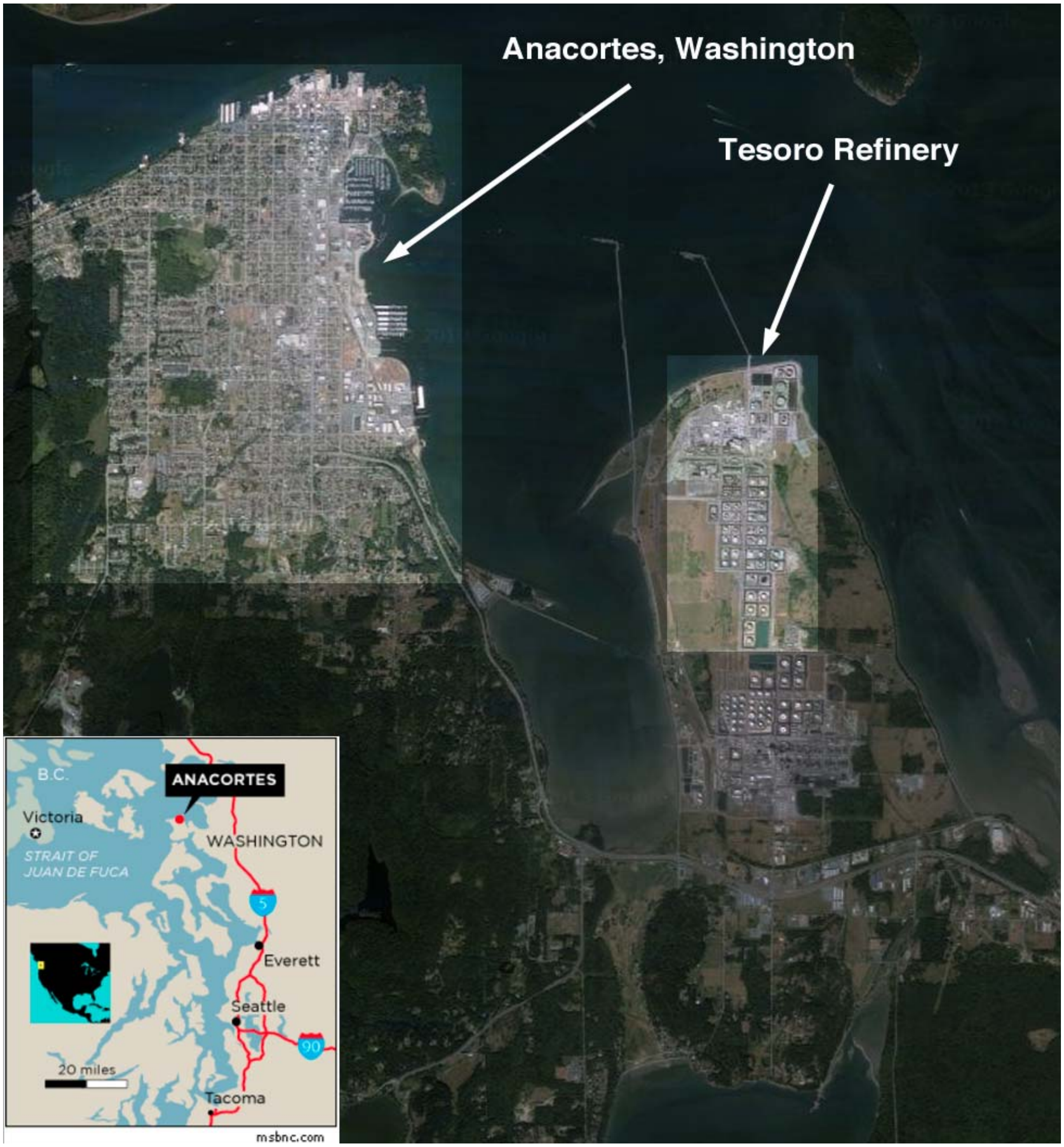

Figure 3. Aerial View of the Tesoro Anacortes Refinery.

2.2 Other Tesoro Refineries

Beginning in the late 1990s, Tesoro made a series of refinery acquisitions. In 1998, Tesoro acquired refineries in Kapolei, Hawaii[31] (from BHP Americas), and Anacortes, Washington (from Shell Oil Company). In 2001, the company purchased refineries in Mandan, North Dakota, and Salt Lake City, Utah (both from Amoco). In 2002, Tesoro acquired the Golden Eagle refinery in Martinez, California

[31] Tesoro no longer owns this refinery.

(from Ultramar, now Valero), and in 2007 Tesoro acquired its Los Angeles refinery (from Shell Oil) and USA Gasoline retail stations (from Chevron).[32] Tesoro purchased its Carson, California, refinery in 2013 (from BP).[33]

2.3 Tesoro Anacortes Refinery NHT Unit

The April 2, 2010, incident occurred in the Tesoro Anacortes Refinery Catalytic Reformer / Naphtha Hydrotreater unit ("the NHT unit"), which includes a naphtha hydrotreating process unit. Hydrotreating is a process that removes sulfur, nitrogen, and oxygen impurities from petroleum feedstock and intermediate products by reacting with hydrogen in the presence of a catalyst. Hydrotreating serves two purposes:[34]

1. It improves the quality and environmental impact of products, especially quality specifications mandated by law (for example, benzene reduction in motor gasoline).
2. It protects sensitive and costly downstream catalysts from contamination.

The Tesoro NHT unit was originally constructed in 1972 with a rated capacity of 24,800 bpd. Modifications and upgrades resulted in a rated capacity at the time of the incident of 40,550 bpd, a 64% capacity increase.

2.3.1 Catalytic Reformer

Catalytic reforming is a chemical process used to convert petroleum refinery naphtha,[35] typically having low-octane ratings,[36] into high-octane liquid products called reformates. The Catalytic Reformer uses a system of fixed bed catalytic reactors to increase the octane rating of gasoline blending stock. The reformate product is then sent to gasoline component storage for use in fuel blending. The reforming reaction generates hydrogen, which is used in the NHT.

2.3.2 Naphtha Hydrotreater – A/B/C & D/E/F Feed/Product Heat Exchangers

The removal of sulfur, nitrogen, and oxygen impurities in the NHT unit requires heating the naphtha to over 600 °F at greater than at 600 pounds per square inch gauge (psig) and mixing it with hydrogen. The initial portion of this heating took place in the NHT unit's E-6600 A/B/C and D/E/F feed and product

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[32] *See* http://www.tsocorp.com/TSOCorp/AboutUs/CompanyHistory/061236, (accessed April 24, 2013).

[33] *See* http://tsocorp.com/about-tesoro/company-history/ (accessed January 4, 2014).

[34] Hydrocarbon Publishing Company, *Worldwide Refinery Processing Review (Individual Technology)*, Hydrotreating summary. 2Q 2012, Item No. B1014

[35] Naphtha is a fraction of crude oil that boils between approximately 85 °F and 400 °F. It includes hydrocarbons ranging from C_5 to C_{12}. Naphtha comprises approximately 15-30 weight % of raw crude oil. *See* Prestvik, R.; Moljord, K.; Grande, K.; Holmen, A. *Compositional Analysis of Naphtha and Reformate.* In G.J. Antos & A.M. Aitani (Eds.), *Catalytic Naphtha Reforming* (p. 2). New York, NY: Marcel Dekker, Inc.

[36] Octane rating represents gasoline-burning efficiency. The higher the octane rating, the less likely it is for gasoline to *knock*, or produce harmful, small explosions that reduce efficiency, in an engine. *See* Van Dyke, K. (1997). *Fundamentals of Petroleum* (4th ed.) (p 318). Austin, Texas: The University of Texas at Austin.

(effluent) heat exchangers,[37] as depicted in Figure 4. (These heat exchangers are referenced throughout this report as the NHT heat exchangers.)

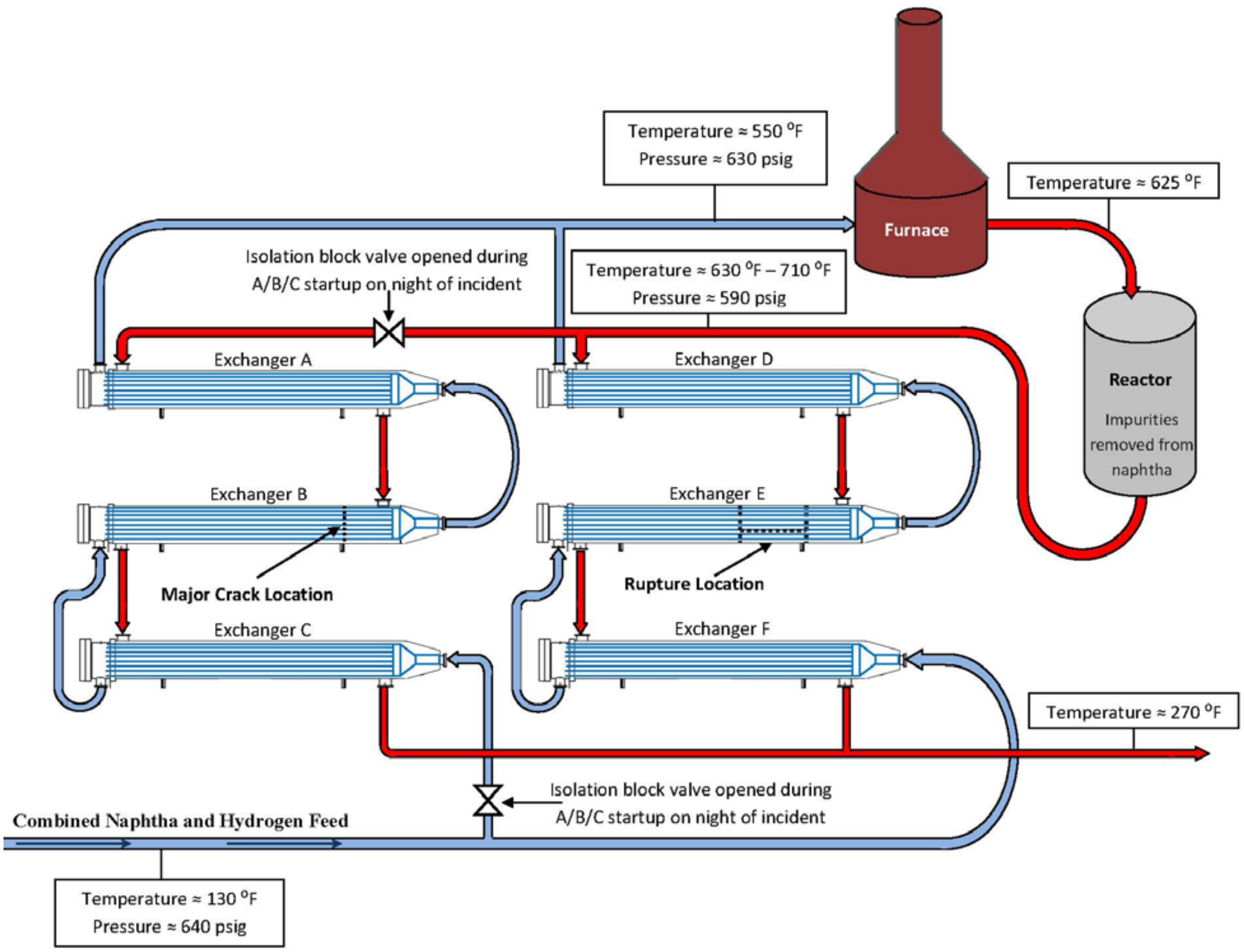


Figure 4. Process Flow of NHT Unit

The function of the NHT A/B/C and D/E/F heat exchangers is to conserve energy by using the hot NHT reactor effluent to heat the cooler reactor feed and thus reduce the energy input needed for the reactor furnace. The cool NHT liquid naphtha feed is pumped from storage and/or other active units and mixed with a stream of hydrogen-rich gas, becoming a combined liquid and gas feed stream. The resulting liquid-gas mixture is then fed to the tube-side[38] of two parallel groups, or banks of three heat exchangers (A/B/C and D/E/F) to be heated by the shell-side[39] fluid. As the liquid-gas mixture inside of the tubes is

[37] The A/B/C and D/E/F exchangers are single-pass shell and tube heat exchangers. A heat exchanger allows heat to be transferred from one process fluid to another. One fluid gets hotter while the other gets cooler. A shell and tube–type heat exchanger consists of a large pressure vessel exterior (shell) with a group (bundle) of small thin-walled pipes (tubes) that reside inside the shell. One process fluid flows through the tubes, and the other process fluid flows through the shell, over the tubes. Heat is transferred (exchanged) from one to the other through the walls of the tubes.

[38] "Tube-side" refers to process fluid that flows inside of heat exchanger tubes.

[39] "Shell-side" refers to process fluid that flows inside of the heat exchanger shell and on the outside of the tubes.

heated, the liquid portion vaporizes completely. Now liquid free, the naphtha and hydrogen vapors enter a furnace where they are further heated and then fed to the NHT reactor. The reactions to remove sulfur, nitrogen, and oxygen take place in this reactor. The hot reactor effluent[40] is then fed through the shell-side of the heat exchangers to preheat the incoming tube-side feed. The impurity-free naphtha is then fed to other processes in the refinery.

40 Effluent is flow exiting a vessel or piece of equipment.

3.0 Incident Description

3.1 Pre-Incident Operations

During normal operation at the Tesoro Anacortes Refinery, the A/B/C and D/E/F heat exchangers were all in use. Because of the original Shell Oil Company design and the process operating conditions, the heat exchangers would foul during operation; that is, they would develop a buildup of process contaminant byproducts both inside of the heat exchanger tubes, as illustrated in Figure 5, and outside of the tubes. The fouling inhibited heat transfer between the tube-side and shell-side process fluid, thus reducing the heat transfer efficiency.

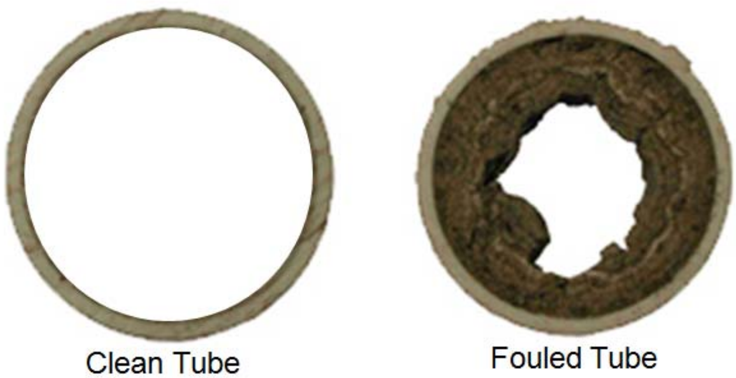


Figure 5. Example of Fouling Deposits on the Inside of Heat Exchanger Tubes. Fouling greatly reduces heat transfer between the shell-side and tube-side process fluids.[41]

Because the heat exchangers fouled, they required periodic cleaning so that process temperature requirements could be maintained. Cleaning was typically required after about six months of continuous operation. When performing this cleaning, one bank of heat exchangers was taken out of service while the other bank continued operating. The cleaned heat exchangers would then be placed back into service by slowly introducing the hot naphtha and hydrogen feed into the heat exchangers. Because of a long history of frequent leaks and occasional fires when putting these heat exchangers back into service (Section 5.1), startup, shutdown, and cleaning activities were a hazardous nonroutine operation.[42] By employing this nonroutine operation, Shell Oil and Tesoro avoided a total shutdown of the NHT unit.

On March 28, 2010, five days before the incident, the A/B/C heat exchanger bank was taken offline so that the fouled tubes in each heat exchanger could be cleaned. The D/E/F heat exchanger bank and the

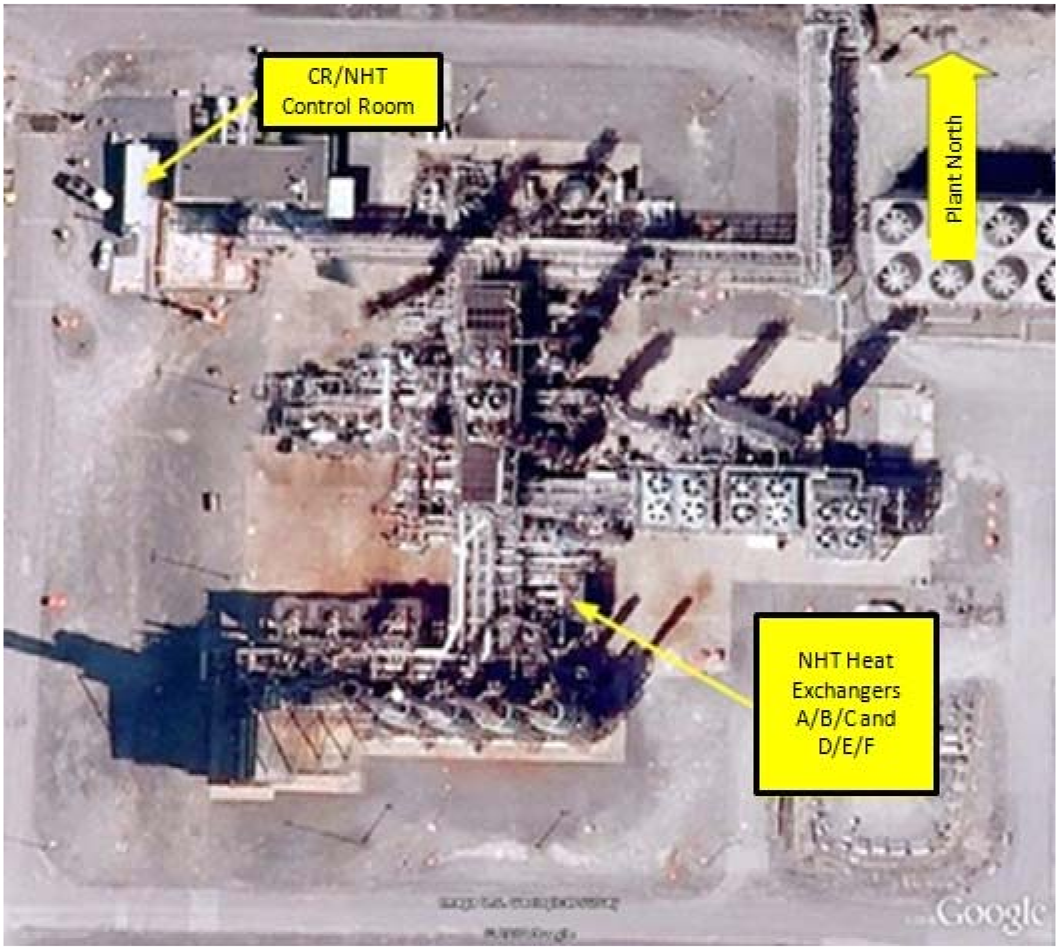
[41] Photograph of fouled tube from http://www.tekleen.com/it/water-filtration-101/ (accessed December 4, 2013).

[42] Nonroutine does not refer to the frequency at which the activity occurs. Nonroutine refers to whether the activity is part of the normal sequence of converting raw materials to finished products. Startup and shutdown of equipment are considered a nonroutine activity. Center for Chemical Process Safety (CCPS), *Guidelines for Risk Based Process Safety*. 2007; p 286.

rest of the NHT unit remained in operation. On March 31, 2010, the three-day maintenance cleaning activity was completed and the equipment was reassembled and prepared for operation.

3.2 Night of the Incident

On the evening of April 1, 2010, Tesoro initiated startup of the A/B/C heat exchanger bank. The NHT unit was staffed in a typical manner, with one inside board operator who monitored the console and one outside operator. An aerial view of the unit is shown in Figure 6.



Source: Google Earth

Figure 6. Aerial View of CR/NHT Unit

The inside NHT operator and the outside NHT operator began the process of placing the heat exchangers back in service. The inside operator used a step-by-step task list for the startup process, physically checking off the steps on a hardcopy of the procedure while maintaining radio communication with the outside operator. Interviews conducted by the CSB indicate that the startup of the heat exchangers was a very difficult assignment for only a single outside operator. The startup procedure required manipulation of several isolation block valves as illustrated in Figure 7, which necessitated a significant amount of manual effort to open.

Figure 7. CSB Animation of Operator Opening Long-Winded Valve on Night of Incident. Valves on heat exchanger structure had to be opened concurrently when performing the heat exchanger bank startup

These valves had to be gradually and concurrently opened, so the operator could not simply stay by each valve until it was fully opened or closed. Also, four steam lances were staged and ready for use during the startup to mitigate any leaks or fires that might occur.[43] These valves and steam lances were located at different positions in the vicinity of the A/B/C and D/E/F heat exchangers. At approximately 10:30 p.m., six additional Tesoro employees (five operators and one supervisor)[44] joined the outside operator, at the request of the supervisor, to assist in bringing the A/B/C heat exchanger bank online. The startup procedure did not specify defined roles for these six additional personnel.

3.3 The Incident

The operators continued the A/B/C heat exchanger bank startup as planned. Two leaks from the heat exchangers were reported during the startup. These leaks did not stop operations however, because leaks during startup of these heat exchangers were frequent and had become a “normal” part of the startup. Furthermore, based on past operating experience, these leaks were expected to cease when the heat exchangers reached typical operating temperature.

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[43] Three of the four steam lances were likely in use at the time of the incident. See Section 5.0 for additional discussion on the use of steam lances.

[44] The five additional operators that assisted in the NHT heat exchanger startup were assigned to the Crude, Utilities, Vacuum Flasher, ROSE, and CFH/DHT units.

At 12:30 a.m. on April 2nd, while the seven outside personnel were still performing A/B/C heat exchanger bank startup operations, the E heat exchanger on the adjacent, in-service bank catastrophically ruptured. The pressure containing "shell" of the heat exchanger separated at weld seams,[45] as depicted in Figure 8, expelling a large volume of very hot hydrogen and naphtha.[46]

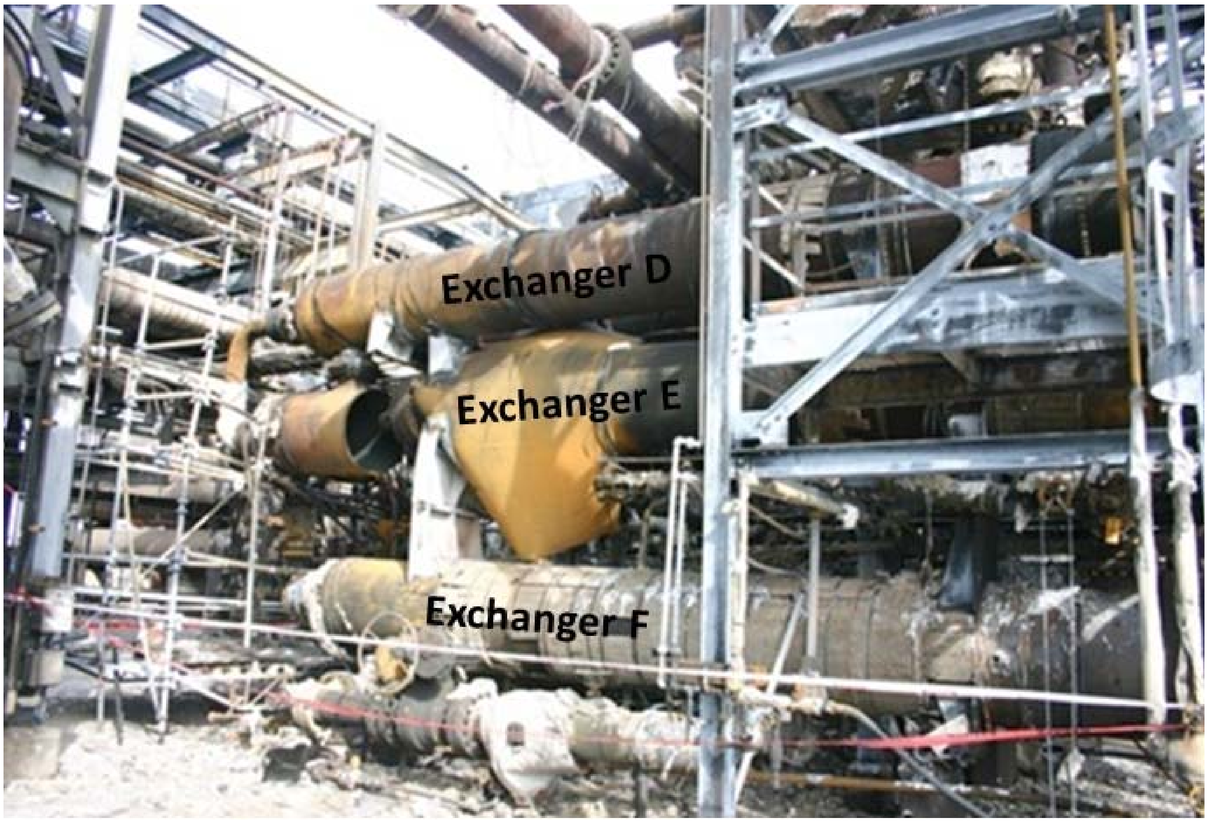

Figure 8. Post-Incident View of D/E/F NHT Heat Exchanger Bank

The naphtha and hydrogen likely autoignited upon release into the atmosphere, creating a large fireball as depicted in Figure 9.

[45] The failure occurred at both circumferential and longitudinal weld seams from fabrication of the exchanger.

[46] The naphtha began to condense to liquid in the B and E heat exchangers. The material in the process was above its atmospheric boiling temperature, so it vaporized when released to atmospheric conditions.

Figure 9. CSB Animation of the Fire Following the NHT Heat Exchanger Failure. The hot naphtha and hydrogen likely autoignited upon release to the atmosphere. The fire engulfed the entire heat exchanger structure.

The operator in the NHT control room told the CSB that he felt the impacts of the rupture at his desk 350 feet away. The CSB determined that at the time of the incident two of the outside operators were likely on the top level of the heat exchanger structure (Figure 10), and the remaining five operators were most likely at ground level. All seven outside operations personnel were badly burned, and within 22 days of the incident, all succumbed to their injuries.

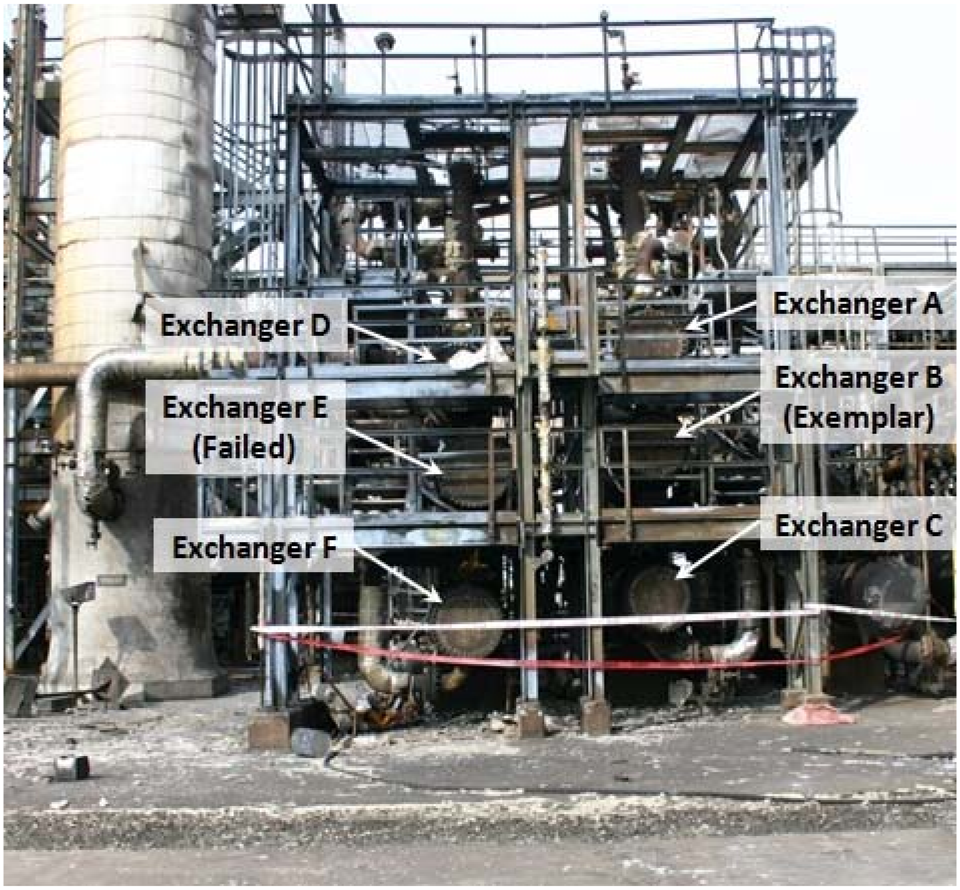

Figure 10. Six NHT Heat Exchangers in Two Banks of Three Heat Exchangers Each

4.0 Technical Analysis

4.1 High Temperature Hydrogen Attack

Post-incident metallurgical analysis determined that the carbon steel E heat exchanger ruptured because it was in a highly weakened state because of high temperature hydrogen attack (HTHA). The HTHA damage mechanism occurs when steel equipment is exposed to hydrogen at high temperatures and partial pressures. The resulting damage severely degrades the mechanical properties of the carbon steel.[47]

> **Carbon steel is more susceptible to HTHA than all other materials of construction considered by API RP 941.**

HTHA occurs when atomic hydrogen diffuses into the steel walls of process equipment, as illustrated in Figure 11. The hydrogen reacts[48] with carbon in the steel, producing methane gas,[49] as depicted in Figure 12. This reaction removes carbon from the steel, a process commonly referred to as "decarburization."[50]

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47 Shih, H.M. and Johnson, H.H. A *Model Calculation of the Nelson Curves for Hydrogen Attack;* Acta Metallurgica, Volume 30. 1982; pp 537-545.

48 Sources differ on whether atomic hydrogen directly reacts with carbon in steel to produce methane or whether the hydrogen recombines inside the steel to form molecular (diatomic) hydrogen before reacting with carbon to form methane.

49 API Technical Report 941. *The Technical Basis Document for API RP 941*. 2008; pp 7-8.

50 Weiner, L.C. *Kinetics and Mechanism of Hydrogen Attack of Steel*. Corrosion, 1961, Volume 17, pp 109-115.

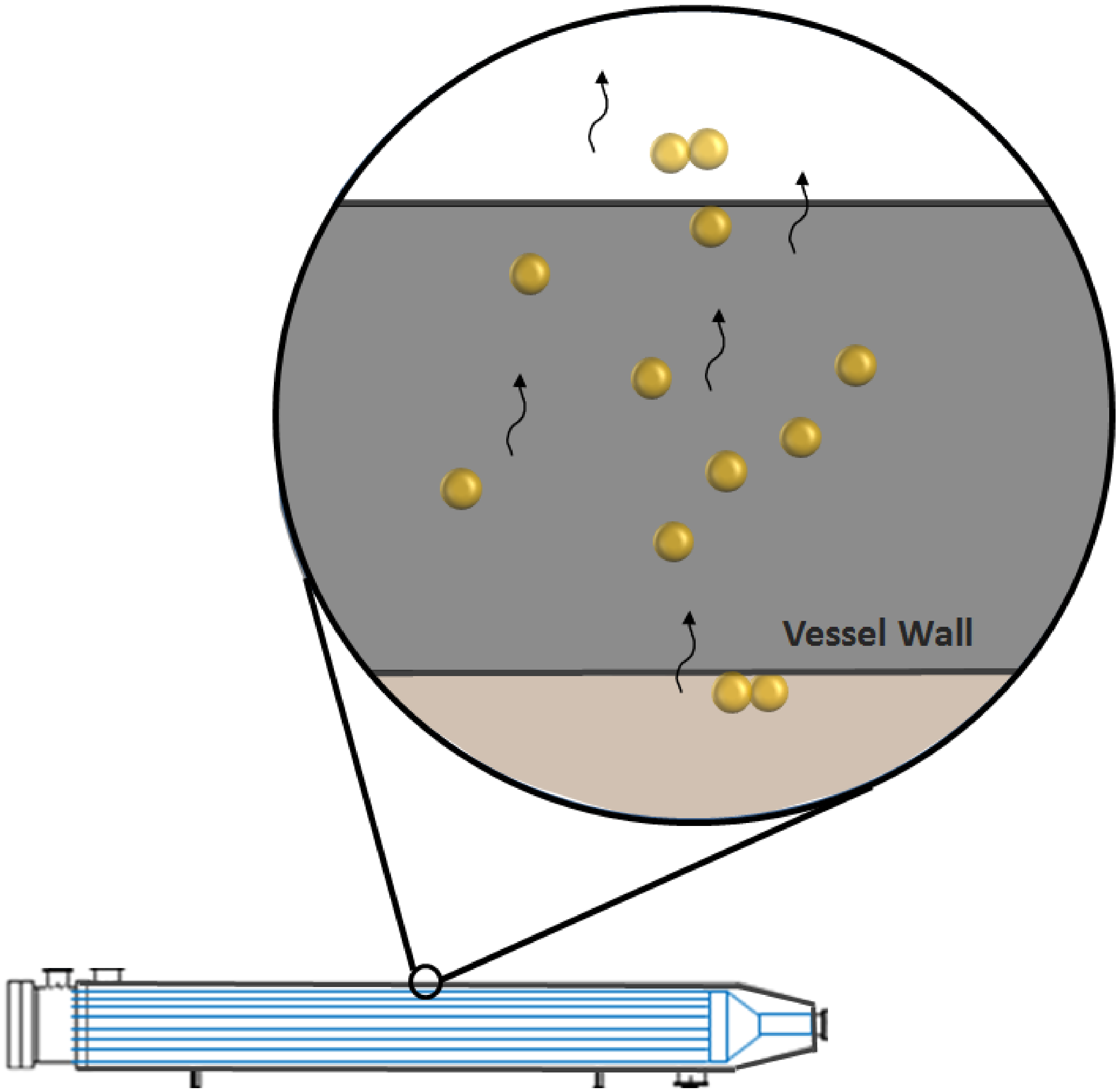


Figure 11. Atomic Hydrogen Diffuses Through Steel. In HTHA, molecular hydrogen dissociates at the vessel wall to form atomic hydrogen, which diffuses through the steel.

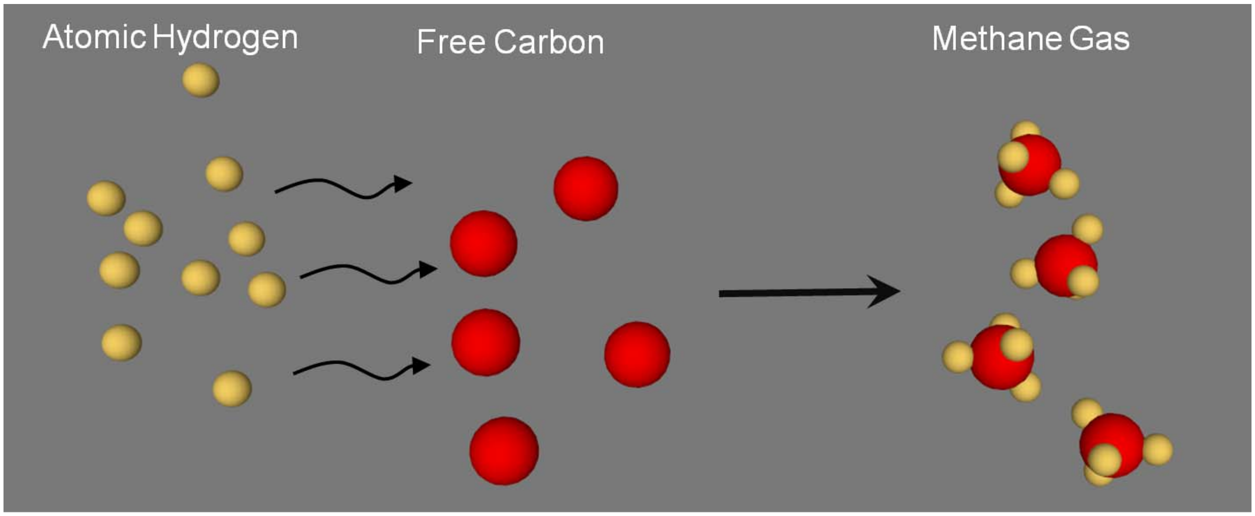


Figure 12. Decarburization Process. When the atomic hydrogen encounters free carbon inside of the steel, hydrogen and carbon react to produce methane gas.

Methane, a much larger molecule than atomic hydrogen, cannot diffuse out of the steel. Rather, it accumulates inside the vessel walls,[51] exerting force on the surrounding steel. As more methane gas is formed, the methane pressure increases. The very high pressure exerted by the methane gas inside the steel can form fissures, as illustrated in Figure 13 or blisters in the steel, as shown in Figure 14.[52]

[51] API Technical Report 941. *The Technical Basis Document for API RP 941*. 2008; pp 7-8.

[52] Allen, R.E., Jansen, R.J., Rosenthal, P.C., and Vitovec, F.H., *The Rate of Irreversible Hydrogen Attack of Steel at Elevated Temperatures*. 26th Midyear meeting of AIChE. May 9, 1961.

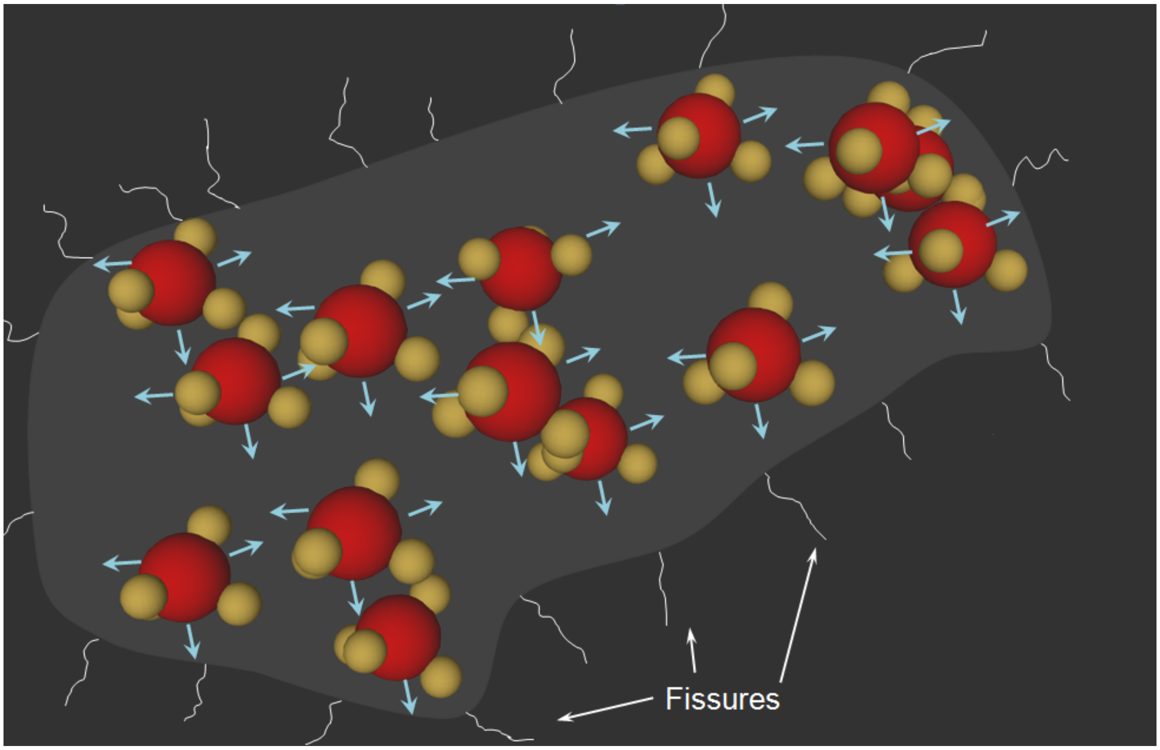


Figure 13. Methane Fissures. When methane molecules cannot diffuse out of the steel, they accumulate inside of the steel, creating high pressure that forms fissures in steel.

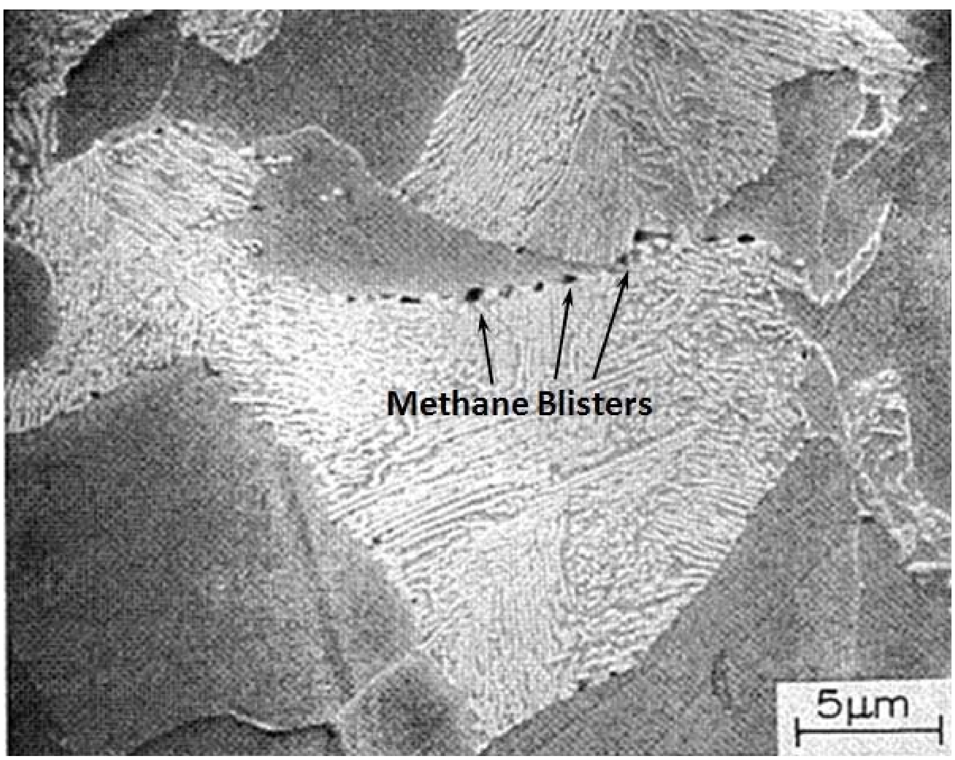
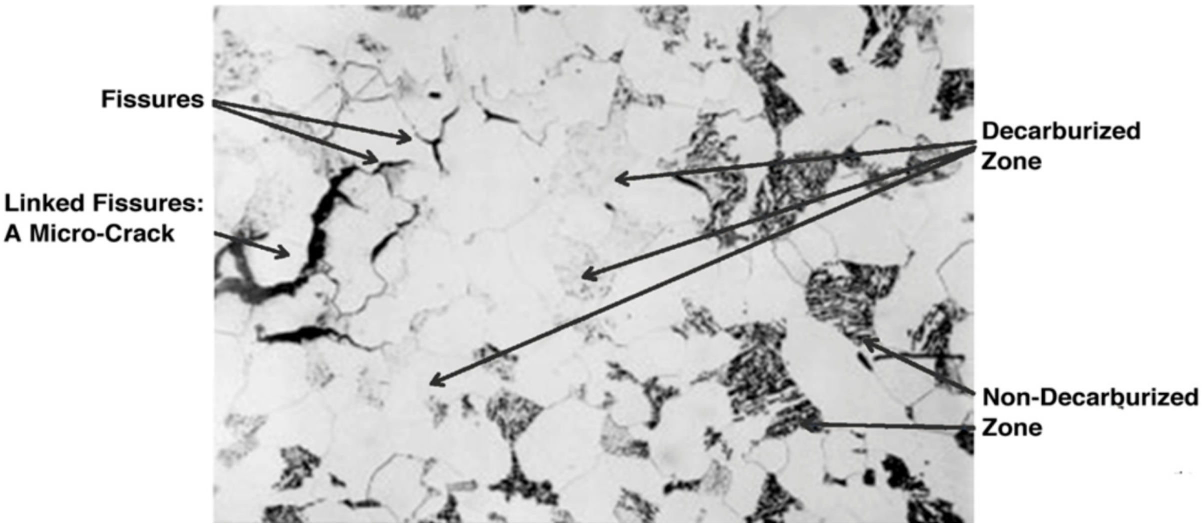


Figure 14. Methane Blisters. Accumulation of methane in steel can also form blisters in the metal.

As more fissures are formed, they can link, forming microcracks in the steel.[53] The linkage of fissures into microcracks is shown in Figure 15. Microcracks can also link to form larger cracks, which greatly weaken the steel and can lead to rupture of the vessel.[54] This process occurred in the E heat exchanger at the Tesoro Anacortes Refinery.



Source: API RP 941, Figure 2

Figure 15. Microcrack Resulting from Linked-HTHA Fissures. This image from API RP 941 shows fissures formed as a result of HTHA linked together to form a microcrack. Decarburized regions appear lighter in color (because of an absence of carbon) than unaffected regions.

[53] Lai, George. *High Temperature Corrosion and Materials Applications.* Materials Park: ASM International, 2007.

[54] *Ibid*.

4.1.1 Predicting the Occurrence of HTHA

Industry relies on a graph in API RP 941 *Steels for Hydrogen Service at Elevated Temperatures and Pressures in Petroleum Refineries and Petrochemical Plants* to predict the occurrence of HTHA in various steels. The lines in that graph are known as Nelson curves, developed in 1949 by George Nelson,[55] who created these curves based on observed industry experience with HTHA. The curves have been adjusted over the years based on additional industry experience.[56] The most recent version of the API RP 941 Nelson curves is shown in Figure 16. Industry uses these curves as a line of demarcation to predict HTHA. At temperatures above each curve, HTHA is possible for that material of construction, and at temperatures below the curve, the prediction is that HTHA will not occur for that material.

Nelson curves include consideration of these HTHA variables:

- **Material of construction**
- **Temperature**
- **Hydrogen partial pressure**

The Nelson curves predict HTHA based on process temperature, hydrogen partial pressure,[57] and material of construction. Carbon steel is represented by the lowest curve, indicating that this material is the most susceptible to HTHA when compared to the other materials of construction shown in Figure 16. For a given material of construction, the Nelson curve indicates that a higher temperature increases the probability that HTHA will occur.[58,59]

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55 G. A. Nelson, *Hydrogenation Plant Steels*. 1949 Proceedings, Volume 29M, API; pp. 163 -174.

56 API Technical Report 941. *The Technical Basis Document for API RP 941*. 2008; p 127.

57 Hydrogen partial pressure is a calculated parameter. It is the pressure that would be exerted by a single component of a gas mixture. For example, the hydrogen partial pressure of a 500 psia gas mixture in a vessel that contains 50 mole percent (mol%) hydrogen and 50 mol% propane equals 250 psia.

58 For most materials included on the Nelson curves, increasing hydrogen partial pressure also increases the probability of HTHA. However, in some areas for some materials, the Nelson curves do not predict a higher probability of HTHA when hydrogen partial pressure is increased.

59 Low carbon steels, which contain very little alloying additions of chromium and molybdenum, are the most susceptible to HTHA. Chromium-rich and molybdenum-rich carbides are inherently more stable than iron carbides, and they resist dissolution of carbon with hydrogen to form methane. Therefore, the alloys containing chromium and molybdenum resist HTHA at higher temperatures and hydrogen pressures. *See* CSB's E-6600E and E-6600B Metallurgical Analysis report (Appendix I).

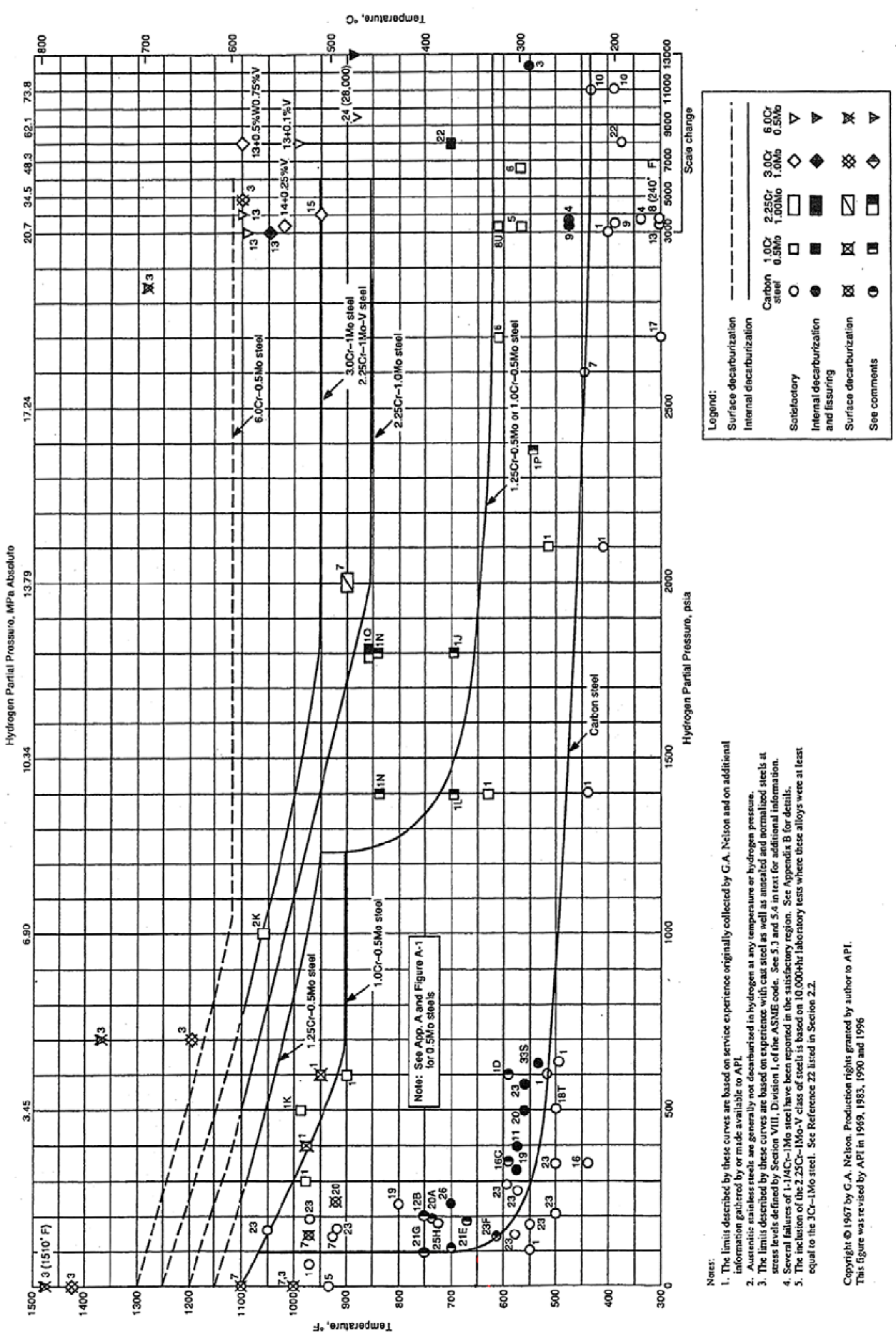

Figure 16. Nelson Curves from Current API RP 941. These Nelson curves are used to predict the occurrence of HTHA in various materials of construction.

4.1.2 Conditions that increase HTHA susceptibility

Welding performed on steel process vessels creates additional HTHA risk factors, such as residual stress.[60] Post-weld heat treatment is a method that can reduce the stress in steel that was generated from the welding process. The process of post-weld heat treatment consists of a sequence of controlled heating and cooling steps applied to the welded structure using externally applied heating elements.[61] This process gives the metal time to readjust to its original, prefabrication state[62] and removes residual stress. The carbon in the steel becomes less reactive, inhibiting the reaction with hydrogen to form methane. Chemical resistance to HTHA is thus modestly improved in post-weld heat-treated steels.[63]

As will be discussed in Section 4.2.1, the carbon steel shells of the B and E heat exchangers were not post-weld heat-treated, and therefore the steel surrounding the welds may have been high-stress areas.[64] HTHA was only found in the areas near the welds in both the B and E heat exchangers.

Post-weld heat treating is a weaker safeguard than using materials that are not susceptible to HTHA damage.

Post-weld heat treating is a manual activity and therefore low on the hierarchy of controls.[65] Consequently, post-weld heat treating carbon steel is a weaker safeguard to prevent HTHA failures than the use of materials that are not susceptible to HTHA damage.[66,67]

60 API Technical Report 941. *The Technical Basis Document for API RP 941.* 2008; p 163.

61 Krishnan, J. and Ahmed, Khaleel; *Post-Weld Heat Treatment- Case Studies*. BARC Newsletter. Centre for Design and Manufacture, Bhabha Atomic Research Centre, May 2002.

62 Gillissie, J.G., *Heat Treatment- What Is It?.* The National Board of Boiler and Pressure Vessel Inspections. October 1981.

63 API Technical Report 941. *The Technical Basis Document for API RP 941.* 2008; p 162.

64 Post-weld heat treatment is generally avoided unless specified as mandatory by codes or standards. Incorrect post-weld heat-treatment procedures can result in metal that is out of specification for the service. In the United States, the ASME Boiler Code is the authority that mandates post-weld heat treatment. If the code requires post-weld heat treatment, it is performed, but if the code does not specify the requirement for post-weld heat treatment, then the heat treatment is generally not performed. The ASME Boiler Code did not require post-weld heat treatment for the B and E heat exchangers. *See* 2011 ASME Boiler and Pressure Vessel Code; Paradowska A., Price J.W.H, and Dayawansa P. *Measurement of Residual Stress Distribution in Tubular Joints Considering Postweld Heat Treatment* Materials Forum Volume 30- 2006. Institute of Materials Engineering Australasia Ltd.; and Funderburk, R. Scott, *Postweld Heat Treatment.* Welding Innovation, Vol. XV, No. 2, 1998.

65 An effectiveness ranking of techniques used to control hazards and the risk they represent can be described as a hierarchy of controls – the higher up (further left) on the hierarchy, the more effective the risk reduction achieved (Figure 17).

66 Improper post-weld heat treating can lead to vessel failure. Steward, M. and Lewis, O. *Pressure Vessels Field Manual Common Operating Problems and Practical Solutions*, 2013; pp 236-237.

67 Post-weld heat treating problems include heat treating errors such as inadequate time at temperature, inadequate or excessive temperature rate, inadequate temperature, cooled too rapidly, cooled too slowly, and cooled to the

Despite the improved HTHA resistance of post-weld heat-treated vessels compared with non-post-weld heat-treated vessels, upgrading vessel materials to inherently safer materials of construction is a better approach to prevent equipment failure from HTHA. This approach is discussed further in Section 4.1.3.

4.1.3 Inherently Safer Design

As defined in the Center for Chemical Process Safety (CCPS)[68] book *Inherently Safer Chemical Processes, 2nd ed.*, inherently safer design is the process of identifying and implementing inherent safety in a specific context that is permanent and inseparable from the process.[69] In the book *Guidelines for Engineering Design for Process Safety, 2nd ed.*, the CCPS states that "inherently safer design solutions eliminate or mitigate the hazard by using materials and process conditions that are less hazardous."[70]

Inherently safer technologies are relative; a technology can be described as inherently safer only when compared to a different technology with regard to a specific hazard or risk.[71] A technology can be inherently safer with respect to one risk but not inherently safer from another risk. Consequently, it is important to carry out a comprehensive documented hazard analysis to identify the individual and overall risks in a process and assess how the risks can be effectively minimized to control hazards. An inherently safer systems or hierarchy of control review details a list of choices that offer varying degrees of inherently safer implementation. The review should include risks of personal injury, environmental harm, and lost production, as well as an evaluation of economic feasibility.[72]

It is simpler, less expensive, and more effective to introduce inherently safer features during the design process of a facility rather than after the process is already operating.[73] Process upgrades, rebuilds, and repairs offer additional opportunities to implement inherently safer design concepts. Conducting a comprehensive hazard review to determine risks and identify ways to eliminate or reduce those risks constitutes an important step in implementing an inherently safer process.

wrong temperature. Canale, L., Mesquita, R., and Totten, G., *Failure Analysis of Heat Treated Steel Components*, 2008; pp 106-109.

[68] The Center for Chemical Process Safety (CCPS) is a corporate membership organization that identifies and addresses process safety needs within the chemical, pharmaceutical, and petroleum industries.

[69] Center for Chemical Process Safety (CCPS). *Inherently Safer Chemical Processes – A Life Cycle Approach*. 2009; section 2.2.

[70] *Ibid* at Section 5.1.1.

[71] *Ibid* at Section 5.2.

[72] *Ibid* at p 184.

[73] Kletz, Trevor and Amyotte, Paul. *Process Plants: A Handbook for Inherently Safer Design*. 2010; p 14.

An effectiveness ranking of techniques used to control hazards and their associated risks can be described as a hierarchy of controls. As depicted in Figure 17, the further left on the hierarchy continuum, the more effective the technique is in reducing risk. All concepts in the hierarchy of controls should be included in the process of risk assessment and reduction. Upgrading the equipment material of construction to a more HTHA-resistant steel is a high-ranking, inherently safer choice in material selection. Holding other variables constant, upgrading the material of construction can eliminate the potential for HTHA. As previously discussed, post-weld heat treating to modestly reduce HTHA susceptibility is low on the hierarchy of controls and thus is a weaker safeguard to prevent HTHA failures than the use of materials that are not susceptible to HTHA damage.

Upgrading metallurgy to prevent HTHA is an inherently safer approach in major accident prevention.

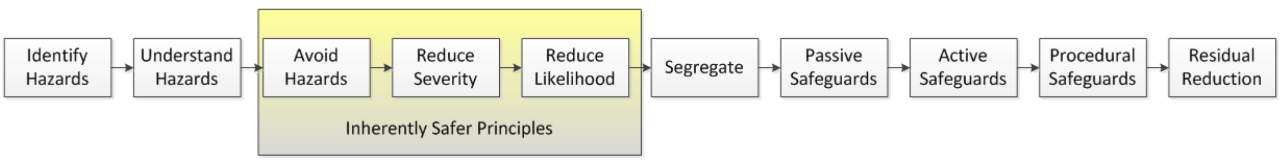

Figure 17. Hierarchy of Controls. The highlighted boxes reflect inherently safer controls, based on *Process Plants: A Handbook for Inherently Safer Design Second Edition*; Kletz, Trevor Amyotte, Paul; CRC Press 2010.

Since the April 2010 incident, Tesoro has installed new NHT heat exchangers, incorporating aspects of an inherently safer design.[74] As discussed in Section 4.4.1.3, the materials of construction of two heat exchangers have been upgraded to significantly reduce the potential for HTHA.

[74] While the material of construction is upgraded in the new exchangers, portions of the heat exchangers that are manufactured with carbon steel are still designed to operate at temperatures higher than 400 °F.

4.1.4 HTHA Inspection Strategy Limitations

While inspection is an important mechanical integrity program component, there are significant limitations with relying solely on inspection strategies to prevent equipment failure from HTHA. For example, refinery equipment must already be damaged by HTHA for equipment inspection to identify HTHA. HTHA damage is also extremely difficult to identify by conducting an inspection. API RP 941 includes a discussion of these difficulties:

> High temperature hydrogen attack is a difficult inspection challenge. The early stages of attack with fissures, or even small cracks, can be difficult to detect. The advanced stage of attack with significant cracking is much easier to detect, but at that point there is already a higher likelihood of equipment failure.[75]

Some existing inspection methods attempt to identify HTHA, as described in Appendix E. However, inspection should not be solely relied on to identify and control HTHA. Inspection results can be unreliable and misleading. Successful identification of HTHA is highly dependent on the specific techniques employed and the skill of the inspector, and few inspectors have this level of expertise.[76]

> **Inspection should not be solely relied on to prevent HTHA equipment failures.**
>
> **Supporting inherently safer design, API has identified materials that are not susceptible to HTHA.**

Inspection thus ranks very low on the hierarchy of controls. API RP 571 *Damage Mechanisms Affecting Fixed Equipment in the Refining Industry* implicitly supports the concept of inherently safer design by describing material selection to avoid HTHA failures noting, "300 Series SS, as well as 5Cr, 9Cr and 12Cr alloys, are not susceptible to HTHA at conditions normally seen in refinery units."[77]

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[75] API RP 941. *Steels for Hydrogen Service at Elevated Temperatures and Pressures in Petroleum Refineries and Petrochemical Plants. 2008*; p 11.

[76] "HTHA is dangerous, difficult to detect and can be missed. The reliability of HTHA inspections depends on the skill of the inspector." *See:* Birring, A., Ultrasonic Testing - Detection of Hydrogen Attack, *See:* http://www.nde.com/hydrogen.htm, (accessed June 13, 2013).

[77] API RP 571. *Damage Mechanisms Affecting Fixed Equipment in the Refining Industry.* 2003; p "5-83".

4.2 Tesoro Heat Exchanger Failure

4.2.1 NHT Heat Exchanger Construction

The NHT heat exchangers were constructed in 1971 and installed and placed in service in Anacortes. The two banks of three heat exchangers were metallurgically identical; the pressure containing "shell" base material for each heat exchanger in the bank was specified based on the design operating conditions.

Exchanger	Shell-Side Materials of Construction
A/D	Mn-0.5Mo steel (SA-302-B), factory clad[78] with 1/8" thick Type 304 stainless steel.
B/E	Carbon steel (SA-515-70), factory clad with 1/8" thick Type 316 stainless steel applied to the 4' Section 4 (Can 4) as shown in Figure 18.[79]
C/F	Carbon steel (SA-515-70).

The general construction of each heat exchanger shell consisted of a series of four steel sections, called "Cans" welded to form a cylinder (exchanger shell). This construction required a longitudinal weld to form each "Can" or section, and three circumferential welds to join the four sections end to end. The B and E heat exchanger design is shown in Figure 18.

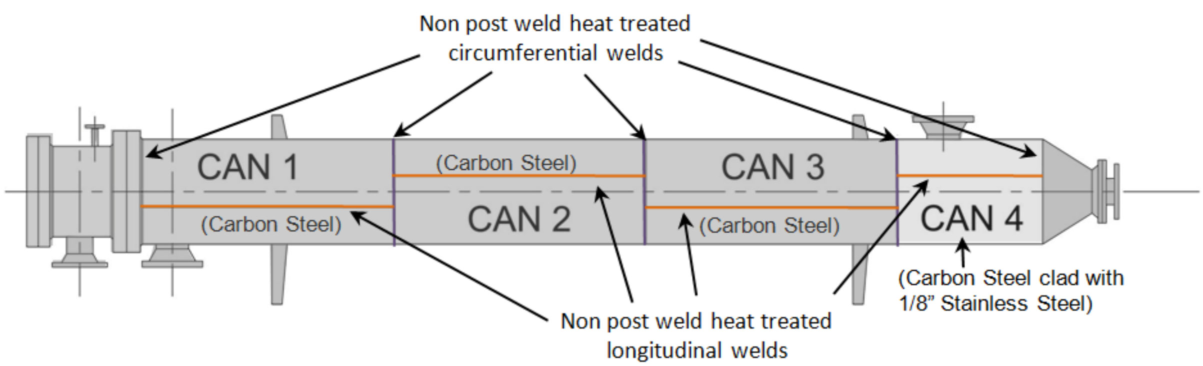

Figure 18. Fabrication Layout of the B and E Heat Exchangers

Design data representing anticipated normal operation and the API RP 941 Nelson curves were used to select materials of construction for the NHT heat exchangers. Carbon steel was selected for the B and E heat exchangers because the design temperatures were below the carbon steel Nelson curve. "Can" 4 of the B and E heat exchangers, the hottest portion of the heat exchangers, was lined on the interior surface with a layer of Type 316 stainless steel on top of the carbon steel. The interior stainless steel was applied in a process known as "cladding." The stainless steel was selected for protection against another damage

[78] Cladding is a process used to join dissimilar metals together to form a single metal piece.

[79] The remaining portions of the exchanger shell (Cans 1, 2, and 3) did not have a 316 stainless steel cladding.

mechanism called sulfidation corrosion.[80] Although protection from sulfidation corrosion is the intent of the stainless steel cladding, the cladding also can be used to reduce the risk of HTHA. The stainless steel cladding reduces the effective hydrogen partial pressure that is acting on the carbon steel beneath the cladding.[81]

The welding construction method used to manufacture the B and E heat exchangers resulted in a large heat-affected zone (HAZ).[82] An example of the welds used to construct the E heat exchanger is shown in a cross-section micrograph in Figure 19.[83] The top of the micrograph is the outside of the heat exchanger shell carbon steel wall.[84]

[80] Sulfidation is a damage mechanism that causes thinning in iron-containing materials, such as steel, because of the reaction between sulfur compounds and iron at temperatures ranging from 450 °F to 800 °F. This damage mechanism causes the metal to gradually thin over time.

[81] API RP 941. *Steels for Hydrogen Service at Elevated Temperatures and Pressures in Petroleum Refineries and Petrochemical Plants.* 2008; p 10.

[82] The process of welding requires substantial heat that alters the material properties of the material near the weld. This affected area near the weld is commonly referred to as the “heat-affected zone” or “HAZ”, shown in Figure 19.

[83] Beta Laboratory, Beta Lab No.M10198, Tesoro Ls2 And Ls2/Cs2 Tee Findings, October 13, 2010 (Appendix H)

[84] Figure 19 also shows the elements of a typical weld in the B and E heat exchangers.

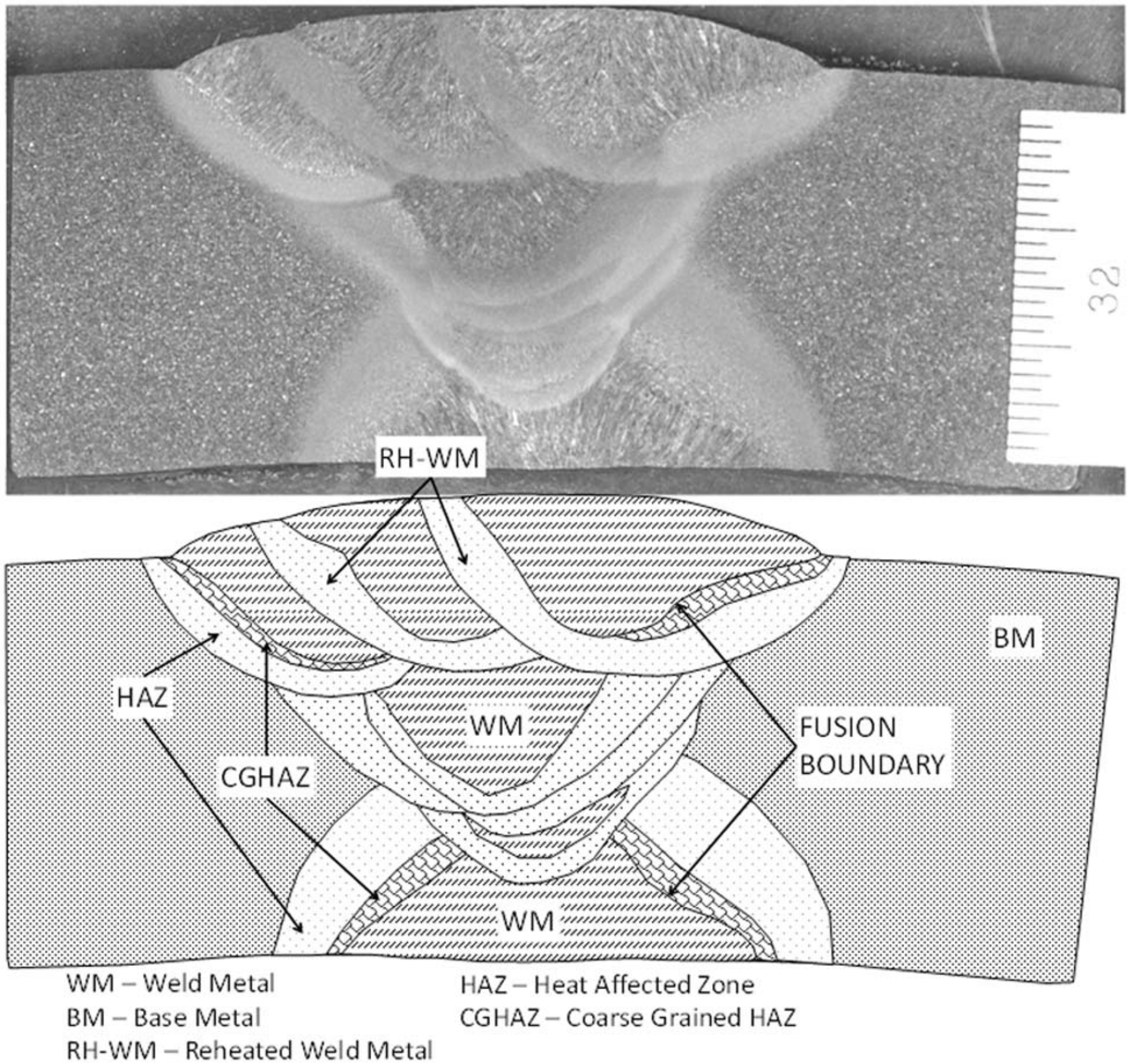

Figure 19. Cross-Section of Sample NHT Heat Exchanger Weld.[85] The cross-section of a multipass weld in the upper graphic is typical of the heat exchangers, and the schematic in the lower graphic defines the terms associated with the weld.

The welds in the B and E heat exchanger shells were not post-weld heat-treated.[86] As a result, the heat-affected zones illustrated in Figure 19 were likely high-stress areas where HTHA damage ultimately accumulated.

[85] *See* Appendix I, Figure 5.

[86] Some components of the heat exchangers were post-weld heat-treated, where wall thickness was at least one inch.

4.2.2 Post-Incident Metallurgical Analysis

BETA Laboratory, located in Mayfield Village, Ohio, conducted metallurgical testing of the B and E heat exchangers through an agreement among Tesoro, the Washington Division of Occupational Safety and Health (DOSH), and the CSB. BETA Laboratory compiled a series of reports, included in Appendix H, on the failed heat exchanger (E) and the exemplar heat exchanger (B)[87] that was removed from service after the accident at Tesoro. Test results indicate that the E heat exchanger failed at the heat-affected zones of the welds surrounding and within "Can" 3, as illustrated in Figure 20.

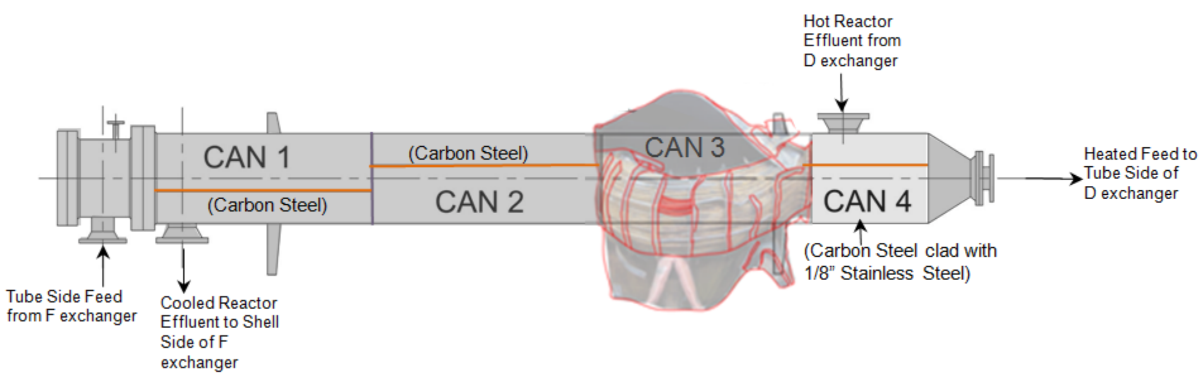

Figure 20. E Heat Exchanger Failure Schematic

The CSB contracted with the National Institute of Standards and Technology (NIST)[88] to perform an independent analysis of the BETA Laboratory reports and to prepare a report that states a professional opinion of the failure mechanism that caused the rupture of the E heat exchanger.[89] NIST metallurgical experts conducted the analysis.

HTHA was the immediate cause of the heat exchanger failure.

NIST determined that the metallurgical damage that caused the failure of the E heat exchanger was a result of HTHA, with other possible contributing co-mechanisms such as hydrogen-induced cold cracking that may have served as HTHA initiation points in the heat affected zones. The full metallurgical analysis is included in Appendix I.

The documented HTHA damage for the failed E heat exchanger is extensive. Damage is evident in the base metal but only in the heat-affected zone adjacent to welds and along fusion boundaries

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[87] The B exchanger was used as an exemplar during metallurgical testing because it experienced nearly identical process conditions and had the same geometry and materials as the E exchanger.

[88] NIST is a non-regulatory federal agency in the U.S. Department of Commerce. The NIST mission is to promote US innovation and industrial competitiveness by advancing measurement science, standards, and technology in ways that enhance the economic security of the nation and improve the quality of life of citizens. *See* http://www.nist.gov/public_affairs/general_information.cfm (accessed December 30, 2013).

[89] *See* CSB's E-6600E and E-6600B Metallurgical Analysis report (Appendix I).

in the welds. No HTHA damage is evident in the base metal outside of the heat-affected zone.[90] Because the fracture paths followed the narrow damaged regions along the welds, much of the damage in these regions was incorporated into the fracture surfaces during the failure as these damaged regions connected to form the macro-fracture.

Similar HTHA damage is also evident and documented in the exemplar B heat exchanger that was unaffected by the incident. The HTHA damage in this heat exchanger is similar to the damage documented in the uncompromised portions of the E heat exchanger. Long and deep subsurface cracks are evident. In the case of the B heat exchanger, one circumferential weld heat-affected zone crack extends over 50 percent of the way around the circumference and more than one third of the way through the thickness of the heat exchanger shell wall,[91] as shown in Figure 21 and Figure 22.

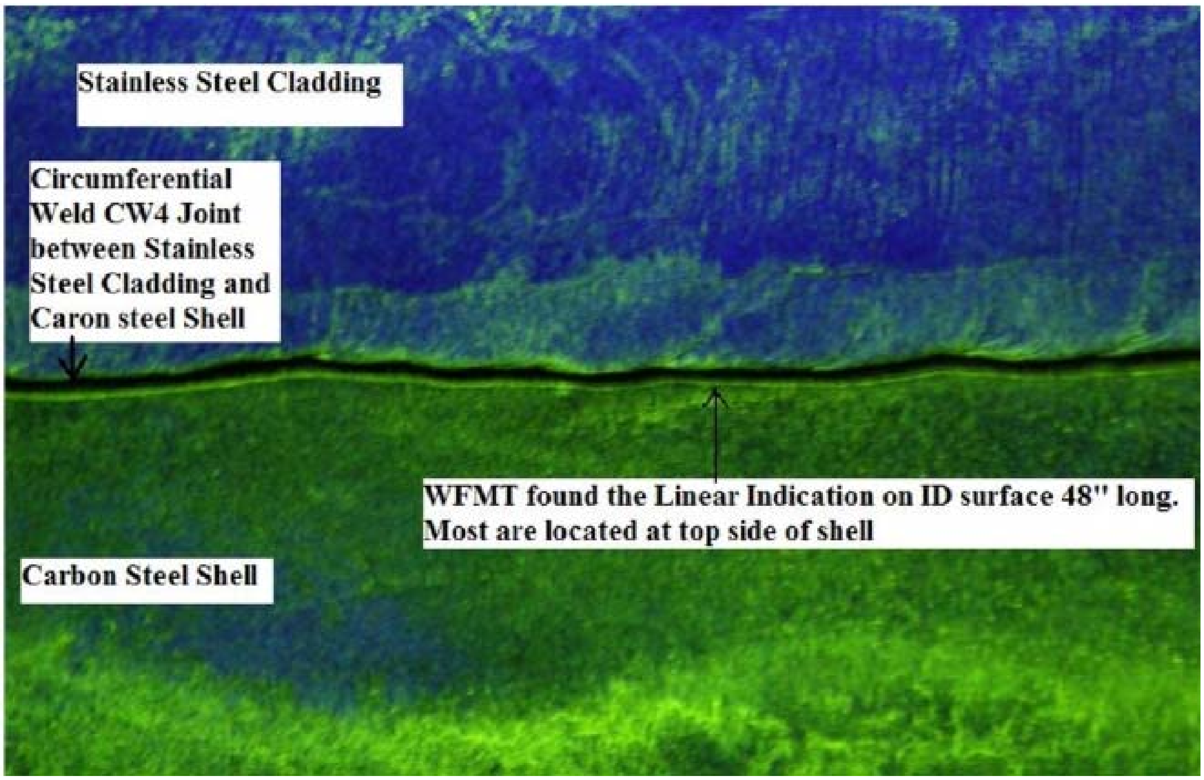

Figure 21. Circumferential Weld Damage in the B Heat Exchanger. This photograph from the Spectrum inspection report on the B heat exchanger (Appendix G) shows the large crack directly downstream of the stainless steel clad portion of the heat exchanger. (The light green line below the dark black area is the crack; the dark portion is the edge of the stainless steel cladding.) This macrocrack formed in the high-stress region near the weld because of the linkage of microcracks and fissures caused by HTHA.

[90] *See* Appendix J

[91] *See* CSB's E-6600E and E-6600B Metallurgical Analysis report (Appendix I).

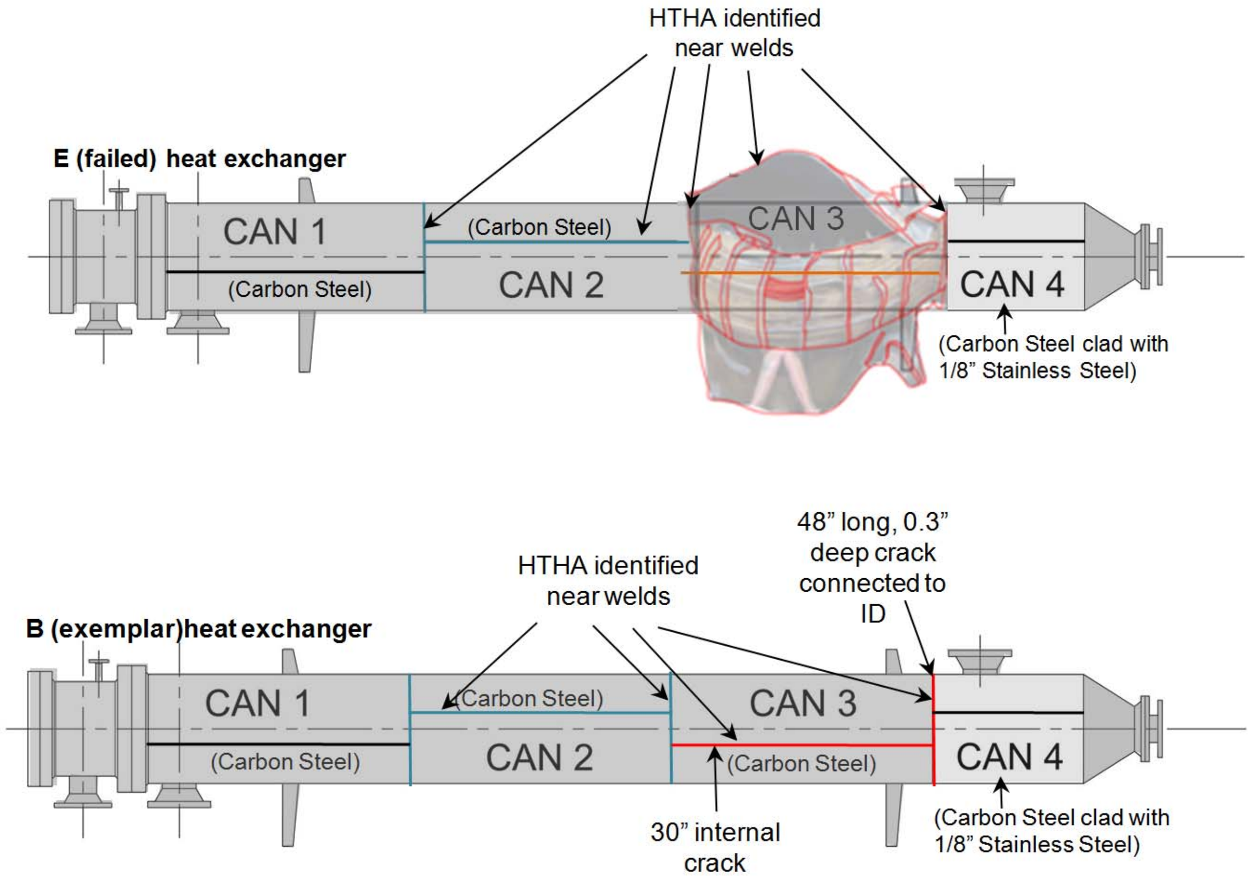

Figure 22. Comparison of Damage Locations in the B and E Heat Exchangers. Severe HTHA damage is found in the B heat exchanger in the same locations where the E heat exchanger ruptured.

NIST determined that without the HTHA damage, it is unlikely that the E heat exchanger would have ruptured under the conditions that occurred during the April 2010 start-up. However, both the B and E heat exchangers were severely degraded and had the potential to suffer a catastrophic rupture because of the advanced stages of HTHA evident in both heat exchangers.

4.3 Timing of the Incident

Process data indicate that the D/E/F tube outlet temperature increased about 75 °F over a span of three minutes immediately before the rupture, as graphed in Figure 23. The CSB compared these changes in temperatures to those from the previous three startups. This magnitude of temperature increase is typical compared to the previous startups (Appendix B) and is likely explained by the difficulty of trying to maintain process control by manually operating large isolation block valves that were not designed as flow control valves.[92]

The E heat exchanger was in a severely degraded mechanical condition because of long-term cracking damage from HTHA. In addition to the increased mechanical stress from the startup of the A/B/C heat exchangers, this momentary increasing temperature appears to have been sufficient to cause the actual material strength of the critically weakened heat exchanger to be exceeded, rupturing the E heat exchanger at its weakest point – the area of the heat exchanger that was most damaged by HTHA. This scenario is the most likely explanation of the timing of the failure of the heat exchanger during the A/B/C heat exchanger startup, but it did not cause the failure.

[92] A block valve is a manually operated valve that is normally fully open or fully closed. Block valves are typically designed for tight shutoff when closed and for minimal obstruction of flow when open. These valves are not designed to throttle or control flow.

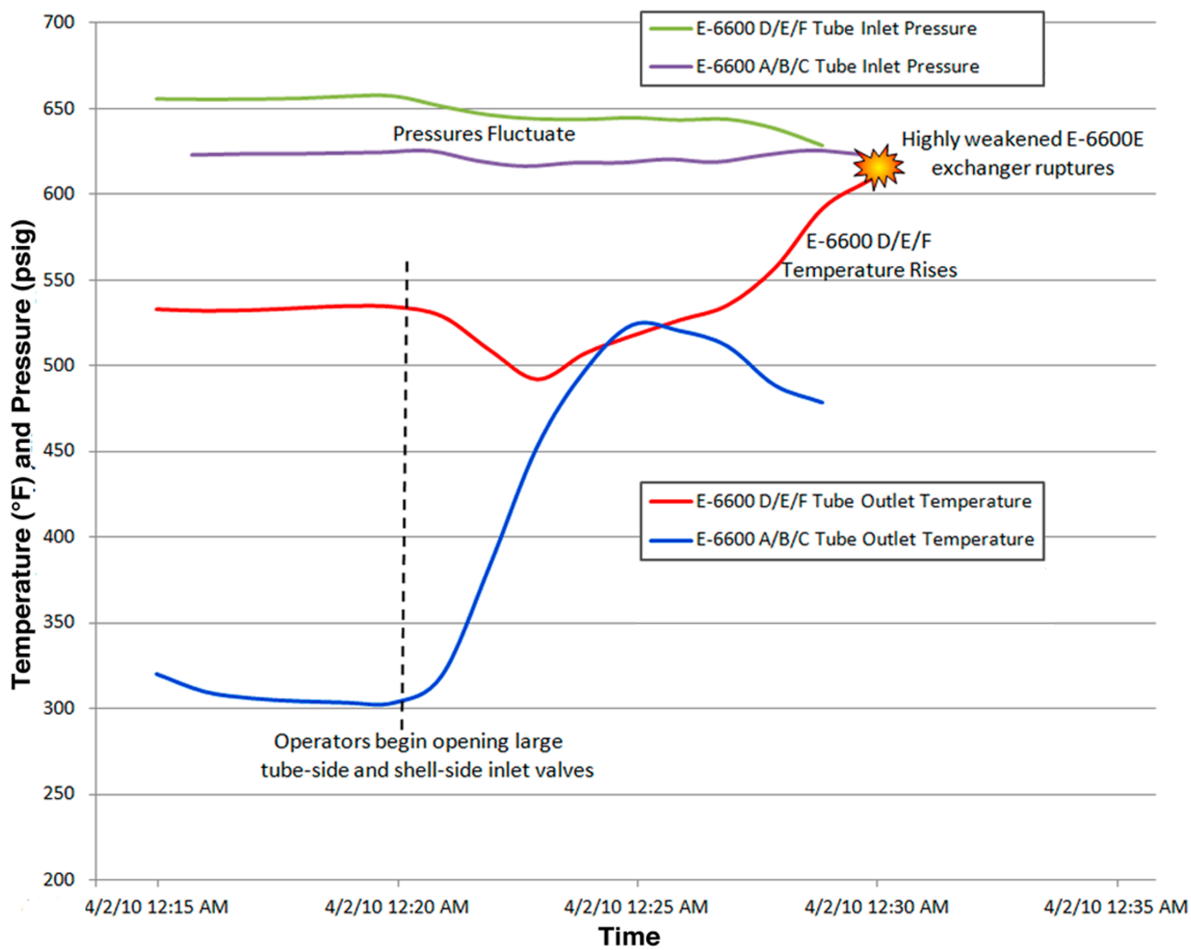

Figure 23. Temperature and Pressure Trends before the Anacortes Incident

4.3.1 NHT Heat Exchanger Startup Conditions

The CSB examined startup activities and process data at the time of the incident and concluded that no equipment mechanical integrity code parameters were exceeded. Temperature trends from the time when the A/B/C heat exchanger bank was coming on-line were compared to those from the three previous startups (as explained in Appendix B). All of the temperature trends are similar. The maximum allowable working pressure of the E heat exchanger was 655 psig at 650 ºF. The operating data indicate that the design temperature of 650 ºF was not exceeded before the rupture.

The E heat exchanger was protected from excessive pressure by a pressure relief valve on a downstream vessel, which was set to relieve the pressure at 585 psig.[93] Operating data indicate that the pressure relief valve was not challenged and did not open before the incident. The relief valve was inspected and tested after the incident, and it opened at the designated set pressure.

[93] This relief valve is located further downstream in the process. As a result the exchanger pressure is higher than the relief valve set pressure. This pressure difference is accounted for by the engineering design and documented in the relief system calculations.

As a result of this analysis, the CSB excluded improper operation of the NHT heat exchangers during startup as a plausible contributing cause of the incident.

4.4 Process Conditions of the B and E Heat Exchangers

In refineries and chemical plants, key temperatures, pressures, flow rates, and other data are typically measured using a distributed control system (DCS). This system tracks and records data reported to the system via instrumentation in the plant and can visibly display important variables to control room operators. Operators also can manually record data from field instrumentation that does not report to the DCS.

Tesoro monitored temperatures and pressures of the process fluid entering and exiting the NHT heat exchanger banks, via both local field instrumentation and instrumentation that reported to the DCS. The locations of the temperature (TI) and pressure (PI) indicators are shown in Figure 24.

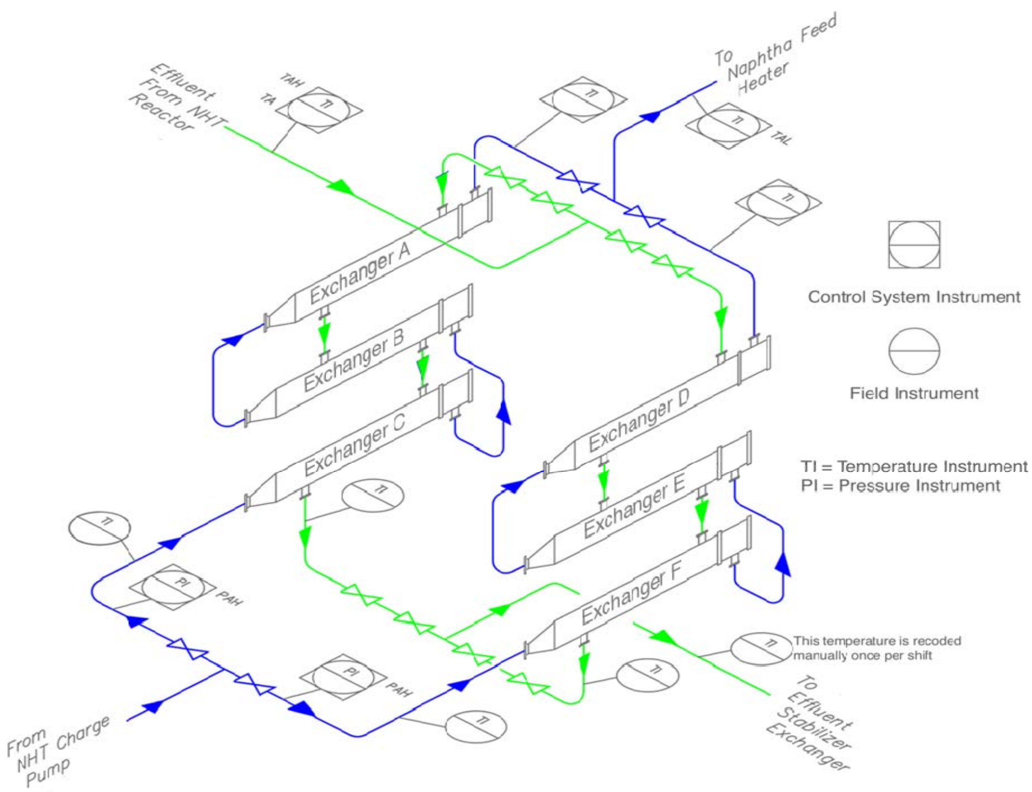

Figure 24. Temperature and Pressure Indicators for the NHT Heat Exchanger Banks. This isometric process flow view depicts the lack of temperature indication on both the shell-side and tube-side of the B and E heat exchanger inlets and outlets.

Although some temperature and pressure measurements were taken surrounding the NHT heat exchanger banks, no temperature measurements were made between the heat exchangers. Thus, Tesoro did not know the operating temperature of the process fluid entering and exiting the B and E heat exchangers.[94] Had Shell Oil or Tesoro performed a technical evaluation or installed instrumentation to monitor temperatures at these locations, a better evaluation of potential HTHA hazards could have been performed, and more effective safeguards could have been implemented.

The B and E heat exchangers lacked instrumentation to monitor shell-side inlet temperatures.

4.4.1 CSB Modeling of the NHT Heat Exchangers

Because of the minimal temperature measurements of the NHT heat exchanger banks, the CSB performed process modeling to estimate the operating temperatures and hydrogen partial pressures of the B and E heat exchangers by using computer-based chemical process design software packages.[95] The model required the use of several assumptions, such as fouling distribution, because of a lack of both process and fouling data gathered by Shell Oil and Tesoro. Consequently, all model results are estimates of the actual process conditions experienced by the NHT heat exchangers. The CSB used the model to estimate the operating conditions of each heat exchanger based on the available Tesoro operating data, including temperatures, pressures, flow rates, and fluid composition data. The model development process and associated results are described in Appendix C. A summary of the modeling results is depicted in Figure 25, Figure 26, and Figure 27.

[94] A single external surface temperature measurement of 455 ºF was taken in October 1998 on the inlet to either the B or E exchanger.

[95] Aspen HYSYS and Aspen Exchanger Design and Rating.

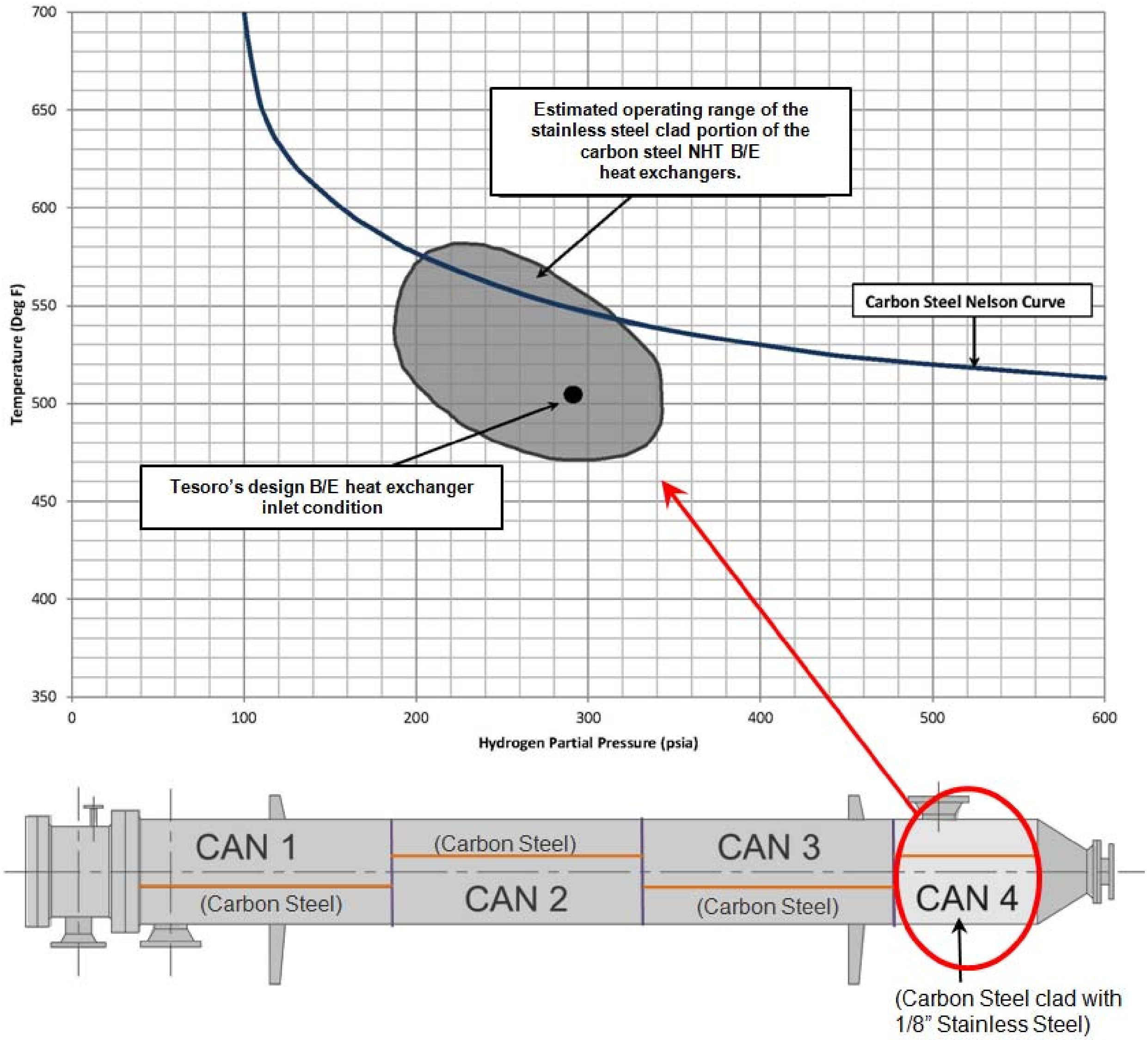

Figure 25. Model Results for Can 4. The stainless-steel-clad portion of the carbon steel B and E heat exchangers was estimated to occasionally operate above the carbon steel Nelson curve. No HTHA was found in this region, likely because stainless steel cladding reduced the potential for HTHA in the carbon steel beneath it. Tesoro's design B and E process condition used for HTHA evaluation (504 °F and 291 psia hydrogen partial pressure) did not represent the entire range of heat exchanger operating conditions.

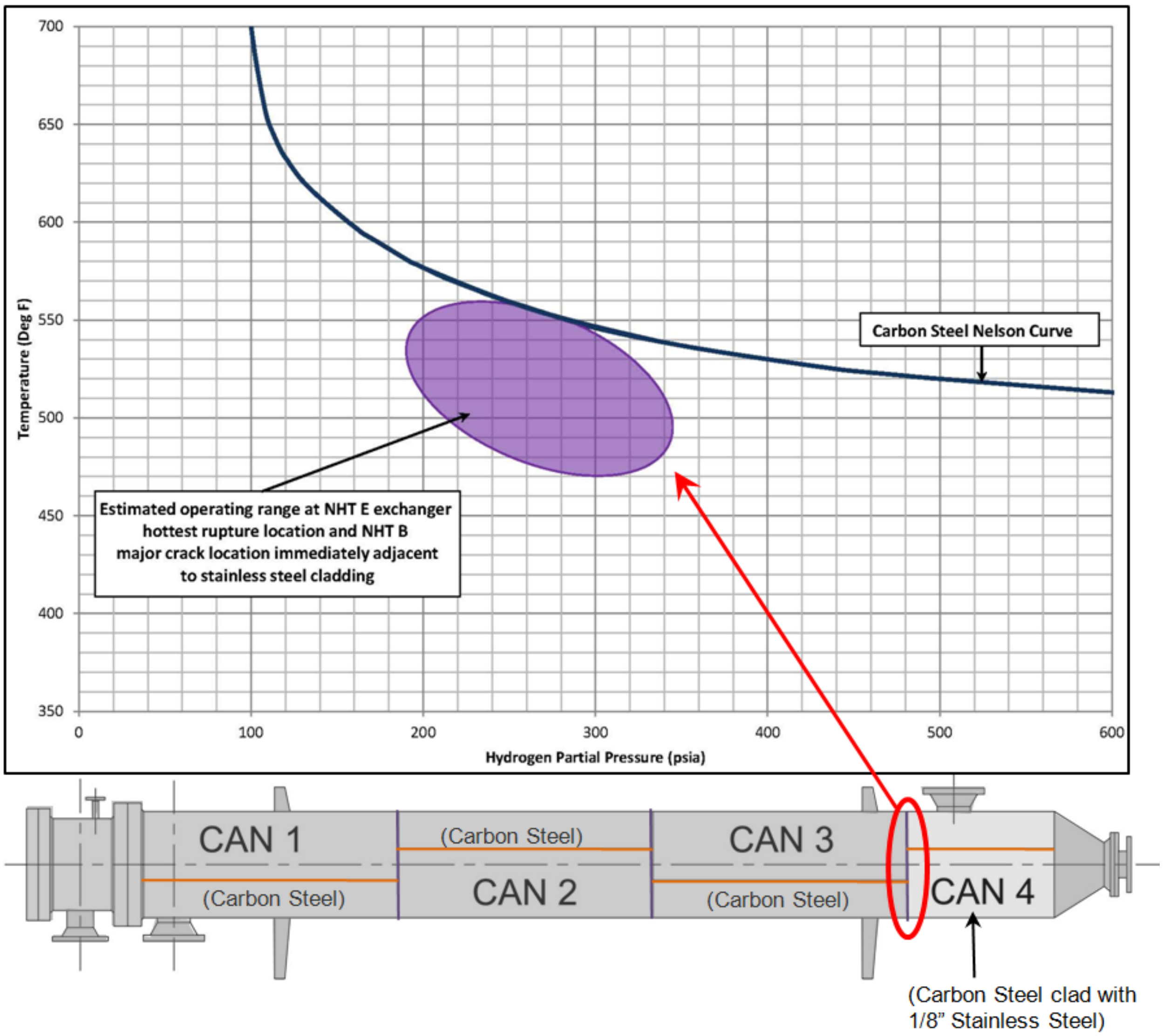

Figure 26. Model Results for the Weld Downstream of Can 4. The circumferential weld immediately downstream of the stainless-steel-clad portion of the carbon steel B and E heat exchangers was estimated to operate just below the carbon steel Nelson curve. Extensive HTHA was found in this region, the hottest rupture location of the E heat exchanger and the major crack location of the B heat exchanger.

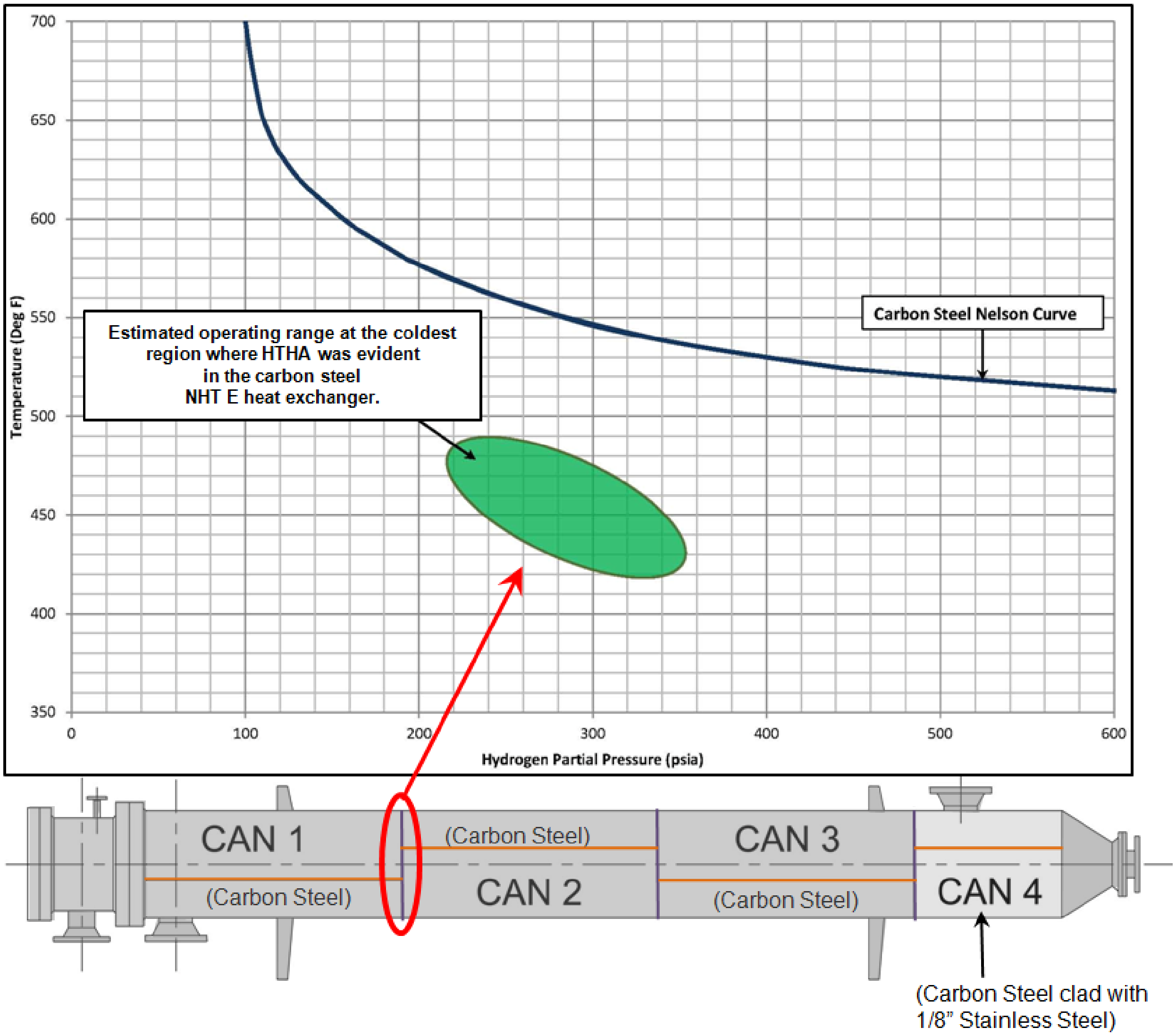

Figure 27. Model Results for the Coldest Region of the E Heat Exchanger. The coldest region of the E heat exchanger with evident HTHA was estimated to operate as much as 120 ^{0}F below the carbon steel Nelson curve.

4.4.1.1 HTHA Occurred Below the Nelson Curve

> **HTHA was found in locations that were estimated to operate up to 120 ^{0}F below the carbon steel Nelson curve.**

CSB process modeling estimates demonstrated that the hottest portion of the B and E heat exchangers with evident HTHA, the circumferential weld between "Can" 3 and "Can" 4, operated below the carbon steel Nelson curve. HTHA was also identified at the circumferential welds between "Can" 2 and "Can" 3, and also between "Can" 1 and "Can" 2. Modeling results also indicate that the coldest region in the E heat exchanger[96] with identified HTHA was estimated to have operated up to 120 °F below the carbon steel Nelson curve. This finding suggests that the long-standing industry carbon steel Nelson curve is inaccurate—it cannot be relied on to prevent HTHA equipment failures, and it cannot be reliably used to predict HTHA equipment damage.

4.4.1.2 Estimate That a Portion of the B and E Heat Exchangers Operated Above the Nelson Curve

The CSB modeling analysis estimated that during operation while fouled, the stainless-steel-clad portion of the B and E heat exchangers at times likely operated above the carbon steel Nelson curve. This section was not damaged by HTHA, probably because the stainless steel cladding protected the carbon steel beneath it. As discussed in Section 5.3.3, operation near or above the carbon steel Nelson curve should have triggered an inspection for HTHA by Tesoro, but the company never performed such an inspection.

4.4.1.3 Tesoro's Replacement Heat Exchangers

Since the April 2010 incident, Tesoro has installed new NHT heat exchangers with upgraded materials of construction to significantly reduce the potential for HTHA.[97] In addition, an advanced process control system is in place to minimize fouling. The heat exchangers are also constructed using only one bank of exchangers. The entire NHT unit now must be shut down for cleaning, eliminating the hazards of online switching and creating a much safer approach for maintenance. The new heat exchangers also incorporate additional instrumentation to allow the monitoring of each heat exchanger for fouling and decrease the likelihood of operation in HTHA-susceptible conditions.

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96 HTHA was not conclusively identified in the B heat exchanger in this region. Only a limited metallurgical analysis was performed on the seam between Can 1 and Can 2 of the B heat exchanger.

97 Although the materials of construction are upgraded in the new exchangers, portions of the heat exchangers that use carbon steel are designed to operate at temperatures of more than 400 °F.

5.0 Organizational Deficiencies

Similar to the results of the CSB investigation of the disastrous March 2005 explosion at the BP Texas City site, the CSB identified deficiencies in the process safety culture and organization at the Tesoro Anacortes Refinery that contributed to the April 2, 2010, incident. At the time of the incident, deficiencies in the Tesoro process safety culture and organization coincided, with catastrophic consequences. The organizational deficiency allowed many personnel in a hazardous region, and the process safety culture problems led to a failure to control HTHA hazards, resulting in a major fire and the loss of seven lives.

5.1 NHT Heat Exchanger Flanges – A History of Leaking

During startup following cleaning, the NHT heat exchangers would frequently leak from flanges, occasionally resulting in fires that created hazardous conditions for workers. This hazard had persisted for more than a decade; the CSB found that the earliest documentation of these leaks was from 1997, when Shell Oil owned the refinery.

Over the years, Tesoro attempted maintenance and engineering solutions to stop the heat exchanger leaks. In 2008, management and labor even jointly conducted a triangle of prevention (TOP)[98] investigation that analyzed, in part, the NHT heat exchanger leaks. However, these attempts did not effectively resolve the problem of the heat exchangers leaking during startup; as a result, various operational techniques were developed to accommodate the fact that the leaking would typically cease once the heat exchangers stabilized at their normal operating temperatures. The leaks were very hazardous as the hot naphtha was highly flammable[99] and had the potential to be operating above its autoignition temperature. However, because these leaks were never effectively prevented, the leaks from the NHT heat exchangers during startup became an accepted and normalized condition at Tesoro.

Tesoro accepted and normalized the hazardous condition of frequent leaks during exchanger startup.

[98] The TOP program is a joint union-management workplace safety program that applies the knowledge of the workforce to understand and eliminate workplace hazards.

[99] The flash point is defined as the minimum temperature at which a liquid gives off sufficient vapor to form an ignitable mixture with air near the surface. The Tesoro Material Safety Data Sheets (MSDSs) for naphtha list its flash point as -7.1 ºF. Liquids with a flash point of less than 23 ºF fall into the highest hazard category of the Globally Harmonized System of Classification and Labeling of Chemicals (known as the GHS). See: https://www.osha.gov/dsg/hazcom/ghs.html#3.1 (accessed December 31, 2013).

5.1.1 Incident Report That Demonstrates Normalization of Hazardous Conditions

The CSB identified an incident report describing a startup of the NHT D/E/F heat exchanger banks in March 2009, a year before the April 2010 incident, that resulted in the exposure of workers to hazards from both hot steam and leaking hydrocarbons while they put the NHT heat exchangers back in service. This incident report demonstrates the normalization of hazardous conditions that had been established at the refinery.

The 2009 report states that the "exchangers leaked substantially" and that the leaks were "steady streams" flowing from each of the three heat exchangers being put in service. The incident report then describes how workers responded to the leaks by continuing the startup, while wearing only standard refinery personal protective equipment, to reach the desired heat exchanger temperatures. This long-standing practice was used to stop atmospheric hydrocarbon releases from the NHT heat exchangers. The report states that "[s]team lances were positioned at all leak locations." Tesoro employees "continued the startup of the heat exchangers while monitoring leak status.…" Eventually, the target exchanger temperatures were achieved, and the leaks stopped.

This continuation of the startup – despite the exposure of workers to significant hazards – demonstrates the normalization of the extremely hazardous NHT heat exchanger leaks. The leaking of high-temperature, highly flammable process fluids constitutes a serious process safety incident. However, during the 2009 incident, the refinery alarm was not sounded; an emergency response team was not activated; the leak was not isolated from the unit; and the unit was not shut down. The incident report also did not address the need for permanent corrections to stop the leaks. Although Tesoro did make additional attempts to correct the heat exchanger leaks as discussed in Section 5.1.4, ultimately these efforts were unsuccessful and the CSB found that leaks did occur during the startup of the NHT heat exchangers on the night of the April 2010 incident.

5.1.2 TOP Investigation of Fires

In 2008, a TOP investigation team was assembled to begin what would become a ten month investigation into a series of loss of containment incidents at the Tesoro Anacortes Refinery, including some that resulted in fires. In all, fourteen refinery incidents that occurred between May 2003 and December 2007 were investigated during this process. The TOP team investigation included the frequent leaks from the NHT heat exchangers during startup.

The findings of the Tesoro TOP investigation team included the following:

- Tesoro classified incidents involving incipient fires[100] as "level 1" incidents that are reported but do not require investigation. The 2008 TOP investigation was launched after multiple level 1

[100] In 29 CFR 1910.155(c)(26), OSHA defines "incipient stage fire" as a fire that is in the initial or beginning stage and that can controlled or extinguished by portable fire extinguishers, a class II standpipe, or small hose systems without the need for protective clothing or breathing apparatus.

incidents appeared to have common causal factors. The report noted that it was very difficult to complete a proper TOP investigation when many of the incidents were so far in the past.

- NHT heat exchanger leaks were common during startup. However, because the leaks tended to stop after operating temperatures were reached, incident reports were sometimes not filed. The incidents were treated as "normal" startup events, and steam lances were considered to be acceptable leak mitigation. The TOP investigation team noted complacency at the refinery because these events were so common and also cited a growing lack of concern toward activating emergency response.
- A Tesoro mechanical engineer had at one time actively pursued mitigation of NHT heat exchanger leaks. Procedural changes for startup and shutdown were made, and the heat exchanger gasket surfaces were repaired. However, the engineer left Tesoro, and no further progress was made because of a combination of poor communication and a lack of implementation tracking.
- Only one of the fourteen incidents investigated had prompted a previous TOP investigation, even though five of the fourteen investigated incidents involved fires in process units. The TOP investigation team concluded that this complacency in investigation practices caused associated complacency in the workforce toward process-related fires.

5.1.3 MOCs Did not Effectively Control Hazardous Conditions

A contributing factor to the presence of some of the six additional personnel in the NHT unit at the time of the April 2010 incident was likely the need for them to assist with steam lance use in anticipation of leaks during startup.[101] Relying on steam suppression to mitigate leaks during NHT heat exchanger startups was a common practice and was part of the startup procedure. In October 2009, Tesoro approved a Management of Change (MOC) to install two new permanent steam stations near the NHT heat exchangers, shown in Figure 28.[102]

[101] The CSB identified four steam lances near the NHT heat exchangers following the April 2010 incident. Three of the four steam lances were likely active at the time of the incident.

[102] The "Purpose" of the change was to "Provide improved response time and safety when responding to flange fires in the vicinity of the E-6600 exchanger structure." However, the steam equipment was installed in the immediate vicinity of the exchangers and nothing prohibited this steam suppression equipment from being used to mitigate a leak from the exchangers. The project to install additional steam suppression equipment was competed in January 2010. One of the new steam stations is shown in Figure 28.

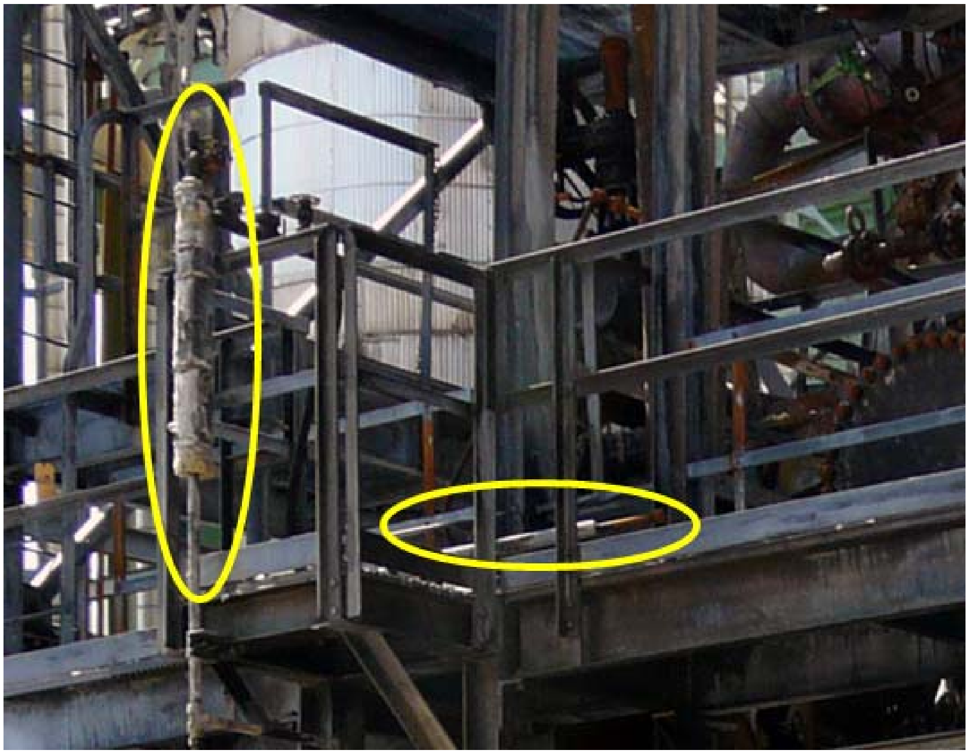

Figure 28. Steam Station and Steam Lance. This post-incident photograph shows a new steam station (left) with a connected steam lance (right).

MOC is one of the 14 elements of the state of Washington PSM regulations.[103] Although the PSM regulations impose a general requirement to perform a PHA [104] at least every 5 years, a formal hazard evaluation is not required for an MOC. The Tesoro MOC policy states, "Management of Change helps ensure that changes to a process do not inadvertently introduce new hazards or unknowingly increase the risk of existing hazards." However, Tesoro decided that a hazard evaluation of the addition of steam stations was not required under their procedures because additional steam stations only involved a minor change to a utility system. Yet, the installation of the additional steam equipment enhanced the ability of the field operator(s) to confront hazardous leaks and extinguish fires in the area of the NHT heat exchangers, and the safety implications of these activities were not considered.

[103] MOC is one of the 14 elements of the WAC rules for PSM of highly hazardous chemicals. *See* http://www.lni.wa.gov/wisha/rules/hazardouschemicals/#WAC296-67-045 (accessed December 25, 2013). MOC is also required by EPA RMP (See http://www.epa.gov/oem/content/lawsregs/rmpover.htm. (accessed December 25, 2013)) and is an element of the federal OSHA PSM regulations (*See* https://www.osha.gov/pls/oshaweb/owadisp.show_document?p_table=STANDARDS&p_id=9760 (accessed December 25, 2013).

[104] A PHA is a hazard evaluation to identify, evaluate, and control the hazards of a process. Facilities that process a threshold quantity of hazardous materials, such as the Tesoro Anacortes Refinery, are required to conduct a PHA per the WAC Title296 Chapter 67, Safety standards for PSM of highly hazardous chemicals (1992). *See:* http://apps.leg.wa.gov/wac/default.aspx?cite=296-67 (accessed September 29, 2013) PHAs are also required by the federal EPA RMP.

Good practice guidelines such as those published by the CCPS advise that a hazard assessment should be performed during MOC reviews.[105] Tesoro should have conducted a formal hazard evaluation for the MOC and should have considered more robust alternatives to steam lances such as protecting workers by effectively correcting the mechanical problems that were causing the leaks.

Washington PSM regulations require MOC reviews to consider the impact of proposed changes on operating procedures.[106] However, operating procedures were not reviewed or modified as part of the MOC review conducted for the new steam suppression equipment. The existing NHT heat exchanger startup procedure only addressed field tasks for a single NHT outside operator. The procedure instructed the operator to have a steam hose (lance) ready in case a leak developed and to warm the heat exchangers slowly to prevent leaks, but if leaks did occur, to continue the startup as follows:

> Keep an active steam hose on hand in case of leaks.
>
> Slowly heating the bundle up to prevent leaks.
>
> Heating the exchanger too fast can cause leaks. If the heads begin to leak, they will usually reseal themselves as they come up to temperature.

When the ability to use multiple steam lances on the NHT heat exchanger leaks was provided, the operating procedure was not updated to reflect the ability for, and likely presence of, additional personnel to operate those steam lances. In addition, no guidance was developed or provided to establish how large a leak or fire the field operator(s) was expected to fight and no evaluation was made to assure there was proper allowance for emergency egress from a large leak or fire. Tesoro did not view the NHT heat exchanger startup and history of leaks as high hazard activity—a reflection of the normalization of the hazardous conditions.

5.1.4 Unsuccessful Tesoro Attempts to Prevent Heat Exchanger Flange Leaks

Tesoro sporadically made attempts to prevent the leaking of the NHT heat exchangers. These attempts included: gasket modifications, changes to torque and bolting practices, resurfacing of flange surfaces, and the installation of warm-up piping to smooth the transition from cold to hot equipment during heat exchanger startup. Following the severe leaks from the NHT heat exchangers during the March 2009 startup, in August 2009 Tesoro installed a different type of gasket in the NHT heat exchangers. During the startup that followed, Tesoro records indicate that no leaks from the heat exchangers occurred. Tesoro representatives told the CSB that this startup was evidence of "success" in correcting the NHT heat

[105] An important aspect of an MOC is assessing the hazards associated with proposed changes. The MOC team should determine the level of hazard evaluation needed for specific types of changes, but site management may decide that formal hazard evaluations are necessary for certain types of changes. The MOC process should provide sufficient information about the change to conduct a hazard evaluation. Center for Chemical Process Safety (CCPS). *Guidelines for the Management of Change for Process Safety*. 2008; pp 52-54.

[106] Modification to operating procedures is part of the MOC requirements addressed by the WAC process safety management regulations. *See* http://www.lni.wa.gov/wisha/rules/hazardouschemicals/#WAC296-67-045 (accessed December 25, 2013).

exchanger leaks. However, this was the last startup before the April 2010 incident, and a single successful startup without leaks is not evidence of long-term success.[107] One of the four steam lances likely used for leak mitigation on the night of the April 2010 incident is shown in Figure 29.

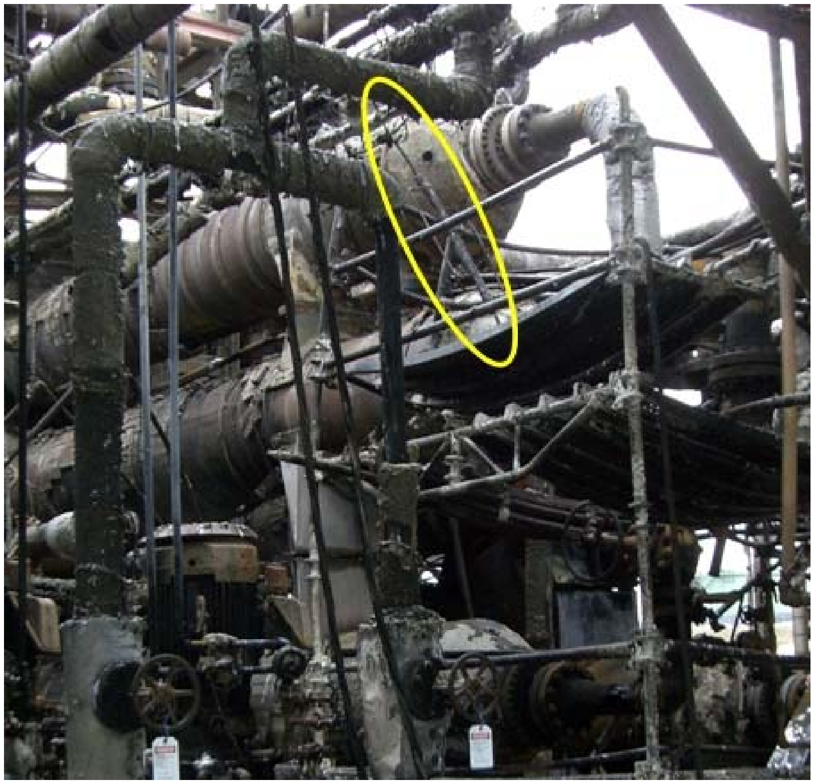

Figure 29. Post-Incident Steam Lance. This photograph shows a steam lance that was likely used during the startup.

In addition, the Tesoro Anacortes Refinery has a history of incidents related to flange leaks.[108] Despite industry best practices that require use of new heat exchanger gaskets, Tesoro documents indicate that the company noted that the new NHT heat exchanger gaskets, installed to prevent future startup leaks, could be re-used after subsequent cleaning cycles.[109] In contrast, gasket manufacturer guidance and industry

[107] On the night of the April 2010 incident, two different operators reported two leaks during the startup of the heat exchangers. One leak was reported just before the incident.

[108] Tesoro incident reports document a history of gasket failures at the refinery. A variety of causes were identified for these past failures including loose bolts, damaged gaskets, installation of the wrong gasket, defective gaskets, and other installation-related causes. The Tesoro 2008 TOP investigation identified a contributing cause to the fires in the NHT unit was that "[f]langes and/or gaskets may have been damaged due to poor access and high maintenance frequency."

[109] The notation indicated that the gasket vendor informed Tesoro that these gaskets could be re-used. Maintenance records indicate that the job plan did call for new gaskets.

best practice guidance indicate that new gaskets should be installed and that gaskets should not be re-used.[110,111]

Regardless, Tesoro's perceived "success" in resolving the NHT heat exchanger leaks in August 2009 did not result in the presence of fewer personnel during the April 2010 startup. In fact, Tesoro normalization of the hazardous NHT heat exchanger leaks ultimately contributed to the presence of a significant number of additional workers near the NHT heat exchangers at the time of the incident and thus a larger number of fatalities as a result of the heat exchanger failure.

5.2 Hazardous Nonroutine Work

Nonroutine work can be a highly hazardous operation. Work is performed on equipment that might or might not be shut down while adjacent equipment containing hazardous process material continues to operate. This type of operation places maintenance and operations personnel at risk. The CCPS provides the following guidance:

> Experience indicates that many accidents do not occur during "normal" operation but, rather, during such nonroutine modes of operation.[112]
>
> By its nature, nonroutine work carries with it the potential for unrecognized hazards that sometimes has led to a catastrophic incident.[113]
>
> During the period 1970 to 1989, 60 to 75% of major incidents in continuous processes occurred during "non-routine" modes of operation; i.e., in operating phases other than the continuous operation of the process after start-up.[114]

The 1989 Phillips Houston Chemical Complex fire and explosion, which killed 23 workers, expedited issuance of the PSM standard. Similar to the April 2010 Tesoro Anacortes Refinery incident, it involved the performance of hazardous nonroutine work in a running process unit.[115]

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[110] When a flanged joint is opened, the gasket should be not be re-used. A new gasket should always be installed. Mannan, S. *Lee's Loss Prevention in the Process Industries, Hazard Identification, Assessment and Control*. Chapter 21, "Equipment Maintenance and Modification." p 25.

[111] Lamons. *Gasket Handbook*. 2012; p 113. *See* http://www.lamons.com/public/pdf/lit_reference/LamonsGasketHandbook2012.pdf (accessed December 27, 2013).

[112] Center for Chemical Process Safety (CCPS). *Revalidating Process Hazard Analyses*. 2001; pp 31-32.

[113] Center for Chemical Process Safety (CCPS). *Guidelines for Auditing Process Safety Management Systems*. 2011; p 393.

[114] Center for Chemical Process Safety (CCPS), *Guidelines for Hazard Evaluation Procedures*. 2008; p 257.

[115] U.S. Department of Labor. *A Report to the President: Phillips 66 Company Houston Chemical Complex Explosion and Fire*. April 1990; p 21.

The state of Washington's PSM regulations also stress the importance of employers identifying the hazards of nonroutine work in process areas and then communicating such hazards to those employees performing the work.[116]

Tesoro acknowledged both the potential hazards and relevance of nonroutine work to the Anacortes refinery incident in its own investigation report on the April 2010 incident.

> Continuous petroleum or chemical processes operate most effectively when they are in a steady state. Non-routine activities, including startup or shutdown, can create additional risks because parameters such as flow, temperature and pressure are in a state of flux.[117]

5.2.1 CSB Investigation of Tosco Avon Refinery

On February 23, 1999, a fire occurred in the crude unit at the Tosco Corporation's Avon oil refinery in Martinez, California.[118] Workers were attempting to replace piping attached to a 150-foot-tall distillation column[119] while the process unit was in operation. During removal of the piping, naphtha was released onto the hot distillation column and ignited. The flames engulfed five workers located at different heights on the column. Four workers were killed, and one worker sustained serious injuries.

The CSB investigated the incident and determined that the refinery's management system did not recognize or control the serious hazards posed by performing nonroutine repair work while the crude processing unit remained in operation.[120] Although the piping replacement activities at Tosco were dissimilar to starting up the heat exchanger bank at the Tesoro refinery's NHT unit, both involved hazardous nonroutine work.

A key conclusion and recommendation from the CSB 1999 Tosco investigation addressed the importance of advance planning and thorough hazard evaluations for the safe performance of higher hazard nonroutine work. Management has the obligation to identify hazards, implement effective controls and

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[116] *See* WAC 296-67-291 Appendix C, *Compliance guidelines and recommendations for process safety management (nonmandatory)* http://www.lni.wa.gov/WISHA/Rules/hazardouschemicals/default.htm#WAC296-67-021 (accessed December 3, 2013).

[117] *See* TOP Investigation Team Report. *Naphtha Hydrotreater E-6600E Failure, 12:35 a.m., April 2, 2010, Anacortes Refinery, Washington*. p 21. http://tsocorp.com/wp-content/uploads/2014/01/Anacortes_final_report.pdf (accessed April 2, 2014).

[118] Ultramar Diamond Shamrock Corporation purchased the Avon oil refinery in September 2000 and renamed it the Golden Eagle Refinery. Tesoro purchased the Golden Eagle Refinery in 2002 and was the final party to respond to the CSB site-based safety recommendations from the 1999 Tosco incident.

[119] A distillation column is an oil refinery processing vessel that separates preheated hydrocarbon mixtures into various components based on boiling point. The separated components are referred to as fractions or cuts. Inside the column some trays draw off the fractions as liquid hydrocarbon products (such as naphtha), and piping transports them to storage or other units for further processing.

[120] CSB Investigation Report, Refinery Fire Incident – Tosco Avon Refinery, March 2001. *See* http://www.csb.gov/assets/1/19/Tosco_Final_Report.pdf (accessed December 4, 2013).

limit personnel exposure to higher-hazard work – but not meeting this obligation is a common failing, identified in both the Tesoro and Tosco investigations, that led to the catastrophic incidents. The CCPS recommends that companies considering tasks that entail employee access to hazardous areas should "minimize the number of people in harm's way should an incident occur."[121]

The likelihood of leaks occurring during the startup of the NHT heat exchangers made returning them to service a serious hazard to the workers involved. Similar to the Tosco incident, the serious hazards could have been more effectively controlled through the use of hazard evaluation techniques and more effective management control of the nonroutine work.

Unlike Tosco, Tesoro had years to evaluate the hazards and effectively control the frequent NHT heat exchanger leaks. Multiple incident reports were developed and hazard reviews were conducted. Each of these events presented opportunities for Tesoro to recognize the hazardous nonroutine work and effectively control the hazards. However, Tesoro never effectively corrected the hazardous startups and failed to limit access to a minimum number of essential personnel.

5.2.2 NHT Heat Exchanger Cleaning and Startup

While in operation, the NHT heat exchangers fouled, reducing heat transfer between the tube-side and shell-side process fluids. This reduction in heat transfer both increased shell-side outlet temperatures and decreased tube-side outlet temperatures. To maintain process requirements, the heat exchangers were periodically cleaned. Tesoro accomplished this task with hazardous nonroutine work, cleaning one bank of heat exchangers at a time while the remainder of the process continued to operate.

During this nonroutine work, one bank of heat exchangers was isolated, opened, and cleaned, while the other bank of heat exchangers remained in operation. This maintenance activity typically lasted at least three days. During some of the cleaning operations – for example, when the tubes were removed from the heat exchanger to facilitate the cleaning – contractors and specialized equipment were needed in the unit. In the past, this operation involved as many as fourteen personnel in the NHT unit at one time while the other heat exchanger bank and the remainder of the process continued to operate around them.

5.2.3 Tesoro Failure to Control Heat Exchanger Startup Hazards

On April 1, 2010, Tesoro operations staff began implementing the procedure to startup the clean A/B/C heat exchanger bank. The startup procedure only described roles for the two NHT operators normally assigned to a shift, one in the control room and one outside in the field. However, additional outside operators from other units frequently assisted in the heat exchanger startup. In addition to responding to potential leaks, supplemental personnel were sometimes requested to assist in the NHT heat exchanger startup operations because of the difficult labor-intensive process involved. When starting up a bank of NHT heat exchangers, the operator was required to open several large block valves to introduce the

[121] Minimize the number of people in harm's way should an incident occur. *See* Center for Chemical Process Safety (CCPS). *Guidelines for Risk Based Process Safety*. 2007; p 296.

process fluid to the heat exchanger bank that was shut down. The block valves were located on three different levels of the NHT structure, as illustrated in Figure 30. The geared mechanisms that opened and closed these valves were of a type referred to as "long-winded" because they were physically demanding, requiring over a hundred turns (by hand) of large wheels to fully open the valves. In addition, the heat exchanger procedures required deliberate and coordinated manipulation of these valves. As a result, startup by only the one official NHT outside operator was complex and difficult, and additional personnel often assisted with the heat exchanger bank startups.

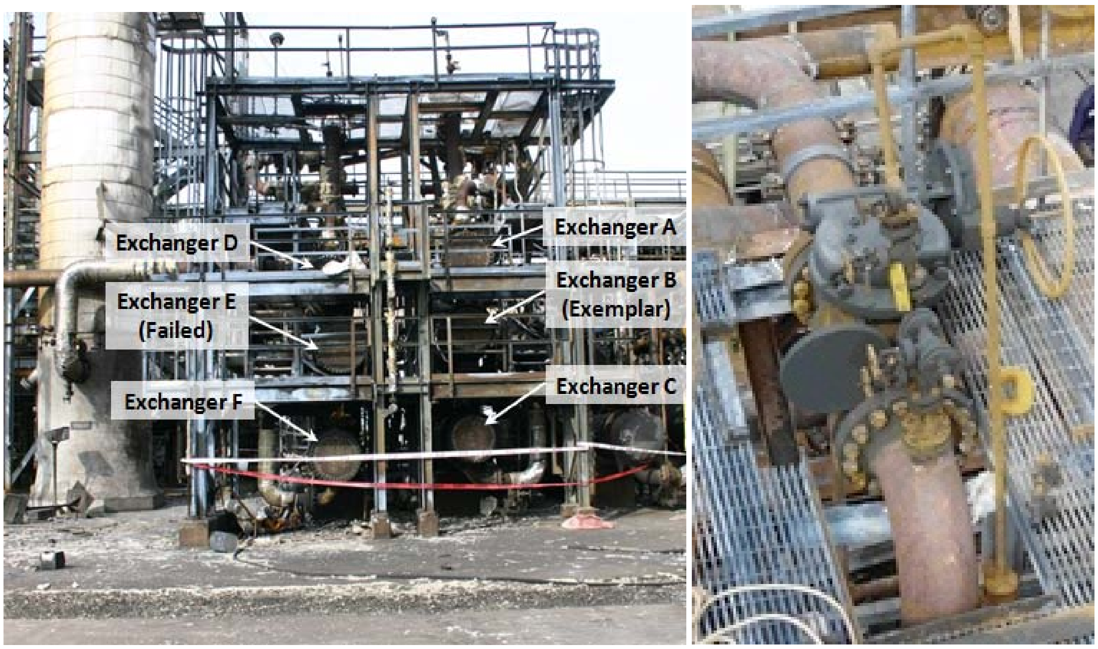

Figure 30. Unit structure (left) and manual block valve (right)

Tesoro routinely relied on additional staff members during NHT heat exchanger startups but never assessed the risks or made any attempts to control them. Tesoro did not conduct an MOC to consider the risks of these organizational changes, despite its policy that required the performance of such a risk assessment.[122]

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[122] The performance of a MOC review to examine the safety implications of organizational change is not required by either the federal OSHA PSM standard or the Washington PSM regulation. Although it is noted that Tesoro MOC procedures went beyond regulatory requirements, its failure to apply its own policy to circumstances that should trigger a MOOC review underscores the need for a PSM regulatory revision to help ensure that needed MOOC safety reviews are not voluntary. In the 2007 BP Texas City investigation report, the CSB recommended to the federal OSHA that it revise the PSM standard to require MOC reviews for organizational changes, including staffing changes. In response, OSHA sent a memorandum in 2009 to its Regional Administrators, stating the new agency position that changes to operating procedures that include organizational changes are subject to MOC requirements, even though they are not explicitly applicable. In August 2013, the CSB Board voted that the OSHA response was "open-unacceptable." In December 2013, OSHA published a Request for Information (RFI) as a step in the rule-making process to revise the chemical accident prevention regulations, including the PSM standard. The RFI seeks public input on whether to revise the PSM standard to explicitly require MOC reviews for organizational changes, citing the BP Texas City CSB recommendations. See: (https://www.osha.gov/pls/oshaweb/owadisp.show_document?p_table=FEDERAL_REGISTER&p_id=24053)

The Tesoro MOC policy includes a requirement for Management of Organizational Change (MOOC), which recognizes that "… changes in an organization can … sometimes result[] in unrecognized negative effects." For examples, an MOOC is needed in the case of staffing modifications, changes in maintenance practices, and shifting of personnel roles and responsibilities – all typical practices used at the refinery to provide additional operators from other units to assist in startup of the NHT heat exchangers. The MOOC policy includes provisions for providing "[c]lear documentation and communication of why the change is necessary" and "[a] clear understanding of the risks involved and application of effective measures to reduce, eliminate, or mitigate those risks." The Tesoro MOOC policy covers "non-routine tasks" and includes requirements for the following:

> Document all identified risks; include methods to reduce, eliminate or mitigate them […]
>
> Review the risks involved with the changes. Ensure discussions include human factors, competence, workload issues, and sufficient resources to ensure the change can be carried out safely.

In post-incident interviews, Tesoro employees described the number of employees in the unit at the time of the explosion (seven workers) as unusually high. Yet, the CSB learned that it was not unusual for a shift supervisor to enlist one to four additional staff members from other units to perform the hazardous nonroutine work associated with the NHT heat exchanger startups. Although some employees might have perceived this as positive (e.g., reflection on individual willingness to help), the practice actually exposes a poor company process safety culture. Tesoro required operators who did not have defined roles in the procedure to assist with the startup, a hazardous activity with a long history of incidents.

An effective PSM system would have corrected the problems with known leaks and fires and would have controlled all aspects of hazardous nonroutine work. This approach would include taking proactive measures to eliminate worker exposure hazards and limiting access to only the minimum personnel needed to perform the tasks.[123] The use of more personnel than the number called for in the procedure exposed more workers to the high-hazard activity. This higher level of risk to workers should have been identified in NHT unit procedural reviews, PHAs, or an organizational MOOC.

(accessed January 3, 2014). While the CSB welcomes this positive step, it is important to note that more timely proactive federal PSM revisions requiring MOOC reviews would also require similar PSM revisions in Washington's State Plan OSHA program. If implemented, the revised regulations would have required a safety review of staffing changes for the NHT exchanger startup and could have had a preventive impact.

[123] Minimize the number of people in harm's way should an incident occur. Center for Chemical Process Safety (CCPS), *Guidelines for Risk Based Process Safety*; 2007; p.296.

For example, in such a review, Tesoro could have recommended automating the NHT heat exchanger startup or redesigning the heat exchangers to a single bank so that online switching was not possible. Automation could have limited the role of the single outside NHT operator and minimized exposure to hazards. With automation, the task for the outside operator could have been reduced to simply opening the primary isolation block valves for the A/B/C heat exchangers. If the heat exchanger leaks had been corrected, there would no longer be a need for multiple operators to be actively prepared to mitigate a leak or fire during the startup, and the single necessary operator could leave the immediate area. The remainder of the startup could have been performed by the automatic system and controlled remotely by the NHT operator in the control room. Such approaches could have eliminated the need to station personnel in the immediate vicinity of the heat exchangers. Since the incident, Tesoro has redesigned the NHT heat exchangers to create a single heat exchanger bank. Now, online switching is not possible, and automated startup can be used to minimize hazards to personnel. If Tesoro had taken such an approach before the incident, the consequences of the April 2010 incident could have been significantly reduced.

Post-incident, Tesoro replaced the NHT heat exchangers with a single exchanger bank.

With the new design, online switching is not possible, and automated startup can be used to minimize hazards to personnel.

5.3 Process Hazard Analyses Failed to Prevent or Reduce the Consequences

CSB process modeling estimates suggest that HTHA occurred at the Tesoro Anacortes Refinery at temperatures and hydrogen partial pressures below the carbon steel Nelson curve. However, the CSB has found that both Shell Oil and Tesoro had many opportunities to prevent the damage caused to the B and E heat exchangers by HTHA long before the April 2010 catastrophic failure. Such opportunities included the following:

- DMHRs to predict potential HTHA damage
- Verification of operating conditions
- PHAs to identify hazards, evaluate safeguards, and assess considerations for inherently safer design.

The PSM-required PHAs[124] conducted on the NHT heat exchangers failed to prevent the April 2010 incident or to reduce the consequences by limiting personnel access to potentially dangerous areas during the hazardous startup activity. The Shell Oil and Tesoro PHAs conducted on the Anacortes refinery NHT unit failed to accomplish the following:

- Effectively evaluate and control hazardous nonroutine operations
- Effectively evaluate and control the frequent leaks during startup
- Restrict or limit the number of personnel present during the hazardous nonroutine startup of the NHT heat exchangers
- Identify effective safeguards to control hazards from damage mechanisms such as HTHA.

5.3.1 Hazardous Nonroutine Operations

None of the Anacortes refinery PHAs effectively evaluated and controlled hazards associated with the nonroutine work necessary to periodically clean the NHT heat exchangers. The Washington PSM regulations address the need for nonroutine operations to be evaluated and require that at least one member of the PHA team has expertise in nonroutine tasks.[125] The CCPS describes the importance of PHA evaluations, as well as the hazardous potential and frequent problems of PHAs that lack sufficient analysis of nonroutine work as follows:[126]

[124] A PHA is a hazard evaluation to identify, evaluate, and control the hazards of a process. Facilities that process a threshold quantity of hazardous materials, such as the Tesoro Anacortes Refinery, are required to conduct a PHA per the WAC, Title 296, Chapter 67, Safety standards for process safety management of highly hazardous chemicals (1992). See: http://apps.leg.wa.gov/wac/default.aspx?cite=296-67 (accessed September 29, 2013). PHAs are also required by the federal EPA Risk Management Program.

[125] *See* WAC 296-67-291 Appendix C--Compliance guidelines and recommendations for process safety management (nonmandatory) http://www.lni.wa.gov/WISHA/Rules/hazardouschemicals/default.htm#WAC296-67-021 (accessed December 3, 2013).

[126] Center for Chemical Process Safety (CCPS). *Revalidating Process Hazard Analyses*. 2001; pp 31-32.

> It is not uncommon for initial PHAs of continuous processes to focus only on normal operations, failing to address nonroutine, critical operating modes such as startup, shutdown, preparation for maintenance, emergency operations, emergency shutdown, and other activities whose characteristics may differ considerably from normal operations.
>
> Experience indicates that many accidents do not occur during "normal" operation but, rather, during such nonroutine modes of operation. Consequently, it is important that a PHA evaluate the hazards of a process during nonroutine as well as normal (routine) operating modes.

The 1996 Shell Oil PHA for the NHT unit did not evaluate or identify any issues related to nonroutine hazardous work associated with the frequent NHT heat exchanger cleaning operations. The 2006 Tesoro NHT unit PHA revalidation identified startup as a nonroutine operation but noted that existing procedures were adequately addressing nonroutine work.

5.3.2 Access Was Not Controlled During Hazardous NHT Heat Exchanger Startup

The 1996 Shell Oil NHT unit PHA did not identify or analyze leaks from the NHT heat exchangers, and no recommendations were made to prevent these leaks. The 2001[127] and 2006 Tesoro NHT unit PHA revalidations also did not mention the frequent leaks from the NHT heat exchangers.[128] The 2010 Tesoro NHT unit PHA team reviewed the March 2009 NHT heat exchanger startup incident where a steady stream of flammable hydrocarbons leaked from the exchangers near workers. In its evaluation of this incident, the PHA team reviewed unspecified "administrative controls" and determined that they were "in place and effective." However, the CSB identified no administrative controls in place to minimize the number of workers present or their exposure to these startup hazards. In April 2010, less than two months after the PHA team determined that the "administrative controls" were in place and effective, seven workers were asked to be present during the hazardous nonroutine startup of the NHT heat exchangers. According to the Tesoro procedure, a single field operator should have conducted this startup work.

[127] The 2001 PHA revalidation conducted by Tesoro did not raise issues related to the NHT heat exchangers. The only mention of these exchangers is in the process description.

[128] The 2008 TOP investigation of fires in the Anacortes refinery NHT unit concluded that complacency about exchanger leaks was a contributing factor in allowing the problem to persist.

5.3.3 Failure to Effectively Identify and Evaluate HTHA Hazards

During the 38 years that the NHT heat exchangers were in operation, the Anacortes Refinery had many opportunities to prevent the April 2010 incident by identifying and effectively controlling the potential for HTHA in the B and E heat exchangers. Both Shell Oil and Tesoro performed DMHRs, commonly known as corrosion reviews, of the Anacortes refinery's process equipment to determine the susceptibility to damage mechanisms such as HTHA.[129] The first documented corrosion study for the NHT unit occurred in 1990, with subsequent studies in 1999, 2003, and 2008.[130]

A problem common to all of the DHMRs conducted over the 20 years before the April 2010 incident is an inaccurate understanding the extent of stainless steel cladding covering the inside surface of the of the B and E heat exchanger shell wall. Each damage mechanism review documents that the B and E heat exchangers had a protective 316 stainless steel cladding covering the carbon steel wall. However as shown in Section 4.2.1, the 316 stainless steel cladding was installed only on the hottest section (Can 4) of the heat exchanger. The other three sections of the B and E heat exchanger shell walls were carbon steel without any protective cladding.

The 1999 and 2003 DMHRs document both recognition of the need for proper materials of construction and a good understanding of the need to determine accurate equipment operating conditions:

> The prevention of HTHA begins with proper materials selection for the anticipated process conditions, i.e., hydrogen partial pressure and temperature. Careful review of these process variables must be made not only for normal operation but also for any other routine or non-routine mode of operation to determine the controlling set of conditions for the materials selection.
>
> Off-normal conditions must be considered in addition to normal operating conditions.

Despite this recognition that the full range of operating conditions should be determined, none of the DMHRs requested that a technical evaluation, such as process simulation, be conducted for estimation or required that instrumentation be installed to measure the full range of operating conditions of the B and E heat exchangers. There were no temperature instruments installed on the B and E heat exchangers, and the hydrogen partial pressure is a parameter that must be calculated. Because these values were not

[129] Corrosion reviews consist of a process-by-process review of the plant for the susceptibility of API RP 571 damage mechanisms. A process flow diagram is marked up with process variables (temperature, flow, pressure, etc.) and evaluated based on current operating data and past equipment repair history.

[130] The 1990 review occurred while Shell Oil still owned the refinery, and was conducted by Shell Oil employees and the Shell Westhollow Corporation of Texas. Following the purchase of the refinery in 1998, Tesoro contracted with Shell Westhollow for preparation of the 1999 and 2003 study. The 2008 study was conducted by Lloyd's Register Capstone.

rigorously evaluated, the Tesoro and Shell damage mechanism hazard reviews relied on design data that did not reflect all operating conditions.

DMHRs were conducted in 1990, 1999, 2003, and 2008. Highlights of the analyses related to HTHA and the NHT heat exchangers are summarized in Figure 31.

DMHR	Author	Significant HTHA Information and CSB Findings
January 1990[131]	Shell Oil Company	• **DMHR:** HTHA inspection of carbon steel is never required for operation more than 25 °F below carbon steel Nelson curve. • **DMHR:** Inspection is required every 2 to 3 years if operation is less than 25 °F below carbon steel Nelson curve. • **CSB:** No specific recommendations are made for B and E heat exchangers. • **CSB:** Entire shells of B and E heat exchangers are listed as fully clad in Type 316 stainless steel, a material resistant to HTHA. However, only the hottest section (Can 4) of the heat exchanger is clad in Type 316 stainless steel. [132]
March 1999 Reviewed again in September 2003	Shell Oil Company	• **DMHR:** HTHA occurs before it is detectable. • **DMHR:** HTHA control requires knowing and accommodating actual operating conditions. • **DMHR:** In many older units operation of the reactors and heat exchangers up to the HTHA limits is economically attractive. • **DMHR:** Operating close to the Nelson curves requires very close control and monitoring of operating parameters, coupled with frequent inspection for HTHA. • **CSB:** The B and E heat exchanger shells are considered members of the same HTHA operating condition – based risk group as the A/D heat exchangers. However, no specific guidance is offered for the B and E heat exchangers. • **CSB:** Entire shells of B and E heat exchangers are listed as fully clad in Type 316 stainless steel, a material resistant to HTHA. However, only the hottest section (Can 4) of the heat exchanger is clad in Type 316 stainless steel.
October 2008	Lloyd's Register Capstone	• **DMHR:** HTHA not a concern since operating conditions are below the Nelson curve. • **CSB:** Tesoro process engineering provides B and E heat exchanger shell-side temperatures. The values are lower than design, implying less risk of HTHA: Capstone data: 500 °F → (B and E shell-side) → 350 °F Design: 504 °F → (B and E shell-side) → 405 °F Capstone data: hydrogen partial pressure → 240 psia Design: hydrogen partial pressure → 291 psia

Figure 31. DMHR and CSB Findings on Anacortes HTHA and Heat Exchangers (1990–2008)

[131] Recommendations reviewed in December 1993.

[132] API RP 941. *Steels for Hydrogen Service at Elevated Temperatures and Pressures in Petroleum Refineries and Petrochemical Plants.* Figure 1, Note 2, August 2008. Section 5.5 of API RP 941 states that it is not advisable to take credit for the presence of a stainless steel cladding. However, the CSB learned that some experts were less concerned about HTHA in the B and E exchangers when information provided to them indicates a Type 316 stainless steel cladding is present.

None of these DMHRs conducted in the 20 years before the incident identified the potential danger of HTHA in the B and E heat exchangers because they primarily relied on design data instead of measured process conditions.[133] Although all of these design data indicated operation below the Nelson curve, CSB modeling estimated that the hottest portions (Can 4) of the heat exchangers at times operated above the Nelson curve. As a result, the B and E heat exchangers were never inspected for HTHA and more HTHA-resistant materials were never considered until after the April 2010 incident. It is vitally important to fully understand actual operating conditions of refinery processes to ensure that all damage mechanism hazards are adequately analyzed.

5.3.3.1 Insufficient Process Instrumentation

An important factor in determining HTHA susceptibility is operating temperature. The Anacortes refinery HTHA inspection procedure "required" instrumentation to ensure and periodically document that the operation was appropriately monitored. However, for the instrumentation to be "required" a determination first had to be made that the process equipment was operating within 25°F or 25 psia[134] of the appropriate Nelson curve. The procedure did not clarify how to make such a determination (which would necessitate accurate measurement capability) without already having an accurate measurement. The procedure stated the following:

> Accurate measurements/determinations of temperature and hydrogen partial pressure should be made routinely and the records maintained to provide assurance that operating conditions remain compatible with Nelson Curve limits.
> Such measurements/determinations/records are required for equipment/piping that operate[s] within 25°F or 25 psia of the appropriate Nelson Curve.[135]

No temperature instrumentation was on the B or E heat exchangers. Figure 32 shows where temperature and pressure measurement instruments were located on the heat exchanger banks. Intermediate temperature and pressure instrumentation was nonexistent. This hazard evaluation barrier adversely affected all DMHRs at the Anacortes refinery. The operating temperature was unknown at the B and E heat exchangers, specifically as it increased significantly from heat exchanger fouling. With these key data absent from the analysis, the technicians, engineers, and damage mechanism experts relied on design operating conditions.

[133] The 2008 Capstone review used a partial pressure of 240 psia based on a modeling effort associated with an engineering project. Also, as previously noted in Section 4.4, a single external surface temperature measurement of 455 ºF was taken in October 1998 on the inlet to either the B or E heat exchanger.

[134] Absolute pressure measured in units of pounds force per square inch, or pounds per square inch absolute (psia).

[135] Although dated January 30, 2006 this procedure appears to have been developed by Shell Oil. The accuracy of the data used to develop the Nelson curve is described as being +/- 20 ºF. The procedure also describes the benefit of stainless steel cladding on the inside surface of equipment to prevent HTHA damage.

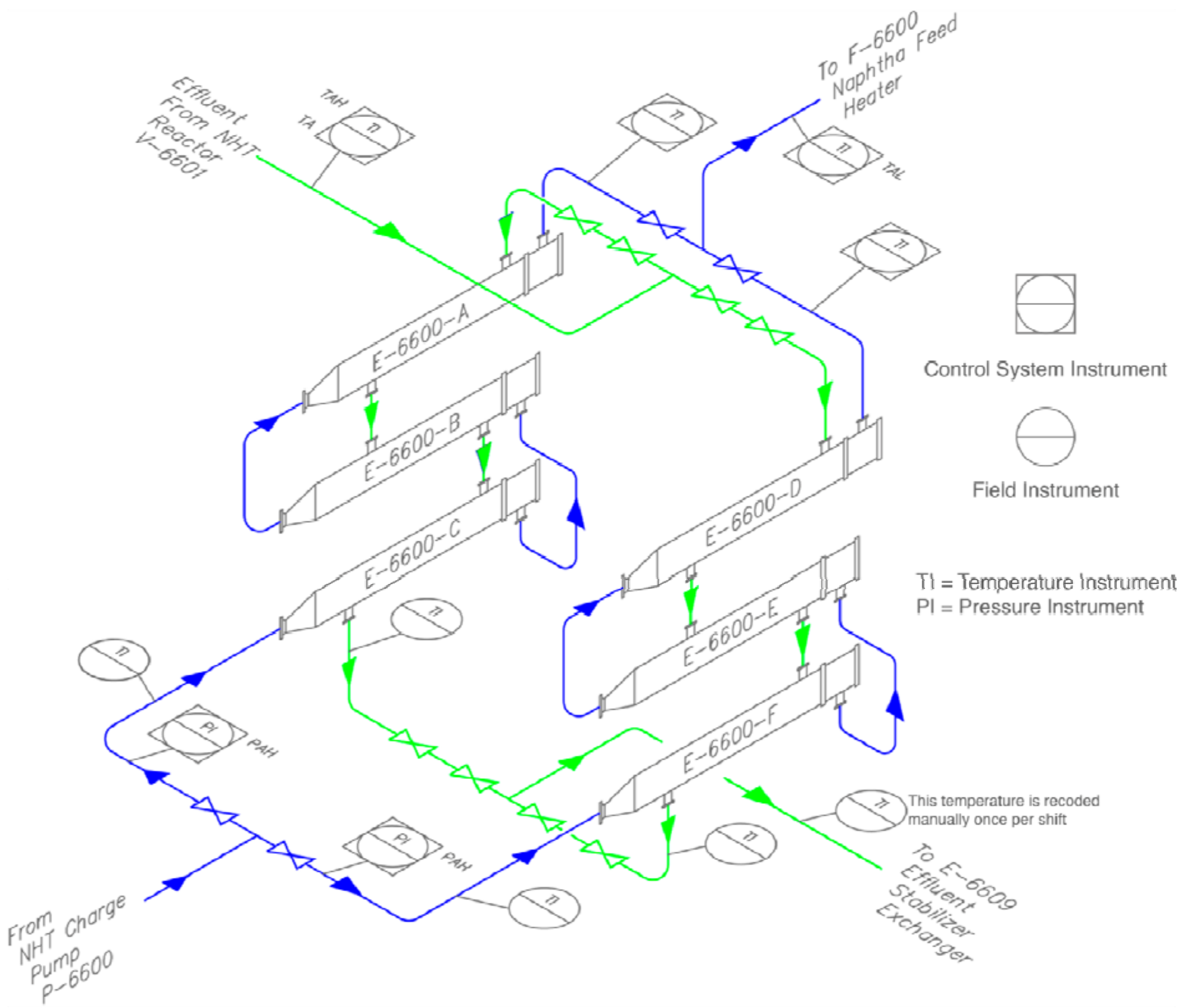

Figure 32. Temperature and Pressure Instruments on the NHT Heat Exchanger Banks. This isometric process flow view shows the lack of temperature indication on both shell-side and tube-side of the E and B heat exchanger inlets and outlets.

5.3.4 HTHA Hazards Were Not Effectively Controlled

In 1995,[136] Shell Oil completed a project PHA related to process modifications that could increase the hydrogen partial pressure in the NHT heat exchangers; however, no consideration, evaluation, or recommendation was made to account for the impact of this change on the potential for heat exchanger damage from HTHA.

The initial NHT unit PHA completed by Shell Oil in 1996 identified the potential for HTHA in the NHT heat exchangers. The PHA cited ineffective, non-specific, judgment-based qualitative safeguards such as the facility's inspection program, unit monitoring, procedures, practices, and limits on key and critical

[136] When this project was implemented, a Management of Change (MOC) review was also conducted. The MOC did not consider or evaluate the potential impact of increased hydrogen partial pressure on equipment susceptibility to HTHA.

variables for temperature (based on the Nelson curve) as safeguards. However, the B and E heat exchangers were never inspected for HTHA, no instrumentation was in place to monitor the inlet temperature of the B or E heat exchangers for Nelson curve limits, and no procedures or practices were in place to provide effective protection from HTHA. The effectiveness of these safeguards was neither evaluated nor documented; instead, the PHA merely listed general safeguards. If the adequacy of these safeguards had been analyzed, improved safeguards to protect against HTHA-related failure of the B and E heat exchangers could have been recommended.

The 2001[137] and 2006 Tesoro PHA revalidations do not address or modify the analysis from the 1996 Shell Oil PHA. In the 2001 PHA Tesoro included a review of the corrosion control program and a specific mechanical integrity checklist associated with the corrosion program. In 2006, the Tesoro corrosion program was still using these documents. However, in the 2006 PHA, Tesoro discontinued a review of these mechanical integrity programs in part because they were “not a legal requirement.” The following CCPS guidance on mechanical integrity does not recommend a focus on minimum compliance with regulation and notes:

> …[A] compliance-only program may miss out on many of the benefits of a more holistic approach, such as reduced risks for employees, the neighboring community, and the facility.[138]
>
> … the more holistic approach helps to ensure compliance with governing regulations and, ultimately, often turns out to be less expensive than the minimum compliance effort would have been.[139]

5.3.4.1 PHA Assumptions That Contributed to Ineffective Control of HTHA Hazards

For the sixteen year period starting in 1996 and ending in 2012, Shell Oil and Tesoro conducted PHAs at the Anacortes refinery that used a set of assumptions for the hazard scenarios and risk assessments generated by the PHA team. The purpose of these assumptions was documented as helping the team to assess “the worst credible scenarios not the worst imaginable scenarios.” However, based on the CSB investigation of the April 2010 incident, the use of these assumptions contributed to PHAs that were not effective in controlling process hazards.

The CSB determined that several of the Tesoro process unit PHA assumptions, shown in boxes in the rest of this section, could lead to ineffective evaluation of significant hazards and proposed safeguards associated with the immediate causes of the April 2010 incident.

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137 The 2001 PHA revalidation conducted by Tesoro did not raise any issues related to the NHT heat exchangers. The only mention of these exchangers is in the process description.

138 Center for Chemical Process Safety (CCPS). *Guidelines for Mechanical Integrity Systems*. 2006; pp 3-5

139 *Ibid* at 5.

Tesoro's PHA assumptions included:

Corrosion Inspection Program

Assumption: The System has a corrosion inspection program. Leaks or loss of containment due to corrosion of pipes and vessels is not credible for pipes and vessels included in these programs.

This assumption likely adversely influenced the evaluation of damage mechanism hazards and contributed to these hazards being ineffectively evaluated during the PHA. Equipment damage is a significant causal factor for loss of containment, and loss of containment is a primary process hazard. The immediate cause of the April 2010 incident was a damage mechanism – HTHA – that the Shell Oil PHA team in 1996 did not effectively evaluate. The 1996 PHA team significantly underestimated the risk of NHT heat exchanger failure. The frequency was appropriately estimated as being less than three percent, which was considered a "Low" frequency in the Shell Oil methodology. However, the consequence of the scenario was determined to be "Low to Medium" and significantly less than the actual consequence of the April 2010 incident. A "Low to Medium" consequence, according to the Shell Oil guidance documents, would include the following:

- A hydrocarbon release of a few hundred to 2,000 pounds;
- Moderate property damage in the $500,000 to $2 million range;
- Some recordable injuries[140] to workers; or
- Moderate disruption to refinery operations, with a return to operation within a few weeks.

As previously noted, to control HTHA hazards the 1996 Shell Oil NHT unit PHA team cited non-specific, judgment-based qualitative safeguards, such as the facility's inspection program, unit monitoring, procedures, practices, and limits on key and critical variables for temperature (based on the Nelson curve) as safeguards. None of these safeguards were effective, and they did not prevent the catastrophic E heat exchanger failure as a result of HTHA damage.

The 1996 Shell Oil NHT unit PHA was revalidated by Tesoro in 2001 and 2006, but these PHA teams did not address or modify the analysis from the 1996 Shell Oil NHT unit PHA.

The Tesoro 2007 PSM and RMP compliance audit indicated that previous PHAs at the Tesoro Anacortes Refinery lacked sufficient detail and did not identify all of the hazards of the process.[141] As a result, in

[140] OSHA provides the following as examples of recordable injuries, "Cut, puncture, laceration, abrasion, fracture, bruise, contusion, chipped tooth, amputation, insect bite, electrocution, or a thermal, chemical, electrical, or radiation burn. Sprain and strain injuries to muscles, joints, and connective tissues are classified as injuries when they result from a slip, trip, fall or other similar accidents." *See* https://www.osha.gov/recordkeeping/new-osha300form1-1-04.pdf (accessed January 2, 2014).

[141] The compliance audit was conducted pursuant to the requirements in 40 CFR 68.79 and to the OSHA PSM Standard, 29 CFR 1910.119, paragraph (o) triennial compliance audit requirement. As an example of the lack of detail in the 2006 Tesoro NHT unit PHA, the 2007 audit compared the NHT unit PHA to the Alkylation unit

2010 Tesoro conducted a new PHA that was a complete line-by-line evaluation. The 2010 NHT unit PHA evaluated hazards associated with the NHT heat exchangers in February 2010, just 38 days before the April 2010 incident. With the "assumptions" still being used and, notably, the corrosion control and mechanical integrity programs no longer being reviewed as part of the PHA program, the 2010 Tesoro NHT unit PHA team did not identify the potential hazard of B or E heat exchanger shell failure because of HTHA damage.[142]

Inspection and Maintenance Program

Assumption: The equipment is inspected per the plant preventive maintenance standards, and maintenance is performed promptly.

Using this assumption contributed to PHA teams not effectively evaluating proposed inspection-related or maintenance-related safeguards. The 1996 Shell Oil NHT unit PHA stated that the inspection program was a safeguard to prevent HTHA failure of the NHT heat exchangers. However, the B and E heat exchangers were never inspected for potential HTHA damage.

Materials of Construction

Assumption: The materials of construction of piping, gaskets, vessels, and valves have been correctly selected according to Shell design standards.

Using this assumption contributed to the PHA teams not considering the susceptibility of materials to failure from damage mechanisms such as HTHA, or recommending inherently safer materials such as 300 series stainless steel to mitigate damage mechanisms such as HTHA.[143]

PHA. The 2007 audit found that although the Alkylation unit had approximately half the complexity of the NHT unit, the Alkylation unit PHA conducted four times more hazard evaluation scenarios and made nearly 15 times more recommendations than the 2006 Tesoro NHT unit PHA.

[142] The term "shell" in this context refers to the pressure containing carbon steel wall of the heat exchanger. The 2010 Tesoro NHT unit PHA did identify HTHA as a possible hazard for the tube side of the B and E exchangers. Heat exchangers of this design have process flow through two sides, separated by mechanical design. Heat is transferred from one side to the other in order to exchange heat. Flow on the inside of the tubes through the heat exchanger is commonly referred to as "tube-side", while flow on the outside of the tubes is called "shell-side". The B and E exchangers had HTHA damage to the pressure containing portion on the shell-side. The 2010 Tesoro NHT unit PHA did not identify HTHA as a hazard where HTHA occurred on the shell-side of the exchanger.

[143] As previously discussed, API RP 571 identifies inherently safer materials to prevent HTHA noting, "300 Series SS, as well as 5Cr, 9Cr and 12Cr alloys, are not susceptible to HTHA at conditions normally seen in refinery units." *See* API RP 571. *Damage Mechanisms Affecting Fixed Equipment in the Refining Industry.* 2003; p "5-83".

5.4 CSB Conclusions on Organizational Deficiencies

For years, management at the refinery under both Shell Oil and Tesoro failed to effectively evaluate the potential for HTHA in the B and E heat exchangers. External corrosion experts repeatedly and erroneously assumed that heat exchanger design conditions were representative of actual process operating conditions despite knowing that these heat exchangers experienced severe heat transfer performance deterioration and required frequent cleaning.

Tesoro management also allowed worker exposure to hazards from fires and significant hydrocarbon leaks during startup of the NHT heat exchangers to become an accepted "normal" practice. Relying on steam suppression to mitigate leaks during NHT heat exchanger startups was a common and acceptable practice and was part of the startup procedure. Tesoro made attempts to correct the heat exchanger design problem that caused the leaks that sometimes resulted in fires, but ultimately these were ineffective. Additional employees were frequently brought in to assist the NHT field operator with the labor-intensive heat exchanger startup and hydrocarbon leak mitigation. On the night of the incident seven workers were performing the role that procedurally was intended for a single outside operator.

Well-known industrial safety and accident analysis experts James Reason and Andrew Hopkins indicate that safety culture is defined by collective practices, arguing that this is a useful definition because it suggests a practical way to create cultural change. More succinctly, safety culture can be defined as "the way we do things around here."[144,145]

Employees respond to issues that capture the attention of leaders.[146] Hopkins notes that leadership qualities that minimize, downplay, or deny risk will erode a process safety culture. A culture of risk denial can include the following characteristics:

- Belief that it cannot happen here
- Normalization of deviance (normalization of hazardous conditions)
- Ad hoc criteria for danger
- Downgrading intermittent warnings
- Burden (onus) of proof – requiring proof of danger rather than proof of safety
- Group think (eliminates minority voices in deference to consensus)[147]

Several of these characteristics were identified during the CSB investigation of the Tesoro Anacortes April 2010 incident, including normalization of hazardous conditions and a misplaced burden of proof of

[144] Hopkins, Andrew. *Safety, Culture and Risk; The Organisational Causes of Disasters*. Sydney, New South Wales: CCH Australia Limited. 2005; p 7.

[145] Center for Chemical Process Safety (CCPS), *Guidelines for Risk Based Process Safety*. 2007; p 40.

[146] Hopkins, Andrew. *Safety, Culture and Risk.* 2005; p 8.

[147] *Ibid* at 20-22.

safety.[148] It is an important distinction that a company culture, including its process safety culture, is the embodiment of its practices and not the sum of its beliefs. Consequently, a process safety culture can be objectively measured by examining the process safety practices and outcomes. The practices of the Tesoro Anacortes Refinery – the use of excessive number of personnel to participate in hazardous activities, the lack of verification of actual process conditions, normalization of hazardous leaks of the NHT heat exchangers, and PHA assumptions that contributed to ineffective hazard evaluation of major hazards – are all indications of a deficient process safety culture at the Tesoro Anacortes refinery.

[148] Burden of proof means to require proof of danger rather than proof of safety. It is applicable to the process safety culture at the Anacortes refinery and is shown through the repeated use of design data to evaluate the NHT exchangers for HTHA susceptibility. Rather than obtain data on actual operating conditions, Shell Oil and Tesoro corrosion experts were allowed to repeatedly rely on design operating conditions. Such design operating conditions were readily available, but there was no instrumentation to obtain actual operating conditions for the B or E exchangers. Refinery management did not require that these experts obtain data on and use the actual operating conditions to prove safety when reaching their conclusion that the B and E exchangers were not susceptible to HTHA damage.

6.0 Industry Codes and Standards

6.1 API RP 941 Operating Limits and Material Selection for HTHA

API RP 941 is the industry guidance document that describes how to predict and manage HTHA. API RP 941 was initially published in 1970 to communicate broadly industry's experience with HTHA – both HTHA occurrences and conditions where HTHA did not occur.

6.1.1 No Minimum Requirements to Prevent HTHA

As discussed in Section 4.1.1, industry uses the Nelson curves as lines of demarcation to predict HTHA. Above each curve, HTHA is possible for that material of construction, and below the curve, the prediction is that HTHA will not occur. Industry also uses these curves to select materials of construction based on the anticipated operating conditions and to create an HTHA inspection and prevention program. However, API RP 941 is written permissively, and there are no minimum requirements for refiners to take any action to prevent HTHA failures.[149] Specifically, there are no user requirements as follows:

- There are no minimum requirements for users to perform HTHA susceptibility evaluations;
- There are no requirements for users to select inherently safer materials of construction; and
- There are no minimum requirements for users to verify process operating conditions of equipment that is potentially susceptible to HTHA.

6.1.2 History of the Nelson Curves

The Nelson curves are based on industry experience with HTHA and were first developed in 1949 by George Nelson,[150] who gathered the original data to create the Nelson curves. After his death, none of his original data were found; only the information contained on the actual Nelson curves was available to API and the rest of industry.[151] On the basis of the Nelson curves, in 1970 the API published API RP 941 *Steels for Hydrogen Service at Elevated Temperatures and Pressures in Petroleum Refineries and Petrochemical Plants*.[152]

API RP 941 contains a submittal sheet for companies to report their experience with HTHA.[153] It tasks the company reporting HTHA equipment damage to provide a limited and simplistic history of operating conditions. API requests only the average and maximum process and metal temperature and a single

[149] API RP 941 uses the term "should" 27 times and the word "shall" once. As used in a standard, "shall" denotes a minimum requirement to conform to the standard, while "should" denotes a recommendation which is advised but not required to conform to the standard.

[150] G. A. Nelson, "Operating Limits and Incubation Times for Steels in Hydrogen Service," Proceedings, 1965, Volume 45, American Petroleum Institute, Washington, D.C. pp. 190-195.

[151] API TR 941. *The Technical Basis Document for API RP 941*. 2008; p 128.

[152] *Ibid* at 127.

[153] HTHA experience includes both reports of HTHA damage and equipment that was not damaged by HTHA.

value for hydrogen partial pressure to represent equipment operating conditions. API provides very limited instructions on completing the datasheet to report HTHA equipment damage. There is no assurance that the data are representative of actual operating conditions. The datasheet reported to API does not ensure that the data cover the life of the equipment versus the year, month, or even week before equipment failure. The use of a single hydrogen partial pressure value does not ensure that the variability of the process is appropriately represented by the data reported.

As demonstrated in the CSB analysis of the B and E heat exchanger operating conditions in Section 4.4.1, refinery equipment often operates at a range of temperatures and hydrogen partial pressures. The API RP 941 technical report acknowledges this, stating that the authors “find it difficult to obtain accurate operating data and material damage assessments.”[154] In addition, not all companies report their HTHA failures to API (for example, Tesoro did not formally report the failure information to API following the April 2010 incident). Furthermore, the consequences of HTHA equipment damage, such as a multi-fatality incident, are not included as part of the data submitted to API. These are significant weaknesses in relying on empirical, self-reported data.

6.1.3 Industry Critiques of Nelson Curves

The applicability and accuracy of the Nelson curves have been called into question within the refining industry. Two comprehensive reports analyze the Nelson curves: the Hydrogen Attack Project and API TR 941, *The Technical Basis Document for API RP 941*.

The Hydrogen Attack Project is a report by the Materials Property Council[155] and the API.[156] The report presents a history of HTHA analysis, the Nelson curves, and API RP 941. The report highlights problems in obtaining accurate data on operating conditions, analogous to the problems that the CSB identified at Tesoro, stating:

> The only really reliable way to get an equipment exposure temperature is to properly measure the actual temperature of the component. Many times the process thermocouples are not well located for measuring the temperature of a particular component or in the case of exchangers, a particular exchanger in a multi-exchanger train. The design and/or process flow diagrams may not provide a very good estimate of actual operating temperatures.[157]

[154] API TR 941. *The Technical Basis Document for API RP 941*. 2008; pp 45-46.

[155] The Materials Properties Council (est. 1966) was founded by the American Society of Mechanical Engineers, ASM International, ASTM and the Engineering Foundation and supported by industry, technical organizations, codes and standards developers, and government agencies in order to provide valid data on the engineering properties of metals. See: http://www.forengineers.org/mpc/index.html (accessed November 21, 2013).

[156] Hydrogen Attack Project, Materials Property Council / American Petroleum Institute, undated.

[157] In this context, the term “train” is synonymous with “bank” and is used to describe multiple heat exchangers in series. Hydrogen Attack Project, Materials Property Council / American Petroleum Institute, p 19, undated.

API TR 941 was issued as the technical basis document for API RP 941.[158] This technical report addresses several possible limitations of the Nelson curves, such as the location and shape of the curves.[159] API TR 941 acknowledges that there is still more to learn about HTHA, stating "We are still far from being able to make quantitative predictions about the behavior of steels subject to HTHA."[160]

Critics of the Nelson curves also contend that, although the curves are easy to apply, their simplicity minimizes their effectiveness.[161] Critics of the curves say that HTHA is a complex phenomenon. The risk of HTHA is a function of more than solely the three variables described by the Nelson curves (material of construction, temperature, and hydrogen partial pressure).[162] Other variables that are not addressed by the curves affect the potential for HTHA, such as stress,[163] carbide stability,[164,165] grain size,[166] type of weld,[167] and time in operation.[168]

Important variables that affect HTHA but are not reflected in the Nelson curves include:

- **Stress**
- **Carbide stability**
- **Grain size**
- **Type of weld**
- **Time in operation**

[158] API Technical Report 941. *The Technical Basis Document for API RP 941.* 2008.

[159] *Ibid* at 2.

[160] *Ibid* at 45.

[161] Van der Burg, M.W.D., Van der Giessen, E., and Tvergaard, V. "A continuum damage analysis of hydrogen attack in a 2.25Cr-1Mo pressure vessel," Materials Science and Engineering A241 (1998) 1-13, p1.

[162] *Ibid* at 12.

[163] API RP 941. *Steels for Hydrogen Service at Elevated Temperatures and Pressures in Petroleum Refineries and Petrochemical Plants.* 2008; Section 3.2.

[164] A carbide is an intermetallic compound containing carbon. There are many possible combinations of carbon and other atoms (such as iron, titanium, niobium, vanadium) that combine to form carbides in steel. Each of these carbides has an effect on the properties of the steel.

[165] Van der Burg, M.W.D, Van der Giessen, E., and Tvergaard, V. "A continuum damage analysis of hydrogen attack in a 2.25Cr-1Mo pressure vessel," Materials Science and Engineering A241 (1998) 1-13, p12.

[166] Grain size is a fundamental characteristic of steel microstructure, indicating the size of each individual crystalline packet of iron atoms (known as a "grain").

[167] Manna, G., P. Castello, and F. Harskamp. "Testing of welded 2.25CrMo steel, in hot, high-pressure hydrogen under creep conditions" Engineering Fracture Mechanics 74 (2007) 956-968, p.956.

[168] Shewmon, Paul. *Hydrogen Attack of Carbon Steel*. Metallurgical Transactions A Vol 7A February 1976, p 280.

API TR 941 warns that applying API RP 941 has become less conservative as equipment is pushed to the limits of the Nelson curves for economic reasons.[169] API TR 941 notes the following:

> The concept of a simple boundary between safe and unsafe operating conditions in hydrogen for common alloys, of the type depicted by the Nelson curves should not be expected. Certainly material composition, heat treatment and stress are well accepted as variables that influence behavior.
>
> Experience shows damage accumulation is time dependent. However, the methods of detection and quantification of damage are so inadequate, operating conditions so poorly recorded, failure analyses so cursory and materials characterization so primitive, that life prediction is on shaky grounds today.[170]

6.1.4 Unreliable Carbon Steel Nelson Curve

As discussed in Section 4.4.1, CSB process modeling of the Tesoro NHT heat exchangers estimates that HTHA occurred below the carbon steel Nelson curve.

As previously discussed, post-incident analysis of the NHT heat exchangers determined that damage from HTHA was occurring in portions of the B and E heat exchangers that were estimated to have operated below the carbon steel Nelson curve. The coldest region in the E heat exchanger with identified HTHA was estimated to operate up to 120 °F below the carbon steel Nelson curve. This finding indicates that the industry developed carbon steel Nelson curve is inaccurate and cannot be relied on to prevent HTHA equipment failures or to predict HTHA equipment damage.

The carbon steel Nelson curve is inaccurate and cannot be relied on to prevent equipment failures due to HTHA.

[169] API Technical Report 941. *The Technical Basis Document for API RP 941* . 2008; p 45.

[170] API Technical Report 941. *The Technical Basis Document for API RP 941*. 2008; p 47.

6.1.4.1 ExxonMobil HTHA Incident Below the Carbon Steel Nelson Curve

ExxonMobil also experienced equipment damage from HTHA at process conditions that were noted as being immediately below the carbon steel Nelson curve.[171] Similar to Tesoro, the ExxonMobil incident included damage to a heat exchanger of a hydrotreating unit.[172] This failure has many similarities to the Tesoro April 2010 incident and further highlights that the carbon steel Nelson curves cannot be relied upon to prevent HTHA equipment failures.[173] Similar to the Tesoro April 2010 incident, cracking was observed in non-PWHT carbon steel constructed in the early 1970's and operating at conditions reported as being below the Nelson curve.[174] The ExxonMobil HTHA failure also occurred adjacent to weld seams in the heat affected zone of the vessel.[175]

6.1.4.2 Other Industry Reports of HTHA Damage to Equipment that Operated Below the Carbon Steel Nelson Curve

The CSB has learned of at least eight recent refinery incidents where HTHA reportedly occurred below the carbon steel Nelson curve. In addition to the ExxonMobil incident, Valero, Shell, and ConocoPhillips have all reported incidents to the API 941 committee where the companies have concluded that equipment operating below the carbon steel Nelson curve was damaged by HTHA. Valero reported three incidents at their Corpus Christi refinery and one incident at their Texas City refinery. Shell reported at least two equipment components in one process unit had HTHA below the carbon steel Nelson curve. In addition, ConocoPhillips reported an incident of HTHA below the carbon steel Nelson curve at one facility. In 2011, API issued an industry alert on HTHA in refinery service.[176] The API alert noted multiple incidents of carbon steel equipment at operating conditions where carbon steel was previously thought to be resistant to HTHA. These refinery incidents and the subsequent API response strongly suggest an industry-wide problem with the carbon steel Nelson curve.

6.1.5 Essential Adjustments Are Needed to API RP 941

Although the potential consequences of HTHA-related failure can be catastrophic, API RP 941 currently imposes no substantive requirements on users. API RP 941 should require companies to verify the actual operating conditions of equipment that is potentially susceptible to HTHA. In addition, API RP 941 should incorporate the principles of the hierarchy of controls and inherently safer design to prevent equipment failures from HTHA. The CSB has identified at least eight incidents in refineries where HTHA equipment damage was found at operating conditions below the carbon steel Nelson Curve.

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[171] McLaughlin, J., Krynicki, J., and Bruno, T. *Cracking of non-PWHT'd Carbon Steel Operating at Conditions Immediately Below the Nelson Curve.* ExxonMobil Research and Engineering Company, Proceedings of the ASME 2010 Pressure Vessels & Piping Division, 2010; pp 18-22.

[172] *Ibid.*

[173] *Ibid.*

[174] *Ibid.*

[175] *Ibid.*

[176] *See*: http://www.api.org/publications-standards-and-statistics/hidden-pages/industry-alert (accessed January 19, 2014).

Furthermore, CSB modeling of the Tesoro Anacortes refinery NHT heat exchangers suggests the E heat exchanger failed from HTHA damage that occurred below the Nelson curve. In support of inherent safety to prevent equipment failures from HTHA, the CSB proposes a new boundary for the carbon steel Nelson curve in Figure 33. This boundary would prohibit carbon steel equipment at process conditions that API has identified as susceptible to HTHA, above 400 ^{0}F,[177] and which operates at greater than 50 psia hydrogen partial pressure.

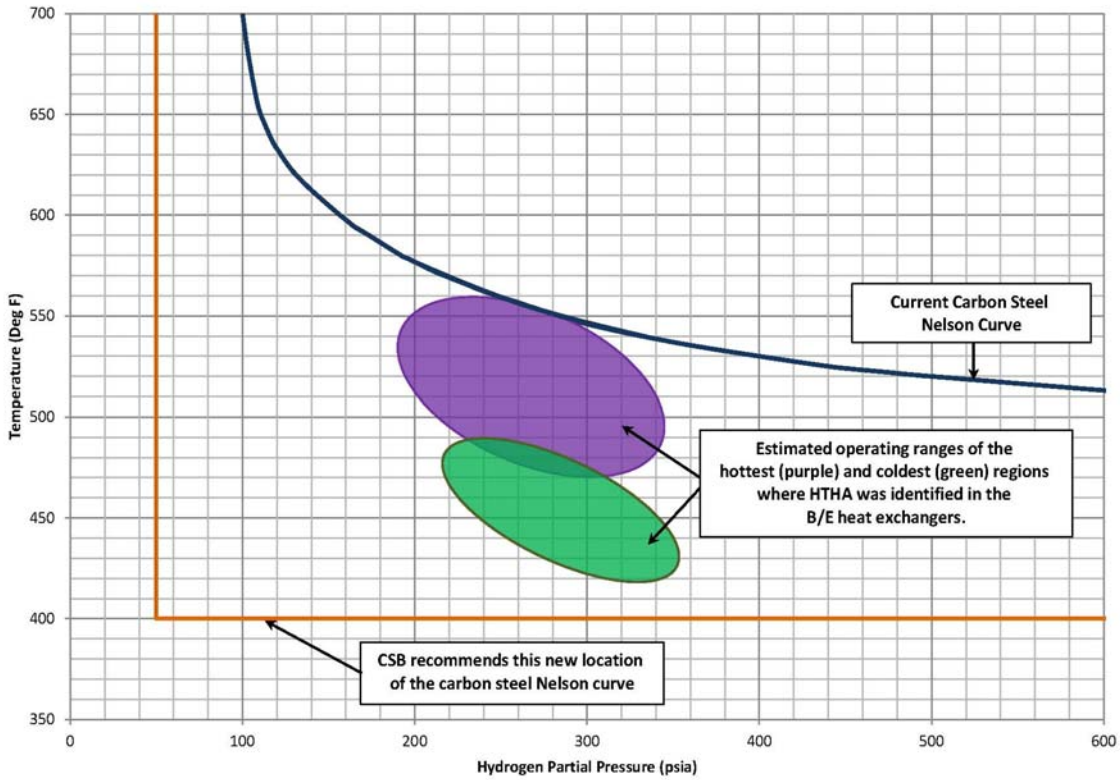

Figure 33. CSB Modeling Results of HTHA and the Nelson Curve at the Tesoro Anacortes Refinery. CSB modeling estimates suggest that HTHA occurred in the B and E heat exchangers below the carbon steel Nelson curve. The CSB recommends that the carbon steel Nelson curve be relocated as shown to prevent HTHA in carbon steel.

[177] API Technical Report 941. *The Technical Basis Document for API RP 941.* 2008; p 6.

6.1.6 ANSI Z10, Exemplifies Standards Clarity

As previously stated, API RP 941 is written permissively with no minimum requirements to prevent HTHA failures. In contrast, the American National Standards Institute[178] (ANSI) Occupational Health and Safety Management Systems standard, ANSI/AIHA Z10-2012 (Z10), provides an improved example of how to clearly define obligations in a standard document.[179] Z10 makes use of both "should" and "shall" language as well as explicit document formatting to differentiate mandatory requirements from voluntary recommendations. The following specification addresses the format, which is illustrated in Figure 34.

> This [Z10] standard is formatted into two columns to help distinguish requirements from recommended practices and explanatory information. Requirements are in the left column and are identified by the word 'shall.' An organization that chooses to conform to this standard is expected to fulfill these requirements. The text in the right hand column uses the word 'should' to describe recommended practices, or explanatory notes to the requirements on the left. This use of the terms 'shall' and 'should' to identify requirements and distinguish them from recommendations and explanatory notes is common practice in ANSI and international standards.[180]

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[178] ANSI is a group comprised of government agencies, organizations, companies, academic and international bodies, and individuals that oversees the development and use of industry guidelines and standards. For more information *see* http://www.ansi.org/about_ansi/overview/overview.aspx?menuid=1 (accessed January 27, 2014).

[179] Z10 was developed by over 50 organizations and included representation workers (USW), regulators (OSHA), and industry (API). Section 5.1.2 requires the use of the hierarchy of controls to achieve risk reduction for identified hazards. ANSI/AIHA Z10-2012. *Occupational Health and Safety Management Systems*. 2012; p x, xi, 15.

[180] ANSI/AIHA Z10-2012. *American National Standard - Occupational Health and Safety Management Systems*. June 27, 2012; p.ix.

5.1.3.2 Process Verification
The organization shall have processes in place to verify that changes in facilities, documentation, personnel and operations are evaluated and managed to ensure safety and health risks arising from these changes are controlled.

E5.1.3.2: These types of processes are sometimes referred to as Management of Change.

The Management of Change process should take into consideration relevant items such as:

- technology, equipment, work practices and procedures
- design specifications and raw materials
- organizational or staffing changes standards or regulations

Management of Change includes changes being made in existing operations, products, or services.

Source: ANSI/AIHA Z10-2012, p.17

Figure 34. Example of ANSI Z10 Obligations Formatting

6.2 API RP 580 Risk Based Inspection / API 581 Risk Based Inspection Technology

API intends for risk-based inspection (RBI) to be a process that enables optimization of inspection efforts by balancing the time between inspections against the risks of equipment failure caused by the known damage mechanisms.[181]

API RP 581, *Risk-Based Inspection Technology* is used in conjunction with API RP 580, *Risk-Based Inspection.* API RP 580 is the API standard for developing an RBI program. API RP 581 is the API standard for implementing an RBI program.

Unlike API RP 941, API RP 581 predicts the susceptibility of HTHA risk versus equipment service time. This time-based increase in risk is based on a mathematical model, associating risk with the type of steel. The API RP 581 model represents an early attempt to address the shortcomings of the empirical Nelson curves. However, API RP 581 lacks specific direction to ensure that users employ appropriate actual operating conditions. As a result, the CSB found that using the Tesoro design operating conditions and 38 years of operation yields a result that the B and E heat exchangers have a "Low Susceptibility" to HTHA.[182]

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[181] Risk Based Inspection (RBI) Best Practice: *The Technical Specification for Ensuring Successful Implementation*. by Ron Selva B.Sc., C.Eng., F. I. Mech. E; 13th International Conference on Pressure Vessel & Piping Technology, 20-23 May 2012, London, Keynote Paper – Technical Session: Managing Risk.

[182] API 581 defines three levels of HTHA susceptibility; Low, Medium, and High. Using the E exchanger design operating conditions of a hydrogen partial pressure of 291 psi and a temperature of 504 ºF along with 38 years of continuous service (333,108 hours) into equation 2.51 from API RP 581 results in a HTHA susceptibility parameter of 4.53. The minimum value for "Low" HTHA susceptibility is greater than or equal to 4.53.

Like API RP 941, API RP 581 is written permissively, so there are no minimum requirements to prevent HTHA failures. There are 19 uses of “shall” in RP 581, but none are substantive—nearly all the uses of “shall” appear in formulas or requirements for damage factor or in inspection effectiveness calculations that are themselves non-mandatory. There are three uses of “shall” in the HTHA section, but again these are employed for calculations that are permissive—such as “the following procedure may be used” or if HTHA is detected, “fitness for service should be performed.” An instructive example of the permissiveness of API RP 581 is that the document provides important guidance for conditions that would make equipment susceptible to HTHA damage. However, if the equipment is identified as meeting the criteria that would indicate HTHA is a credible damage mechanism, the guidance provided by API RP 581 is that the equipment “should” be evaluated for HTHA susceptibility.

7.0 Regulatory Oversight of Petroleum Refineries in Washington

As addressed in the recently released CSB draft Chevron Regulatory Report, many regions around the world such as the United Kingdom (UK) and Australia have implemented regulatory systems for high hazards consisting of both prescriptive[183] and goal-setting elements[184] that place the duty on the owner or operator of the facility, known as the duty holder,[185] to demonstrate to the regulator that they have reduced risks to as low as reasonably practicable, or ALARP. The CSB determined that there are key features of an effective major accident prevention regulatory:

- Duty Holder Safety Responsibility, including a process safety report
- Continuous Risk Reduction to ALARP
- Adaptability and Continuous Improvement
- Active Workforce Participation
- Process Safety Indicators that Drive Performance
- Regulatory Assessment, Verification, and Intervention; and
- Independent, Competent, Well-Funded Regulator.

The findings, analysis, and conclusions of the Chevron Interim Report and the draft CSB Chevron Regulatory Report are applicable to the CSB Tesoro investigation and are incorporated into this report by reference. The Chevron Interim Report and the draft Chevron Regulatory Report can be accessed in Appendix F.

The United States has persisted in the use of a more activity-based[186] regulatory approach that does not adequately engage companies and their employees in continuous improvement and risk reduction. The CSB has found that the existing regulatory approach for onshore petroleum refineries in Washington:

- relies on a framework that is primarily activity-based without a risk reduction target;
- does not effectively involve the workforce in hazard analysis and prevention of major accidents; and
- does not employ a sufficient number of staff members with the technical expertise needed to provide sufficient oversight of petroleum refineries.

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[183] A prescriptive regulation or standard describes the specific means or activity-based actions to be taken for hazard abatement and compliance.

[184] Performance or goal-based regulations state the objective to be obtained (such as risk reduction or hazard abatement) without describing the specific means of obtaining that objective.

[185] Duty holders are considered to be "those who create and/or have the greatest control of the risks associated with a particular activity. Those who create the risks at the workplace are responsible for controlling them." UK Health and Safety Executive, *Planning to do business in the UK offshore oil and gas industry? What you should know about health and safety;* October 2011; p 2. http://www.hse.gov.uk/offshore/guidance/entrants.pdf (accessed June 5, 2013).

[186] Activity-based standards and regulations require the mere completion of an activity and do not focus on the effectiveness of major accident prevention or risk reduction.

7.1 Background

The occurrence of a number of large accidents, including a massive explosion and fire at the Phillips 66 Company's Houston Chemical Complex in Pasadena, Texas, resulting in 23 fatalities, and the 1984 toxic release in Bhopal, India, which caused several thousand known fatalities, resulted not only in the creation of the CSB but also in the first federal regulations specifically designed to prevent major chemical accidents that threaten workers, the public, and the environment. One of these regulations is the OSHA PSM standard, which was adopted in 1992. This standard applies to a process[187] involving a chemical at or above the listed threshold quantity (also known as a highly hazardous chemical), or flammables in a quantity of 10,000 pounds or more.[188] It contains broad requirements to implement management systems, identify and control hazards, and prevent "catastrophic releases of highly hazardous chemicals."[189] Many processes in a petroleum refinery are subject to the PSM standard.

The frequent occurrence of refinery accidents demonstrates the pressing need to examine the current regulatory structure.

As discussed in the draft Chevron Regulatory Report, the CSB has concluded that the frequent occurrence of refinery accidents demonstrates the pressing need to examine the current regulatory structure in place in the US. Despite the fact that the nation's roughly 150 petroleum refineries represent only a small fraction of the thousands of industrial and chemical facilities in the US, the CSB has noted a considerable number of significant and deadly incidents at refineries over the last decade. In 2012 alone, the CSB tracked 125 significant incidents at US petroleum refineries.[190] Three of these incidents took place in the state of Washington.

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[187] The PSM standard defines "process" as "any activity involving a highly hazardous chemical including any use, storage, manufacturing, handling, or the on-site movement of such chemicals, or combination of these activities." 29 CFR §1910.119(b) (1992).

[188] 29 CFR §1910.119(a)(1) (1992). This standard also applies to the manufacture of explosives and pyrotechnics in any quantity [29 CFR §1910.109(k)(2) & (3)].

[189] Preamble to Process Safety Management of Highly Hazardous Chemicals; Explosives and Blasting Agents. Section 1 – I. Background (March 4, 1992). *See* http://www.osha.gov/pls/oshaweb/owadisp.show_document?p_table=PREAMBLES&p_id=1039 (accessed May 10, 2013).

[190] These incidents were reported to the Department of Energy and/or the National Response Center and examined by the CSB's Incident Screening Department.

7.2 L&I Division of Occupational Safety and Health (DOSH)

Section 18 of the Occupational Safety and Health Act of 1970 (OSHAct) encourages states to develop and operate their own job safety and health programs, referred to informally as an OSHA State Plan. OSHA approves and monitors State Plans and provides as much as 50 percent of an approved plan's operating costs. These programs must be "at least as effective in providing safety and healthful employment" as the federal PSM standard.[191] DOSH administers an approved state occupational Safety and Health Plan in accordance with the OSHAct and enforces Washington's PSM standard under the Washington Administrative Code (WAC).[192] Although most State Plan states are funded through a state general fund, DOSH is funded mostly by an insurance group and by federal OSHA. Unlike the California Division of Occupational Safety and Health (Cal/OSHA), DOSH does not have a dedicated PSM unit; rather, it currently employs four PSM specialists, including one chemical engineer, to regulate nearly 270 PSM-covered facilities in the state, including five petroleum refineries. One of those specialists has previous refinery experience; the other three have experience with ammonia facilities and chemical manufacturing.

7.2.1 Causal Findings Analysis

The findings in this report identify a number of weaknesses with Tesoro process safety performance. In many of these causal issues, the existing Washington PSM regulations did not require Tesoro to perform at a more effective level to control hazards and prevent incidents. In Figure 35 below, the CSB identifies the causal issues which highlight the gaps within the Washington and federal PSM regulations, and how each issue is more effectively managed in a more robust goal-setting approach. In this section of the report, some of these examples will be examined in relation to key features of a more effective regulatory approach.

[191] 29 U.S.C. §667(c)(2) (1970). https://www.osha.gov/pls/oshaweb/owadisp.show_document?p_id=2743&p_table=OSHACT (accessed September 24, 2013).

[192] The Washington PSM standard is established under Title 296, Section 67 of the Washington Administrative Code (WAC).

Process Safety Concept	Causal Finding	Washington and Federal PSM Regulation and Enforcement	Goal-Setting Regulatory Approach
MOC	Tesoro added steam stations in the vicinity of the heat exchanger structure. This equipment enhanced the ability of the field operator(s) to confront hazardous leaks and extinguish fires in the area of the NHT heat exchangers, and the safety implications of these activities were not considered. The MOC developed by Tesoro did not evaluate or control hazards associated with the heat exchanger leaks, emergency egress, or with how the steam equipment would be used. Although affected, heat exchanger startup procedures were not reviewed or modified to account for the change.	The MOC element requires implementation of written procedures to manage changes that shall address the impact of the change on health and safety; however the element is activity based rather than performance based and there is no requirement to control hazards. There is no WAC PSM requirement to actually control hazards through the MOC process. Current regulations allowed Tesoro's narrow focus in looking at the change as a minor modification to a utility system rather than taking a broader view of how the change could impact the overall process.	The duty holder is required to drive risk to ALARP. Demonstration of MOC effectiveness in managing major accident hazard risk is a key requirement of a robust goal-setting regulatory system. The mere existence of MOC written procedures is insufficient under the more robust goal-setting regulatory approach.

Process Safety Concept	Causal Finding	Washington and Federal PSM Regulation and Enforcement	Goal-Setting Regulatory Approach
PHA	PHAs in 1996, 2001, and 2006 cited ineffective, non-specific, judgment-based, qualitative safeguards to prevent equipment failure from HTHA. However, the effectiveness of these safeguards was neither evaluated nor documented; instead the PHA merely listed them.	Although the PHA element requires addressing the control of hazards, it does not require addressing the effectiveness of the controls or using the hierarchy of controls. For example, the standard would not require the use of improved materials of construction or inherently safer design to mitigate corrosion hazards.	The goal-setting regulatory approach requires use of the most effective practical safeguards to achieve ALARP. The goal-setting approach requires the use of inherently safer design and the hierarchy of controls.[193]
PHA	The 2010 Tesoro NHT unit PHA failed to identify HTHA as a hazard for the shell of the B and E heat exchangers.	DMHRs are not required by the PSM regulation. The PHA element does not require consideration of RAGAGEPs such as API RP 571, *Damage Mechanisms Affecting Fixed Equipment in the Refining Industry*. Washington L&I did not cite Tesoro for this issue.	In the UK, the Health and Safety Executive (HSE) has worked with industry to develop guidance on DMHRs in the UK offshore petrochemical industry. The implementation of best practice standards referenced by a duty holder's process safety report may be enforced by the regulator to achieve ALARP.

[193] According to the HSE, essential considerations for determining whether a duty holder has reduced risks to ALARP include "the adoption of inherently safer designs…". HSE. *The Safety Report Assessment Manual, Sections 8 to 15.* p 30. http://www.hse.gov.uk/comah/sram/s8-15.pdf (accessed October 30, 2013). The HSE also notes that the guidance to Control of Major Accidents Hazards (COMAH) Regulation 4 (General Duty) "describes the application of all measures necessary to reduce risk of a major accident to ALARP based on a hierarchical approach (inherent safety, prevention, control, mitigation)." *Ibid* at 8.

Process Safety Concept	Causal Finding	Washington and Federal PSM Regulation and Enforcement	Goal-Setting Regulatory Approach
PHA	PHAs identified HTHA as a hazard for the B and E heat exchangers, but ineffective safeguards failed to control the hazard. L&I did not effectively review the PHAs before the incident.	WAC does not require submission of the PHA to L&I to be reviewed for sufficiency and acceptance. L&I does not have a sufficient number of technically qualified PSM personnel to perform effective reviews of PHAs.	Under the more robust goal-setting regulatory approach, the PHA is part of the report submitted to the regulator for acceptance. The duty holder is required to drive risk to ALARP. Effective goal-setting regulatory systems employ sufficient numbers of technically competent personnel to assess, verify, and intervene as necessary.
PHA	In the 2006 NHT unit PHA, Tesoro discontinued a review of their corrosion control and mechanical integrity programs in part because they were “not a legal requirement.” Tesoro conducted the optional review ineffectively and then ended it when they determined it was not strictly required.	There is no requirement in the PSM regulation for a performance based DMHR.	By shifting the responsibility for risk management to the duty holder, the goal-setting approach would require continual risk reduction and performance of an effective DMHR. This review is not just an activity but must meet the goal of preventing equipment failures.

Process Safety Concept	Causal Finding	Washington and Federal PSM Regulation and Enforcement	Goal-Setting Regulatory Approach
Incident Investigation	There was a history of leaks and fires on the NHT heat exchangers during startup, as identified in a Tesoro investigation report. Tesoro attempted to address the problems, but the hazard was never controlled.	Washington PSM regulations require incident investigation and preparation of a report, but do not require recommendations or control of hazards identified in the investigation. Although the regulations do not require recommendations to be developed, if recommendations are made the regulation requires them to be resolved.	Investigation of incidents is required to demonstrate legal compliance with framework legislation. The ALARP requirement would require remedial action including cross-company learning from incident investigations. The HSE can require duty holder compliance with investigation report recommendations.
Nonroutine Work	Tesoro failed to perform an evaluation of the higher hazards of the nonroutine work of starting up a bank of heat exchangers. Tesoro also did not define or control the number of workers required to perform the startup.	Although the WAC PSM regulation contains guidance on ways to control hazards when performing nonroutine work, compliance is not mandatory. The WAC regulations do not require either a hazard evaluation of nonroutine work or limitations on essential personnel during higher-hazard activities.	The goal-setting regulatory approach would require incorporation of good-practice guidance to achieve ALARP, such as the CCPS *Risk Based Process Safety* guidelines that address nonroutine work.

Process Safety Concept	Causal Finding	Washington and Federal PSM Regulation and Enforcement	Goal-Setting Regulatory Approach
Mechanical Integrity	API RP 941 has no minimum requirements to control, identify, or prevent the occurrence of HTHA in process equipment.	The mechanical integrity element of PSM requires that employers follow RAGAGEPs for inspection and testing procedures. However, API RP 941 has no minimum requirements. Post-incident, L&I cited Tesoro for insufficient testing and inspection procedures for the heat exchangers but did not specifically reference API RP 941 or HTHA.	In a goal-setting regulatory system, the regulator can reject the use of weak and inadequate standards referenced in a process safety report (by rejecting the report) and can require more rigorous performance to achieve ALARP.
Inherently Safer Design	The B and E heat exchangers were constructed of carbon steel – the most HTHA-susceptible material of construction used by industry. API RP 571 identifies materials that are not susceptible to HTHA.	Neither Washington nor federal OSHA requires the use or implementation of inherently safer design.	The goal-setting regulatory approach requires the implementation of inherently safer systems analysis.[194]

[194] According to the HSE, essential considerations for determining whether a duty holder has reduced risks to ALARP include "the adoption of inherently safer designs…". HSE. *The Safety Report Assessment Manual, Sections 8 to 15*. p 30. http://www.hse.gov.uk/comah/sram/s8-15.pdf (accessed October 30, 2013). The HSE also notes that the guidance to COMAH Regulation 4 (General Duty) "describes the application of all measures necessary to reduce risk of a major accident to ALARP based on a hierarchical approach (inherent safety, prevention, control, mitigation)." *Ibid* at 8.

Process Safety Concept	Causal Finding	Washington and Federal PSM Regulation and Enforcement	Goal-Setting Regulatory Approach
Process Safety Indicators	For more than a decade during startup following cleaning, the NHT heat exchangers would frequently leak from flanges, occasionally resulting in fires that created hazardous conditions for workers.	Federally and in the state of Washington, neither the PSM nor RMP regulations require companies to utilize or report process safety indicators.	Process safety indicators that drive performance are a key feature of a goal-setting regulatory approach. Publicly reported indicators can reveal critical safety areas that must be targeted for improvement to prevent accidents.

Figure 35. Gaps Within the Washington and Federal PSM Regulations. Causal findings highlight the gaps within the Washington and federal PSM regulations and how the process safety concept relating to each finding is more effectively managed in a more robust goal-setting regulatory approach.

7.3 OSHA National Emphasis Program

7.3.1 Federal National Emphasis Program

In a 1992 compliance directive,[195] OSHA stated that the primary enforcement model for the PSM standard would be planned, comprehensive, and resource-intensive Program Quality Verification (PQV) inspections.[196] These inspections consisted of the following three parts:

1. determining whether the elements of a PSM program are in place
2. evaluating whether the programs comply with the requirements of the standard, and
3. verifying compliance with the standard through interviews, data sampling, and field observations.

The CSB noted in its BP Texas City Final Investigation Report that for the 10-year period before the Texas City incident, federal OSHA conducted no planned PQV inspections in petroleum refineries. As a result, the CSB recommended in its report that OSHA strengthen the planned enforcement of the OSHA PSM standard by developing more highly trained and experienced inspectors to conduct more comprehensive inspections similar to those under the OSHA PQV program, at facilities posing the greatest risk of a catastrophic accident.

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[195] Compliance directives are the main method OSHA uses to communicate plans, inspection methods, and compliance expectations to their Compliance Safety and Health Officers (CSHOs) for enforcing a new regulation.
[196] OSHA Instruction CPL 02-02-045 (1994).

Spurred in part by recommendations in the CSB BP Texas City Final Investigation Report, OSHA adopted the Petroleum Refinery Process Safety Management NEP on June 7, 2007.[197] The NEP was a federal program that established guidelines for inspecting petroleum refineries to ensure compliance with the PSM standard. The NEP was designed to address the prevention and minimization of the consequences of catastrophic releases of toxic, reactive, flammable, or explosive chemicals in the refining industry.[198] In adopting the NEP, OSHA noted that no other industry sector in the country had experienced as many fatal or catastrophic incidents related to highly hazardous chemicals.[199]

Unlike the PQV approach to inspections, which "employs a broad, open-ended inspection strategy and uses a more global approach to identify compliance deficiencies…," the NEP "provide[d] CSHOs [Compliance Safety and Health Officers] with a tool to evaluate for compliance with the standard."[200] The tool is meant to identify "a particular set of requirements from the PSM standard from which CSHOs are to review documents, interview employees, and verify implementation for specific processes, equipment, and procedures."[201] According to CPL 03-00-004, the NEP inspections were required to be conducted by a team consisting of at least one Team Leader and one Level 1 Team Member.[202,203] Although the CSB called for an ongoing comprehensive inspection program, inspections being conducted pursuant to the NEP ended in 2011 in part because these inspections were very time consuming and resource intensive. OSHA has publicly stated[204] that NEP inspection hours were roughly 40 times greater than average OSHA inspection hours.

7.3.2 Washington State National Emphasis Program

OSHA State Plan states such as Washington were strongly encouraged but not required to adopt the NEP. However, on February 8, 2008, DOSH formally adopted the NEP through DOSH Directive 2.64[205] for the

[197] Originally Directive Number CPL 03-00-004, *Petroleum Refinery Process Safety Management National Emphasis Program*. Extended August 18, 2099 as Directive Number CPL 03-00-010 to allow more time to complete NEP inspections under the original CPL 03-00-004.

[198] https://www.osha.gov/pls/oshaweb/owadisp.show_document?p_id=3589&p_table=DIRECTIVES, Accessed October 30, 2013.

[199] OSHA Directive number CPL 03-00-004, Section VIII, Background

[200] CPL 03-00-004, Section X(D)(1). 2007. https://www.osha.gov/pls/oshaweb/owadisp.show_document?p_id=3589&p_table=DIRECTIVES (accessed September 24, 2013).

[201] *Ibid*

[202] CPL 03-00-004, Section X(C)(1). 2007. https://www.osha.gov/pls/oshaweb/owadisp.show_document?p_id=3589&p_table=DIRECTIVES (accessed September 24, 2013).

[203] A Level 1 Team Member is considered to be Trained OSHA personnel with experience in the chemical processing or refining industries. CPL 03-00-004, Section X(C)(2).

[204] See Barab, Jordan. OSHA's Refinery & Chemical National Emphasis Programs. Power Point presentation made at CSB Public Hearing on Process Safety Indicators; July 20, 2012. http://www.csb.gov/UserFiles/file/Barab%20%28OSHA%29%20PowerPoint.pdf (accessed August 14, 2013). Also see Transcript of CSB Public Hearing on Safety Performance Indicators; p 52. http://www.csb.gov/assets/1/19/CSB_20Public_20Hearing.pdf (accessed August 14, 2013).

[205] DOSH Directive 2.64. Petroleum Refinery Process Safety Management. February 8, 2008. http://www.lni.wa.gov/Safety/Rules/Policies/PDFs/WRD264.pdf (accessed September 24, 2013).

five refineries[206] in the state of Washington. The stated purpose of DOSH Directive 2.64 was to "reduce or eliminate the workplace hazards associated with the catastrophic release of highly hazardous chemicals at petroleum refineries."[207] The directive required the DOSH staff to follow the compliance directions in OSHA Instruction CPL 03-00-004 when conducting NEP inspections. When CPL03-00-004 referenced another CPL, DOSH instead followed any existing equivalent DOSH policy and directives. DOSH also used WAC equivalents in place of the OSHA 1910.119 PSM standard. For example, when auditing PSM section 1910.119(j) "Mechanical Integrity," DOSH instead used WAC 296-67-037.

CPL 03-00-004 provides for a two-step NEP inspection process. The first step is a PSM compliance review based on a "static" list of inspection priority items. The second is a PSM compliance review based on a "dynamic" list of priority inspection items.[208]

The DOSH NEP team consisted of six people, including a team lead who had been with L&I since the early 1990s. The team lead had more process safety and refinery experience than the other team members. None of the team members had an engineering or metallurgy background, and the team as a whole had limited experience with PSM and with refinery operations.

[206] The five petroleum refineries in Washington are BP Cherry Point Refinery; Conoco Phillips Ferndale Refinery; Tesoro Anacortes Refinery; Shell Oil Products Refinery; and US Oil and Refining Refinery.

[207] DOSH Directive 2.64. Petroleum Refinery Process Safety Management. February 8, 2008; p 1. http://www.lni.wa.gov/Safety/Rules/Policies/PDFs/WRD264.pdf (accessed September 24, 2013).

[208] Static questions within the NEP are publicly available. The company can prepare for them. Dynamic questions are not available to the company prior to the audit. Reference: OSHA CPL 03-00-004 Section X (D)(3). (June 7, 2007). *See:* https://www.osha.gov/pls/oshaweb/owadisp.show_document?p_id=3589&p_table=DIRECTIVES (accessed September 24, 2013).

7.3.3 Tesoro National Emphasis Program Audit

Following Washington's adoption of the federal NEP, the DOSH NEP team lead developed a proposed refinery inspection plan. To determine the focus for the NEP audit at each facility, the DOSH NEP team examined the age of each process in the refinery, hazards surrounding different process units, and past events, including near misses.

On October 7, 2008, the DOSH NEP team initiated a formal NEP audit of the Tesoro CR and NHT units. The selection of these units was based primarily on the fact that the NHT unit stood out to the team as problematic in terms of previous incidents and near misses. The Tesoro NEP Audit Report noted the following:

> Elsewhere, refinery records indicate a relatively higher incidence of process safety related events occurring in the Catalytic Reformer and Naphtha Hydrotreater (CR/NHT) process areas when compared to other units, with the possible exception of the Catalytic Cracking unit equipment when viewed in its entirety.
>
> From 2002 to 2007, the CR/NHT experienced a total of 117 records related to process safety. Of those, 36% were attributed to equipment failures, 33% human error, and the remaining 31% were attributed to failure of a process control or safeguard.
>
> Previous inspection activities at the refinery have included at least five safety and health compliance inspections since 2003. These have included scheduled inspections, complaints, and accident and near miss investigations.

The NEP team spent several weeks at the Tesoro refinery during the NEP audit. The refinery NEP inspection process was a two-step process. The first step consisted of a compliance review based on a static list of inspection priority items. The CSHO was required to follow the list verbatim. The list of questions related to various aspects of process safety, such as equipment, engineering and administrative controls, and safe work practices. The answers to these questions were the basis for determining compliance with various PSM requirements. The second step focused on a dynamic list of inspection priority items that were directed towards the specific selected process unit.[209]

7.3.3.1 Tesoro NEP Results Associated with the E Heat Exchanger

The Tesoro Anacortes NEP audit is noteworthy, as it was the only audit conducted under the federal OSHA NEP program that focused on a unit that subsequently experienced a catastrophic accident that the CSB investigated. The heat exchanger that failed, the E heat exchanger, was a fundamental component of the Tesoro NEP audit. Within the scope of the NEP nine pressure vessels were selected at random; the E

[209] OSHA Directive CPL 03-00-004, Section X, (D) (3).

heat exchanger was one of the vessels reviewed. The NEP states, "Inspection records for all nine vessels were examined and found to be in order. No citable deficiencies found."

Like the CSB, the DOSH NEP identified the issue of PHA assumptions for the PHA. Reflecting the weakness in the current PSM requirements for PHAs, DOSH mentioned the problematic nature of using the assumptions but did not cite Tesoro in this area. The NEP states the following:

> Problems were identified in the area of procedures, inspection, and testing of devices that indicate assumptions made by PHA teams inhibits identification of problematic areas.

Given the methodology used and expertise available, the mechanical integrity issues related to the failure of the E heat exchanger were not detected during the NEP audit. To prevent the April 2010 incident, the NEP audit needed to identify the susceptibility of the E heat exchanger to HTHA and to recognize that Tesoro had incorrectly concluded that it was not susceptible. The topics investigated during the NEP audit were contained in prescriptive questions for the individual unit, which resulted in a shallow technical review. For example, significant emphasis was placed on verifying the existence of basic protocols for conducting thickness monitoring. On the basis of the CSB review of the question sets applied for the Tesoro refinery, there was no mention of HTHA, corrosion studies, or failure mechanisms and no references to the API RP 571 damage mechanisms. The NEP team lead confirmed that little emphasis was placed on possible damage mechanisms that could be present, including HTHA. The NEP found the following:

> In general, the refinery maintains corrosion control documentation that attempts to identify corrosivity data and potential failure mechanisms.
>
> The inspection procedure I-08.01 addresses metallurgy and corrosion in the refinery.
>
> The refinery has a procedure for conducting corrosion awareness training of staff and managing corrosion control procedures.

Unless a member of the NEP audit team had a personal interest in metallurgical damage mechanisms, or had experience to prompt investigation into the area of metallurgy, reliance on these static and dynamic lists would not lead to the conclusion that the B and E heat exchangers were susceptible to HTHA.

The NEP inspection was formally closed on March 12, 2009; at that time, a summary of the audit findings was presented to Tesoro. The NEP inspection team identified 17 process safety code violations under Chapter 296-67 of the WAC,[210] but only two of these addressed mechanical integrity,[211] and neither related to the NHT heat exchangers or to identification or control of HTHA.

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[210] *See* http://apps.leg.wa.gov/wac/default.aspx?cite=296-67 (accessed September 25, 2013).

[211] Mechanical integrity violations of WAC 296-67-037 were issued for the following:
a. No written procedures for controls and emergency shutdowns; 13 instances were documented in which the employer did not have written procedures for the inspection and testing of emergency equipment; and

On October 23, 2009, six months before the incident, a settlement agreement was reached between L&I and Tesoro whereby Tesoro agreed to perform a PSM compliance audit with an industry recognized PSM consultant within 60 days of the agreement date and to commit to a completed compliance audit within six months of the consultant's contract initiation date. In exchange for the audit, L&I agreed to reduce the citations from seventeen (17) to three (3) citations. Subsequently, the total penalty was reduced from $85,700 to $15,450.[212] The same consulting firm that Tesoro hired for its most recent OSHA-mandated compliance audit also conducted the audit under the settlement agreement. However, the compliance audit conducted by the consulting firm was not a comprehensive audit of the entire refinery PSM program. It was limited only to those areas covered by the fourteen eliminated citations from settlement agreement between L&I and Tesoro.

7.4 Risk Reduction and Continuous Improvement

The CSB Chevron Regulatory Report provides a detailed discussion of the advantages of adding robust goal-setting regulatory attributes to make the PSM standard more effective in preventing major accidents. Many countries throughout the world implement a goal-setting regulatory approach, which provides the regulator with the tools needed to drive continuous improvement among facilities and to ensure that duty holders are identifying and controlling hazards and reducing risks to ALARP. The existing federal and state of Washington PSM standards, on the other hand, are more reactive in nature and contain activity-based requirements that do not focus on specific risk reduction; rather, the mere completion of the activities satisfies the requirements.

Highlighting the reactive nature of the Washington PSM standard, following the Tesoro incident, DOSH initially cited Tesoro for 39 willful violations and five serious violations related to the incident, with a total proposed fine of $2.39 million.[213] Four of the citations were issued to Tesoro for failing to follow recognized and generally accepted good engineering practice (RAGAGEP) for mechanical integrity under WAC 296-67-(4)(b) "such as those published by the American Petroleum Institute."[214] No RAGAGEPs were specified in the citations. RAGAGEPs are technologically focused, with no emphasis on organizational issues, human factors, or culture-based measures. OSHA developed the mechanical integrity RAGAGEP requirement to "make sure that process equipment is inspected and tested properly, and that the inspections and tests are performed in accordance with appropriate codes and standards."[215] However, as in this case, OSHA mainly enforces RAGAGEP reactively. Here, DOSH used unspecified

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b. Documenting inspections and tests – 24 instances identified in which the employer did not document testing of emergency field devices or where the record did not identify what testing procedure was used.

[212] *See* http://www.osha.gov/pls/imis/establishment.inspection_detail?id=312459290; (accessed on June 19, 2013).

[213] Tesoro has appealed these citations.

[214] State of Washington Department of Labor and Industries, Division of Occupational Safety and Health. *Tesoro Citation – Notice Inspection.* October 1, 2010; p 9. http://www.lni.wa.gov/Main/Docs/TesoroCitation-NoticeInspectionNo314251315.pdf (accessed September 25, 2013).

[215] OSHA. Preamble to 29 CFR Part 1910, Process Safety Management of Highly Hazardous Chemicals, Section 3, Title III. Summary and Explanation of the Final Rule, 1992. Available at http://www.osha.gov/pls/oshaweb/owadisp.show_document?p_table=PREAMBLES&p_id=1041 (accessed June 6, 2013).

RAGAGEPs to issue a citation to Tesoro post-incident, rather than working to drive continuous improvement and risk reduction through preventative NEP inspections. Although many OSHA inspectors have cited to RAGAGEPs following NEP refinery audits, DOSH did not cite any RAGAGEPs for mechanical integrity following its NEP audit of the Tesoro refinery in 2008.

Similar to OSHAct Section 5(a)(1), also known as the General Duty Clause, the WAC requires employers to provide employees a workplace "free from recognized hazards[216] that are causing, or are likely to cause, serious injury or death."[217] Similar to federal OSHA, DOSH may use this provision following an incident to cite a company for hazards not addressed by the regulations, but these citations are often difficult to prove especially if the regulator lacks industry-specific expertise, and are resource intensive to sustain. DOSH did not cite Tesoro for General Duty Clause violations following the April 2010 incident.

Washington's Safety Standards for Process Safety Management of Highly Hazardous Chemicals were established to "prevent[] or minimiz[e][] the consequences of catastrophic releases of toxic, reactive, flammable, or explosive chemicals."[218] Washington's PSM standard contains many activity-based elements that are almost identical to those in the federal PSM standard. For example, an employer must perform a PHA "appropriate to the complexity of the process and shall identify, evaluate, and control the hazards involved in the process."[219] This language does not support the principle of ALARP and makes no mention of reduction of risk or continuous improvement. As a result, PHAs may satisfy Washington's PSM requirement by merely listing safeguards, and there is no requirement to evaluate or document the effectiveness of those safeguards, or to show that the safeguards reduce risks.

Following the April 2010 incident DOSH issued two citations to Tesoro for its 2006 PHA revalidation.[220] One of these citations was dismissed and the second citation addressed Tesoro's failure to establish and implement written procedures to manage the change made by discontinuing the PHA revalidation system that included mechanical integrity and corrosion control review in 2006.[221] However, as discussed in Section 5.3, PHAs conducted on the NHT unit cited non-specific, judgment-based qualitative safeguards that in light of the April 2010 incident were not effective. If the Washington PSM standard had required an evaluation and documentation of safeguard effectiveness, Shell Oil and Tesoro would have been obligated to conduct this analysis, and DOSH inspectors could have relied on the regulation for support during inspections.

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216 According to L&I, "A hazard is recognized if it is commonly known in the employer's industry, or if there is evidence that the employer knew or should have known of the existence of the hazard, or if it can be established that any reasonable person would have recognized the hazard." 296 WAC 800-11005 (2012).

217 296 WAC 800-11005 (2012). http://www.lni.wa.gov/wisha/rules/corerules/PDFs/296-800-110.pdf (accessed September 26, 2013).

218 26 WAC 67-001(1) (1992).

219 26 WAC 67-017(1) (1992).

220 Under appeal, citation item 1-37 was dismissed.

221 In the 2001 PHA, Tesoro included a review of the corrosion control program and a specific mechanical integrity checklist associated with the corrosion program. In 2006, Tesoro excluded these items because they were being used in the DMHR and it was "not a legal requirement" for PHAs.

Tesoro conducted a PHA for the NHT unit between February 1, 2010, and May 21, 2010. Despite the fact that the PHA was being conducted at the time of the April 2010 incident, the PHA failed to identify significant hazards associated with the immediate causes of the incident, including damage mechanisms such as HTHA. The PHA also took credit for inspection safeguards that did not exist. The PHA failed to address HTHA damage in the B or E heat exchangers on the shell-side and the PHA used inspection as a safeguard to mitigate HTHA consequences on the tube side. As discussed in Section 5.3.3, no inspection for HTHA was ever conducted on the B or E heat exchangers. No evaluation was documented to demonstrate the effectiveness of the inspection safeguards claimed by the PHA team; that is a manual activity and thus low in the hierarchy of controls. The PHA analysis concluded that the worst consequence resulting from a loss of primary containment (catastrophic failure of the E heat exchanger) was a disabling injury and substantially understated the actual consequence of seven worker fatalities. The combination of understating the consequence and overstating the safeguards resulted in underestimating the risk of a catastrophic failure of the E heat exchanger, despite the fact that the incident took place 50 days before completion of the PHA.

Tesoro's NHT unit PHAs cited non-specific, judgment-based, qualitative safeguards that were not effective in major accident prevention.

A PHA may inadequately assess the risk of major hazards under the current regulatory system.

In a robust goal-setting regulatory approach, a risk assessment such as this would be part of the process safety report submitted to the regulator to demonstrate and ensure that the hazards are adequately identified and that risks are being reduced to ALARP. If the hazards are not sufficiently identified and controlled, the regulator may reject the process safety report and require improvements and further risk reduction. In this case, because mere completion of the PHA satisfied the PSM requirements, DOSH did not analyze or address Tesoro's failure to adequately identify and control hazards. In addition, DOSH did not issue any post-incident citations to Tesoro regarding its 2010 NHT unit PHA.

The existing regulatory approaches in the US and Washington, such as the PSM and RMP programs, do not require companies to reduce risks to ALARP. While the Clean Air Act (CAA) directed the EPA to promulgate the RMP regulations "to provide, to the greatest extent practicable, for the prevention and detection of accidental releases of regulated substances,"[222] there is no RMP ALARP requirement. Under both the PSM and RMP regulations, an employer must "control" hazards when conducting a PHA of a covered process. However, there is no requirement to address the effectiveness of the controls or the

[222] 42 U.S.C. §7412(r)(7)(B)(i) (1990).

hierarchy of controls. Thus, a PHA that meets the regulatory requirements might still inadequately identify or mitigate major hazard risks. In addition, there is no requirement to submit PHAs to the regulator, and the regulator is not responsible for assessing the quality of the PHA or the proposed safeguards.

The Tesoro PHA goals encourage the PHA team to identify high-consequence, low-frequency hazards that are possible but might not be realized. The company's PHA goal supports the principle of ALARP. The Tesoro PHA policy states the following:

> In the end, the reduction of RISK is the goal.
>
> Any improvement in a layer of protection that is permanent and inseparable, and not easily weakened or removed from the system, is considered to be a process safety improvement in an inherently safer direction.
>
> Can the Likelihood be reduced?
>
> If the Hazard cannot be removed, and Consequences cannot be reduced, then what can be done to reduce the likelihood of the event(s) occurring?

None of the Tesoro PHA teams ever considered applying the principles of inherently safer design by upgrading the heat exchangers before the incident; yet, following the April 2, 2010, incident, more HTHA-resistant materials were used for the replacement equipment. In conducting its PHA of the NHT unit, which was required under the state of Washington PSM standard,[223] Tesoro did not address inherently safer design or implement effective safeguards to prevent HTHA. However, there is no Washington (or federal) PSM requirement to consider inherently safer design or to evaluate the effectiveness of safeguards. Thus, Tesoro was never cited for failure to evaluate or implement inherently safer design or for the PHA claim of HTHA inspection as a safeguard despite the company never inspecting the E heat exchanger for possible presence of HTHA.

Under a robust goal-setting regulatory approach, Tesoro would be required to apply the hierarchy of controls and inherently safer design to achieve ALARP. As detailed in the CSB Chevron Regulatory Report, a company must demonstrate how inherently safer design concepts were applied in the design decisions that were taken. This principle applies to all life cycle stages of a facility, and includes materials selection and corrosion management in the design.[224]

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[223] Under WAC 296-67-001 Process safety management of highly hazardous chemicals. See: http://www.lni.wa.gov/wisha/rules/hazardouschemicals/default.htm#WAC296-67-001 (accessed September 28, 2013).

[224] HSE. *Assessment Principles for Offshore Safety Cases (APOSC);* March 2006; p 7. http://www.hse.gov.uk/offshore/aposc190306.pdf (accessed August 6, 2013).

7.5 Workforce Participation

As the CSB noted in its Chevron Interim and draft Chevron Regulatory Reports, workforce participation is a key element of process safety and effective major accident prevention. The CCPS lists workforce involvement as one of 20 essential management components necessary to reduce process safety risks and prevent major chemical accidents.[225] In one of its publications, the CCPS states that workforce participation leads to worker empowerment, management responsiveness, and process safety performance improvement.[226] The OSHA PSM standard provides for participation by workers and their representatives. It requires employers to consult with employees and their representatives on the performance and development of PHAs and on the development of the 13 remaining PSM elements, and to develop a written plan of action regarding the implementation of the employee participation required under this section.[227] However, other regions such as the UK go further to ensure effective worker participation by specifying the election of safety representatives by the workers to serve many functions related to health and safety, including investigating complaints and accidents and conducting inspections.[228] UK regulations also require employers to establish a safety committee when one is requested by at least two health and safety representatives.[229]

Like the federal PSM standard, the WAC provides for workforce participation in a company's PSM program and has implemented language identical to that contained in the federal PSM standard.[230] However, throughout its investigation of the Tesoro incident, the CSB has seen that the Tesoro refinery workforce and its representative, the United Steelworkers Union (USW), expressed concerns regarding the NHT unit that were not adequately addressed by Tesoro managers in the lead-up to the incident. During a 2006 PHA revalidation on the NHT unit at the Tesoro Anacortes Refinery, workers noted 31 near misses in the NHT unit in the last 5 years because of many possible factors, including too many outside tasks and continual rotation of the field and control room operators. The PHA team requested a review of experience and training for NHT operators to address these workload concerns. A manager at the refinery closed the action item with one simple statement: "Experience levels of teams, where and when individuals are trained on the NHT are managed by team supervisor." The action item was closed without resolution of the concerns expressed by the Tesoro workers on the PHA team.

Concerns raised by NHT unit workers were not adequately addressed by Tesoro management.

[225] CCPS. *Guidelines for Risk Based Process Safety;* March 2007; p liv.
[226] *Ibid* at 125.
[227] 29 CFR §1910.119(c) (2012).
[228] *See*: the Safety Representatives and Safety Committees Regulations, 1977, and the Health and Safety (Consultation with Employees) Regulations 1996.
[229] *Ibid.*
[230] See: WAC §296-67-009 (1992). http://apps.leg.wa.gov/wac/default.aspx?cite=296-67-009 (accessed September 26, 2013).

7.6 Funding and Regulator Competency

The CSB stated in both its BP Texas City Final Investigation Report (issued in March 2007) and its draft Chevron Regulatory Report (Appendix F) the importance of having a well-resourced, competent regulator consisting of individuals with the necessary training, education, and experience to conduct comprehensive and robust inspections of facilities with the goal of preventing catastrophic accidents. As noted above, currently DOSH employs only four Process Safety Specialists to cover approximately 270 PSM facilities within the state of Washington, and only one of those has significant refinery experience. None have metallurgical experience and only one has an engineering background. Despite the fact that DOSH performed a detailed NEP inspection at the Tesoro refinery, the team did not have the technical expertise to inspect for and identify possible damage mechanisms present in the NHT unit such as HTHA. Individuals within L&I have expressed to the CSB that there is currently no funding in the state of Washington to form a multi-disciplinary process safety group to conduct more thorough facility inspections. This was also the case in California at the time of the Chevron incident in August 2012. Despite the fact that Cal/OSHA had formed a dedicated PSM unit, it did not have the staffing, funding, or experience to oversee the state's 15 petroleum refineries. Following the Chevron incident, the California State Legislature approved a 2013-2014 state budget bill (AP 110) that allows the California Department of Industrial Relations to charge state petroleum refineries a "fee" by March 31, 2014, to help pay for at least 15 new positions in Cal/OSHA's Process Safety Unit, which enforces the California PSM standard throughout the state.[231]

Adding more robust goal-setting regulatory attributes to the existing PSM regulation will require a full commitment and extensive effort by the Washington legislature, regulators, and Washington petroleum refineries. The CSB believes that this effort is necessary to ensure that Washington, like other regions around the world, is effectively managing process safety and risk, and in the process, preventing major accidents such as the April 2, 2010, Tesoro incident.

7.7 Similar Deficiencies in the Anacortes and Richmond Refinery Incidents

The CSB identified a number of similar causal findings for both the April 2010 Tesoro Anacortes Refinery incident and the August 2012 Chevron Richmond Refinery incident. These findings included ineffective PHAs, lack of effective safeguards to prevent damage mechanism hazards, no requirements to use the hierarchy of controls or to implement inherently safer design to the greatest extent possible, weak and permissive industry standards that lack minimum requirements to control damage mechanism hazards, and regulators that lack sufficiently qualified personnel to provide effective oversight.

[231] *See*: http://www.caltax.org/homepage/062113_Legislature_Approves.html (accessed July 9, 2013).

7.7.1 Reliance on Inspection Instead of Inherently Safer Design in Mechanical Integrity Programs at Tesoro and Chevron Refineries

The August 6, 2012, Richmond, California, Chevron refinery incident occurred when a severely thinned, low-silicon carbon steel pipe component ruptured, releasing hot hydrocarbons that autoignited and endangered the lives of 19 employees.[232] Like HTHA, low-silicon areas that result in rapid corrosion are very difficult to identify by inspection. Identification of this hazard requires the inspection of every single component in a carbon steel piping circuit to identify the quickly corroding pieces. Despite this difficulty and despite Chevron's notable expertise on sulfidation corrosion,[233] the refinery still operated the high-risk piping circuit with a carbon steel material of construction, the steel that is most susceptible to rapid rates of sulfidation corrosion in low-silicon components. The refinery then relied on its inspection program to identify any quickly corroding pieces, a very low-ranking method on the hierarchy of controls, to prevent process safety incidents. Ultimately, the inspection program failed to detect the low-silicon component in the piping circuit. Had Chevron designed the piping circuit by using an inherently safer material of construction, such as high-chromium steel, the corrosion rates in the piping circuit would have been much slower and much more uniform, and the incident would not have occurred.

The Anacortes refinery also in effect relied on its mechanical integrity program to identify damage mechanisms such as HTHA in its NHT heat exchangers instead of incorporating design elements that would eliminate the risk of HTHA. Although Tesoro was not actively looking for HTHA in the B and E heat exchangers, this is the only mechanical integrity component that could identify the damage in the heat exchangers. As described previously, inspection for HTHA is very difficult and not sufficiently reliable. The use of inherently safer materials of construction, such as high-chromium steels, significantly lowers the risk of HTHA in this type of service.

Both Tesoro and Chevron had the expertise and capability needed to design the damage mechanisms out of the equipment by incorporating inherently safer design. However, both companies continued to rely on mechanical integrity programs, such as inspection, to identify the damage after it had already occurred in the system. Although inspection programs are needed they are very low on the hierarchy of controls, and in both cases the inspection strategies failed to prevent a major process safety incident. Since the incidents, both Chevron and Tesoro redesigned the equipment that failed, incorporating inherently safer design practices. Now, sulfidation corrosion in Chevron's new piping circuit will be significantly reduced and without risk of variable corrosion rates. Tesoro installed new NHT heat exchangers, using materials of construction that are highly resistant to HTHA.

[232] The CSB plans to release three separate reports on the Chevron incident. All draft and final reports can be found at http://www.csb.gov/chevron-refinery-fire/ (accessed January 6, 2014).

[233] Chevron employees were leaders in the development of the industry standard on sulfidation corrosion, API RP 939-C.

7.7.2 Ineffective PHAs at Tesoro and Chevron

PHAs are a crucial opportunity to identify hazards in a refinery process unit. However, neither Tesoro nor Chevron PHAs identified the significant hazards that led to the April 2010 and August 2012 incidents, respectively. The CSB found similar deficiencies in the PHA of both companies. Instead of performing a rigorous analysis of damage mechanisms present in the refinery during the PHA process, both companies simply cited non-specific, judgment-based qualitative safeguards to reduce the risk of damage mechanisms. The effectiveness of these safeguards was neither evaluated nor documented; instead, the PHAs merely listed general safeguards. If the adequacy of these safeguards to control and prevent damage mechanisms had been verified, recommendations could have been made to improve safeguards intended to protect against the failure of the highly susceptible carbon steel equipment.

7.7.3 Applicable API Standards Lack Minimum Requirements to Control Hazards

The Anacortes and Richmond refineries relied on API standards to assist in the selection of materials of construction for both Tesoro NHT heat exchangers and the Chevron piping circuit: specifically, API RP 941, *Steels for Hydrogen Service at Elevated Temperatures and Pressures in Petroleum Refineries and Petrochemical Plants*, and API RP 939-C, *Guidelines for Avoiding Sulfidation (Sulfidic) Corrosion Failures in Oil Refineries*. Both documents provide guidance on how to avoid HTHA and sulfidation corrosion failures, respectively, but neither document imposes minimum requirements on the user to adequately control hazards. In fact, the CSB found in its Chevron investigation that API RP 939-C was specifically written to ***not*** require any action by the user (emphasis added). Thus, API's current consensus, standard creating process is not effective in ensuring that companies perform essential safety practices that can prevent fatal process safety incidents.

7.7.4 Weak Regulations and Ineffective Regulators

The CSB found significant gaps in the regulations and the technical abilities of the regulators in both Washington and California. Refineries in both states are required to comply with requirements in the state OSHA PSM and EPA RMP regulations. However, neither state's regulations were successful in preventing the April 2, 2010, and August 6, 2012, major process safety incidents.

Under the existing regulatory systems in both Washington and California, there is no requirement to conduct DMHRs or to reduce risk to ALARP. Both Tesoro and Chevron were required to "control" hazards, but there was no requirement to evaluate the effectiveness of the controls or to ensure the use of the hierarchy of controls. In addition, there is no requirement to submit PHAs to the regulator, and the regulator is not responsible for assessing the quality of the PHA or the proposed safeguards. Furthermore, neither Washington nor California requires the use of inherently safer design to the greatest extent practicable. A more robust goal-setting regulatory approach in both states would help to ensure that all of the refineries in these states rigorously apply process safety concepts that focus more effectively on prevention. The PSM regulations in the state of Washington should be augmented with more robust goal-setting attributes including requirements to implement inherently safer designs and the hierarchy of controls to prevent major process safety incidents.

Both states also have significant weaknesses in their PSM staffing resources. Washington L&I (the Washington PSM regulator) and Cal/OSHA (the California PSM regulator) lack sufficient technically experienced and qualified staff members to verify that PSM requirements are being implemented adequately. Cal/OSHA has only seven inspectors, and only one with a technical background, for 1,700 PSM-covered facilities including 14 petroleum refineries, and Washington L&I has only four inspectors, and only one with a technical background, for more than 270 PSM-covered facilities including five petroleum refineries.

As described in the CSB Chevron Regulatory Report and in Section 7.0 of this report, it is essential that regulators of high-hazard facilities are independent, well funded, well staffed, and technically qualified. These regulators must be able to communicate effectively with refinery personnel and to monitor the adequacy of refinery process safety practices.

7.8 Environmental Protection Agency and Chemical Accident Release Programs

The CSB determined that a key causal factor of the April 2010 incident was Tesoro's failure to implement more effective safeguards to prevent the heat exchanger failure, such as the use of inherently safer materials that are resistant to HTHA. In a number of recent CSB investigations, such as the Chevron Richmond Refinery incident, the CSB found that the implementation by the company of the hierarchy of controls and inherent safety could have helped to prevent the incident. A number of these incidents had significant offsite consequences or had the potential to do so. The CSB has determined that Tesoro policies and relevant API standards do not require the application of inherently safer systems analysis or use of the hierarchy of controls to more effectively prevent chemical accidents. In this section of the report the CSB will examine the requirements of the use of inherent safety under the Clean Air Act and EPA's Risk Management Program.

> **Both the Chevron and Tesoro incidents could have been prevented if inherently safer equipment construction materials had been used.**

7.8.1 Background

Under the authority of the Clean Air Act (CAA) section 112(r),[234] the EPA adopted the Risk Management Program regulations at 40 CFR Part 68, which went into effect in 1999. The CAA provides that the

[234] 42 U.S.C. §7412(r)(7)(B)(ii) requires the Administrator to promulgate regulations that "shall require the owner or operator of stationary sources at which a regulated substance is present in more than a threshold quantity to prepare and implement a risk management plan to detect and prevent or minimize accidental releases of such

regulations and appropriate guidance developed "provide to the greatest extent practicable, for the prevention and detection of accidental releases of regulated substances and for response to such releases by the owners or operators of the sources of such releases."[235] The EPA's Risk Management Program requires facilities that contain more than the threshold quantity of any of the 77 listed toxic chemicals or 63 flammable substances[236] to prepare and submit to the regulating agency emergency contact information, descriptions of processes and hazardous chemicals onsite, an accident history, and worst-case release scenarios.[237] The regulation defines three different Program levels (Program 1, 2, or 3) based on a process unit's potential for impact to the public and the requirements to prevent accidents.[238] Program 3 processes are subject to additional, more stringent requirements to prevent accidents similar to those of the OSHA PSM standard. Program 3 facilities must implement elements of a prevention program, including: process safety information (PSI), PHA, standard operating procedures (SOPs), training, mechanical integrity, compliance audits, incident investigations, MOC, pre-startup reviews, employee participation, and hot work permits. These prevention program elements are based primarily on the OSHA PSM standard, and much of the language contained in each element is identical to the PSM standard.

Each covered facility is required to submit a risk management plan (RMP) to EPA for all covered processes[239] and update and resubmit these plans at least once every five years, or whenever a major accident occurs or the emergency contact information changes. Completing and submitting the RMP satisfies the regulatory requirement; again, the effectiveness of the RMP in risk reduction is not assessed by the EPA, rendering this another activity-based requirement for a covered facility. There is no approval of the RMP by the EPA, and there is no additional duty on the facility to implement what it says it is doing in the RMP, unlike the more robust goal-setting regulatory approach.

Any facility with one or more covered processes must include in its RMP an executive summary; the registration for the facility; the certification statement; a worst-case scenario for each process involving flammables or toxics; the five-year accident history for each process; information concerning emergency response at the facility; at least one alternative release scenario analysis for each regulated toxic substance or flammable; a summary of the prevention program for each Program 2 process; and a summary of the prevention program for each Program 3 process.[240]

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substances from the stationary source, and to provide a prompt emergency response to any such releases in order to protect human health and the environment." (1990).

235 42 U.S.C. §7412(r)(7)(B)(i) (1990).

236 According to 40 CFR §68.10(a), "[a]n owner or operator of a stationary source that has more than a threshold quantity of a regulated substance in a process, as determined under §68.115, shall comply with the requirements of this part no later than the latest of the following dates…"

237 *See* 40 CFR §68.12. General Requirements.

238 *See* 40 CFR §68.10. Applicability.

239 40 CFR §68.150 (1999).

240 EPA Office of Solid Waste and Emergency Response. *General Guidance on Risk Management Programs for Chemical Accident Prevention (40 CFR Part 68);* March 2009; pp 9-1 and 9-2. *See* http://www.epa.gov/osweroe1/docs/chem/Toc_final.pdf (accessed May 14, 2013).

The Tesoro Anacortes Refinery is a covered facility under the RMP program, and its CR/NHT unit is considered to be a Program 3 process, as it contains more than the threshold quantity of a flammable mixture including butane, ethane, hydrogen, methane, and propane.[241] The refinery last submitted an updated RMP to EPA on March 28, 2011. The RMP contained a five-year accident history that listed the April 2, 2010, NHT catastrophic heat exchanger failure as well as a section on worst-case scenarios, which stated that the worst-case scenario associated with a release of flammable substances at Tesoro would be a vapor cloud explosion involving the full inventory of the largest storage tank containing an RMP regulated flammable mixture.[242]

7.8.2 Enforcement of Inherent Safety in the United States

Although industry good practice guidance provides[243] that inherently safer technology (IST) is the preferable and often the most effective safety precaution in the hierarchy of controls to prevent major accidents it is not enforced by the EPA through its RMP program or through its General Duty Clause or other provisions of the Clean Air Act.

7.8.3 The EPA RMP Program

As discussed in Section 4.1.3, the hierarchy of controls is a well-recognized safety tool to rank the effectiveness of techniques to control hazards, with inherent safety being the most effective choice. The CCPS defines inherently safer design as the process of identifying and implementing inherent safety in a specific context that is permanent and inseparable.[244] The CCPS also notes that "inherently safer design solutions eliminate or mitigate the hazard by using materials and process conditions that are less hazardous."[245] Regulatory systems around the world have recognized the importance of inherent safety; for example, the HSE requires major hazard facilities in the UK to implement inherently safer systems analysis including at the design stage in order to satisfy the risk reduction requirement of as low as reasonably practicable, or ALARP.[246]

The RMP program regulations under 40 CFR Part 68 do not require the use or implementation of inherently safer design or the hierarchy of controls. This is reflected in both the regulatory language,

[241] *See* http://data.rtknet.org/rmp/rmp.php?database=rmp&detail=3&datype=t&facility_id=100000028034 (accessed January 23, 2014).

[242] *Ibid.*

[243] CRC Press, *Process Plants: A Handbook for Inherently Safer Design Second Edition*; Kletz, Trevor and Amyotte, Paul; 2010; pp 15-16.

[244] Center for Chemical Process Safety (CCPS). *Inherently Safer Chemical Processes – A Life Cycle Approach.* 2nd ed., Section 2.2, 2009.

[245] *Ibid* at Section 5.1.1.

[246] According to the HSE, essential considerations for determining whether a duty holder has reduced risks to ALARP include "the adoption of inherently safer designs…." HSE. *The Safety Report Assessment Manual, Sections 8 to 15.* p 30. http://www.hse.gov.uk/comah/sram/s8-15.pdf (accessed October 30, 2013). The HSE also notes that the guidance to COMAH Regulation 4 (General Duty) "describes the application of all measures necessary to reduce risk of a major accident to ALARP based on a hierarchical approach (inherent safety, prevention, control, mitigation)." *Ibid* at 8.

which does not mention either concept, as well as citations issued by the EPA to companies following an incident. As of January 2014, the EPA had issued no civil enforcement penalties to Tesoro as a result of its April 2010 incident that resulted in seven fatalities. The EPA did conduct "post-incident" inspections of the Tesoro Anacortes Refinery in January and October of 2011. However, no violations were issued related to the implementation of inherently safer systems analysis or the hierarchy of controls. In December 2013 the EPA also issued a Finding of Violations relating to the Chevron Richmond Refinery incident of August 2012. Again, no violations related to either accident prevention approach.

The CSB found in both its Chevron and Tesoro investigations that the incidents could have been prevented if inherently safer materials of construction had been used. In the years leading up to the Chevron incident, Chevron employees repeatedly recommended implementing inherently safer designs through the management of change (MOC) process, incident investigations, technical reports, and recommendations from employees in the past. However, despite the fact that Chevron's training programs on inherently safer systems stated that "the greatest opportunity to eliminate or minimize hazards [is] during the development phase of new projects or major revamps of existing facilities," the CSB did not identify any documented, thorough analysis of these proposed inherently safer solutions. Instead, Chevron repeatedly failed to implement proposed inherently safer recommendations to upgrade crude unit piping from carbon steel to metallurgy that was less susceptible to sulfidation corrosion. This led to extremely thinned piping which ultimately ruptured on August 6, 2012.

At Tesoro, the CSB found that the carbon steel E heat exchanger ruptured because it was in a highly weakened state because of HTHA. As discussed in Section 7.4 the Tesoro PHA goals encourage PHA teams to seek inherently safer safeguards to reduce risk. However, these approaches were never implemented until after the April 2010 incident. As discussed in Section 4.1.3, the CSB determined that implementing inherently safer design by using materials that are HTHA-resistant, such as stainless steel, is higher on the hierarchy of controls than post-weld heat treating or reliance upon inspections, and is therefore a better approach to prevent HTHA damage.

7.8.4 The General Duty Clause

Section 112(r)(1) of the Clean Air Act, known as the General Duty Clause, states the following:

> It is the objective of the regulations and programs authorized under this subsection to prevent the accidental release and to minimize the consequences of any such release of any substance listed pursuant to paragraph (3) or any other extremely hazardous substance. Owners and operators of stationary sources producing, processing, handling, or storing such stances under paragraph (3) have a general duty to identify hazards which may result from accidental releases using appropriate hazard assessment techniques, to design and maintain a safe facility

> taking such steps as are necessary to prevent releases, and to minimize the consequences of accidental releases which do occur.[247]

The General Duty Clause has been in effect since November 15, 1990, when Congress adopted the Clean Air Act Amendments of 1990. According to EPA guidance on the General Duty Clause, "EPA believes that owners and operators who have [] [extremely hazardous] substances must adhere, at a minimum, to recognized industry standards and practices (as well as any government regulations) in order to be in compliance with the general duty clause."[248] The EPA notes that to comply with the General Duty Clause, "many industries have developed standards and generally recognized safe practices to manage the risks associated with extremely hazardous substances."[249]

The application of IST is considered by many to be good industry practice. Yet inherent safety concepts are not enforced by the EPA through the General Duty Clause. According to process safety expert Dr. Paul Amyotte in a presentation at the CSB's April 2013 Chevron Interim Report Public Meeting in Richmond, California, there are numerous resources available on the topic of inherent safety, most of which are written by "industrial practitioners." The call for widespread use of inherently safer design principles in industry is being made mainly by people in industry.[250] For example, as discussed in Section 4.1.4, API RP 571 *Damage Mechanisms Affecting Fixed Equipment in the Refining Industry* implicitly supports the concept of inherently safer design by describing material selection to avoid HTHA failures, noting "300 Series SS, as well as 5Cr, 9Cr and 12Cr alloys, are not susceptible to HTHA at conditions normally seen in refinery units."[251] In addition, the CCPS has stated in its 2009 book *Inherently Safer Chemical Processes A Life Cycle Approach*, which was written by 18 committee members, 16 of which were listed as having affiliation with industrial companies, that the modern approach to chemical process safety "is to apply risk

Although inherently safer technology (IST) is the most effective major accident prevention approach in the hierarchy of controls, it is not enforced by the EPA through the General Duty Clause under the Clean Air Act.

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[247] 42 U.S.C. §7412(r)(1) (1990).

[248] EPA. *Guidance for Implementation of the General Duty Clause Clean Air Act Section 112(r)(1).* May 2000; p 2. http://www.epa.gov/oem/docs/chem/gdcregionalguidance.pdf (accessed January 23, 2014).

[249] *Ibid.*

[250] Dr. Paul Amyotte. Presentation to the U.S. Chemical Safety and Hazard Investigation Board Public Meeting to Release Interim Report and Safety Recommendations Resulting from Chevron Refinery Investigation. Richmond, CA April 19, 2013; p 2.

[251] API RP 571. *Damage Mechanisms Affecting Fixed Equipment in the Refining Industry.* 2003; page '5-83'.

management systems theory…[which] includes recognition of the hazards posted by the process, and a continual effort to analyze the risks, and to reduce or control them to the lowest levels practical….”[252]

7.8.5 The EPA’s Authority to Enforce Inherent Safety

The EPA has acknowledged that it has the authority to require the application of IST through the General Duty Clause. In an August 2013 letter responding to a Congressional inquiry that specifically asked, among other things, whether the EPA believes it “has the authority to mandate the use and/or consideration of Inherently Safer Technologies under Section 112(r) of the Clean Air Act[,]” EPA Assistant Administrator Mathy Stanislaus stated that the EPA has “broad authority to promulgate regulations for chemical accident prevention…” and can “consider factors such as facility design, equipment, and quantity of substances handled (and other factors).” He also stated that the EPA was currently evaluating various methods of improving increased chemical plant safety including safer management, increased preparedness management, and facility design and operations, and would also be examining best practices being utilized by industry leaders.

The EPA has the authority to require the application of IST through the General Duty Clause.

Others have argued that the EPA has additional authority under Clean Air Act section 112(r)(7)(A) to promulgate a new rule requiring industries to implement IST. This section authorizes the EPA Administrator to “promulgate release prevention, detection, and correction requirements which may include monitoring, record-keeping, reporting, training…and other design, equipment, work practice, and operational requirements.”[253] Section 112(r) further requires that the risk management plan include “safety precautions and maintenance, monitoring and employee training measures” to prevent accidental releases.[254] As described in Section 4.1.3, inherent safety and the hierarchy of controls are long established, widely recognized methods for achieving more effective safety precautions to prevent chemical accidents. Incorporating requirements for the implementation of inherent safety and the hierarchy of controls is not only consistent with the 112(r) proscribed features of the risk management plan but in fact serves to make the safety precautions more effective in preventing accidental releases.

Despite its acknowledged authority to do so, to date the EPA has not required industries to implement IST through either the creation of a new rule or the enforcement of the Clean Air Act General Duty Clause. In the wake of Bhopal and more recently the 9/11 tragedy, many groups have urged the EPA to create a new regulation requiring the implementation of IST or at a minimum, use its authority under the General Duty

[252] CCPS. *Inherently Safer Chemical Processes – A Life Cycle Approach.* 2nd ed.; 2009; p 9.
[253] 42 U.S.C. §7412(r)(7)(A) (1990).
[254] 42 U.S.C. §7412(r)(7)(B)(ii)(II) (1990).

Clause to require industries to implement IST. On March 14, 2012, the National Environmental Justice Advisory Council[255] (NEJAC) sent a letter to the EPA urging the agency to promulgate new rules or guidance to "utilize its authority under the 'General Duty Clause' of the 1990 Clean Air Act section 112(r) (also known as the Bhopal clause) to require covered chemical facilities to prevent, where feasible, catastrophic chemical releases."[256] The NEJAC noted that flaws in the chemical security law administered by the U.S. Department of Homeland Security (DHS) prohibited the agency from requiring the use of safer chemical processes at facilities. The group also reiterated that the EPA had made a proposal in 2002 to implement the General Duty Clause to make chemical plants safer. According to the proposal, chemical plants would be made "inherently safer by reducing quantities of hazardous chemicals handled or stored, substituting less hazardous chemicals for extremely hazardous ones, or otherwise modifying the design of processes to reduce or eliminate chemical hazards."[257] The NEJAC also stated that in 2003, the Government Accountability Office (GAO) concluded that the EPA could "'interpret the Clean Air Act's general duty clause to address chemical facility security… According to EPA, it would not have to make any regulatory changes as it currently implements the general duty clause through guidance... to address the specific threat of disastrous risks to vulnerable communities."[258] The NEJAC concluded by recommending that "EPA use its authority under the 1990 Clean Air Act, Section 112(r), to reduce or eliminate these catastrophic risks, where feasible, by issuing new rules and guidance to fully implement the General Duty Clause. This action would reduce the danger and imminent threat that chemical plants, chemical manufacturing, and the transport and storage of hazardous chemicals pose to environmental justice and communities."[259]

On July 25, 2012, the Coalition to Prevent Chemical Disasters[260] ("the Coalition") petitioned the EPA to "commence a rulemaking [pursuant to the Administrative Procedure Act (AP), 5 U.S.C. §553(e), and section 112(r)(7)(A)[261] of the Clean Air Act (CAA), 42 U.S.C. §7412(r)(7)(A)] to require the use of inherently safer technologies, where feasible, by facilities that use or store hazardous chemicals." The petition also requested that, pending completion of the rulemaking, EPA revise its guidance concerning

[255] NEJAC is a federal advisory committee to EPA that was established on September 30, 1993. It provides advice and recommendations about issues related to environmental justice. For more information *see* http://www.epa.gov/Compliance/ej/nejac/index.html (accessed January 24, 2014).

[256] *See* https://www.documentcloud.org/documents/332041-nejac-letter.html (accessed January 22, 2014).

[257] *Ibid.*

[258] *Ibid.*

[259] *Ibid.*

[260] The Coalition consists of over 100 organizations formed to prevent chemical disasters and protect workers. For more information *see* http://preventchemicaldisasters.org/ (accessed January 24, 2014).

[261] 42 U.S.C. §7412(r)(7)(A) states: "In order to prevent accidental releases of regulated substances, the Administrator is authorized to promulgate release prevention, detection, and correction requirements which may include monitoring, record-keeping, reporting, training, vapor recovery, secondary containment, and other design, equipment, work practice, and operational requirements. Regulations promulgated under this paragraph may make distinctions between various types, classes, and kinds of facilities, devices and systems taking into consideration factors including, but not limited to, the size, location, process, process controls, quantity of substances handled, potency of substances, and response capabilities present at any stationary source. Regulations promulgated pursuant to this subparagraph shall have an effective date, as determined by the Administrator, assuring compliance as expeditiously as practicable."

the enforcement of the CAA's general duty clause, section 112(r)(1), 42 U.S.C. §7412(r)(1), to "make clear that the duty to prevent releases of extremely hazardous substances includes the use, where feasible, of safer technologies to minimize the presence and possible release of hazardous chemicals."[262]

In the wake of the April 2013 explosion and fire that occurred at a facility in West, Texas, and resulted in fifteen fatalities and hundreds of injuries, President Obama issued Executive Order 13650 on August 1, 2013. It established the Chemical Facility Safety and Security Working Group, which includes OSHA and the EPA, and tasked the group with, among other things, developing options for enhancing and modernizing policies, regulations, and standards to improve the safety and security of chemical facilities.[263] A senior EPA official overseeing implementation of the Executive Order has stated the EPA is examining the successes of a New Jersey program that requires facilities to consider IST, such as safer chemicals, as a possible model for a federal IST policy.[264] New Jersey's 2008 IST rule has led facility owners and operators to take a "hard look at opportunities to reduce risk" at industrial plants.[265]

New Jersey is the only state that currently implements and enforces IST requirements.[266] The Toxic Catastrophe Prevention Act (TCPA) implements IST requirements in New Jersey, and covers approximately 90 facilities in the state.[267] An owner or operator of a covered facility must complete an IST review report and must submit it to the New Jersey Department of Environmental Protection (DEP). The report "…shall identify available inherently safer technology alternatives or combinations of alternatives that minimize or eliminate the potential for an EHS [extraordinarily hazardous substance] release."[268]

IST alternatives that are identified must be determined as "feasible" in order for implementation to be required. Feasible means "capable of being accomplished in a successful manner, taking into account environmental, public health and safety, legal, technological, and economic factors."[269] If IST is not implemented, they must provide a written justification using a qualitative and quantitative evaluation of

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262 https://www.documentcloud.org/documents/404584-petition-to-epa-to-prevent-chem-disasters-filed.html (accessed January 22, 2014).

263 *Improving Chemical Facility Safety and Security.* Exec. Order No. 13650, 78 Fed. Reg. 48029 (August 1, 2013). http://www.whitehouse.gov/the-press-office/2013/08/01/executive-order-improving-chemical-facility-safety-and-security (accessed January 24, 2014).

264 http://insideepa.com/Risk-Policy-Report/Risk-Policy-Report-12/03/2013/epa-looks-to-new-jersey-program-as-possible-model-for-ist-requirements/menu-id-1098.html (accessed January 22, 2014).

265 *Ibid.*

266 Contra Costa County, California has a guidance document entitled "Attachment C: Inherently Safer Systems Checklist" which is provided as a tool for facilities to utilize during the PHA process. The actual use of the checklist is not required. *See* http://cchealth.org/hazmat/pdf/iso/attachment_c.pdf (accessed April 17, 2013).

267 Under Title 7 of the New Jersey Administrative Code. *See* N.J.A.C. Section 7:31-4.12 (2010). Available at http://www.nj.gov/dep/rpp/brp/tcpa/downloads/conrulerev9_no%20fonts.pdf (accessed January 23, 2014).

268 N.J.A.C. Section 7:31-4.12 (d) (2010).

269 N.J.A.C. Section 7:31-1.5 (2010).

environmental, public health and safety, legal, technological, and economic factors. If they decide to implement the IST, they must provide a schedule of when they will do it.[270]

An update is required every five years for all covered processes and at the same time as the updates of applicable hazard reviews or process hazard analysis. An update of the IST review is also required when there is a major change. While New Jersey's IST rule contains positive features, it is primarily focused on the activity of the production of the IST report and lacks rigorous goal setting elements such as requiring facilities to reduce risks to as low as reasonably practicable, or ALARP or requiring that the use of IST prevent accidental chemical releases.

7.8.6 The Role of Inherent Safety in Major Accident Prevention

In 2011, Dr. Paul Amyotte released an article analyzing 63 CSB reports, studies, and bulletins resulting from CSB incident investigations to identify examples related to inherent safety and risk reduction measures. The article identified over 200 examples of the hierarchy of controls, with 36 percent of those being inherent safety.[271] He concluded that the CSB products contained numerous examples where the use of the hierarchy of controls, including inherent safety, would be helpful in reducing risk in the process industries.[272] The four main principles of inherent safety (minimization, substitution, moderation, and simplification) all play a role in the prevention and mitigation of process incidents.

Simply put, the CSB has investigated numerous major process safety incidents over the years, including the Chevron and Tesoro incidents, where the implementation of inherently safer design and materials of construction could have prevented the incident. The EPA should work with industry and stakeholders to develop and implement a new regulation requiring companies to use inherently safer systems analysis and the hierarchy of controls in establishing safeguards for identified process hazards to help prevent these major process safety incidents from occurring in the future. While the new regulation is being adopted, the EPA should use its existing authorities under the CAA General Duty Clause to implement inherently safer systems and the hierarchy of controls to the greatest extent feasible for chemical accident prevention.

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[270] N.J.A.C. Section 7:31-4.12 (e) and (f) (2010).

[271] Amyotte, Paul; MacDonald, Dustin K.; and Khan, Faisal I. *An Analysis of CSB Investigation Reports Concerning the Hierarchy of Controls.* 2011; p 1.

[272] *Ibid.*

8.0 Recommendations

Pursuant to its authority under 42 U.S.C. §7412(r)(6)(C)(i) and (ii), and in the interest of promoting safer operations at petroleum refineries and protecting workers and communities from future accidents both in the state of Washington and nationally, the CSB makes the following safety recommendations:

8.1 The U.S. Environmental Protection Agency

2010-08-I-WA-R1

Revise the Chemical Accident Prevention Provisions under 40 CFR Part 68 to require the documented use of inherently safer systems analysis and the hierarchy of controls to the greatest extent feasible when facilities are establishing safeguards for identified process hazards. The goal shall be to reduce the risk of major accidents to the greatest extent practicable, to be interpreted as equivalent to as low as reasonably practicable (ALARP). Include requirements for inherently safer systems analysis to be automatically triggered for all management of change, incident investigation, and process hazard analysis reviews and recommendations, prior to the construction of a new process, process unit rebuilds, significant process repairs, and in the development of corrective actions.

2010-08-I-WA-R2

Until Recommendation 2010-08-I-WA-R1 is in effect, enforce through the Clean Air Act's General Duty Clause, section 112(r)(1), 42 U.S.C. §7412(r)(1) the use of inherently safer systems analysis and the hierarchy of controls to the greatest extent feasible when facilities are establishing safeguards for identified process hazards.

2010-08-I-WA-R3

Develop guidance for the required use of inherently safer systems analysis and the hierarchy of controls for enforcement under 40 CFR Part 68 and the Clean Air Act's General Duty Clause, section 112(r)(1), 42 U.S.C. §7412(r)(1).

2010-08-I-WA-R4

Effectively participate in the Tesoro Anacortes Refinery process safety culture survey oversight committee as recommended under recommendation 2010-08-I-WA-R15. Incorporate the expertise of process safety culture experts in the development and interpretation of the safety culture surveys. Ensure the effective participation of the workforce and their representatives in the development of the surveys and the implementation of corrective actions.

8.2 Washington State Legislature, Governor of Washington

2010-08-I-WA-R5

Based on the findings in this report, augment your existing process safety management regulations for petroleum refineries in the state of Washington with the following more rigorous goal-setting attributes:

a. A comprehensive process hazard analysis written by the company that includes:

i. Systematic analysis and documentation of all major hazards and safeguards, using the hierarchy of controls to reduce those risks to as low as reasonably practicable (ALARP);

ii. Documentation of the recognized methodologies, rationale and conclusions used to claim that safeguards intended to control hazards will be effective;

iii. Documented damage mechanism hazard review conducted by a diverse team of qualified personnel. This review shall be an integral part of the Process Hazard Analysis cycle and shall be conducted on all PSM-covered process piping circuits and process equipment. The damage mechanism hazard review shall identify potential process damage mechanisms and consequences of failure, and shall ensure effective safeguards are in place to control hazards presented by those damage mechanisms. Require the analysis and incorporation of applicable industry best practices and inherently safer design to the greatest extent feasible into this review; and

iv. Documented use of inherently safer systems analysis and the hierarchy of controls to the greatest extent feasible in establishing safeguards for identified process hazards. The goal shall be to drive the risk of major accidents to As Low As Reasonably Practicable (ALARP). Include requirements for inherently safer systems analysis to be automatically triggered for all Management of Change and Process Hazard Analysis reviews, prior to the construction of new processes, process unit rebuilds, significant process repairs, and in the development of corrective actions from incident investigation recommendations.

b. A thorough review of the comprehensive process hazard analysis by technically competent regulatory personnel;

c. Required preventative audits and preventative inspections by the regulator;

d. Require that all safety codes, standards, employer internal procedures and recognized and generally accepted good engineering practices (RAGAGEP) used in the implementation of the regulations contain adequate minimum requirements;

e. Require an increased role for workers in management of process safety by establishing the rights and responsibilities of workers and their representatives on health and safety-related matters, and the election of safety representatives and establishment of safety committees (with equal representation between management and labor) to serve health and safety-related functions. The elected representatives should have a legally recognized role that goes beyond consultation in activities such as the development of the comprehensive process hazard analysis, management of change, incident investigation, audits, and identification and effective control of hazards. The representatives should also have the authority to stop work that is perceived to be unsafe or that presents a serious hazard until the regulator intervenes to resolve the safety concern. Workforce participation practices should be documented by the company to the regulator; and

f. Requires reporting of information to the public to the greatest extent feasible such as a summary of the comprehensive process hazard analysis which includes a list of safeguards implemented and standards utilized to reduce risk, and process safety indicators that demonstrate the effectiveness of the safeguards and management systems.

2010-08-I-WA-R6

Establish a well-funded, well-staffed, technically qualified regulator with a compensation system to ensure the Washington Department of Labor and Industries regulator has the ability to attract and retain a sufficient number of employees with the necessary skills and experience to ensure regulator technical qualifications. Periodically conduct a market analysis and benchmarking review to ensure the compensation system remains competitive with Washington petroleum refineries.

2010-08-I-WA-R7

Work with the regulator, the petroleum refining industry, labor, and other relevant stakeholders in the state of Washington to develop and implement a system that collects, tracks, and analyzes process safety leading and lagging indicators from operators and contractors to promote continuous process safety improvements. At a minimum, this program shall:

a. Require the use of leading and lagging process safety indicators to actively monitor the effectiveness of process safety management systems and safeguards for major accident prevention. Include leading and lagging indicators that are measureable, actionable, and standardized. Include indicators that measure safety culture, such as incident reporting and action item implementation culture. Require that the reported data be used for continuous process safety improvement and accident prevention;

b. Analyze data to identify trends and poor performers and publish annual reports with the data at facility and corporate levels;

c. Require companies to publicly report required indicators annually at facility and corporate levels;

d. Use process safety indicators (1) to drive continuous improvement for major accident prevention by using the data to identify industry and facility safety trends and deficiencies and (2) to determine appropriate allocation of regulator resources and inspections; and

e. Be periodically updated to incorporate new learning from world-wide industry improvements in order to drive continuous major accident process safety improvements in Washington.

8.3 Washington State Department of Labor & Industries - Division of Occupational Safety and Health

2010-08-I-WA-R8

Perform a verification audit at all Washington petroleum refineries to ensure:

a. Prevention of HTHA equipment failure and safe operation of the equipment. Audit HTHA prevention and process condition monitoring techniques used at all Washington petroleum refineries. Verify that all affected equipment in use meets the requirements contained in Recommendation 2010-08-I-WA-R10;

b. For nonroutine work, a written hazard evaluation is performed by a multidisciplinary team and, where feasible, conducted during the job planning process prior to the day of the job execution. Verify that each facility has an effective written decision-making protocol used to determine when it is necessary to shut a process down to safely perform work or conduct repairs. Ensure the program reflects the guidance in the CCPS *Risk Based Process Safety* book related to hazardous nonroutine work; and

c. Effective programs are in place to control of the number of essential personnel present during all hazardous nonroutine work.

2010-08-I-WA-R9

Effectively participate in the Tesoro Anacortes Refinery process safety culture survey oversight committee as recommended under recommendation 2010-08-I-WA-R15. Incorporate the expertise of process safety culture experts in the development and interpretation of the safety culture surveys. Ensure the effective participation of the workforce and their representatives in the development of the surveys and the implementation of corrective actions.

8.4 American Petroleum Institute

2010-08-I-WA-R10

Revise American Petroleum Institute API RP 941*: Steels for Hydrogen Service at Elevated Temperatures and Pressures in Petroleum Refineries and Petrochemical Plants* to:

a. Clearly establish the minimum necessary “shall” requirements to prevent HTHA equipment failures using a format such as that used in *ANSI/AIHA Z10-2012, Occupational Health and Safety Management Systems;*

b. Require the use of inherently safer materials to the greatest extent feasible;

c. Require verification of actual operating conditions to confirm that material of construction selection prevents HTHA equipment failure; and

d. Prohibit the use of carbon steel in processes that operate above 400 ºF and greater than 50 psia hydrogen partial pressure.

2010-08-I-WA-R11

Revise American Petroleum Institute API RP 581: *Risk-Based Inspection Technology* to:

a. Clearly establish the minimum necessary “shall” requirements to prevent HTHA equipment failures using a format such as that used in *ANSI/AIHA Z10-2012, Occupational Health and Safety Management Systems;*

b. Prohibit the use of carbon steel in processes that operate above 400 ºF and greater than 50 psia hydrogen partial pressure; and

c. Require verification of actual operating conditions to determine potential equipment damage mechanisms.

8.5 Tesoro Refining & Marketing Company LLC

2010-08-I-WA-R12

Actively participate with API in the completion of recommendation 2010-08-I-WA-R10. Document this participation.

2010-08-I-WA-R13

Once recommendation 2010-08-I-WA-R12 is in effect, develop and implement a plan to meet the requirements established through the acceptable completion of recommendation 2010-08-I-WA-R10. Document the implementation of the plan and the corrective actions taken.

2010-08-I-WA-R14

Revise and improve the Process Hazard Analysis (PHA), the Integrity Operating Window (IOW), and the damage mechanism hazard review (DMHR) programs and cross-linking among these three programs such that all identified hazards are effectively managed in each program. For all Tesoro refineries require:

a. the IOW to review damage mechanism hazards from the most recent PHA and safeguards identified to control these hazards;

b. the IOW review or revalidation to be conducted at least every five years;

c. the IOW to analyze and incorporate applicable industry best practice, the hierarchy of controls, and inherently safer design to the greatest extent reasonably practicable;

d. the DMHR report to be developed by the DMHR team and not just the "corrosion expert;"

e. the DMHR team to review the operating data to verify an accurate understanding of how the data was obtained, what it represents, and that it appropriately addresses both routine and nonroutine operations;

f. the DMHR and/or IOW review to identify and review gaps between current industry best practices and existing Tesoro practices with regard to material selection and process controls and make recommendations that reduce risks from damage mechanism hazards;

g. the DMHR and IOW review to review applicable Tesoro and industry-wide damage mechanism incidents as part of the respective DMHR or IOW review;

h. the DMHR to review relevant MOCs to fully evaluate the impact of the MOC on damage mechanism hazards;

i. the identification of minimum qualifications for the "corrosion expert" and ensure that the DMHR team has the necessary skills to meet these requirements;

j. for sites that have a corrosion/materials engineer, the corrosion/materials engineer shall be a required participant in the DMHR;

k. the PHA to review the most recent DMHR and IOW reviews in order to contain a complete record of all identified damage mechanism hazards, evaluate existing safeguards, and propose new safeguards to control the identified hazards;

l. the PHA to review the consequence of damage mechanism hazards identified in the risk-based inspection (RBI) program and IOW reviews to ensure effective safeguards are present to control the damage mechanism hazard; and

m. the PHA to use the hierarchy of controls and implement opportunities for inherently safer design to the greatest extent reasonably practicable.

8.6 Tesoro Anacortes Refinery

2010-08-I-WA-R15

Implement a process safety culture continuous improvement program at the Tesoro Anacortes Refinery including a written procedure for periodic process safety culture surveys across the work force. The process safety culture program shall be overseen by a tripartite committee of Tesoro management, USW representatives, Washington State Department of Labor and Industries – Division of Occupational Safety and Health, and the U.S. Environmental Protection Agency. This oversight committee shall:

a. Select an expert third party that will administer a periodic process safety culture survey;

b. Review and comment on the third party expert report developed from the survey;

c. Oversee the development and effective implementation of action items to address identified process safety culture issues; and

d. Develop process safety culture indicators to measure major accident prevention performance.

The process safety program shall include a focus on items that measure, at a minimum, willingness to report incidents, normalization of hazardous conditions, burden of proof of safety in plant process safety programs and practices, and management involvement and commitment to process safety. The periodic process safety culture report shall be made available to the plant workforce. The minimum frequency of process safety culture surveys shall be at least once every three years.

8.7 United Steelworkers Local 12-591

2010-08-I-WA-R16

Effectively participate in the Tesoro Anacortes Refinery process safety culture survey oversight committee as recommended under recommendation 2010-08-I-WA-R15.

Appendix A AcciMap Causal Analysis

The CSB team has developed an accident map (AcciMap) as a visual depiction of the casual factors of the April 2, 2010 Tesoro Anacortes Refinery explosion and fire (Figure 36).[273] An AcciMap is a multi-layered causal diagram that provides visualization of higher level causes at the company, industry and governmental levels. This diagram is especially useful for developing broadly applicable recommendations for accident prevention, [274] and includes five levels:

- *Outcome:* Consequences of the incident
- *Physical Events and Conditions:* The immediate causes of the incident.[275]
- *Tesoro:* Latent causes of the incident associated with company rules and policies.
- *Industry Codes and Standards:* Latent causes of the incident associated with industry recommended practices, codes, and standards.
- *Government:* Latent causes associated with government laws and legislation developed to manage highly hazardous industries.

[273] A full-size, high resolution version of the Tesoro AcciMap is located on the CSB website.

[274] The AcciMap tool was developed by Jens Rasmussen and popularized by Andrew Hopkins. Rasmussen, J., &. A. Hopkins. *Risk Management in a Dynamic Society: A Modeling Problem.* Safety Science, 27 (2.3), 1997; pp 183-213

[275] Immediate causal factors are the actions and conditions that directly lead to the consequence. However, while understanding immediate causal factors is vital, they are typically symptoms of systemic, or latent, causal factors. Latent causal factors are the pre-actions and pre-conditions that enabled the immediate causal factors to occur. It is these latent causal factors that must be alleviated in order to provide broad corrective change and prevent recurrence of similar incidents.

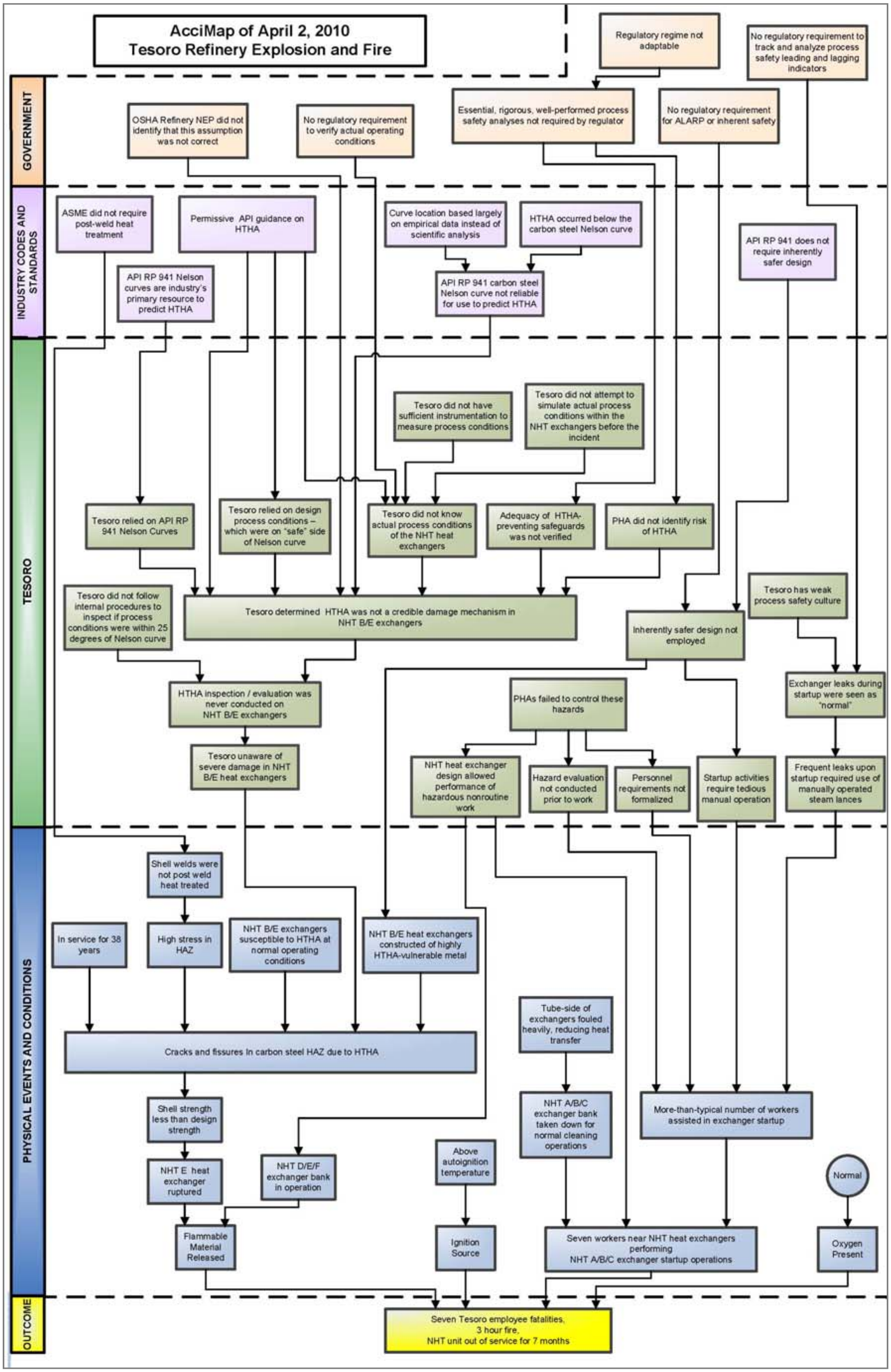

Figure 36. AcciMap of April 2, 2010 Tesoro Anacortes Refinery Explosion and Fire

A.1 AcciMap Outcomes

Seven Tesoro operations personnel were fatally injured following the sudden catastrophic failure of the in-service E heat exchanger that resulted in an explosion and fire. The fire burned for more than three hours and resulted in a seven month shutdown.

A.2 Physical Events and Conditions

The explosion and fire resulted from the sudden catastrophic rupture of the E heat exchanger, releasing flammable material that ignited likely because it was above its autoignition temperature.

The seven fatally-injured employees, a more-than-typical number of workers for this job, were in the process of putting a bank of three heat exchangers (A/B/C) back in service. These heat exchangers were taken out of service several days before the incident for a maintenance cleaning operation to remove fouling, a deposit that greatly reduced heat transfer efficiency of the heat exchangers. While the A/B/C bank of heat exchangers was being cleaned, the NHT Unit continued to operate on the other bank, a matching series of three heat exchangers (D/E/F).

When returning the three clean heat exchangers back to service, the middle heat exchanger of the D/E/F heat exchanger bank (the E heat exchanger) catastrophically ruptured. Post-incident metallurgical analysis determined that the E heat exchanger ruptured because of an advanced stage of HTHA. The HTHA occurred in both the B and E heat exchangers in the high stress, non post-weld heat-treated welds. The heat exchangers were in service for 38 years and were constructed of carbon steel, a material that is highly vulnerable to HTHA damage.

A.3 Tesoro

The intention of the established Tesoro procedures for startup of a bank of these heat exchangers was to require only one operator to be in the unit for the startup activity that was proceeding at the time of the incident. However, the more common practice was for additional operators to assist with this physical, labor-intensive startup activity. On the night of the incident, the operations supervisor requested five additional personnel to assist with the startup. All seven were present at the time of the incident and were working near the site of the explosion and fire.

During startups of these heat exchangers, Tesoro routinely relied on the addition of ad hoc operations staff from other nearby operating units. This use of such additional personnel was explained as a result of both a collaborative culture and a need driven by task requirements. The startup of the heat exchangers required coordinated manual labor. In addition, a history of leaks was seen by the company as “normal” because of the high frequency of such leaks. The mitigation of these leaks required personnel standing by with steam lances, which some of the additional workers were likely doing on the night of the incident.

The startup of the NHT heat exchangers was hazardous nonroutine work. Leaks routinely developed that posed hazards to workers conducting the startup activities. Shell Oil and Tesoro PHAs at the refinery repeatedly failed to ensure that these hazards were controlled and that the number of workers exposed to these hazards was minimized.

Tesoro was not aware of the severe HTHA damage in the B and E heat exchangers because it never performed any type of HTHA examination of the heat exchangers. Tesoro took this approach because corrosion experts had concluded HTHA was not a credible damage mechanism in these heat exchangers. This conclusion was based on a combination of reliance on the carbon steel Nelson curve (which the CSB has found to be unreliable) and a lack of knowledge of the actual operating conditions of the NHT heat exchangers. Instead of monitoring or modeling process conditions for use in PHAs and damage mechanism reviews, corrosion experts relied on process design data that suggested a lower HTHA susceptibility than indicated by the CSB modeling estimates. Therefore, these opportunities to identify the risks of HTHA were unsuccessful in preventing the April 2010 incident.

A.4 Industry Codes and Standards

API RP 941 is the industry standard for preventing equipment failure from HTHA by establishing equipment operating limits. This standard contains empirical industry HTHA experience based on temperature and hydrogen partial pressure. It notes operating boundaries at locations where various materials of construction have failed because of HTHA and where they apparently have not failed. Over the years, the boundaries have become more conservative in response to industry failures that occurred outside of the previously experienced operating limits.

API RP 941 is written with permissive language. It is presented as a guideline that “is often used when selecting materials in hydrogen service.” It is also described as “an aide for materials selection.” API RP 941 does not establish minimum requirements to prevent HTHA failures:

- There are no minimum requirements for performing HTHA susceptibility evaluations.
- There are no minimum requirements for selection of materials of construction to ensure that inherently safer design is employed.

Analysis of the metal recovered from the B and E heat exchanger shell walls revealed a significant occurrence of HTHA well within the “safe” operating limits established by API RP 941, indicating that the current location of the carbon steel Nelson curve cannot be trusted to prevent equipment failure and cannot be relied on to predict the occurrence of HTHA. Damage from HTHA was occurring in portions of the B and E heat exchangers that CSB process modeling determined were operating as much as 120 °F degrees below the carbon steel Nelson curve.

Other industry standards, such as API RP 581, offer guidance on how to predict, mitigate, and control the occurrence of HTHA. However, such standards share similar weaknesses with API RP 941. API 581 does not require verification of actual operating conditions when identifying applicable damage mechanisms. API RP 581 calculations to determine susceptibility of equipment to HTHA confirmed that the B and E heat exchangers were not susceptible to HTHA.

A.5 Government

The existing federal and state of Washington regulations for PSM of highly hazardous chemicals were not sufficient to prevent this incident as they were primarily activity based and did not focus on specific risk reduction (such as ALARP), inherently safer design, require leading and lagging process safety indicators, or require continuous improvement. For example, the unit PHA ineffectively identified and managed hazards, but its completion still satisfied the state of Washington's PSM standard. In addition, despite its ability to do so, the EPA does not require facilities to analyze opportunities to implement inherently safer design.

The state of Washington's L&I completed a formal inspection of the CR and NHT process units as part of the OSHA Refinery NEP in March 2009, just more than one year before the incident. However, the NEP inspection lacked the level of detail required to detect the technical deficiencies in the Tesoro refinery's mechanical integrity program. No HTHA issues were identified, and no citations relating to the E heat exchanger were issued. The state of Washington did not have sufficient personnel resources with the required technical knowledge and experience to seek out and oversee the highly technical area of failure mechanisms. The state of Washington has only four PSM specialists in its compliance section to regulate nearly 270 PSM-covered facilities, including five petroleum refineries.

Appendix B NHT A/B/C Heat Exchanger Startup Trend Data

Trends of tube-side outlet temperatures are shown in Figure 38 through Figure 41 for the night of the incident and for the three previous startups for the A/B/C heat exchangers. The locations of the two temperature measurements are shown in Figure 37.

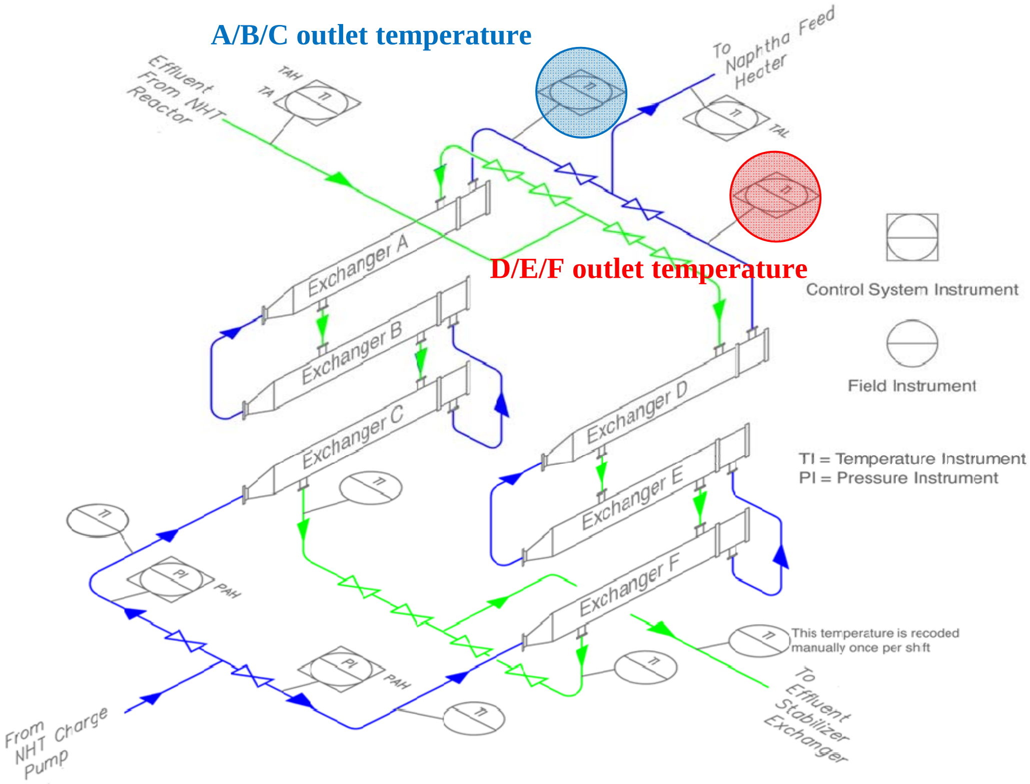

Figure 37. Location of the Two Outlet Temperature Measurements

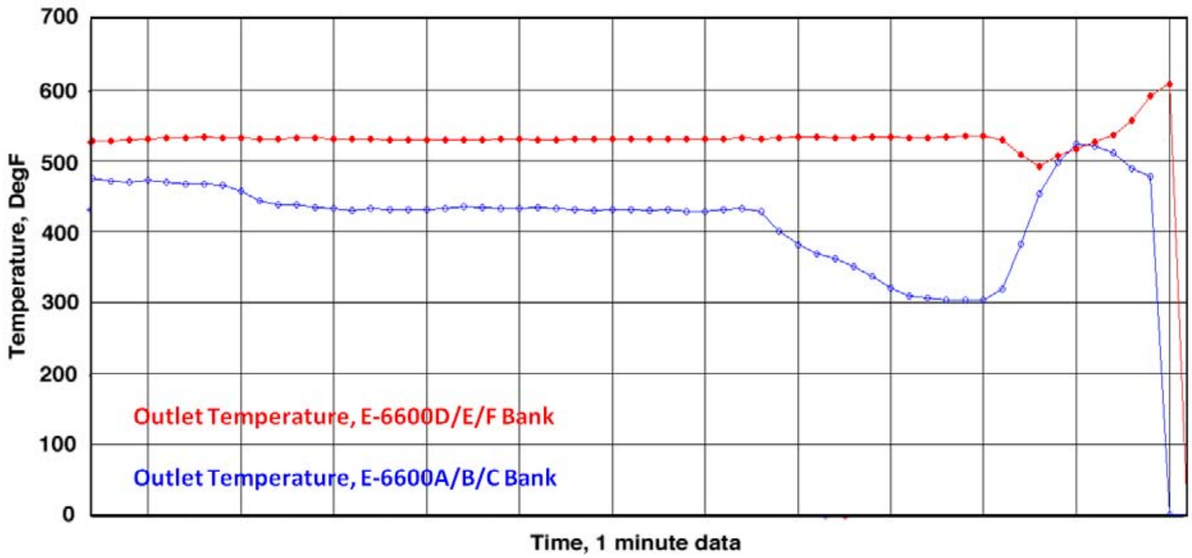

Figure 38. Temperature Data During NHT A/B/C Heat Exchanger Bank Startup on Night of the Incident

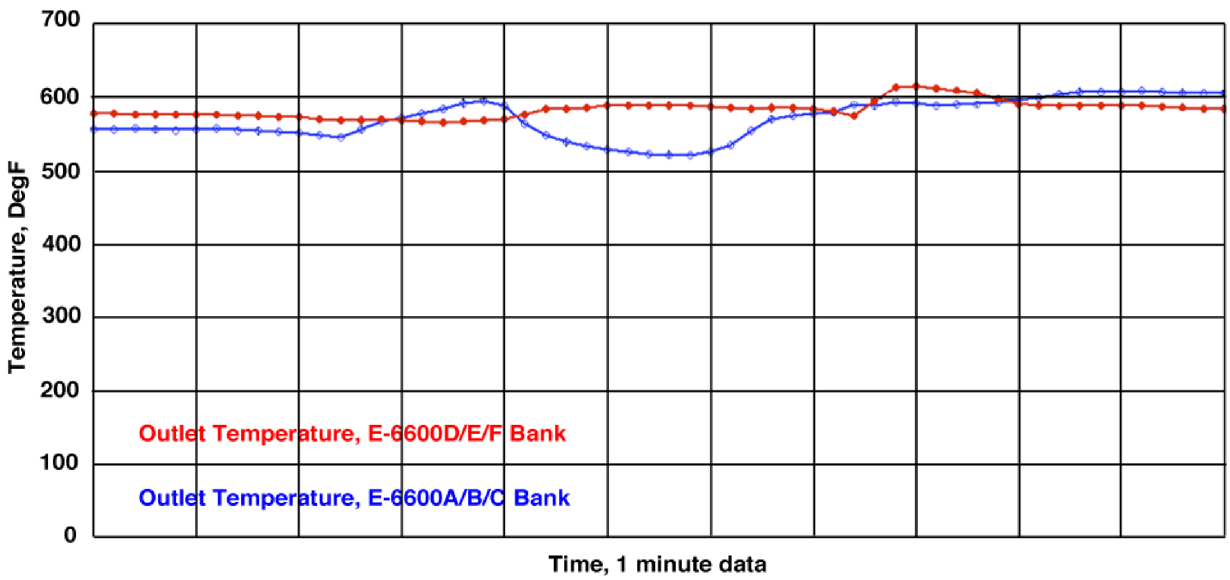

Figure 39. Temperature Data During NHT A/B/C Heat Exchanger Bank Startup on August 29, 2009

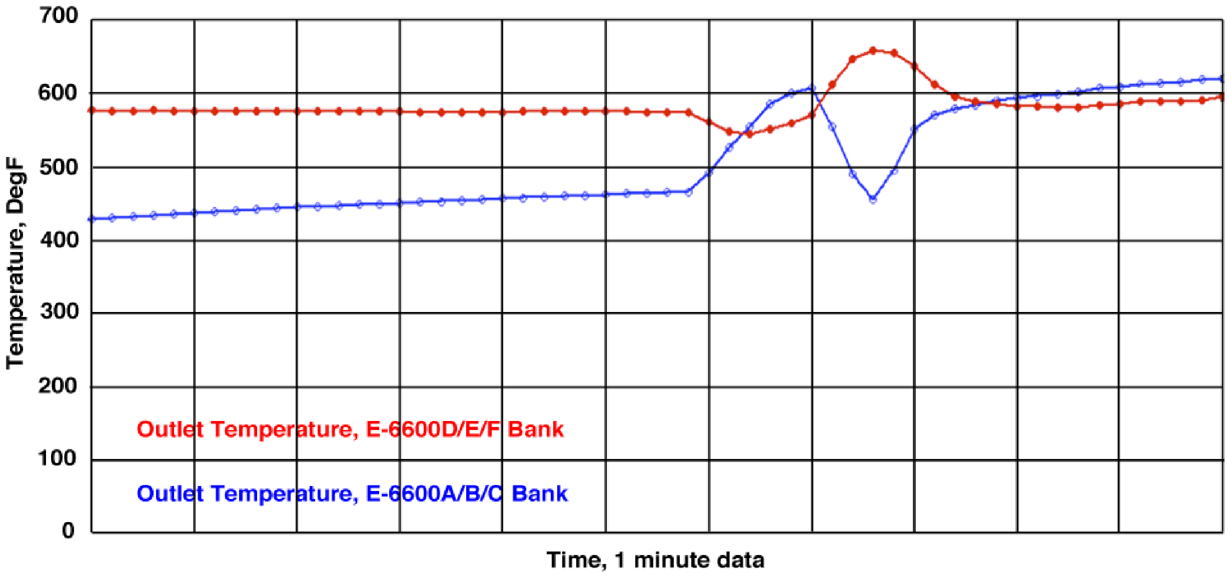

Figure 40. Temperature Data During NHT A/B/C Heat Exchanger Bank Startup on April 2, 2009

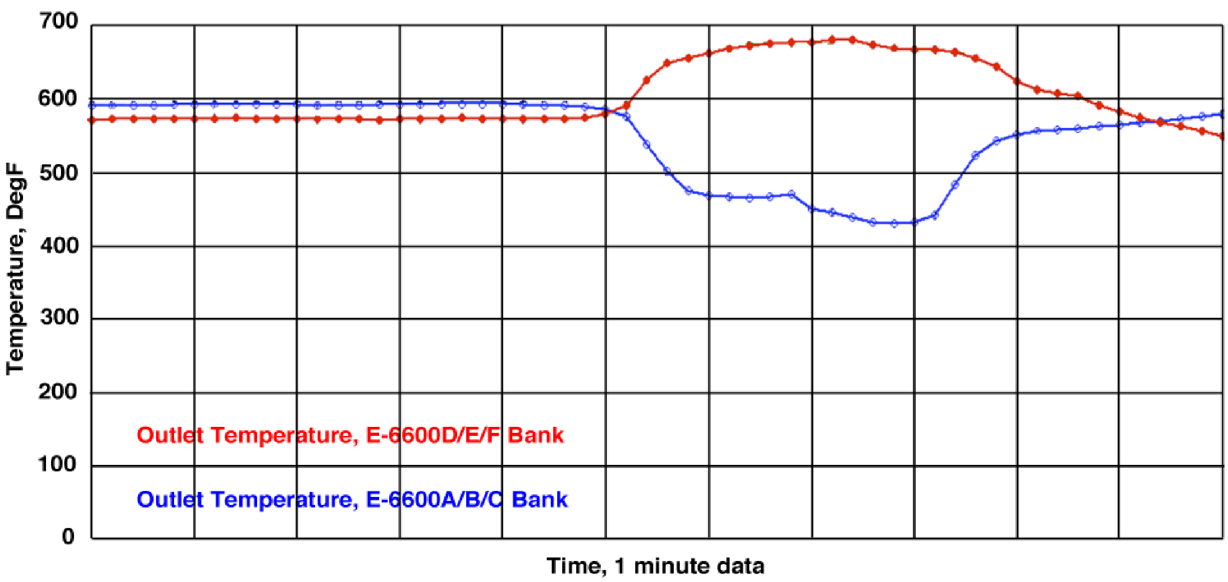

Figure 41. Temperature Data During NHT A/B/C Heat Exchanger Bank Startup on February 3, 2008

Appendix C CSB Simulation of the NHT Heat Exchangers

C.1 Background

Process conditions (temperature, pressure, flow, and composition data) were available for the NHT feed streams entering and exiting the two banks of the NHT heat exchangers (Figure 42). However, the system lacked instrumentation between the individual heat exchangers. Therefore, the actual process conditions of the fluid entering and exiting the B and E heat exchangers were not available. The CSB used the *Aspen HYSYS®* and *Aspen Exchanger Design and Rating* process simulation computer software to model the A/B/C and D/E/F heat exchanger banks for estimating process conditions in the B and E heat exchangers where HTHA occurred.

Of particular importance was the capability to model the qualitative fouling observations documented by Shell Oil workers.[276] These observations indicate that the heat exchangers primarily fouled within the tubes. The observations also indicate that fouling in the A and D tubes was “Heavy”, fouling in the B and E tubes was “Moderate”, and fouling in the C and F tubes was “Light.”[277] The documented observations show that the shell-side of the NHT heat exchangers experienced the formation of a light scale.

[276] These observations were made when Shell Oil owned the refinery.

[277] Other qualitative descriptions were also noted. However, these conditions were most frequently reported.

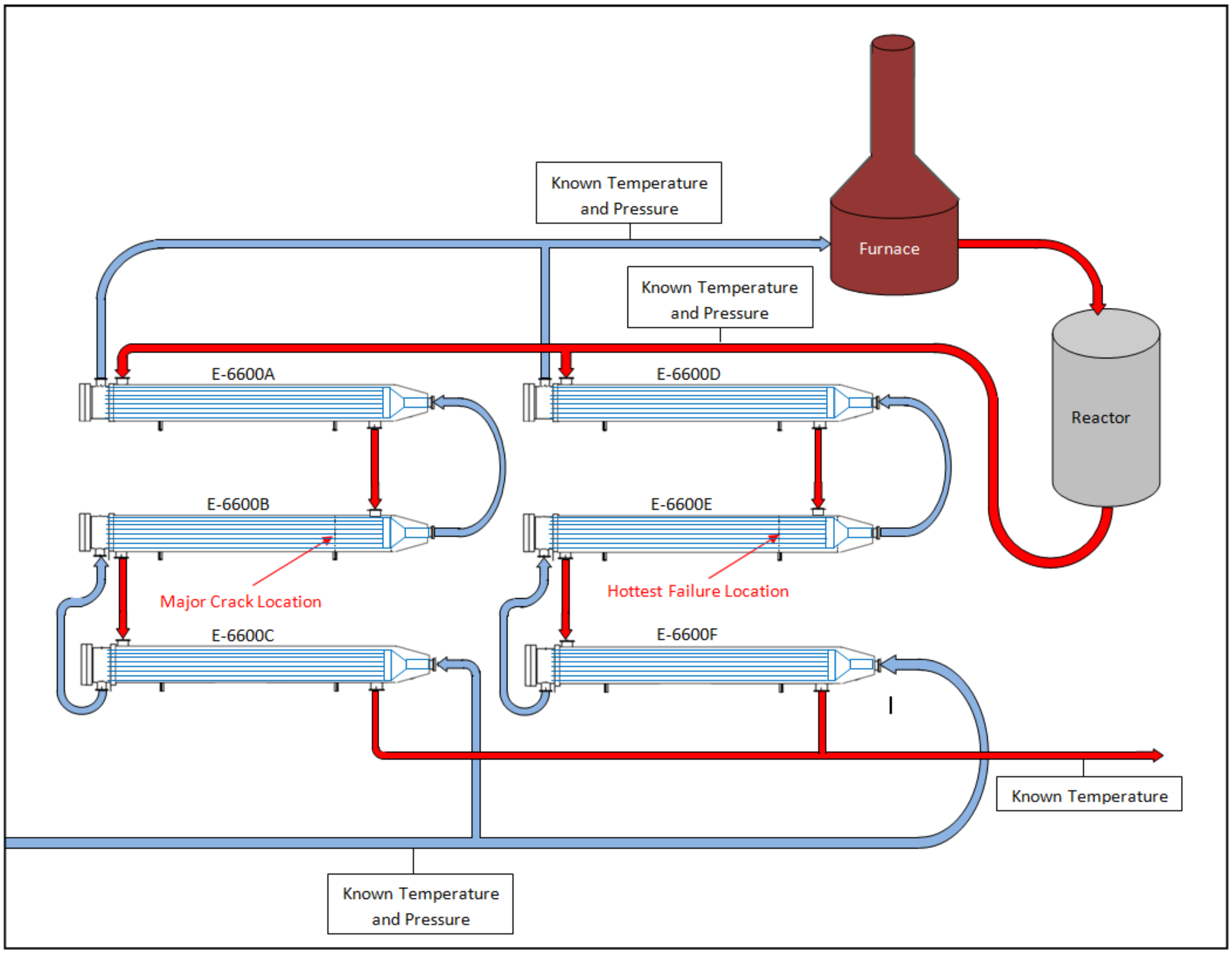

Figure 42. NHT Heat Exchanger Configuration with Known Process Conditions Indicated

C.2 Modeling Approach

The computer program *Aspen Exchanger Design and Rating* is a tool that allows the development of a rigorous mechanical model of a heat exchanger based on the actual mechanical details. The heat exchanger design data entered into the program included specific construction details such as the heat exchanger type; the shell dimensions; the number, diameter, and length of tubes; the baffle configuration; and the material of construction.

The model developed using *Aspen Exchanger Design and Rating* was then used as an input to another Aspen computer program, *Aspen HYSYS*®. This software provides the capability to combine the heat exchanger mechanical model into a process model of an entire section of a refinery process, such as the NHT heat exchangers. Model inputs include data from the process, such as flow rates, temperature, pressures, process compositions and process physical properties. The CSB used the *Aspen HYSYS*®

model to simulate past performance of the NHT feed/effluent heat exchangers. Historical DCS data and composition data were input into the model to reflect actual operating conditions.

C.3 Fouling Distribution

A key focus of the CSB modeling effort was to estimate operating conditions of the heat exchangers when they were fouled. Fouling results in higher shell-side temperatures, and the potential for HTHA would have been most severe during higher-temperature periods. The model includes input parameters, called *fouling resistance*, for estimating heat exchanger fouling. The CSB calibrated these fouling parameters by matching actual operating data under fouled conditions. Next, the CSB apportioned the level of fouling among the various heat exchangers. In both the model results and the data for actual heat exchangers in the unit, distribution of fouling among the A/D, B/E, and C/F heat exchanger tubes greatly affects the process conditions within the B and E heat exchangers.

Because actual fouling distribution throughout the heat exchangers was not known, the CSB performed a sensitivity analysis of possible fouling distributions on the tube-side of the heat exchangers to approximate conditions that existed based on the available qualitative visual observations. For example, these observations described a uniformly light scale on the shell-side of each heat exchanger. As a result, a constant, light fouling resistance was incorporated in the model to represent this light scale. Qualitative observations also described fouling inside the tubes, with the extent of observed fouling increasing from C/F to B/E and then to A/D. The tube-side fouling distributions analyzed for the sensitivity analysis are shown in Figure 43. Distribution 2 was selected for the model because it best matched the overall documented observations of heat exchanger fouling.

	Percent fouling resistance in A/D exchangers	Percent fouling resistance in B/E exchangers	Percent fouling resistance in C/F exchangers
Distribution 1	60%	30%	10%
Distribution 2	55%	32.5%	12.5%
Distribution 3	50%	35%	15%

Figure 43. NHT Heat Exchanger Fouling Distributions Analyzed

A schematic of how these distributions may appear visually is shown in Figure 44.

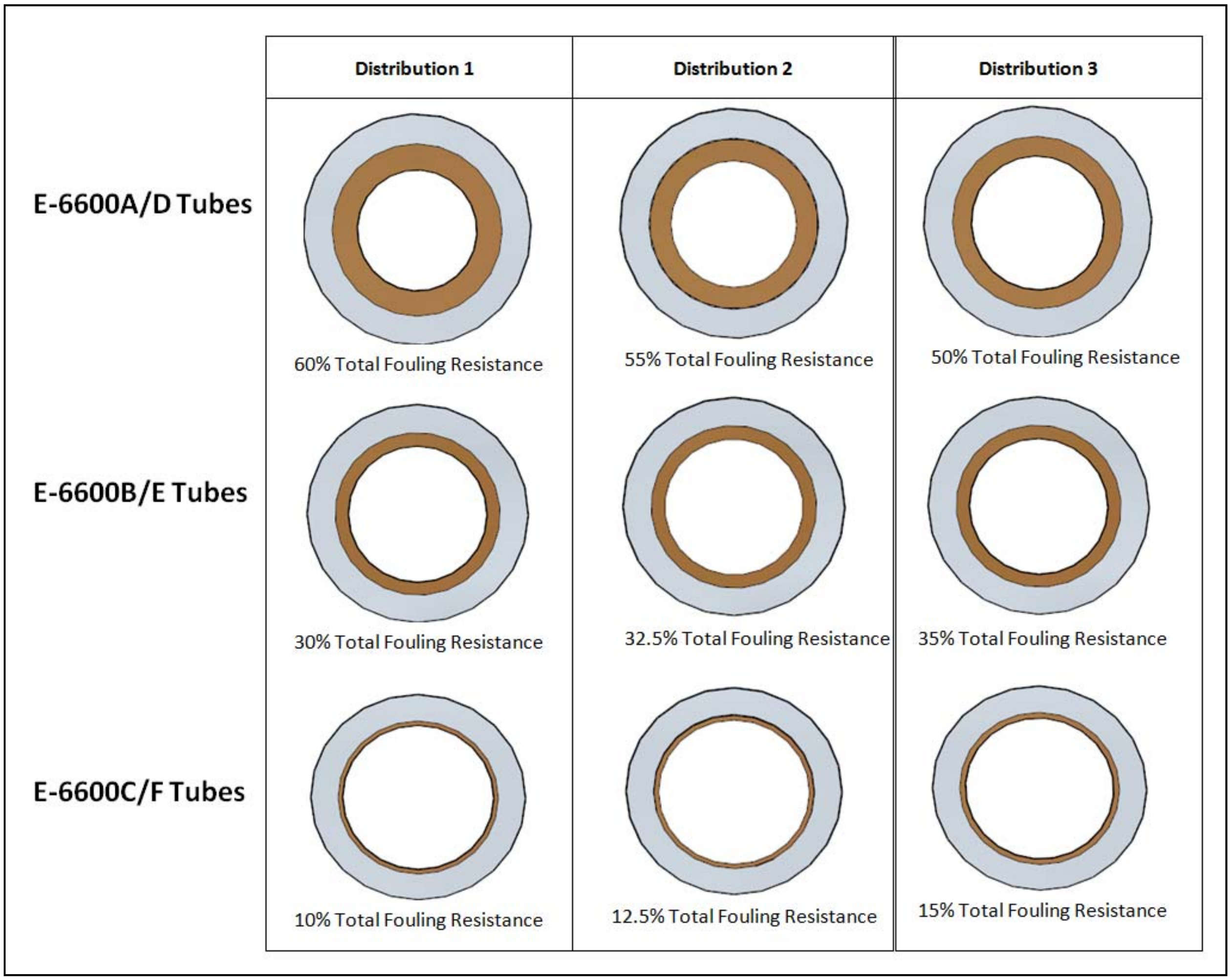

Figure 44. Visualization of Possible Tube-Side Fouling Distributions

C.4 DCS Data and Composition Data Availability

The necessary DCS and fluid composition data needed to model the heat exchangers were only available between 2007 and 2010.[278] As a result, all modeled values represent estimates of process conditions causing HTHA from 2007 through 2010. HTHA degradation of the B and E heat exchangers during this time period is likely because the heat exchangers had experienced higher temperature and greater mechanical stress in the 2007 to 2010 time period than on the night of the incident.[279]

[278] The Tesoro Anacortes, Washington refinery first installed its DCS system in 2002. However, not all variables necessary for process simulation of the NHT heat exchangers were measured until 2007.

[279] On February 23, 2008, the D/E/F heat exchanger tube outlet temperature increased by 100 °F over a 10 minute period before being brought down for a cleaning operation, reaching a maximum temperature of 681 °F. On August 22, 2009, during a startup of the D/E/F heat exchanger bank following a cleaning operation, the D/E/F exchanger bank tube outlet temperature increased by 100 °F over a four minute period, reaching a maximum temperature of approximately 641 °F during the startup. Other high-stress events during exchanger

The CSB modeled 10 days of operation during this 2007 to 2010 time period. Two of the periods modeled were characterized by clean heat exchanger conditions; during three of the periods modeled, middle-of-run operation conditions existed; and five of the periods modeled were characterized by fouled heat exchanger conditions near the end of a run.

C.5 Calibration of Model with Actual Process Data

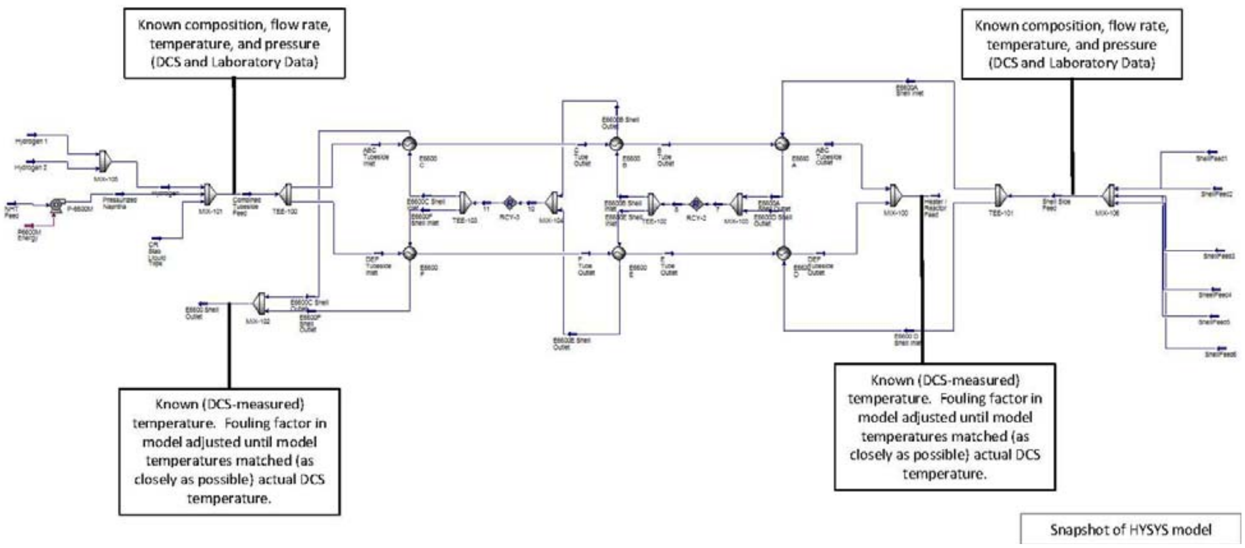

Figure 45. Calibration of HYSYS Model with Actual Process Data. The fouling resistances (fouling factors), maintaining the 55%, 32.5%, 12.5% split, were adjusted until the tube-side and shell-side outlet model temperature results closely matched actual DCS-measured temperatures.

Shown in Figure 45, actual composition data, flow rates, temperatures, and pressures were available for the process fluid entering both the tube-side and shell-side of the heat exchanger banks. Measured temperature values were available for the fluid exiting both the tube-side and shell-side of the heat exchanger banks. The fouling resistances (fouling factors) were adjusted in the model, maintaining the 55%, 32.5%, and 12.5% split until the model's tube and shell outlet temperatures closely matched the actual, measured process temperatures. This method resulted in an average of 2.5% error between the model's outlet temperatures and the actual, measured tube and shell outlet temperatures. The temperature profile of the B and E heat exchangers was then analyzed to determine temperatures and hydrogen partial pressures along the length of the heat exchangers.

startup are also shown in Appendix B. The E heat exchanger did not rupture as a result of the temperature and mechanical stresses of these startups.

C.6 Modeling Results

The resulting plot of modeled operating conditions of the B and E heat exchangers is shown in Figure 46, which illustrates the full operating region of the B and E heat exchangers, the operating conditions at the rupture location, and the operating conditions at the CS2 seam (the coldest location where signs of HTHA were evident in the E heat exchanger). All graphed regions use the Distribution 2 fouling allocation.

The estimated operating regions for the stainless steel clad portion of the B and E heat exchangers extended above the carbon steel Nelson curve. At the rupture location, the estimated operating conditions are just below the carbon steel Nelson curve. Model results for the coldest area of the E heat exchanger where signs of HTHA were evident (the CS2 weld between Cans 1 and 2) indicate HTHA damage in equipment that operated between 70 °F to 120 °F below the carbon steel Nelson curve. All graphed regions use the Distribution 2 fouling allocation. The model results illustrate the imprecision of the carbon steel Nelson curve.

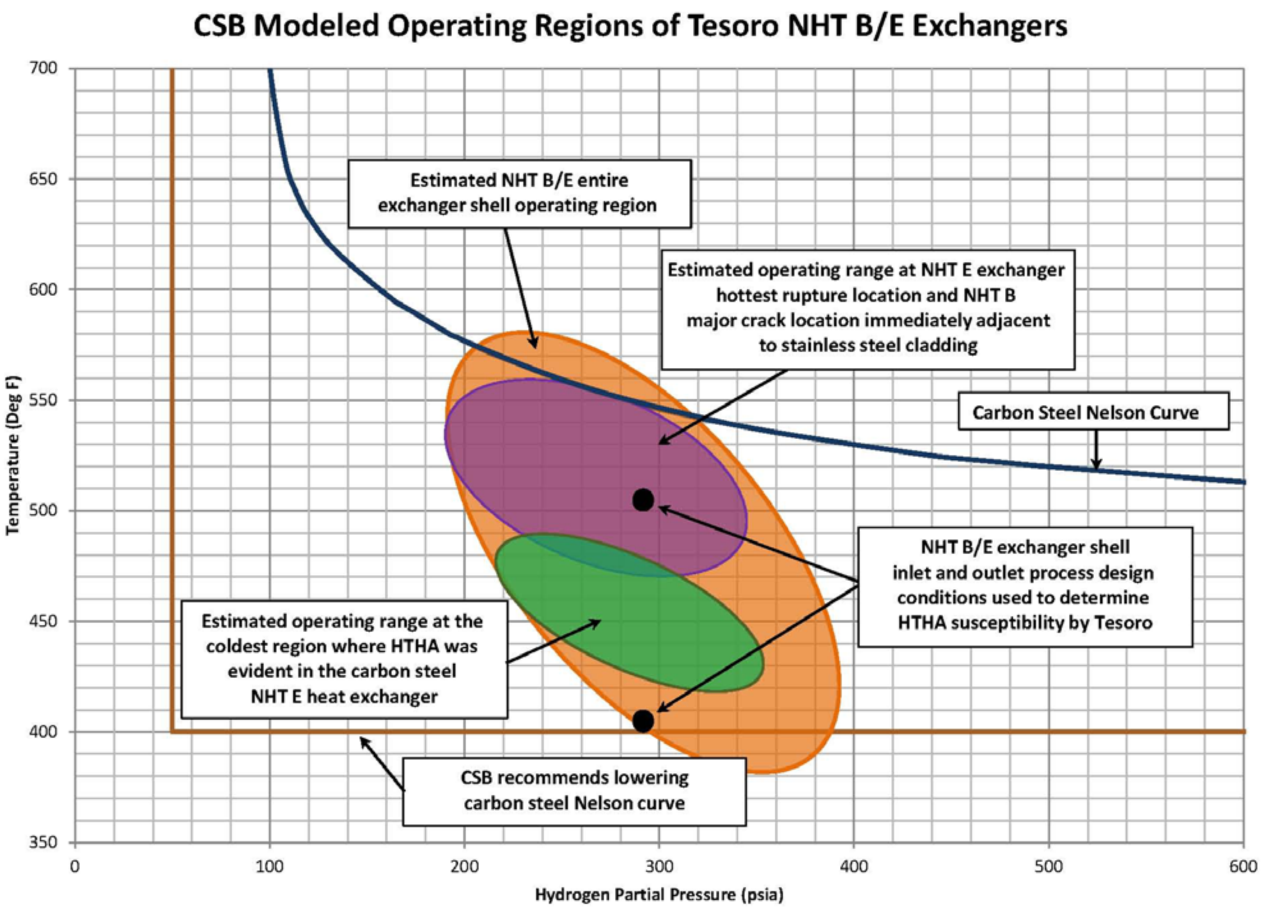

Figure 46. Estimated Operating Conditions of the B and E Heat Exchangers

Appendix D Evaluation of Current Tesoro Programs to Identify and Control Damage Mechanism Hazards

In developing a recommendation for Tesoro to address several of the findings in Section 1.2.2, the CSB evaluated current Tesoro standards for conducting DMHRs, PHAs, and Integrity Operating Window (IOW). In addition to the incident-specific analyses described in the report, this evaluation provides the necessary detail and support for recommendation 2010-08-I-WA-R14.

DMHRs evaluate a subset of hazards within the scope of a PHA.[280] Because of the specialized focus and expertise required to properly assess damage mechanism hazards, Tesoro has developed a program to evaluate these hazards outside of the PHA process, using external hired experts. The PHA team is then required to review this information and incorporate it into the applicable PHA.

The Tesoro PHA standard includes a requirement for the PHA team to review the most recent DMHR. This requirement establishes a link between the DMHR and the PHA, but it is not currently sufficient. To provide a better connection between the DMHR and the PHA, the DMHR team should be required to review the most recent PHA and validate the damage mechanism hazards and the safeguards identified to control these hazards. The PHA standard does not include a link between the IOW and the PHA. The PHA team should be required to review IOWs and validate the damage mechanism hazards and the safeguards identified to control these hazards.

IOWs are intended to address operating limits to prevent unexpected degradation of equipment. Like DMHRs, IOW reviews evaluate a subset of hazards within the scope of a PHA. The IOW standard addresses 51 degradation mechanisms that Tesoro has determined should be evaluated outside of the PHA process. The results of the IOW review must be integrated into the PHA; however, the PHA standard does not currently contain language to ensure that this requirement is completed. Although IOWs provide a mechanism to qualitatively rank degradation hazard risks, there is no provision to evaluate the effectiveness of safeguards, consider the hierarchy of controls, or evaluate opportunities for inherently safer design to the greatest extent feasible. The results of the DMHR are reviewed and incorporated into the development of IOWs. Although degradation hazards are evaluated in the IOW review process, IOWs are only revalidated every 10 years, twice the 5-year revalidation frequency allowed by the PSM regulations.[281] The IOW does evaluate incidents, but there is no provision to evaluate or consider industry-wide incidents. The IOW process does consider both routine and nonroutine operations.

The Tesoro PHA standard includes guidance to provide direction to the PHA team on its responsibilities. This guidance suggests that the PHA team is responsible only for a review of the completed critical

[280] The state of Washington PSM rule requires that the PHA shall address the hazards of the process. See: http://www.lni.wa.gov/wisha/rules/hazardouschemicals/#WAC296-67-017 (accessed December 29, 2013). These regulations do not specifically require a DMHR.

[281] WAC 296-67-017(6), "Process hazard analysis," requires the PHA to be updated and revalidated at least every 5 years. See: http://www.lni.wa.gov/wisha/rules/hazardouschemicals/#WAC296-67-001 (accessed January 11, 2014).

process data sheet that the corrosion expert produces as part of the DMHR. A specific requirement is never explicitly made for the PHA team to identify damage mechanism hazards, evaluate existing safeguards, and propose new safeguards to control these hazards.

None of the Tesoro PHA, DMHR, or IOW standards ensure that effective safeguards are identified and evaluated to control damage mechanism hazards. Such a review is implied by the overarching requirements in the Tesoro PHA standard. However, the language used in the standard could functionally reduce the responsibility of the PHA team to a mere review of the critical process data sheet developed by the corrosion expert as part of the DMHR. No formal evaluation of safeguards is ever described as a requirement for damage mechanism hazards or for the establishment of IOWs.

To improve the DMHR, this team should conduct a review of the relevant PHA hazards that address damage mechanisms. For these hazards, the DMHR should validate consequence, frequency, and proposed safeguards to control damage mechanism hazards. The DMHR should also evaluate alternatives that consider the hierarchy of controls and opportunities for inherently safer design to the greatest extent feasible.

The final deliverable from a Tesoro DMHR is a written report that the corrosion expert prepares. Because the DMHR team does not review and approve this final report, it does not meet OSHA PSM requirements for a PHA. There is an OSHA interpretation letter from October 31, 1996, that essentially states that a "team"[282] must perform the hazard analysis. OSHA's intent appears to be that the analysis and recommendations developed remains a team product. As written, the Tesoro DMHR results in a team analysis but with a report developed by an individual.

Under the Tesoro DMHR standard, the corrosion expert is required to assemble a critical process data spreadsheet. This spreadsheet is submitted to someone who has process expertise to provide the required process operating data. However, there is no guidance on how these data should be obtained or assurance that the data are appropriate to properly evaluate a given damage mechanism. In light of the April 2010 incident at the Anacortes refinery, for each identified damage mechanism, there should be a clear understanding of what process data are required as well as a provision to ensure that design operating data are not used in lieu of obtaining actual measurements or performing a technical evaluation such as a process simulation to estimate needed process data. The DMHR team should review the operating data and collection techniques to verify an accurate understanding of how the data were obtained and what they represent, and it should appropriately consider routine and nonroutine operations as well as the full range of operating conditions.

Before the April 2010 incident, in 2003, API identified materials that are not susceptible or are highly resistant to HTHA damage.[283] Neither Shell Oil nor Tesoro damage mechanism reviews considered these materials as inherently safer controls for HTHA hazards. The Tesoro DMHR and IOW processes do not

[282] See: https://www.osha.gov/pls/oshaweb/owadisp.show_document?p_table=INTERPRETATIONS&p_id=22289 (accessed December 29, 2013).

[283] API RP 571. "Damage Mechanisms Affecting Fixed Equipment in the Refining Industry." Pages 5–56, 2003.

ensure that gaps between current industry best practices and existing Tesoro practices are identified, evaluated, and considered when creating recommendations to reduce risk of damage mechanism hazards.

Tesoro should maintain an incident database on damage mechanism incidents, both for Tesoro and industry-wide. The DMHR and IOW teams should conduct a review of these incidents that should be included in the DMHR and IOW reports.[284]

As a result of separating the evaluation of damage mechanisms from the formal PHA process, potential gaps exist when the PHA team reviews MOCs and incident reports during the PHA process.[285] In addition to a review by the PHA team, MOCs relevant to potential damage mechanisms should be reviewed by the IOW team to fully evaluate the impact of proposed and planned changes within the refinery on relevant damage mechanism hazards. The IOW standard requires integration of IOWs into the MOC process, but the MOC standard currently has no provision to consider IOWs.

The Tesoro DMHR is one component of the Tesoro RBI program, which determines potential consequences for hazards such as equipment failure from damage mechanisms. Tesoro currently determines the consequences of damage mechanism hazards as a separate activity from the PHA, and there is no verification that the consequences determined by the DMHR are consistent with the PHA. To improve the Tesoro PHA process, PHA teams should review and validate the relevant consequence of hazards identified by the RBI program.[286]

Tesoro requires a corrosion expert to lead the DMHR process. However, the qualifications of the corrosion expert are not defined. Minimum qualifications should be clearly defined, and additional personnel should be added to the team if the identified corrosion expert does not meet all of the minimum qualifications.

The Tesoro requirement for DMHR meeting participants is confusing and should be clarified. The refinery corrosion and materials engineer is listed as a required participant, but then the DMHR document uses the language "if present." It is not clear why or under what conditions Tesoro would conduct a DMHR without the participation and expertise of the refinery corrosion and materials professional.

[284] The identification of any previous incident that had a likely potential for catastrophic consequences in the workplace is a requirement of the State of Washington PSM rule. See: http://www.lni.wa.gov/wisha/rules/hazardouschemicals/#WAC296-67-017 (accessed December 29, 2013).

[285] The Tesoro PHA standard requires PHA revalidations to address "Changes since the last PHA(s)—Management of Change (MOC)." The Tesoro PHA standard also requires the PHA to evaluate previous incidents. The standard requirements mirror the language of the State of Washington PSM rule, "The identification of any previous incident which had a likely potential for catastrophic consequences in the workplace."

[286] For these hazards, the PHA team should ensure that there are effective safeguards to control damage mechanism hazards. The PHA team should also evaluate alternatives that consider the hierarchy of controls and opportunities for inherently safer design to the greatest extent feasible.

Appendix E Inspection Techniques

The most basic nondestructive examination (NDE) technique is simply a visual examination that typically evaluates for physical damage such as dents or cracks, discoloration, or the presence of foreign material (such as process fouling or corrosion products similar to rust). However, significant damage is not always visible to the naked eye. Much like a doctor uses of X-rays or an MRI, or a CAT scan, the inspector uses more sophisticated tools and techniques to determine the condition of the refinery equipment. Typical NDE techniques include the following:

- **Ultrasonic Technique (UT)—**is the primary NDE technique for determining the extent of general corrosion attack. UT uses high frequency sound waves that are transmitted into a material and travel in a straight line and at a constant speed until they encounter a surface. The surface interface causes some of the wave energy to be reflected, and the rest of it is transmitted. The quantity of reflected versus transmitted energy is detected. Expert examination of the data provides information such as the presence of discontinuities and the thickness of the material or coating.[287]

- **Radiographic Technique (RT)—**also referred to as X-ray, is commonly performed using two different sources of radiation, X-ray and gamma ray. Advantages include a minimum surface preparation requirement and sensitivity to changes in thickness, corrosion, voids, cracks, and material density. The disadvantages are safety precautions required for the safe use of radiation, and access constraints in the field.[288]

- **Dye Penetrant Inspection (DPI)—**also called Liquid Penetrant Inspection (LPI) or Penetrant Technique (PT), is a widely applied and low-cost inspection method used to locate surface-breaking defects in all non-porous materials (such as metals, plastics, or ceramics). DPI is used to detect cracks, surface porosity, lack of penetration in welds and defects resulting from in-service conditions (for example fatigue cracks of components or welds) in castings, forgings, and welding surface defects.[289]

- **Magnetic Particle (MT)—**is used for finding surface and near surface defects in ferromagnetic material and is a versatile inspection method for field and shop applications. Magnetic particle testing works by magnetizing a ferromagnetic specimen using a magnet or special magnetizing equipment. If the specimen has discontinuity, the magnetic field flowing through the specimen is interrupted and leakage field occurs. Finely milled iron particles coated with a dye pigment are applied to the specimen. These are attracted to leakage fields and cluster to form an indication directly over the discontinuity. The indication is visually detected under proper lighting

[287] *See:* http://www.mistrasgroup.com/services/traditionalndt/ut.aspx (accessed August 1, 2013).

[288] *See:* http://www.mistrasgroup.com/services/traditionalndt/rt.aspx (accessed August 1, 2013).

[289] *See:* http://www.eceglobal.com/services/inspection-approvals/non-destructive-examination-nde/penetrant-testing-pt/, (accessed June 3, 2013).

conditions. Wet Fluorescent Magnetic Particles (WFMPT) is sometimes applied to increase sensitivity for locating very small defects.[290]

- **Ultrasonic Shear Wave—**also called Angled Beam Ultrasonic Technique, can be used to inspect pipe, critical welds in pressure vessels and plate weldments, and can be used to inspect cracks for depth, size, length and orientation. This is a common technique used for weld inspection, which provides a sensitive, fast and cost effective method to detect, locate, and validate a range of large to small defects and deterioration. [291]

- **Phased Array Ultrasonic Technology (PAUT)—**has the capability of creating multiple beam angles and focal points with the use of a multi-element ultrasonic transducer, and providing full volumetric sectorial scans (S-Scans), a feature unique to this technology. S-Scans are real-time side view images generated from a single inspection point; in essence, it depicts an internal view of the component being inspected. With this technology, weld flaw and crack detection and sizing can be achieved at a high rate of speed, many times faster than conventional shear wave inspection can achieve.[292]

- **Advanced Ultrasonic Backscatter Technique (AUBT)—**developed by Shell Oil in the early 1990s, is currently the best NDE method for detecting and quantifying damage from HTHA. The technique uses conventional UT probes and a digital oscilloscope to provide both an A-Scan display and frequency analysis.[293] AUBT is a sophisticated technique and requires a very high level of expertise.[294] There is no general certification of inspector competence in the application of HTHA detection techniques.

- **Velocity Ratio:** HTHA reduces the velocity of both shear and longitudinal waves. When a material is attacked by HTHA, the velocity reduction is slightly more with longitudinal than with shear waves. This in effect increases the ratio of shear wave to longitudinal wave velocities or the ratio of the transit times. This ratio of transit times can be used as an indicator of HTHA. Tests have shown that the velocity-ratio approach is only effective at high levels of HTHA and is limited to the base metal.[295]

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290 *See:* http://www.mistrasgroup.com/services/magnetic-particle-testing.aspx, (accessed June 3, 2013).

291 *See:* http://techcorr.com/services/Inspection-and-Testing/Ultrasonic-Shear-Wave.cfm (accessed July 16, 2013).

292 *See:* http://www.autsolutions.net/Phased_array.html (accessed July 16, 2013).

293 *See:* http://www.spi-matrix.com/advanced-ultrasonic-backscatter.php (accessed July 16, 2013).

294 See: http://www.nde.com/hydrogen.htm (accessed June 13, 2013).

295 *See*: http://www.ndt-ed.org/EducationResources/CommunityCollege/Ultrasonics/Physics/modeconversion.htm (accessed January 13, 2013).

Appendix F CSB Chevron Reports Incorporated by Reference

Both the CSB Chevron Interim Report and the draft Chevron Regulatory Report have been incorporated into this report on the Tesoro Anacortes Refinery incident by reference to support the regulatory analysis and recommendations. The Chevron Interim Report can be accessed at http://www.csb.gov/assets/1/19/Chevron_Interim_Report_Final_2013-04-17.pdf and the draft Chevron Regulatory Report can be accessed at http://www.csb.gov/chevron-refinery-fire/.

Appendix G Spectrum Inspection Reports

The Spectrum Inspection Reports can be accessed at http://www.csb.gov/tesoro-refinery-fatal-explosion-and-fire/.

Appendix H Beta Laboratory Reports

The Beta Laboratory Reports can be found at http://www.csb.gov/tesoro-refinery-fatal-explosion-and-fire/.

Appendix I Metallurgical Review

The metallurgical report can be accessed at http://www.csb.gov/tesoro-refinery-fatal-explosion-and-fire/.

Appendix J Additional HTHA Evaluation Report

This report can be accessed at http://www.csb.gov/tesoro-refinery-fatal-explosion-and-fire/.

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CSB Investigation Reports are formal, detailed reports on significant chemical accidents and include key findings, root causes, and safety recommendations. CSB Hazard Investigations are broader studies of significant chemical hazards. CSB Safety Bulletins are short, general-interest publications that provide new or noteworthy information on preventing chemical accidents. CSB Case Studies are short reports on specific accidents and include a discussion of relevant prevention practices. All reports may contain include safety recommendations when appropriate. CSB Investigation Digests are plain-language summaries of Investigation Reports.

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U.S. Chemical Safety and Hazard Investigation Board

US Ink/Sun Chemical Corporation

Ink Dust Explosion and Flash Fires in East Rutherford, New Jersey

October 9, 2012

Seven Employee Injuries

No. 2013-01-I-NJ

KEY ISSUES:

- Combustible Dust
- Engineering Design
- Management of Change
- Process Hazard Analysis
- Hazard Communication
- Management Oversight
- Regulatory Oversight

This case study examines the explosion and flash fires that occurred at the US Ink manufacturing facility in East Rutherford, New Jersey, on Tuesday, October 9, 2012. Seven workers suffered burn injuries when they congregated at the entrance to the ink mixing room after hearing a loud thump from the newly installed dust collection system on the top of the facility and seeing signs of an initial flash fire from a bag dumping station. A second flash fire then occurred that led to the employee injuries.

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1.0 INTRODUCTION

On October 9, 2012, at approximately 1:15 pm Eastern Standard Time (EST), a flash fire caused burn injuries to seven workers, including three who sustained third-degree burns, at the US Ink/Sun Chemical Corporation ink manufacturing facility in East Rutherford, New Jersey. Workers were drawn to a black ink mixing room (commonly called the pre-mix room at US Ink) by the initial flash of the fire from a bag dumping station and by a loud thumping noise from the rooftop. As the workers congregated at the doorway, they observed a small fire in the ductwork of a newly installed dust collection system above a process mixing tank. Suddenly, a large flash fire emerged from the pre-mix room and engulfed the seven employees in flames. Coworkers responded to the seven injured employees and took them out of the building. Emergency responding units from the East Rutherford Volunteer Fire Department arrived on scene at 1:20 pm EST. Emergency responders transported the victims to the local hospital while firefighters began combating the fire. After the incident, production was suspended pending internal and external investigation by the company, U.S. Occupational Safety and Health Administration (OSHA), and U.S. Chemical Safety and Hazard Investigation Board (CSB). Some production of colored inks resumed about a week later, but black ink production was halted until the end of December.

1.1 COMPANY BACKGROUND

US Ink[1], a division of Sun Chemical Corporation, is an ink manufacturer established in 1993 through the merger of two organizations, U.S. Printing Ink and the News Ink Division of Sun Chemical Corporation. US Ink maintains headquarters in Carlstadt, New Jersey, and had seven regional manufacturing locations across the country, including the East Rutherford facility, at the time of the incident. Sun Chemical Corporation is a global graphic arts corporation divided into a number of subsidiaries that encompass different segments of the market (such as ink, plates, pigments, and films). Sun Chemical owns and operates 143 active manufacturing facilities in and outside of the United States, with approximately 9,000 employees worldwide. At the time of the incident, the US Ink East Rutherford facility had 34 employees, and 28 employees were on shift.

1 See http://www.usink.com/about-us.html.

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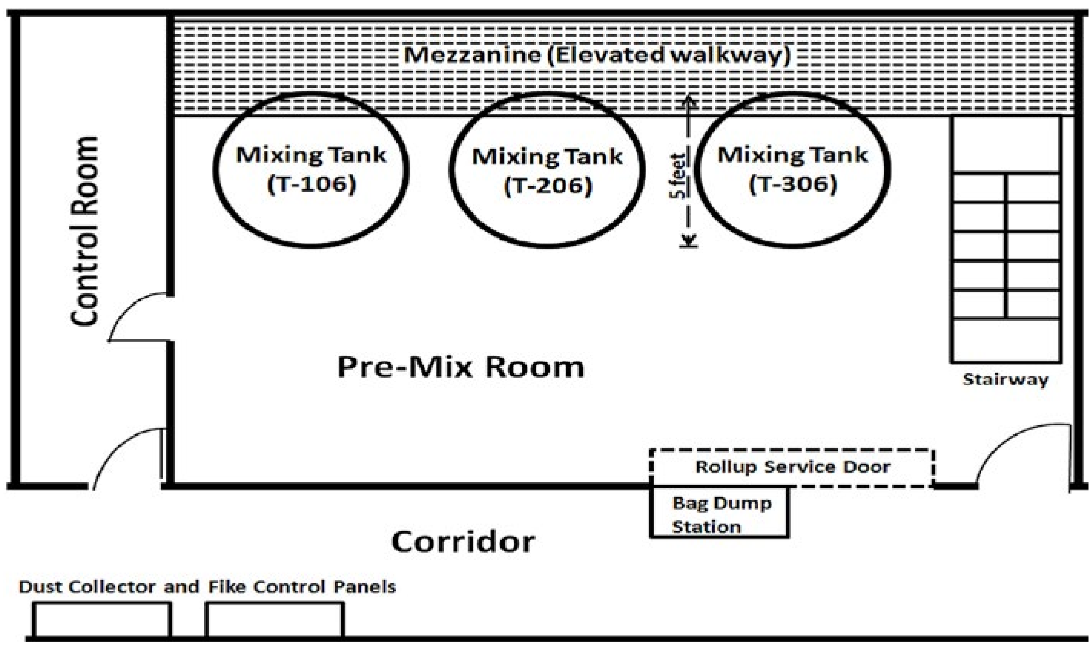
1.2 BLACK INK PROCESS DESCRIPTION

The US Ink East Rutherford plant (built in the 1920s) manufactures both black and color oil-based ink for various commercial clients. A key step in the ink production process is mixing solid and liquid ingredients to produce a liquid suspension. The mixing operation for black ink ingredients is performed in the pre-mix room, where the October 9, 2012, incident occurred. Figure 1 depicts a simplified plan view of the pre-mix room containing three large mixing tanks in which the various ink formulations are made. The room is 30 feet wide by 17 feet deep and has cinder block walls up to the 30-foot ceiling height. The black ink manufacturing process at US Ink involved the pneumatic transfer[2] of bulk solid powder under vacuum to one of three mixing tanks, labeled as 106, 206, and 306 (T-106, T-206, and T-306, respectively).

FIGURE 1

Pre-mix room layout[3]



Two solid ingredients, carbon black and kaolin clay, are received by rail (while Gilsonite is shipped by truck) to the facility and are transported to the mixing tanks by vacuum through piping from a manual raw material feeding station (known at US Ink as the bag dump station,[4] shown in Figure 2) or by gravity from three overhead receiver hoppers containing carbon black and kaolin. The liquid ingredients are transported to the facility via rail and are pumped into the mixing tanks via pipes connected to the bottom of the tanks. All three mixing tanks are 5 feet in diameter and about 10 feet high. Operators coordinate

2 The pneumatic transfer process is a mechanical method of conveying materials via compressed or pressurized gases.

3 This diagram is not drawn to scale.

4 The bag dump station was positioned in the doorway of the pre-mix room. An overhead rollup service door was installed for access to the pre-mix room. At the time of the incident, the CSB found that the rollup service door was chained into a fixed rolled-up position to provide easier entry into the room. Witness accounts from plant employees and contractors indicated that Gilsonite dust generated from the bag dumping operation often accumulated around the facility but particularly on flat surfaces. US Ink did not provide an effective means of containing fugitive dust at the bag dumping station because emptied bags were often stacked alongside the bag dump, which in turn lofted dust into the air.

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FIGURE 2

Bag dump station

the ingredient mixing process and monitor tank weights and temperatures from a control room adjacent to the pre-mix room. An automatic sprinkler system[5] was installed as a fire protection feature in the pre-mix room.[6]

When complete, the mixed suspension contains both combustible and noncombustible particulate ink components. The heat generated as the solids are dissolved in the mixing tank increases the solution temperature to about 240°F. This increase in operating temperature is useful because it ensures complete dispersion of the solid materials into the liquid phase; it also contributes to greater evolution of condensable vapors. Once mixing is completed, a laboratory technician analyzes ink quality. If cleared, the batch is pumped into an empty tank for further processing (milling) and then to another tank in preparation for delivery to customers. Each batch weighs about 6,600 pounds when completed.

1.3 DUST COLLECTION SYSTEM

Before October 2012, the facility used a wet scrubber system[7] to collect particulate materials during the dry material charging stages of the ink mixing process. However, the scrubbing system deteriorated over the years. In addition, the wet scrubber system did not prevent the release of fugitive dust into the pre-mix room when new ink formulations used higher powdery clay content, producing higher levels of particulate emissions. Therefore, a new particulate dust collection system was needed. The new dust collection system was installed to improve the management of particulate material and produce an overall improvement in the operating conditions of the black ink production process.

5 The sprinkler system was also connected to an automatic audible alarm. Once the sprinkler system was activated, an automatic signal was relayed via an external central monitoring station to the local fire department for immediate response.

6 During the incident, the sprinklers were activated after the second flash event.

7 Wet scrubber systems are devices that remove pollutants from a furnace flue gas or from other gas streams. In a wet scrubber, the polluted gas stream is brought into contact with the scrubbing liquid by spraying it with the liquid, forcing it through a pool of liquid, or using some other contact method to remove the pollutants. Wet scrubbers remove dust particles by capturing them in liquid droplets.

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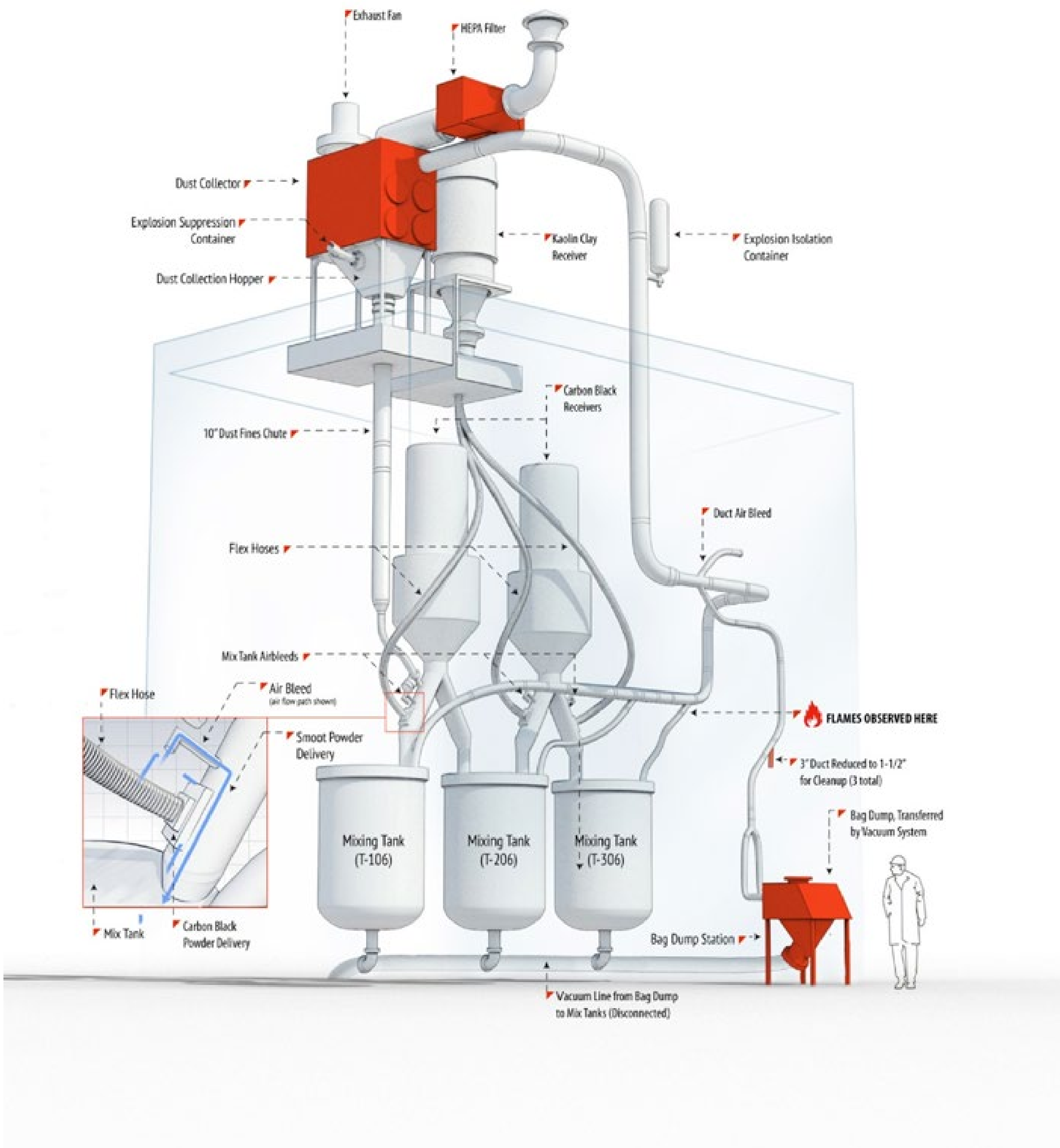
A US Ink lead engineer worked in collaboration with the manufacturer of the dust collection system[8] to design the new dust collection system. The engineer retired before the dust collection system was installed and commissioned on Friday, October 5, 2012.[9] The dust collection system illustrated in Figure 3 consisted of a branching system of various sizes of ducts, including flexible connectors attached to the top of each mixing tank and to the bag dump station. The flexible ducts joined an 8-inch duct, which transitioned to a 9-inch duct and ultimately a vertical 12-inch duct (riser) going up through the pre-mix room ceiling. Dust particles were suctioned though the ducts and riser into the exhaust fan–driven dust collector, located on the roof of the facility (Figure 3).

FIGURE 3

Overview of the newly installed dust collection system



8 Additional design specifications and support were provided by other US Ink engineers and by representatives of the manufacturers of the duct-work, dust collector, and fire explosion suppression and isolation system that was coupled to the dust collection system.

9 In Section 6, Safety Management Analysis, of this report, the CSB concludes that the engineer's retirement led to a less comprehensive design review and commissioning process for the dust collection system.

The roof-mounted dust collector used an eight (four rows of two each) cylindrical filter cartridge system to remove the residual particulate dust. Dust-laden air and vapor from the mixing tanks entered the collector above the four cylindrical filter cartridges and was drawn down over the cartridges, where the dust was removed from the air stream. The dust collector was mounted with a 25-horsepower (hp) fan and an inlet total static pressure rating of a 17-inch water column. The 25-hp fan was designed to convey dust up to the collector at an airflow volume rate of 3,300 cubic feet per minute. The dust collector was mounted with a system fan with a 25-hp motor. The mounted fan for the dust collector discharged through a high-efficiency particulate air (HEPA) filter and then into the atmosphere. Compressed air periodically pulsed through the filter cartridges to dislodge the filtered dust into the hopper of the dust collection system. The collected dust was recycled into the ink-making process. A rotary airlock on the bottom of the hopper used gravity to control the discharge of recycled fugitive dust from the collector and back into the mixing tank (T-106) for reprocessing in the pre-mix room. Beyond the rotary air lock valve, the 10-inch-diameter pipe reduced to 4 inches in diameter at T-106.

The company added three housekeeping connections, not included in the initial design, to the vacuum system of the dust collection system for operator use in picking up dust and other debris in the pre-mix room.[10] This auxiliary equipment attached to the ductwork associated with the bag dump station and to the main ducts above T-206 and T-306. The dust collector included an explosion suppression system (shown in Figure 4 and Figure 5), which would actuate and release the suppressant, sodium bicarbonate, if a rapid pressure increase occurred in the dust collector. The design intent focused on preventing damaging explosive overpressures in the collector and inlet duct in the event of a drastic pressure rise and on containing any explosion hazard within the dust collector.[11] Fike Corporation[12] manufactured the explosion suppression and chemical isolation system, and the designers recognized the explosion hazard associated with dust.

US Ink/Sun Chemical Corporation provided information—including specification of the raw materials utilized in the black ink pre-mix process, flash point of oils, and dust deflagration index (K_{ST}) values for solid ingredients—to the manufacturer of the explosion suppression and isolation system. Although US Ink/Sun Chemical originally considered a roof-mounted dust collector equipped with explosion vent panels for explosion protection and with a mechanical isolation valve, US Ink decided instead to use an explosion suppression and chemical isolation system. US Ink based this decision on reduced installation costs and external recommendations (from Fike and the third-party property loss prevention and risk management consultants hired by US Ink) to avoid any potential environmental releases of combustible dust particulates (or fire) into areas near residences.

The new dust collection system was commissioned at the facility in the week preceding the incident. The flash fire occurred in the dust collection system during the first day of normal production after initial equipment start-up, on Tuesday, October 9, 2012.

10 The dust collection system design included four dust pickup points: three housekeeping connections and the opening at the bag dump station. The ductwork at the top of each mixing tank had a connection (6 inches in diameter) for dust collection, and two 6-inch connections at the bag dump hood allowed suctioning of dust particles from the dumping station. In addition, three 3-inch ducts were reduced to 1.5 inches in diameter for vacuum cleaning hoses that were added to the ductwork design for housekeeping purposes.

11 The explosion suppression system would actuate and inject sodium bicarbonate via an independent suppression container and chemical isolation container located at two injection points in the system: the dust collector hopper (Figure 4) and the collector inlet riser (Figure 5). The suppressant was designed to be injected if a rapid pressure rise occurred in the dust collector and was intended to suppress a flame front from propagating from the dust collector back through the riser into the interconnected ductwork and pre-mix room.

12 See www.fike.com.

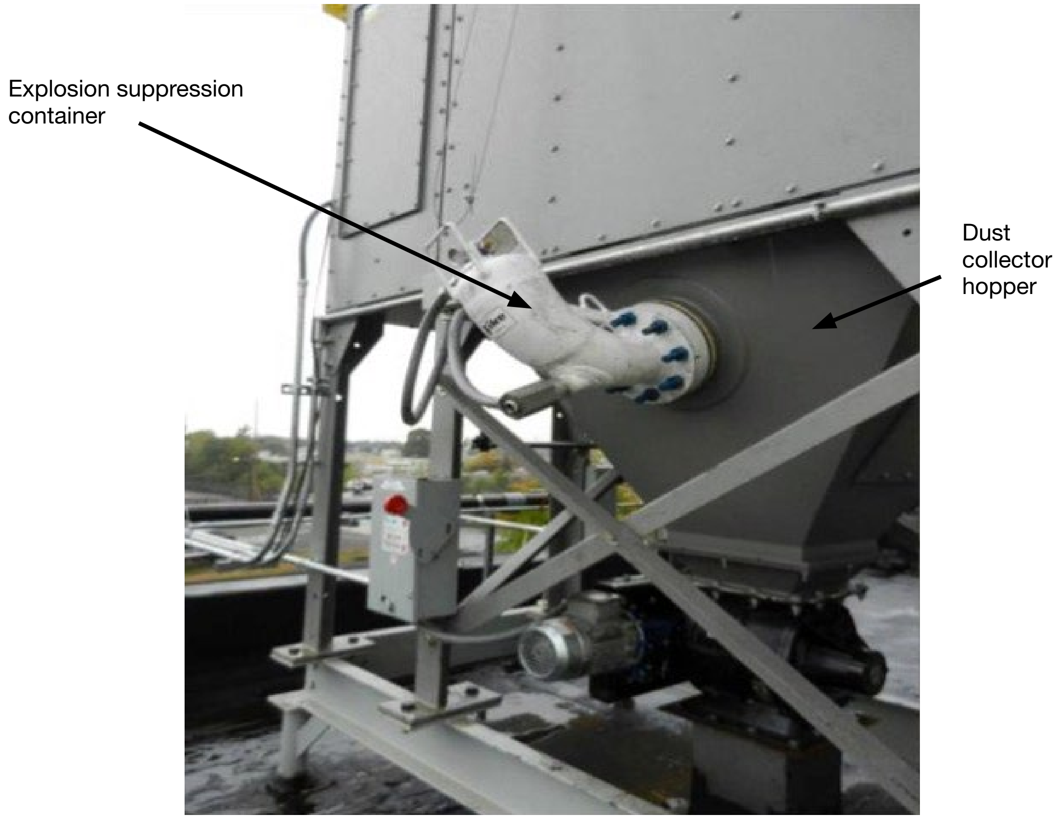


FIGURE 4

Dust collector with explosion suppressant

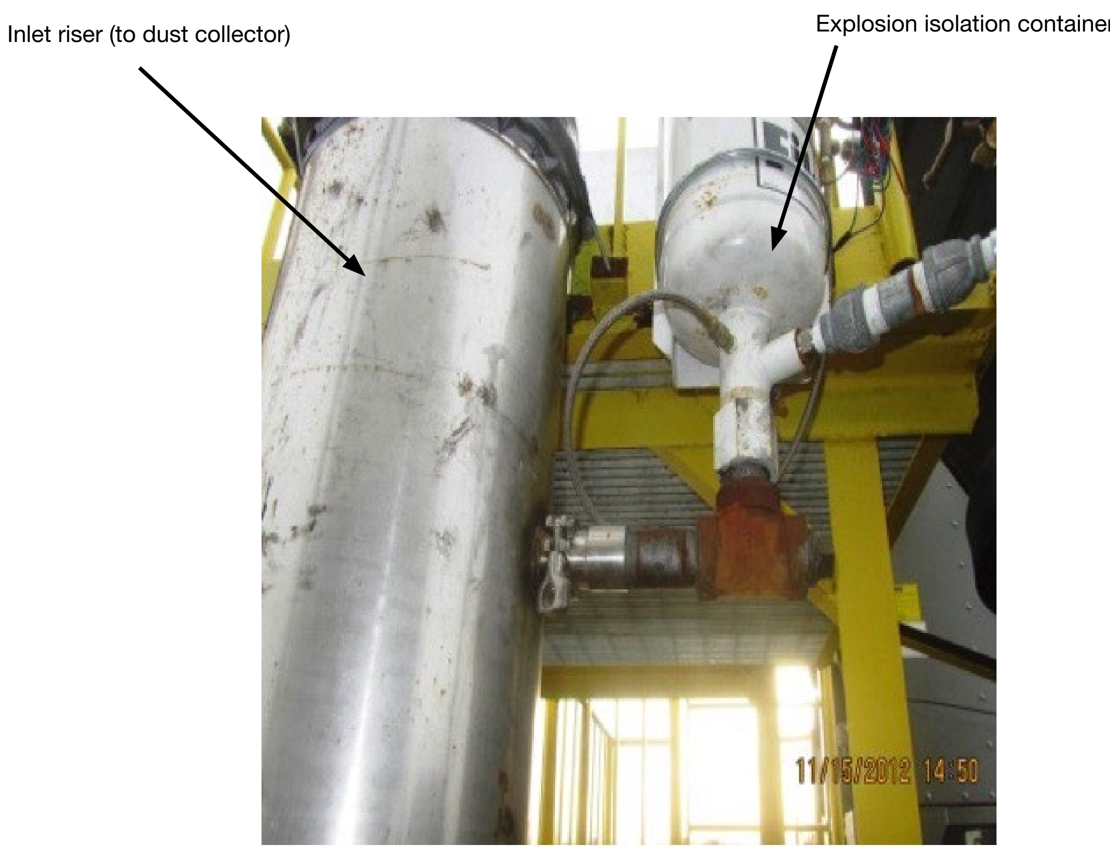


FIGURE 5

Dust collector inlet with explosion isolation

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1.4 MATERIALS INVOLVED IN THE INCIDENT

The US Ink facility produces black and color oil-based inks for various clients but primarily for the print media industry. A typical black ink formulation at the East Rutherford plant includes the following ingredients:

- Petroleum napthenic distillate[13] (product name: Raffene® 750K oil)
- An alternative petroleum distillate (product name: mineral seal oil)
- Natural asphalt resin particulate (product name: Gilsonite[14])
- Carbon black particulate pigment (product name: Printex 310[15])
- Bentonite (aluminum silicate clay) particulate (product name: Bentone 34)
- An alternative aluminum silicate clay (product name: kaolin)
- Tall oil fatty acid, a minor ingredient (additive)

Gilsonite and carbon black are combustible while the petroleum distillate is flammable, so they can be considered as possible contributors to the formation of the explosive atmosphere on the day of the incident.[16] The boiling points and flash points of the two oils are listed in Table 1.

TABLE 1. OIL PROPERTIES (FROM MATERIAL SAFETY DATA SHEETS)

Property	Raffene Oil 750K	Mineral Seal Oil[17]
Open cup flash point	360°F	275°F
Initial boiling point	550°F	492°F
Autoignition temperature	Not given	Not given

Mineral seal oil[18] is more volatile than Raffene oil, but the flash points of both oils are sufficiently high (more than 200°F) to make them Class IIIB liquids according to the combustible liquids classification in the National Fire Protection Association (NFPA) code *NFPA 30, Flammable and Combustible Liquids Code*.[19] Occasionally, US Ink also used linseed oil, but not in the batches blended before the incident.

13 Petroleum distillates (e.g., hydrocarbons such as mineral spirits, kerosene, white spirits, and naphtha) are often used as an organic solvent in painting and decorating (http://www.northerntails.com/images/What_are_Petroleum_Distillates.pdf). Heavier fractions such as naphthenic or paraffinic distillates are often used in ink manufacturing processes.

14 Gilsonite, a resinous hydrocarbon, is widely used as the primary carbon black wetting agent for black news inks and heat set and gravure inks. Gilsonite has a National Fire Protection Association (NFPA) flammability rating of 1, and special precautions warn that dust is subject to explosion upon contact with sparks, open flames, or temperatures in excess of 1,000°F (570°C).

15 Carbon black, with a particle size of PM-10 (particles with a diameter of 10 micrometers or less), is an odorless and insoluble powder with an atoignition temperature greater than 284°F. It can burn or smolder (decompose) at temperatures greater than 572°F and is virtually pure elemental carbon in the form of colloidal particles that are produced by incomplete combustion or thermal decomposition of gaseous or liquid hydrocarbons under controlled conditions. Although some grades of carbon black are sufficiently electrically nonconductive to allow a static charge buildup during handling, dust at sufficient concentrations can form explosive mixtures with air. Carbon black has an NFPA flammability rating of 1.

16 The American Gilsonite Company Material Safety Data Sheet (MSDS) for Gilsonite resin indicates that Gilsonite is not hazardous; however, in the storing and handling section, the MSDS states, "Avoid raising any powdered material into dust explosion hazard." The MSDS for carbon black states that OSHA classifies the product as hazardous and that dust at sufficient concentrations can form explosive mixtures with air. The MSDSs do not reference NFPA standards except in a carbon black MSDS where NFPA ratings are provided. Sun Chemical did have guidance on combustible dust (SunCare HSE Procedure 065, *Combustible Dust*), which included a section for references that listed NFPA 35, 68, 77, 484, and 654.

17 Citgo Petroleum Corporation, *Mineral Seal Oil Material Safety Data Sheet* (http://www.docs.citgo.com/msds_pi/19540.pdf).

18 The Citgo mineral seal oil MSDS suggests that it can burn but does not readily ignite. Mineral seal oil releases vapors when heated above the flash point temperature. In addition, it can ignite when exposed to a source of ignition. In enclosed spaces (such as the ductwork of the dust collection system), heated mineral seal oil vapor can ignite with explosive force. Mists or sprays can burn at temperatures below the flash point (http://www.docs.citgo.com/msds_pi/19540.pdf).

2.0 INCIDENT DESCRIPTION

2.1 EVENTS BEFORE THE INCIDENT

The new dust collection system for the pre-mix room was commissioned for service on the morning of Friday, October 5, 2012, and then operated until the end of the production shift at 3:00 pm EST.[20] At commissioning, US Ink employees who would operate the system (several black ink production supervisors and one of the day-shift operators) received 15 minutes of operational training and instruction as well as a walkthrough of the Fike explosion suppression and isolation system.[21] Both the dust collection system and the Fike explosion suppression and isolation system were equipped with control panels (containing system status indicator lights), installed on the wall near the pre-mix room (Figure 1). As designed, the dust collection system started automatically when any of the mixing tank motors was energized and automatically shut off (after a specified delay) when all mixers were inactive. However, the dust collection system actually continued to run overnight, even when all the ink mixers were shut off.[22]

On Saturday, October 6, 2012, the plant maintenance employees used housekeeping connections on the new dust collection system to vacuum dust and debris in the pre-mix room. A US Ink maintenance employee reported in an interview that upon his arrival on Saturday, although the mixing tanks were shut down the night before, the dust collection system had run all night, a departure from the initial design intent of automatic start-up and shutdown, in sync with the mixing tanks.[23] At the end of housekeeping activities, a maintenance employee manually shut down the dust collection system. Although the maintenance employee reported the dust collection system equipment malfunction to his superiors and to the electrical contractor that wired the dust collection system, US Ink/Sun Chemical Corporation management took no action to immediately investigate the failure or to shut down the ink mixing operation until the malfunction was corrected.[24] Employees restarted the mixing tanks and the dust collection system on the Monday night shift, October 8, 2012, in preparation for the production runs scheduled for Tuesday, October 9, 2012.

19 NFPA, a nonprofit standards organization, has been developing standards since 1896 that directly affect fire services at the department level. NFPA produces more than 300 consensus codes and standards intended to minimize the possibility and effects of fire and other risks (http://www.nfpa.org/about-nfpa). The codes are voluntary standards that industry can adopt and regulatory agencies can enforce. Standards are an attempt by an industry or profession to self-regulate by establishing minimal operating, performance, or safety criteria.

20 Representatives from Fike had earlier provided a system orientation of the explosion suppression and isolation system to the US Ink maintenance staff on October 1, 2012.

21 Section 5, Engineering Design Analysis, includes a discussion of the failure to conduct system performance measurement at start-up and commissioning of the dust collection system.

22 The dust collection system was designed to be controlled by a controller whenever it was running, and the controller was set up to continuously control the fan and pulse jets whenever the dust collection system was in operation. However, the automatic shutoff did not engage as designed once the system was energized and thus had to be manually turned off and on by US Ink maintenance employees and pre-mix room operators.

23 The CSB did not find any evidence that the automatic start system worked in sync with the mixing tanks at commissioning.

24 US Ink/Sun Chemical Corporation management did not give stop-work authority to the maintenance employee or the night-shift pre-mix room operator to shut down dust collection system operation once a malfunction was reported. US Ink claimed it encouraged employees to report unsafe acts; however, the CSB did not find any record of a US Ink requirement for employees to shut down any equipment perceived as faulty that could lead to an unsafe condition or hazards. This lapse in management oversight allowed the dust collection system to continue running during the ink mixing operation until the system eventually failed on Tuesday, October 9, 2012.

2.2 ONSET OF FLASH FIRE AND EXPLOSION

On Tuesday morning, October 9, 2012, black ink production continued, with batches being run in all three mixers. When the batch in T-306 was completed, the pre-mix room operator emptied the tank. The operator left for lunch at about noon and returned to the pre-mix room at about 12:30 pm EST. At that time, a new ink batch was started in T 306. At about 1:00 pm, the pre-mix room operator was loading Gilsonite into the bag dump station (Figure 1) when he heard a strange (squealing)[25] noise from T-206. Because of the odd noise, the operator went to the control room to check the mixing tank temperature and speed to confirm that the equipment was working properly. As he left the control room, he saw a flash fire originating from the bag dump station where he had just been working. Without shutting down the mixing operation and the dust collection system from the control panels near the pre-mix room, the operator immediately proceeded to his supervisor's office to alert him of the fire, moving away from the pre-mix room. At about the same time, other workers heard a loud thump that shook the building.

In response to the flash from the bag dump station and the subsequent loud thump, workers congregated at the entrance to the pre-mix room. Employees stated that the rubberized spiral-wound duct hose material that connected T-306 to the dust collection riser appeared to be melting and dripping onto the tank (Figure 6).

FIGURE 6

Burned ductwork over T-306

[25] The squealing noise signaled a possible increase in the amperage, which would have necessitated the addition of more oil to the mixing tank. The pre-mix room operator testified to the CSB that upon checking the amperage chart for the mixing tanks, he discovered that everything was fine.

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2.3 INCIDENT AND INJURIES

Two employees retrieved fire extinguishers to put out the flames. One employee ascended the stairs near T-306 in an attempt to extinguish the flames. The employee reported that before he was in position to discharge the extinguisher, he heard a "sizzling" sound from T-306 and saw an orange fireball erupt, advancing toward him. He squeezed the extinguisher handle and jumped from the stairs as fire erupted from the tank. The flames engulfed him and six other employees who were positioned outside the pre-mix room doorway.

Another employee who approached the pre-mix room area noticed that the lights on the alarm panel for the dust collector explosion suppression system were red, indicating detection of a pressure rise and activation of the system. However, this system did not produce an audible alarm.[26] The employee alerted the other workers in the area that the explosion suppression system had activated and there was a fire. Just seconds before the large flash fire at T-306, the employee retreated from the pre-mix room area to call 911, but after running 25 to 30 feet, he was knocked to the ground by the pressure wave caused by the fireball. Witnesses observed not only the initial fireball from T-306 but also a thick black cloud venting into the corridor[27] just ahead of the fireball, and they reported an audible "whoosh." These observations are consistent with the sights and sounds of a combustible dust deflagration.[28]

All employee burn injuries resulted from the large flash fire and heated dust mixture that originated from above T-306 and propagated into the corridor from the entrance of the pre-mix room. The injured employees had clothing covered in black dust, and they experienced burns to exposed skin. Some burns occurred after their clothing ignited from the fireball. The injuries consisted mostly of burns to upper torsos, arms, necks, and heads. Other employees helped the injured employees out of the plant, and emergency responders transported the injured to hospitals. One of the injured employees was wearing a short-sleeve T-shirt that day and sustained third-degree burns on his left arm, neck, and upper torso. The employees were not wearing flame-resistant clothing (FRC).

To reduce the risk of thermal injury from flash fire incidents in production-related operations, workers are required to wear FRC. As part of its personal protective equipment (PPE) standard (29 CFR 1910.132), OSHA requires employers to provide workers with FRC in workplaces when flash fire or explosion hazards are present.[29] This standard also mandates that employers must conduct a hazard assessment of their workplaces to identify hazards that require the use of protective equipment. Because the US Ink facility

26 US Ink/Sun Chemical maintained that Fike did not fulfill its requirement to fully install and ensure the operation of an audible alarm, despite providing an initial specification that indicated the presence of an audible alarm. Best practices indicate that US Ink should not have accepted the new dust collector as complete if system start-up checks revealed that the audible alarms were not working as expected. Fike attested that the local visual and audible alarm for the explosion suppression and isolation control was operating when verified on October 1, 2012. However, the local audible output might not have been heard by US Ink employees on the day of the incident due to the room ambient noise in the room. Also, US Ink did not incorporate any other area or building -wide audible or visual alarm or emergency responder notifications into their notification strategy.

27 CSB investigator observations of the ceiling of the US Ink East Rutherford facility shortly after the incident indicated the outward L-shaped path of the fireball along the corridor near the pre-mix room.

28 A deflagration is the propagation of a flame through a fuel-air mixture at less than the speed of sound. It can be either a flash fire or an explosion, depending on the level and consequences of the pressure generated during flame propagation.

29 FRC can reduce the severity of burn injuries sustained during a flash fire when engineering and administrative controls fail. Usually worn as coveralls, FRC is made of treated natural or synthetic fibers that resist burning and withstand heat.

did generate dusts, the potential existed for a dust explosion, flash fire, or both. If US Ink had followed OSHA standards on hazard assessment and PPE selection, the US Ink/Sun Chemical safety managers would have identified "harmful dust" and provided additional PPE. NFPA 2113 provides guidance for the selection, use, and maintenance of FRC.[30] NFPA 2113 states, "Factors in determining if flame-resistant garments are required shall include the presence of flammable materials in the environment during process operations." This standard would include dust generated during the ink mixing process. The CSB learned that no corporate policy required the use of FRC by US Ink plant employees.[31]

2.4 FIRE DEPARTMENT AND EMERGENCY RESPONSE

The flash fire triggered the fire sprinkler system in the pre-mix room. Firefighters and other first responders arrived at the scene of the incident within 3 minutes of the first alarm.[32] After they arrived and entered the plant, East Rutherford Fire Department personnel did not see any flames in the pre-mix room because the sprinklers had extinguished fires outside of the enclosed equipment.

Although they observed no visible signs of flames after the large flash event at T-306, responding firefighters reported that after checking with their heat sensors, they detected several ductwork fires and extinguished them with water after separating the affected ducts. The firefighters went up to the dust collector on the roof and opened the four covers on the cartridges but did not need to extinguish any residual burning materials in the collector because the explosion suppression and isolation system, which was designed to respond to any explosion within the dust collector, had already prevented the fire from entering the dust collector after the initial event. The design of the chemical suppression and isolation system protected the dust collector from explosion within the collector but did not extinguish any external fires.[33]

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30 National Fire Protection Association, *NFPA 2113: Standard on Selection, Care, Use, and Maintenance of Flame-Resistant Garments for Protection of Industrial Personnel Against Short-Duration Thermal Exposures*, 2012 Edition (Quincy, MA: NFPA, 2012).

31 Sun Chemical Corporation, "Sun Chemical Material Safe Handling Form." This form indicated the following for recommended personal protective equipment (PPE): respirator (organic vapor cartridge) or self-contained breathing PPE apparatus, disposable sleeves worn over long-sleeved uniform tops or disposable Tyvek suit, nitrile or Neoprene gloves, and safety glasses with side shields. In addition, the corporate Health, Safety and Environment (HSE) PPE policy lists examples of types of PPE that could be used, including protective clothing; however, FRC is not listed as a specific type of protective clothing. Although employees received some communications regarding appropriate PPE, the CSB investigation could not find any evidence to indicate that US Ink actually supplied FRC to employees.

32 East Rutherford Fire Department, *East Rutherford Fire Department Inspection and Incident Report*, October 22, 2012.

33 National Fire Protection Association, *NFPA 654-2006: Standard for the Prevention of Fire and Dust Explosions from the Manufacturing, Processing, and Handling of Combustible Particulate Solids*, Section 7.13.1.2.1. This section states that where both an explosion hazard and a fire hazard exist in an air material separator, protection for each type of hazard shall be provided.

3.0 INCIDENT ANALYSIS

THREE DISTINCT EVENTS OCCURRED DURING THIS INCIDENT:

1. An employee observed a flash originating from the bag dump station, which attracted the attention of several workers in the area.
2. At about the same time, workers heard a large thumping sound that they described as coming from overhead, accompanied by a pulse that shook the entire building, drawing more workers from their respective workplaces to investigate.
3. After about 2 minutes, seven workers observed an approximately 1-foot flame directly over T-306. The flame then gained additional energy from the powdery mixture of accumulated carbon black, Gilsonite, and clay in the ductwork of the dust collection system. The mixture acted as fuel, and the fire flashed over the assembled workers in the doorway of the pre-mix room.

The CSB investigated three possible points of origin of the fire: within the dust collector, within the ductwork above T-306, or within T-306. Chemical test results,[34] engineering design analysis,[35] physical evidence of excessive deformation, heat charring of the ductwork directly above T-306, and corroborated witness testimony all indicated that the fire originated within the ductwork of the dust collection system.

3.1 SEQUENCE OF FIRE AND EXPLOSION EVENTS

The CSB concluded that the explosion and flash fires occurred because of continuous manually controlled heating of the mixing tanks and operation of the dust collection system for several hours after commissioning, with the system continuing to draw condensable vapors into the duct. Continuous operation of the dust collection system led to self-heating and spontaneous self-ignition of the accumulated sludge-like material and the powdery dust mixture of Gilsonite, carbon black, and clay in the ductwork above T-306. As a result of this activity, the dust collection system drew air past the site where the spontaneous ignition occurred, thereby enhancing combustion of the condensed vapors and combustible dust. With the dust collection system still in operation, the air in the system blew the dust mixture toward the collector while the fire burned. This situation caused ignition and a pressure rise in the dust collector, which was already filled with the blend of Gilsonite, carbon black, and clay.

Although the ignition led to a dust explosion within the dust collector, the pressure rise activated the Fike explosion suppression system, which prevented the structural failure of the dust collector.[36] The pressurized discharge of the explosion suppression canister caused the thumping sound that employees heard coming from outside the building. At the same time, the ignition at the dust collector and discharge of the 5-liter suppression and 9-liter

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34 Chemical test results are discussed in detail in Section 4, Sample Test Results and Incident Implications.

35 Engineering design analysis is covered in detail in Section 5, Engineering Design Analysis.

36 The Fike explosion suppression and isolation system prevented the structural failure of the dust collector by suppressing the deflagration and isolating the dust collector as designed.

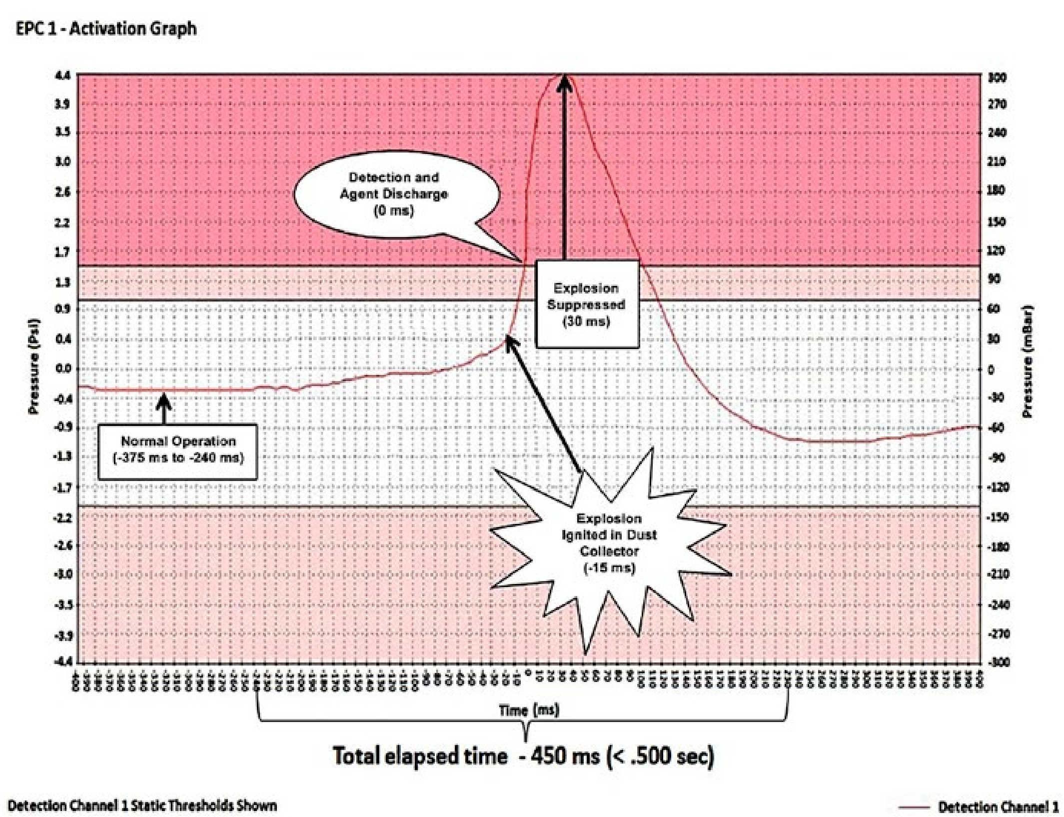
isolation canisters created a pressure spike of 4.4 pounds per square inch gauge (psig) in the dust collector and caused the flame front to propagate counter-current toward the mixing tanks. This rapid pressure rise (and the associated rapid flame propagation back through the ducting) triggered an initial flash fire at the bag dump station and within the rubberized ducts above T-306 (where the second and more volatile flash fire occurred). After the incident, the CSB learned that the design total suppression pressure (maximum design pressure for suppressed explosion) predicted for the dust collector was 3.8 psig. The increase in the total suppression pressure occurred because of the higher rate of pressure rise of the dust mixture compared to the expected design KST of 165 bar-meters per second (bar-m/sec).[37]

3.2 FIKE EXPLOSION SUPPRESSION SYSTEM DATA

Suppression Systems Incorporated (SSI)[38], a Fike distributor, provided pressure sensor data retrieved from the memory of the Fike system, using plots attached to a December 2012 Fike incident report. The report indicated that both the 5-liter extinguishing agent container on the dust collector and the 9-liter extinguishing agent container on the inlet duct discharged as designed on the day of the incident. The pressure sensor data pulled from the Fike system on the day of the incident shows the sequence of events in the dust collection system. The recorded data are shown in the graph in Figure 7.

FIGURE 7

Annotated Fike system pressure plot [39]



37 This is addressed in Table 3, ASTM E1226 dust explosibility test data.

38 SSI is a Fike distributor and the installer of the Fike dust collection system at US Ink.

39 The Fike system design plot is based on a dust explosion hazard corresponding to a maximum pressure (PMax) of 10 bar gauge (barg) and a normalized rate of pressure rise (KST) of 165 bar-m/s.

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3.3 IMPACT OF THE ELIMINATION OF THE SCRUBBER SYSTEM

Before installation of the dust collection system, employees observed vapor escaping from the mixing tanks. When the wet scrubber system was removed, an unsealed makeshift vapor absorbent was installed at the opening of the tank heads. The operators used the vapor generation to gauge the speed and temperature of the mixing process. This qualitative information was the basis for their adjustment of the mixing process speed and served as their indicator of the escape of vapor from the process. Despite this, US Ink maintained that the operators relied on their training in the process to properly operate the mixers. In addition, the temperature of each of the tanks was measured and available at all times to the operators. Moreover, each batch ticket specified the target operating limits, which the operator used to prepare each batch of ink.

US Ink/Sun Chemical claimed that each operator was trained to monitor the mixer temperature to ensure that it remained sufficiently low and to adjust the mixing operation accordingly to mitigate high mixing temperatures. However, one of the plant operators testified to CSB investigators that he relied on his individual instincts, observations of combustible vapor, and sounds generated during the mixing process to manually adjust (from the control room) the speed of the tank mixing agitators. After examining the US Ink control room, the CSB concluded that despite the presence of temperature gauges and recorders, no temperature control system governed the mixing tanks and that the ink mixing process design did not define any safe temperatures. With no automatic temperature control and no guidelines, plant operators relied on individual instincts, observations of vapor from combustible liquids, and sounds generated during the mixing process as the basis for manually adjusting (from the control room) the speed of the tank mixing agitators.

After installation of the dust collection system, operators in the pre-mix room could not observe the vapor and use it as an indicator because the dust collection system metal ducts were connected to the opening of the mixing tank heads. In addition, after removal of the scrubber system, the combustible vapor generated by the ink mixing operation could no longer be eliminated because the new dust collection system was not designed to release condensable vapor. The vapors subsequently were trapped within the ductwork of the dust collection system.[40]

3.4 PHYSICAL ANALYSIS OF THE BUILDING AND MIXING TANKS

Although minor cracks were visible on the exterior of the building wall, this incident caused no apparent structural damage to the building. Equipment in the pre-mix room (including ductwork, motors, electrical cables, and conduit) sustained extensive thermal damage. Portions of the dust collection ducting were separated, and at least one housekeeping connection end cap blew off. Moreover, extensive smoke and dust deposits accumulated on the structure and equipment surfaces in the hallway (ostensibly caused by the burning fireball) and around the pre-mix room.

After the incident, the CSB commissioned a visual and video borescope inspection[41] of the mixing tank (T-306) to determine whether the second flash fire originated within T-306. The inspectors opened the top hatch and found the liquid level just below the set of toothed vertical agitation blades. Thick ink coatings were apparent on the visible portions of the interior walls and the top of the tank. The tank and mixing elements showed no indication

40 Section 5, Engineering Design Analysis, discusses the lack of consideration of the presence of condensable vapor in the ductwork.

41 A borescope is an optical instrument used to inspect work areas or the inside of structures that are inaccessible by other means. The borescope is often inserted into the structure or work area through a small hole.

of thermal degradation. In addition, the inspectors removed the motor of the overhead agitator on T-306 to check for damage to the agitation blades and found no major damage, only regular wear on the blade edges.

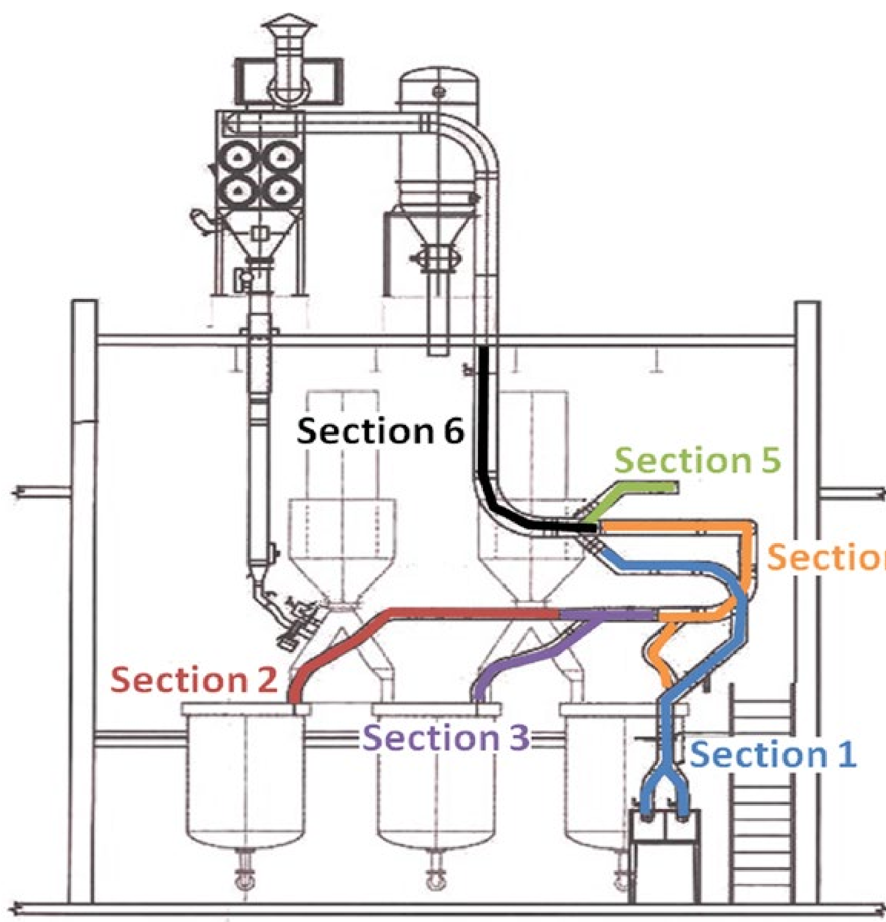
4.0 SAMPLE TEST RESULTS AND INCIDENT IMPLICATIONS

The CSB observed removal of the dust collection system ductwork in December 2012. Investigators collected residue samples from six sections of the entire ductwork system (shown in Figure 8). They inspected the interior of various ductwork sections and took material samples from inside the ducts. These inspections revealed large accumulations of black, burned, and unburned materials. Most of the accumulations appeared to be black sludge–like material. The CSB investigators collected samples of the sludge-like material for further chemical composition analysis and testing to develop possible ignition scenarios.

Several different types of tests were conducted on the samples. Chemical composition analyses were performed, using Fourier transform infrared spectrometry and gas chromatography/mass spectrometry. Ignitability and dust explosibility tests were conducted,

FIGURE 8

Ductwork sections for sampling



using the ASTM International[42] standard test method for ignition temperatures, minimum ignition energy, and dust explosibility. The composition analysis showed that the duct sludge was a mixture of hydrocarbon oil, clay, and carbon black. Table 2 lists the different tests performed to develop possible ignition scenarios and the associated results.

TABLE 2. TEST RESULTS

Sample Description	Test Conducted	Values
750 oil from supply tank	Closed cup flash point	378°F
Oil from T-306	Closed cup flash point	392°F
Oil from T-206	Closed cup flash point	338°F
Oil from T-106	Closed cup flash point	361°F
Carbon black	Hot air over layer ignition temperature	676°F
Gilsonite	Hot air over layer ignition temperature	453°F
Carbon black	Dust cloud minimum ignition energy	>10 J
Gilsonite[43]	Dust cloud minimum ignition energy	<3 mJ
Residue from duct section 2	Self-heating onset temperature	340°F
Residue from duct section 2 (lower region)	Spontaneous heating value	1°F
Residue from duct section 2 (upper region)	Spontaneous heating value	0°F
Residue from duct section 3	Spontaneous heating value	0°F
Residue from duct section 4 (lower region)	Spontaneous heating value[44]	0°F
Residue from duct section 4 (middle region)	Spontaneous heating value	3°F
Residue from duct section 4 (upper region)	Spontaneous heating value	4°F

[42] ASTM International (formerly the American Society for Testing and Materials) is a standards organization that develops, publishes, and delivers voluntary international consensus technical standards (http://www.astm.org/ABOUT/overview.html).

[43] Previous incidents involving Gilsonite fires and explosions have occurred in underground mines. One such incident occurred in December 1910 in an asphalt mine in Oklahoma. In 1945, a fire resulted from a Gilsonite explosion at the Bonanza Mine in Utah. In 1953, a violent explosion and fire at the only Gilsonite mine in Utah killed eight miners (http://www3.gendisasters.com/utah/8897/bonanza-ut-mine-blast-kills-eight-nov-1953).

[44] ASTM International, *ASTM 3523-92: Standard Test Method for Spontaneous Heating Values of Liquids and Solids (Differential Mackey Test)*. According to this method, the spontaneous heating value of a substance is a measure of the ability of that substance to undergo self-heating reactions while supported by cellulosic or other fibrous materials in the air. It is an index of the autoignition tendency of the substance under such conditions. The spontaneous heating value can be lower than the test temperature. A negative result does not preclude spontaneous heating initiating at a temperature higher than the test temperature.

4.1 IGNITION TEMPERATURE AND SPONTANEOUS HEATING TESTS

The oil flash points and powder layer ignition temperatures are all higher than both the typical 240°F temperature for the mixing tanks and the maximum 300°F recorded for T-306 and T-106 on the day of the incident. The spontaneous heating data indicate a low tendency for spontaneous residue heating at temperatures around 180°F. Although the residue self-heating onset temperature was 340°F, the duct sludge before the incident would have had a lower self-heating onset temperature because it would have contained the more volatile components subsequently driven off during the incident fires.

4.2.MINIMUM IGNITION ENERGY TESTS

Minimum ignition energy (MIE)[45] tests were conducted for Gilsonite and carbon black dust to determine their level of susceptibility to electrostatic discharge.[46] The low MIE measured for the Gilsonite sample, less than 3 millijoules (mJ) demonstrated that Gilsonite[47] dust clouds are susceptible to ignition from electrostatic discharges. However, the Gilsonite in the main trunk of the dust collector ductwork was mixed with carbon black and with oil vapor condensates. Because the carbon black was conductive, it greatly reduced the chances for electrostatic charging of high-resistivity materials such as the dust collector filter cartridges. Furthermore, the carbon black had a high MIE, more than 10 joules (J), making it not susceptible to electrostatic discharge ignitions unless mixed with enough Gilsonite to produce a mixture with an MIE less than 100 mJ. Therefore, electrostatic discharge ignition in the dust collector was less likely than the scenario described previously (i.e., duct accumulation, self-heating, and autoignition).

4.3.DUST EXPLOSIBILITY TESTS

The CSB conducted ASTM E1226[48] explosibility tests to determine the explosion severity of the dust involved in this incident. Table 3 shows the resulting explosion pressure (P_{Max}) and normalized maximum rate of pressure rise (K_{ST}) values for carbon black, Gilsonite, and dust samples collected within the dust collector.

TABLE 3. ASTM E1226 DUST EXPLOSIBILITY TEST DATA

Dust Sample Material	Particle Size Tested	P_{max} (barg)	K_{ST} (bar-m/sec)
Carbon black	98% <75 µm	8.0	98
Gilsonite (first sample)	98% <75 µm	8.1	199
Gilsonite (second sample)	97% <75 µm	7.5	235
Dust collector sample 1	98% <75 µm	8.3	123
Dust collector sample 2	98% <75 µm	7.6	102

45 MIE is the minimum amount of energy required to ignite a combustible vapor, gas, or dust cloud.

46 An electrostatic discharge occurs when two separated surfaces come into contact and then accumulated charges are transferred from one surface to the other via a discharge. For an electrostatic discharge to occur, one of the surfaces must be highly electrically insulating.

47 The National Institute for Occupational Safety and Health conducted explosibility testing based on experimental mine explosions that indicated Gilsonite is 84 percent volatile, much higher than coal dust at 36 percent volatile (http://www.msha.gov/S&HINFO/RockDusting/JLP-Exp-Mine-paper%20emald.pdf).

48 ASTM International, *ASTM E1226: Standard Test Method for Pressure and Rate of Pressure Rise of Combustible Dusts.* This method indicates that the values for maximum explosion pressure (PMAX) and maximum rate of pressure rise are determined by using a 1-cubic-meter (m3) or 20-liter sphere test apparatus. The dust sample is dispersed within the sphere and ignited by chemical igniters, and the pressure of the resulting explosion is measured. The cloud concentration is varied to determine the optimal dust concentration. The PMAX and maximum rate of pressure rise are measured and used to calculate the dust deflagration index (KST) value of the dust cloud. These data can be used to design dust explosion protection measures (such as explosion relief venting, suppression, and containment) and to classify the explosion severity of a material.

According to an SSI system design drawing, the design for the Fike dust collector explosion suppression and isolation system was based on a dust explosion hazard corresponding to a maximum pressure (P_{Max}) of 10 bar gauge (barg) and a normalized rate of pressure rise (K_{ST}) of 165 bar-m/sec.[49] The P_{Max} data for all five dust samples listed in Table 3 were less than 10 barg. The obtained K_{ST} values for three of the dust samples were less than 165 bar-m/sec, but the K_{ST} values for the two Gilsonite dust samples were more than 165 bar-m/sec (Table 3). The low MIE and higher K_{ST} values indicate that Gilsonite is a faster-burning dust that represents both a greater susceptibility to deflagration and a more demanding explosion protection system challenge than the specified K_{ST} value of 165 bar-m/s.

4.4. GO/NO-GO DUST EXPLOSIBILITY AND SPECIAL FLAMMABILITY TESTS

The go/no-go dust explosibility screening test[50] (using a residue sample from the duct) and the special sludge oil flammability test were conducted to determine whether the burning sludge observed in the duct stub above T-306 after the dust collector explosion also could be partially responsible for the second fireball and explosion. The go/no-go explosibility test result demonstrated that the residue powder was indeed explosible at dust concentrations of 100 grams per cubic meter (g/m3) and higher. The special sludge oil flammability test demonstrated that the burning sludge in the duct stub would not ignite the vapors in the tank itself if the tank liquid were at a temperature below its flash point, even if the burning sludge fell into the tank.

On the basis of all the test results, the CSB concluded that the incident probably started with the self-heating and spontaneous ignition of the accumulated sludge (mostly Gilsonite and carbon black mixed with hydrocarbon oils) in the ductwork of the dust collection system. Transport of the burning sludge to the dust collector caused the dust collection explosion. The explosibility of the accumulated sludge and powder deposits in various sections of the duct combined with the flame propagation back from the dust collector explosion to cause more extensive residual burning in the various duct sections. Dust deposits in and around the ducting, including deposits produced from the dust collector explosion, dispersed as the US Ink employee climbed the stairs,[51] intending to suppress the visible flame in the detached flexible duct above Tank 306. The residual flame ignited the dispersed dust, and the subsequent fireball dislodged and lifted more dust so that an expanding fireball vented through the doorway into the corridor. This expanding fireball (or flash fire) was responsible for the multiple burn injuries.

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49 Engineers from US Ink provided Fike representatives with values for maximum rate of pressure rise (KST) for combustible materials used in the ink manufacturing process based on values that US Ink obtained from material suppliers.

50 The explosibility screening (go/no-go) test is used in the laboratory to determine whether a powder or dust will explode while in the form of a dust cloud when exposed to an ignition source. The test results for a material classify it as either a go type (explosible) or a no-go type (nonexplosible). Thus, the test is also known as the go/no-go test.

51 The dust dispersal may have been due to one of the following phenomena: (1) thermal failure of the flexible connection to T-306, (2) vibrations caused by the employee climbing the stairs, (3) initiation of the extinguisher discharge, or (4) sudden vaporization of a layer of condensed water vapor (produced by the burning sludge and dust) after the water dripped back into the tank and started sinking into the hot oil.

5.0 ENGINEERING DESIGN ANALYSIS

CSB interviews with the US Ink design engineer, manufacturer, and distributor for the newly installed dust collection system revealed some design deficiencies. The CSB determined that improper design and operation of the new dust collection system were major contributing factors that led to the October 9, 2012, incident. The dust pickup points in the dust collection system pulled excessive quantities of dust and condensable vapors into the ductwork, which operated at low conveying velocities (as demonstrated by the quantities of accumulated dust found in the ductwork after operating the system for less than 2 days). This accumulation in the ductwork was the fuel for the primary deflagration that initiated the incident chain of events.

Other design issues contributing to material accumulation, observed post-incident in the ductwork of the dust collection system, include the following (each discussed in more detail in a subsequent section, as noted):

- Dust pickups at mix tanks that pulled air through the tank headspaces and extracted excessive quantities of condensable vapors and dust into the duct mains (Section 5.1)
- Dust loading from housekeeping dust pickups with insufficient makeup air (Section 5.2)
- Duct blockage because of failure to consider the effect of condensable vapors in the ductwork (Section 5.3)
- Blockage of the Dust Collector Dust Fines Chute Because of Design Failure (Section 5.4)
- Duct main blockage from low conveying velocity (Section 5.5)
- Ineffective system checkup at commissioning of the dust collection system (Section 5.6)
- Lack of system controlling parameters for operators to monitor performance and detect system degradation (Section 5.7)
- Dust collection system that was not designed to prevent and contain fires or extinguish fires (Section 5.8)

5.1. MIXING TANK DUST PICKUPS THAT RELEASED VAPORS AND DUST INTO DUCT MAIN

On the basis of analytical testing of the materials in the ductwork (summarized in Section 4), the CSB concluded that excessive quantities of condensable vapors were released into the ductwork of the dust collection system during its operation. An essential consideration in the design of a dust pickup of a dust collection system is how air enters the pickup and travels to the connected duct. In a closed system such as the mix tanks, air from the tanks is displaced when the tanks are filled with liquid or powders, and air must be drawn into the tanks as the liquid ink mixture is pumped out of the tank. At the US Ink East Rutherford facility, each of the three mixing tanks in the pre-mix room had a small air bleed duct (1.5 inches in diameter) on the rectangular powder fill chute from the carbon black delivery systems. Also attached was a flexible hose for delivering kaolin clay to the mixing tank. The tank was connected to the dust collection system through a flexible duct (6 inches in diameter) a few feet from the powder delivery chute (depicted in Figure 3).

During operation of the mixing tanks and the dust collection system, air entering the tank through the 1.5-inch air bleed duct fluidized some of the powder in the chute on the way to the mixing tank during powder addition. Once in the tank, the air and some of the powder dust mixture traveled across the tank headspace, also picking up condensable vapors before exiting the tank in the flexible duct. The air volume admitted through a 1.5-inch duct is not

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sufficient for an adequate conveying velocity[52] in the 6-inch duct for dust, so only the finest particle sizes will continue moving.

The CSB investigation revealed that the US Ink engineers initially had a design that would minimize high dust and condensable vapor loading of the dust collection system. However, the final design of the installed dust collection system did not avoid a continuous airflow through the tank headspace, which would discharge condensable vapors and dust mixture from each of the mixing tank headspaces into the moving air stream in the duct main.

5.2 DUST LOADING FROM HOUSEKEEPING DUST PICKUPS WITH INSUFFICIENT MAKEUP AIR

The addition of three housekeeping hoses to the system contributed additional dust to the main ductwork, but not the makeup air needed to convey the additional dust to the dust collector. The three (1.5-inch) hoses were connected to the bottom of the adjacent mix tank ducts via enlargement to a hose 3 inches in diameter. The American Conference of Governmental Industrial Hygienists (ACGIH) Industrial Ventilation Manual (IVM) states, "All branches should enter the main at the center of the transition at an angle not to exceed 45° with 30° preferred in most cases (Figure 5-23)."[53] In addition, ACGIH noted, "To minimize turbulence and possible particulate fall out, connections should be to the top or side of the main with no two branches entering at opposite sides."[54] The ductwork design for the US Ink dust collection system did not comply with this guideline.

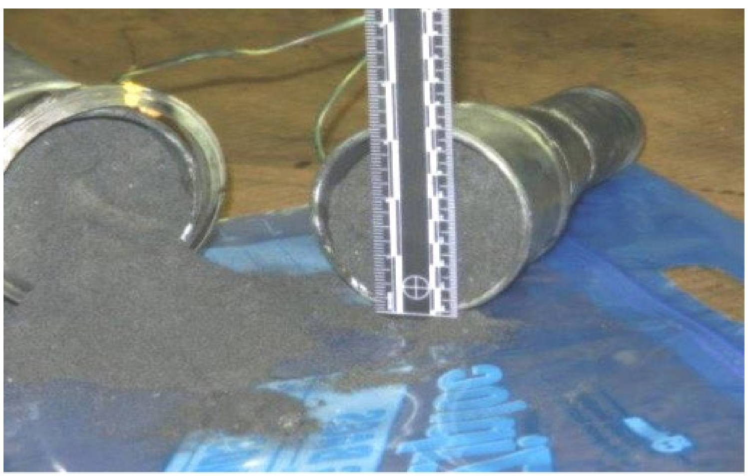

FIGURE 9

Vacuum cleaning ducts, plugged after less than 2 days of operation

The 3-inch ducts were disassembled during the investigation; they were plugged with free-flowing dust, a sign of insufficient conveying velocity (as illustrated in Figure 9). The connection of housekeeping hoses to a dust collection system is not a good practice because the pressure drop required to move air at 4,000 feet per minute (ft/min) in the 1.5-inch hose (1.5 to 2.0 inches of mercury or 20 to 27 inches of water column) is much greater than the available system static pressure of 17 inches of water column. In addition, doubling the duct diameter reduced the air velocity to less than 25 percent of that available in the hose, plugging the 3-inch duct in less than 2 days of operation.

52 Conveying velocity is the minimum air velocity required to move or transport particles within a duct system. It is measured in feet per minute (ft/min).

53 At the time of the incident, the 2007 edition of the IVM provided the applicable guidance; however, since then, ACGIH revised the guidance and published a 2013 edition of the IVM.

54 American Conference of Governmental Industrial Hygienists, *Industrial Ventilation: A Manual of Recommended Practice for Design*, 26th Edition (Cincinnati, OH: ACGIH, 2007) 5-27.

5.3 DUCT BLOCKAGE BECAUSE OF FAILURE TO CONSIDER EFFECT OF VAPORS AND DUST IN DUCTWORK

The design of ductwork for the dust collection system did not reflect consideration of the presence of condensable vapor generated by the high temperature of the ink mixing process. US Ink did not make any provisions to prevent or clean out the uncontrolled condensation. The ACGIH IVM states, "If solid particulates or condensable vapors are being transported through the system, a minimum velocity is required."[55] The CSB concluded that the failure to consider the effect of condensable vapors in the design of the dust collection system led to formation of the sludge in the ductwork. In addition, the condensable vapors mixed with the dust, forming either a sludge in the duct or a cohesive dust in the dust collector.

The CSB learned that the system volume capacity for the US Ink dust collection system was 3,300 actual cubic feet[56] per minute (ACFM)[57] at 210°F, while the design for 6-inch duct velocity indicated at an estimated airflow rate of 1,150 ft/min. On the basis of a review of the heavy or moist dust description in Table 5-1 of the ACGIH IVM,[58] a minimum duct conveying or transport velocity of 4,500 ft/min would have been more appropriate for the design of the dust collection system at US Ink.[59]

The ACGIH IVM provides research data and information on the design, maintenance, and evaluation of industrial exhaust ventilation systems that are applicable to the US Ink dust collection system. A design minimum conveying velocity of 4,500 ft/min could have provided a more effective means of moving any moist dust within the dust collection system. US Ink did not provide any information or record that the engineers responsible for design and installation of the new dust collection system measured the dust conveying velocity of the system at commissioning. NFPA 654-2006,[60] paragraph 7.6.1, states, "Ducts that handle combustible particulate solids shall conform to the requirements of NFPA 91." NFPA 654 (2006 edition)[61] and NFPA 91 (2010 edition)[62] note the requirement, "All ductwork shall be sized to provide the air volume and air velocity necessary to keep the duct interior clean and free of residual material."

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55 American Conference of Governmental Industrial Hygienists, *Industrial Ventilation: A Manual of Recommended Practice for Design*, 26th Edition (Cincinnati, OH: ACGIH, 2007) 5-10.

56 An initial US Ink dust collection system design intent drawing allotted 500 cubic feet per minute (cfm) exhaust to each mix tank and 1000 cfm to the bag dump. Another 300 cfm was allotted for the three cleanup hoses. A later order confirmation placed the system volume capacity at 3,300 acfm at 210oF.

57 ACFM is a unit of volumetric capacity commonly used by manufacturers of blowers and compressors. This capacity is the actual gas delivery with reference to inlet conditions; it is the volume of gas (air) flowing anywhere in a system, independent of its density.

58 American Conference of Governmental Industrial Hygienists, *Industrial Ventilation: A Manual of Recommended Practice for Design*, 26th Edition (Cincinnati, OH: ACGIH, 2007) 5–11.

59 International Association of Plumbing and Mechanical Officials, *Uniform Mechanical Code* (Ontario, CA: IAPMO, 2009), Table 5-1, 46.

60 National Fire Protection Association, *NFPA 654: Standard for the Prevention of Fire and Dust Explosions from the Manufacturing, Processing, and Handling of Combustible Particulate Solids*, 2006 Edition (Quincy, MA: NFPA, 2006).

61 National Fire Protection Association, *NFPA 654: Standard for the Prevention of Fire and Dust Explosions from the Manufacturing, Processing, and Handling of Combustible Particulate Solids*, 2006 Edition (Quincy, MA: NFPA, 2006), 13.

62 National Fire Protection Association, *NFPA 91: Standard for Exhaust Systems for Air Conveying of Vapors, Gases, Mists, and Noncombustible Particulate Solids*, 2010 Edition (Quincy, MA: NFPA, 2010), 8.

5.4 BLOCKAGE OF THE DUST COLLECTOR DUST FINES CHUTE BECAUSE OF DESIGN FAILURE

The dust collector dust hopper and dust fines chute were filled with approximately 322 pounds of dust fines in just 2 days of system operation. The 10-inch-diameter chute reduced to 4 inches in diameter to return the fines to the mix tank. The cohesive dust in the 10-inch-diameter chute bridged the opening and did not flow through the 4-inch chute. The dust chute design did not allow for the stop-and-start nature of dust fines return.[63] If the incident had not halted operation of the process, the dust collector would have been plugged within a few more days of operation.

5.5 DUCT MAIN BLOCKAGE FROM LOW CONVEYING VELOCITY

The duct main[64] had insufficient conveying velocity until the three-way junction where the bag dump branch and the duct-mounted air bleed joined the duct from the three mix tanks and the housekeeping system pickups. The small 1.5-inch-diameter mix tank air bleeds would not admit enough air for conveying velocity in the 6-inch mix tank ducts or the 8-inch and 9-inch ducts with combined mix tank exhaust; this configuration created conditions in this section of the dust collection system that allowed the accumulation of condensable vapors and dust.[65] As stated previously, locating the duct air bleed ahead of the first mix tank would have provided a makeup air source for a reliable conveying velocity in the duct main.[66]

5.6 INEFFECTIVE SYSTEM CHECKUP AT COMMISSIONING OF THE DUST COLLECTION SYSTEM

Outside contractors performed all construction and installation of the new dust collector. Sun Chemical selected two contractors to configure the dust collection system, based on direction from the US Ink senior engineer. US Ink/Sun Chemical Corporation did not perform onsite risk and hazard assessments before start-up of the new dust collection system to determine the effectiveness of performance of the newly installed dust collection system. In addition, after contractors completed the dust collection system installation, no onsite inspection or measurement of system performance parameters (such as airflow rate and conveying velocity) was conducted to ensure that the system was working appropriately.[67]

No pitot tube[68] holes were visible in the ducts, indicating that no system pressure measurements were taken at commissioning of the dust collection system. NFPA 91 and NFPA 654 require initial system testing, including measurement of all system branches to verify that the system delivers target airflows and to set the blast gates as necessary.

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63 Very low conveying velocities in the ductwork, combined with air flow through the dust powder delivered in the chute, ended up putting dust and vapors into the duct but did not carry sufficient dust away through the recycle process and back into T-106.

64 The duct main is the section of the ductwork where other incoming duct branches join the main duct.

65 US Ink and its contractors responsible for the efficiency of the dust collection system performance did not perform any measurements to confirm the designed air flow rate and conveying velocity.

66 Bag dump and duct air bleeds should have been located at the far end of the duct to provide continuous airflow.

67 US Ink/Sun Chemical maintained that a US Ink contractor engineer performed a brief system start-up to ensure that everything was working properly. During that time, the suction of the dust collection system was checked. In addition, the conveying velocity was intended to be manually adjusted as production progressed, by use of the weighted damper, to ensure that the system was getting the right amount of suction. Although US Ink employees claimed there was too much suction (rather than too little), iterative testing of the process could not be performed to confirm actual flow rates as all the drops of dry materials had been completed for the day. Despite this argument by US Ink, the CSB asserts that visual observation of the suction rate by US Ink employees does not convey that a system start-up check or measurements were taken to quantify the performance and efficiency of the new dust collection system.

68 A pitot tube is an instrument used to measure air or fluid flow velocity under pressure. The basic pitot tube consists of a tube pointing directly into the air or fluid flow. Pressure can be measured based on the level of fluid in the tube.

Section 10.3.1 of NFPA 91 specifies the requirement, "When installation of a new system is complete, the system shall be tested to demonstrate performance before acceptance by the user."[69] Annex paragraph A.10.3 lists required system test activities, including:

- Measure the air volume, fan static pressure,[70] motor speed and electric current, and temperature of air in the system
- Determine pressure drops across all components (such as air cleaning equipment)
- Record the test data and design specifications
- Compare the test data with design specifications and determine whether system alterations or adjustments are necessary to meet specifications[71]

The CSB concluded that US Ink/Sun Chemical Corporation did not perform any of the previously listed tests after installation of the US Ink dust collection system. The commissioning data are critical because they provide a reference point for ongoing system monitoring and maintenance to ensure that the dust collection system runs within design parameters.

5.7 LACK OF SYSTEM CONTROLLING PARAMETERS FOR OPERATORS TO MONITOR PERFORMANCE

Dust collection system designs seek to overcome the anticipated flow resistance of the hoods, ducts, dust collector, auxiliary equipment, and exhaust stack. Many possible causes for anticipated resistance in these areas could affect system performance. For example, dust buildup in a duct reduces flow but increases local duct pressure between the dust collector and the plug; an increase in filter differential pressure restricts flow to the entire system, reducing hood exhaust airflow and hood static pressures. By knowing the pressure profile of different points in the system, as established with a newly commissioned system, operators can monitor changes in this information to enable timely interventions to keep the system working. Although the US Ink dust collection system had some remote indicators of differential pressures for the dust collector and the HEPA filter, none of the pressure gauges displayed action limit information, and no local static pressure devices near the mixing tanks or the bag dump hood warned the operator of performance problems, as recommended in the ACGIH manual, "Industrial Ventilation, A Recommended Practice for Operation and Maintenance."[72]

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69 National Fire Protection Association, *NFPA 91: Standard for Exhaust Systems for Air Conveying of Vapors, Gases, Mists, and Noncombustible Particulate Solids*, 2010 Edition (Quincy, MA: NFPA, 2010), 15.

70 Static pressure (SP) is defined as the pressure in the duct that tends to burst or collapse the duct and is expressed in inches of water gauge. It is usually measured with a water manometer, hence the units. SP can be positive or negative with respect to the local atmospheric pressure but must be measured perpendicular to the air flow. American Conference of Governmental Industrial Hygienists, *Industrial Ventilation Manual*, 28th Edition (Cincinnati, OH: ACGIH, 2013).

71 National Fire Protection Association, *NFPA 91: Standard for Exhaust Systems for Air Conveying of Vapors, Gases, Mists, and Noncombustible Particulate Solids*, 2010 Edition (Quincy, MA: NFPA, 2010), 18.

72 The ACGIH IVM recommends performing system testing at the time of initial installation (commissioning) to verify the volumetric flow rates and to obtain other information that can be compared with the original design data. Initial system testing is also necessary to provide a baseline for periodic maintenance checks. The ACGIH IVM recommends static pressure measurements and close visual inspections during maintenance checks if no alterations have been made to the system.
American Conference of Governmental Industrial Hygienists, *Industrial Ventilation: A Manual of Recommended Practice for Operation and Maintenance*, 26th Edition (Cincinnati, OH: ACGIH, 2007), Chapter 2, "Commissioning and Proof of Performance."

5.8 DUST COLLECTION SYSTEM NOT DESIGNED TO PREVENT, CONTAIN, OR EXTINGUISH FIRES

US Ink employee testimonies revealed that the rubberized flexible hoses were the first part of the system to fail when the duct fire started. The US Ink mixing tanks had flexible hose lengths of 6 to 8 feet, which increased airflow restriction at the mixing tanks.[73] The hose lengths of 8 to 10 feet at the bag dump station also added resistance to that branch. US Ink maintained that flexible ducts were used because the ink mixers were on weight scales. In addition, US Ink believed that the flexible ducts—constructed of Conduct-O-Flex, a material which had a conductive spiral core and was specifically intended (and used by US Ink) to prevent static buildup—were properly bounded and grounded to the rigid duct and mixer connections. The recommended best practice suggests using flexible duct only to aid mobility of moving parts or equipment and making lengths as short as possible (usually not more than 3 feet).[74]

In addition, rubberized flexible hoses are not electrically conductive because airborne powder moving through a plastic or rubberized hose can generate some static electrical charge. Combustible dust particles with a low MIE can ignite because of an electrostatic discharge from a nonconductive hose. The combustible flexible hoses used in the dust collection system design burned through rapidly and ultimately released the flash fire from the top of T-306 into the pre-mix room. The fire did not seriously damage any of the metal ducts, but all of the flexible hoses along the fire path suffered severe burns.

A detailed examination of the US Ink dust collection system revealed the absence of duct cleanout doors. Duct cleanouts are commonly needed for dust collection systems as part of routine system monitoring and maintenance. The ACGIH IVM states, "Where the air contaminant includes particulate that may settle in the duct, clean-out doors should be provided in horizontal runs, near elbows, junctions, and vertical runs (see Figure 5-17)."[75] Cleanout doors provide access to clean out accumulated dust and also serve as locations where firefighters can introduce water to fight fires. Because the US Ink facility had no cleanout doors,[76] the East Rutherford firefighters had to break a section of ductwork to apply water to smoldering ductwork sections.

The CSB inspection of the US Ink dust collection system indicated that ducts with cross-sections larger than 75 square inches (about 9.5 inches in diameter) did not have an automatic fire extinguishing system.[77] Chapter 9 of NFPA 91 (2010 edition)[78] specifies, "Any portion of an exhaust system utilizing combustible components or having the potential for combustible residue buildup on the inside, where the duct cross-sectional area is greater than or equal to 75 in^2 (480 cm^2), shall be provided with an automatic

73 The flexible hoses used in the dust collection system design were longer than needed and led to failure points during the incident.

74 National Fire Protection Association, *NFPA 91: Standard for Exhaust Systems for Air Conveying of Vapors, Gases, Mists, and Noncombustible Particulate Solids*, 2010 Edition (Quincy, MA: NFPA, 2010). This standard emphasizes the need to minimize the use of flexible hose, using it only for equipment that needs to move and then only in lengths as short as possible.

75 American Conference of Governmental Industrial Hygienists, *Industrial Ventilation: A Manual of Recommended Practice for Design*, 26th Edition (Cincinnati, OH: ACGIH, 2007), 5-27.

76 US Ink/Sun Chemical maintained that the dust collection system featured "easy-open" connections between pieces of the ductwork, which enabled easy inspection (and cleaning) of the ductwork interiors. US Ink believed that the easy-open connection was used in place of duct cleanout doors and as such served a similar purpose. Although the easy-open connection provided a reasonable alternative to the cleanout doors, firefighters could not use it to apply water to burning duct sections.

77 The ductwork assembly from section 6 (ductwork that was vertically installed from the pre-mix room up to the rooftop and continuing to the dust collector, as shown in Figure 8) was measured at 12 inches in diameter.

78 National Fire Protection Association, *NFPA 91: Standard for Exhaust Systems for Air Conveying of Vapors, Gases, Mists, and Noncombustible Particulate Solids*, 2010 Edition (Quincy, MA: NFPA, 2010), 15.

extinguishing system within the duct and at the duct intake, hood, enclosure, or canopy, or shall be constructed of material listed for use without sprinkler protection."[79] Although the Fike chemical suppression and isolation system attached to the dust collector stopped an explosion, it was not designed to extinguish fires, other than preventing backward flame propagation from the dust collector past the location of the chemical isolation device.[80] In addition, incorporating sprinklers or some other extinguishing system in the 12-inch duct might have helped minimize duct damage on the day of the incident. Moreover, sprinklers are prudent for a dust collector protected by a chemical suppression system because an explosion suppression and isolation system is not designed to extinguish a fire in the ductwork or in the dust collector. CSB investigations revealed that US Ink engineers and the third-party loss prevention and risk management consultants (hired by US Ink/Sun Chemical Corporation) considered including internal sprinkler protection and explosion venting within the dust collector but ultimately decided against including sprinklers because of installation of the Fike explosion suppression and isolation system and because of cost-effectiveness factors.

6.0 SAFETY MANAGEMENT ANALYSIS

The lack of adequate oversight by Sun Chemical Corporation management personnel in the planning, design, installation, and commissioning of the dust collection system likely contributed to the October 9, 2012, incident. The CSB identified significant management issues, including inadequate project oversight, ineffective employee training on the dust collection mechanism, and failure to develop and implement corrective actions from a previous incident.

6.1 INADEQUATE PROJECT OVERSIGHT

Before design of the new dust collection system, the engineering team filed a Capital Appropriations/Asset Request (CAR),[81] which contained various levels of approvals from the local plant, engineering department, local operations manager, division controller and accounting department, corporate environmental health and safety department, and CAR approval committee. Sun Chemical project management policy requires the CAR, which must be prepared if the total cost of a project exceeds $350,000. The estimate for the US Ink dust collection system exceeded $350,000 in capital costs; therefore, a CAR was required.

In the CAR environmental health and safety section, a checkbox indicating the need for a process hazard analysis (PHA) or management of change (MOC) was not checked, indicating that neither a PHA nor a MOC was necessary for the dust collection system.[82] During interviews with company engineers and senior management, CSB investigators

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79 NFPA 91 is applicable to the incorporation of a sprinkler system in the ductwork design because it is a standard for exhaust systems for air conveying of vapors, gases, and mists (all generated from heating of ink ingredients and oils) and for noncombustible particulate solids (such as bentonite, used by US Ink).

80 Fike maintains that explosion suppression and chemical isolation device prevented backward flame propagation of a more rapid flame propagation speed at a pressure of 4.4 psig than was expected based on the predicted maximum pressure of 3.8 psig at the specified KST value of 165 bar-m/s.

81 The CAR system was designed so that Sun Chemical managers, engineers, and company decision-makers could approve projects electronically and so that information relating to the approval and rejection of a project could be saved for later reference.

82 The requirements for PHA and MOC procedures are described in: National Fire Protection Association, *NFPA 654: Standard for the Prevention of Fire and Dust Explosions from the Manufacturing, Processing, and Handling of Combustible Particulate Solids*, 2006 Edition (Quincy, MA: NFPA, 2006), Section 4.2 and Section 4.3.

learned that the engineering team considered installation of the dust collection system as a replacement in kind for the old wet scrubber system.

The CSB investigation revealed that corporate engineering managers who were responsible for executing the US Ink dust collection system project at Sun Chemical relied on the judgments and decisions of their reports and did not adequately oversee the dust collection system project. The new dust collection system is completely different from the old wet scrubber system, with different functions and design specifications. US Ink/Sun Chemical management did not seek a building permit for a completely new process because they failed to acknowledge that a PHA was required for the new process.[83] If a PHA had been conducted, it would have triggered consideration of additional safety factors, including the need to obtain a building permit. The CSB determined that, as a result, US Ink/Sun Chemical management provided inadequate oversight of the capital project.

6.2 INADEQUATE MANAGEMENT OF ORGANIZATION CHANGE AND CONTRACTOR OVERSIGHT

A senior engineer who retired from US Ink before completion of the project coordinated the design of the dust collection system.[84] Upon retirement of the senior engineer, another US Ink engineer and an engineering contractor assumed oversight of the dust collection project. Although not fully involved in initial design of the dust collection system, the new engineers completed contractor hiring and equipment ordering and oversaw installation of the dust collection system. There was no record of adequate communication of transitional knowledge concerning the handover of the dust collection system from the retired senior engineer to the new engineers. External contractors (who were not fully involved in the design concept of the dust collection system) performed all construction and installation activities for the new dust collection system. The engineers communicated primarily by telephone and emails to the subcontractors, without observing the actual installation process for the dust collection system.

CSB interviews with the US Ink engineers revealed that US Ink/Sun Chemical Corporation lacked an adequate and effective process for management of organizational change. No procedures allowed for transferring and retaining design knowledge and forwarding information to the new engineer. In this case, the company relied on the retired senior engineer solely for technical guidance throughout the design, construction, and installation phases of the dust collection system. When the original design engineer left, accountability for the dust collection system fell to the new engineer, who was not directly involved in the initial design of the dust collection system, and to the in-house contractor engineer, who made frequent trips to the East Rutherford facility to observe progress on the installation process for the dust collection system. However, US Ink/Sun Chemical claimed to rely on the expertise of the manufacturers of the dust collection system and on their contractors for smooth operation of the system. As a result, US Ink/Sun Chemical did not provide additional contractor oversight for the dust collection project. In addition, the new engineer did not consult other company engineers who could support the design, installation, and commissioning of the dust collection system.

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83 The US Ink East Rutherford facility was not covered by OSHA process hazard management (PHM). However, NFPA 654 (2006 edition) requires that a combustible dust hazard assessment must be conducted and used as the basis for choices in fire and explosion protection systems. In addition, conducting an assessment of the major deficiency areas of the dust collection system would have at least triggered the need for PHA.

84 Contractors and manufacturers that specialized in dust collection systems fabricated and installed the dust collection system.

6.3 INEFFECTIVE HAZARD COMMUNICATION AND EMERGENCY RESPONSE PLANNING

Employee injuries likely would have been prevented if US Ink had developed and implemented an effective hazard communication and emergency response plan. US Ink fire and explosion emergency procedures called for a designated chief coordinator to use the public address system to announce the fire and its location as soon as it was observed. The designee also had the task of pulling the alarm box outside the main office and calling the fire department. The plant evacuation plan required all employees to evacuate the building immediately after the fire alarm was pulled. On the day of the incident, the designated fire coordinator did not perform any of the duties (announcing the fire or pulling the alarm box) because he was among those injured while assembled at the entrance to the pre-mix room. Although the pre-mix room operator informed the designee about the first flash fire from the bag dump station, the employee decided to go to the pre-mix room to observe the situation instead of performing his duties as the plant-designated fire coordinator.

In addition, the US Ink hazard communication and emergency response plan did not require that an employee attempt to control a fire with an extinguisher after a manually triggered fire alarm was actuated; rather, the plan required employees to evacuate the building immediately. Because no fire alarm sounded, employees attempted to extinguish the fire. Although all employees eventually evacuated the building, the evacuation did not occur until after the injuries were sustained. Witness interviews revealed that although the company occasionally conducted training and fire drills, employees did not follow the existing emergency response plan on the day of the incident.[85] This circumstance indicated that the fire hazard and emergency training received by plant employees was inadequate.

The sprinkler system in the pre-mix room was connected to an automatic audible alarm that was relayed to the East Rutherford Fire Department, but no record indicated that the automatic fire alarm provided adequate (if any) notification to employees. The CSB observed that no other automatic fire alarm system was located anywhere in the US Ink East Rutherford facility. An effective automatic fire alarm would have immediately notified employees of the flash fires and triggered an immediate evacuation; instead, employees congregated at the entrance of the pre-mix room. The manual alarm notification system that US Ink adopted was ineffective on the day of the incident. NFPA 72 (National Fire Alarm Code, 2007 edition[86]) specifies requirements for the installation and operation of automatic fire alarms and other fire detection systems, including audible and visible fire emergency notification systems.

6.4 INEFFECTIVE EMPLOYEE TRAINING ON DUST COLLECTION MECHANISM

After initial start-up of the dust collector, a 15-minute meeting was held on October 5, 2012, for supervisors and one of the day-shift operators[87] and was less than adequate. At the meeting, the system manufacturer provided a walkthrough of the dust collection system and a brief interpretation of visual indicators. The meeting did not include information on how the dust collection system was designed to work and how operators could troubleshoot problems. This limited training did not adequately prepare the staff to address a malfunction of the dust collection system. In addition, US Ink did not develop a fire or

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85 The CSB review of records for fire safety training and drills indicated that the hazards of combustible dust explosions were communicated to the employees; US Ink employees followed the "pre-planned" annual drills; and seven employees were injured on the day of the incident as a result of the failure to follow the hazard communication procedures outlined in the training and fire drills.

86 National Fire Protection Association, *NFPA 72: National Fire Alarm and Signaling Code*, 2007 Edition (Quincy, MA: NFPA, 2007).

87 The night-shift pre-mix room operator did not receive the 15-minute walkthrough and instructions.

explosion incident prevention program to reinforce employee understanding of the potential hazard severity associated with the newly installed dust collection system. Moreover, no mechanism was in place for pre-mix room operators to determine changes in dust collection system performance.

6.5 FAILURE TO DEVELOP AND IMPLEMENT CORRECTIVE ACTIONS RESULTING FROM A PREVIOUS INCIDENT

Before October 9, 2012, a similar fire incident involving a mixing tank occurred at the US Ink East Rutherford facility on February 29, 2008, when the East Rutherford Bureau of Fire Safety and the East Rutherford Fire Department responded to a fire incident at the US Ink facility. The fire occurred in an ink mixing tank (about 80 percent oil and 20 percent carbon black). According to the East Rutherford Bureau of Fire Safety, the fire occurred because of overheating of ingredients in the mixing tank. The official report documenting the emergency response indicated that the ductwork at the top of the tank was consumed by the flames generated during the fire. An employee initially attempted to suppress the fire with a fire extinguisher but, after failing to do so, exited the building.[88] The US Ink security service company notified the East Rutherford Fire Department, and responding units extinguished the fire.

No injuries were reported as a result of this previous incident. US Ink did not address any lessons learned from this incident. It did not discourage employees from attempting to extinguish fires in an environment with flammable vapor and combustible dust. In addition, the company did not install temperature indicators and temperature interlocks that would activate when the temperature from the ink mixing operation became too high.

7.0 REGULATORY ANALYSIS

7.1 U.S. OCCUPATIONAL SAFETY AND HEALTH ADMINISTRATION

7.1.1 Combustible Dust Standard

The CSB has investigated multiple combustible dust incidents since 2003. The agency initiated a study of dust explosions in general industry after three catastrophic incidents in one year, and it issued the Combustible Dust Hazard Study in 2006. This CSB study identified 281 combustible dust incidents between 1980 and 2005, which led to the deaths of 119 workers, injured 718, and extensively damaged numerous industrial facilities.[89] The need to control the risk of dust explosions in general industry became apparent, and as a result, the Board issued six recommendations; one advocated a new federal OSHA standard based on existing NFPA standards for combustible dust.

The CSB study found that a comprehensive federal regulation specific to combustible dust was necessary because the reliance on industry to voluntarily comply with consensus standards, fire codes, or both was insufficient to control combustible dust hazards. US Ink

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88 The US Ink hazard communication and emergency response plan did not require an employee to try to control a fire with an extinguisher but instead required employees to evacuate the building immediately when a fire alarm sounded. Industry best practices discourage employees from attempting to extinguish fires in a combustible dust environment because this approach could be deadly.

89 U.S. Chemical Safety and Hazard Investigation Board, *Final Report: Combustible Dust Hazard Study*, Investigation Report No. 2006-H-1 (Washington, DC: CSB, 2006) (http://www.csb.gov/combustible-dust-hazard-investigation/ and http://www.csb.gov/assets/1/19/Dust_Final_Report_Website_11-17-06.pdf).

did not consistently follow NFPA-prescribed design requirements or ACGIH standards when designing its new dust collection system (discussed in Section 5). Moreover, OSHA enforcement of existing regulations failed to address dust hazards. OSHA initially cited US Ink and fined it $25,000 for the October 9, 2012, incident, characterizing the accident as a dust explosion. The citations included violations of OSHA standards for exit routes, storage and handling of liquefied petroleum gases, portable fire extinguishers, and hazard communication. However, many of the listed violations were not causally linked to the flash fire that burned the seven workers. Consequently, US Ink corrective actions to address those violations would not prevent or mitigate the risk of a future combustible dust incident. OSHA inspectors need a comprehensive standard to regulate the design and operation issues of processes involving combustible dust to effectively prevent combustible dust incidents.

Since 2006, the CSB has continued to investigate catastrophic combustible dust incidents in all types of industries. For example, just 2 years after the CSB issued its study, an explosion of sugar dust at the Imperial Sugar Company manufacturing and packaging facility in Port Wentworth, Georgia, killed 14 workers and injured 38 others. In 2010, an explosion involving titanium dust ripped through the AL Solutions, Inc., processing facility for titanium and zirconium scrap metal in New Cumberland, West Virginia, killing three workers and injuring one. Just over a year before the US Ink incident, the CSB investigated three iron dust incidents at the Hoeganaes Corporation steel and iron powder manufacturing facility in Gallatin, Tennessee, that killed five workers and injured three others in 2011. The findings from these investigations reinforced the CSB 2006 study findings and led to reiteration of the CSB recommendation to OSHA to issue a combustible dust standard and to do so promptly. The CSB also has been tracking combustible dust incidents, documenting 50 accidents involving combustible dust that caused 29 fatalities and 161 injuries from 2008 to 2012.[90]

To date, OSHA has not promulgated a combustible dust standard, although it has started the rulemaking process. In 2009, OSHA published an Advance Notice of Proposed Rulemaking (ANPR) for combustible dust that defines the hazard as “all combustible particulate solids of any size, shape, or chemical composition that could present a fire or deflagration hazard when suspended in air or other oxidizing medium.” US Ink carbon black and Gilsonite powders are characterized as “combustible” according to Material Safety Data Sheets (MSDSs) and therefore would be covered by this proposed rule.

Although the agency has continued to place the combustible dust rule on its regulatory agendas over the years, OSHA has not moved forward in rulemaking. As a result, the CSB held a public meeting in Washington, DC, on July 25, 2013, declaring OSHA actions “unacceptable” because of the delay in issuing a combustible dust standard, and the CSB also placed the issue of combustible dust on its Most Wanted Chemical Safety Improvement Program list.[91]

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90 U.S. Chemical Safety and Hazard Investigation Board, *Final Report: AL Solutions*, Investigation Report No. 20011-3-I-WV (Washington, DC: CSB, 2011), Appendix C (http://www.csb.gov/assets/1/19/Final_Case_Study_7.161.pdf, accessed August 13, 2014).

91 U.S. Chemical Safety and Hazard Investigation Board, *U.S. Chemical Safety Board Determines OSHA Response to Seven Open CSB Recommendations on Dust, Fuel Gas, and Process Safety Management to Be “Unacceptable”; Board Votes to Designate a Combustible Dust Standard as “Most Wanted”* (Washington, DC: CSB, 2013) (http://www.csb.gov/us-chemical-safety-board-determines-osha-response-to-seven-open-csb-recommendations-on-dust-fuel-gas-and-process-safety-management-to-be-unacceptable/). Also: *U.S. Chemical Safety and Hazard Investigation Board, U.S. Chemical Safety and Hazard Investigation Board Recommendations Status Change Summary* (Washington, DC: CSB, 2013) (http://www.csb.gov/assets/recommendation/Status_Change_Summary_Dust.pdf, accessed August 12, 2014).

OSHA does recognize that regulating combustible dust will prevent these accidents. Previous OSHA experience in regulating dust explosions in the grain industry proved that the number and severity of grain dust explosions decreased after promulgation of the Grain Handling Facilities Standard in 1987. During a 2003 regulatory review of the standard, OSHA found that grain explosions had declined by 42 percent, injuries by 60 percent, and fatalities by 70 percent.[92]

Furthermore, recent OSHA inspection data indicated that inspectors were using the general duty clause (GDC) almost seven times more often for citations related to combustible dust than for all other citations. Inspectors use the GDC when no specific standard applies to a recognized hazard. OSHA found that the most common GDC violations for dust hazards cited equipment that was not adequately equipped to prevent excessive dust accumulations, failure to effectively protect systems to prevent a dust explosion or deflagration, and failure to reduce ignition sources in the presence of dust. These hazards are addressed in consensus standards, which inspectors referenced when using the GDC. OSHA concluded that the "unusually high proportion" of GDC citations supported the need for a comprehensive OSHA combustible dust standard.[93]

7.1.2 OSHA Combustible Dust Education and Enforcement Efforts

Since the release of the CSB 2006 study, OSHA has made efforts to educate employers who might have combustible dust hazards. On its website, OSHA created a resource page ("Combustible Dust: An Explosion Hazard") that includes guidance for workers and emergency responders on precautions to take when handling or responding to incidents involving combustible dust.[94]

OSHA also has increased its enforcement actions, moving toward identifying and correcting combustible dust hazards as a result of some of the CSB recommendations from the 2006 study. In October 2009, OSHA reported training more than 350 compliance officers on combustible dust and developed other training courses that both federal OSHA and state personnel have attended since December 2007.[95]

OSHA also initiated the Combustible Dust National Emphasis Program (NEP) in 2007, an inspection program to target specific industry hazards during a specified time period. OSHA reissued the Combustible Dust NEP in 2008 after the Imperial Sugar accident to intensify enforcement activities for facilities that have combustible dust hazards. States that fall under federal jurisdiction, such as New Jersey, are required to inspect in accordance with the Combustible Dust NEP. Each OSHA Area Office receives a list of establishments in that geographical region with North American Industry Classification System (NAICS) codes that correspond to industry sectors identified by OSHA as "industries with more

92 "Regulatory Review of OSHA's Grain Handling Facilities Standard," 29 *Code of Federal Regulations* (CFR) 1910.272, February 2003 (https://www.osha.gov/dea/lookback/grainhandlingfinalreport.html, accessed August 13, 2014).

93 U.S. Occupational Safety and Health Administration, Advance Notice of Proposed Rulemaking, 29 CFR Part 1910, "Combustible Dust: Proposed Rule," 74 *Federal Register* (FR) 22, October 21, 2009.

94 U.S. Occupational Safety and Health Administration, *Combustible Dust: An Explosion Hazard* (https://www.osha.gov/dsg/combustibledust/enforcement.html, accessed August 13, 2014).

95 U.S. Occupational Safety and Health Administration, *Status Report on Combustible Dust National Emphasis Program*, October 2009 (https://www.osha.gov/dep/combustible_dust/combustible_dust_nep_rpt_102009.html, accessed August 14, 2014).

frequent and/or high consequence combustible dust explosions/fires" (as listed in Appendix D-1 of the Combustible Dust NEP directive) or to industries "that may have potential for combustible dust explosions/fires" (as listed in Appendix D-2 of the Combustible Dust NEP directive). On the basis of its familiarity with local industries, the OSHA Area Office can make appropriate additions or deletions. Random number selection is then used to identify facilities where the area office will conduct programmed Combustible Dust NEP inspections in a given fiscal year. Each OSHA Area Office must conduct at least three inspections per year at establishments with NAICS codes that appear in Appendix D-1 of the Combustible Dust NEP directive and at least one inspection per year at establishments with NAICS codes that appear in Appendix D-2.

The NAICS code assigned to the US Ink Facility (325910, Printing Ink Manufacturing) does not appear on either the Appendix D-1 list or the Appendix D-2 list of the OSHA Combustible Dust NEP directive. This NEP even identifies Class II locations as hazardous sites with the presence of certain substances, such as "carbonaceous dust" (i.e., carbon black).[96] The OSHA Region II Area Office did not use its discretionary authority to add the U.S. Ink facility to either list. Therefore, the facility was never subjected to a programmed inspection under the Combustible Dust NEP.

Moreover, as previously mentioned, no dust-related citations resulted from the US Ink inspection after the October 9, 2012, incident, although the incident was characterized as a dust explosion.[97] The Combustible Dust NEP requires an inspection in accordance with its guidelines after an accident involving combustible dust and provides guidance on citations, noting, "A citation under section 5(a)(1) of the OSH Act (the general duty clause) may be issued for deflagration, explosion or other fire hazards that may be caused by combustible dust within a dust collection system or other containers, such as mixers."[98] No such citation was issued to US Ink, calling into question how effectively the Combustible Dust NEP and training on combustible dust are communicated to OSHA local area offices.

7.1.3 National Impact of the NAICS Code

The latest U.S. Census data show that the total number of establishments[99] in the United States with NAICS Code 325910 (Printing Ink Manufacturing) is 429, with 11,488 paid employees. Of these sites, 5 percent are in New Jersey[100] and employ 364 workers.[101] Because no comprehensive OSHA standard regulates the hazards of combustible dust in general industry, many of these employees remain at risk of a combustible dust explosion and fire at their workplaces.

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96 U.S. Occupational Safety and Health Administration, *Combustible Dust National Emphasis Program (Reissued)*, CPL 03-00-0008 (Washington, DC: OSHA, 2008).

97 OSHA Inspection Detail, October 9, 2012, "Sun Chemical Inc. Inspection No. 704178.015" (https://www.osha.gov/pls/imis/establishment.inspection_detail?id=704178.015, accessed November 21, 2014).

98 OSHA Instruction, "Combustible Dust National Emphasis Program (Reissued)," March 11, 2008 (https://www.osha.gov/pls/oshaweb/owadisp.show_document?p_table=directives&p_id=3830#purpose, accessed November 21, 2014).

99 Establishment is defined as "a single physical location where business is conducted or where services or industrial operations are performed" (https://www.census.gov/econ/susb/definitions.html, accessed August 15, 2014).

100 New Jersey has a total of 25 establishments under NAICS Code 325910.

101 U.S. Census Bureau, *Statistics of U.S. Businesses, 2011 Annual Data* (http://www.census.gov/econ/susb/data/download_susb2011.html, accessed August 15, 2014).

7.2 STATE OF NEW JERSEY

7.2.1 New Jersey State Uniform Construction Code Act

In 1975, the New Jersey state legislature enacted the State Uniform Construction Code (UCC) Act, which is administered by the Department of Community Affairs (DCA), the primary agency in the state for building codes and standards. This act provided for a single mandatory construction code and for a fundamental restructuring of the enforcement process. Hence, the UCC—that is, New Jersey Administrative Code (N.J.A.C.) 5:23, et seq.—was adopted and became effective on January 1, 1977.[102] Under the current New Jersey UCC, a number of subcodes have been adopted, such as the International Building Code (IBC) (2009 edition) and the National Electric Code (2011 edition).

The New Jersey UCC mandates that any installation of new equipment requires the owner to file an application for a construction permit, which involves various building permits for electrical, fire, and plumbing.[103] A permit application leads to an inspection by the local building authority and ensures that appropriate codes (e.g., building, electrical, plumbing, and fire codes) are followed. The CSB found that US Ink did not submit an inquiry to the local building department, the East Rutherford Building Department, to determine whether a construction permit for the new dust collection system was necessary. Therefore, US Ink never applied for a building permit, and as a result, the building department did not inspect the new dust collection system before the incident.

The CSB found that US Ink did not apply for the permit because it thought an exemption applied under the New Jersey UCC, which excludes "manufacturing, production and process equipment." Equipment covered under the exemption is defined as "all equipment employed in a system of operations for the explicit purpose of the production of a product" and lists "air pollution equipment, such as scrubbers" as the type of equipment that is exempted.[104] US Ink applied this exemption to its dust collection system because it considered the system as "air pollution equipment" connected to the manufacturing process, capturing raw materials and recycling them back into the pre-mix room to produce the final ink product.

However, although the New Jersey UCC did not regulate the dust collection equipment at US Ink, the new structural and electrical changes involved in installing the new dust collection system still required US Ink to file for a construction permit. The New Jersey UCC states that it is unlawful to "repair, renovate, alter, reconstruct or demolish a structure…without first filing an application with the construction officials."[105] A 1992 New Jersey Register notice explains:

> Highly specialized, often preassembled equipment designed for commercial or industrial use, manufacturing, production and process equipment, or "process equipment," is often unique to its function and designed beyond the referenced standards in the UCC. This makes it impractical or impossible for code officials to review it in an appropriate way. They do, however, review electrical, water, and sanitary connections to such process equipment, as these can affect public safety.[106]

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102 Bureau of Construction Project Review website (http://www.state.nj.us/dca/divisions/codes/offices/constructionprojectreview.html, accessed September 5, 2014).

103 N.J.A.C. 5:23-2.14.

104 N.J.A.C. 5:23-2.2(a)1.

105 N.J.A.C. 5:23-2.14(a).

106 *New Jersey Register* 24:19 (October 5, 1992), 4.

This notice explains the intent of the exemption, to relieve code officials from inspecting the function and design of such equipment when the New Jersey UCC at the time referenced no standards on which to base their enforcement. However, the connections or structural building changes associated with that equipment still require a permit. Consequently, the East Rutherford Building Department cited the company after the October 2012 incident for not obtaining a construction permit.[107]

Nevertheless, if the construction permit had been obtained, it would only have required the East Rutherford facility to comply with structural and electrical code requirements. The New Jersey UCC would not have covered the design of the dust collection equipment because of the existing exemption for "manufacturing, production and process equipment." New Jersey exempted that equipment because of the lack of referenced standards in the UCC to assist code officials. However, once New Jersey adopted the IBC,[108] which includes engineering and fire protection standards set by consensus organizations such as the NFPA, the explanation from the 1992 New Jersey Register notice was no longer valid. In New Jersey, no current building or fire standards have jurisdiction over the design of the dust collection system at US Ink. The company received environmental permits for its dust collection system before installation.[109] The New Jersey environmental standards, however, only set minimum emission standards to control pollution rather than safety requirements to prevent a fire and explosion.

If the dust collection equipment had been covered by the current New Jersey UCC, US Ink would have been required to follow the IBC (2009), which requires occupancies handling combustible dust (such as carbon black) to comply with fire protection standards such as NFPA 654,[110] which US Ink did not apply appropriately in the design of the dust collection system (discussed in Section 5). The IBC defines H-2 occupancies as "buildings and structures containing materials that pose a deflagration hazard or a hazard from accelerated burning" and lists combustible dusts as a type of such material. Combustible dust in the code is defined as "finely divided solid material that is 420 microns or less in diameter and which, when dispersed in air in the proper proportions, could be ignited by a flame, spark or other source of ignition." According to its MSDS, the carbon black at US Ink met this definition. Under these provisions, US Ink would be required to have a licensed professional develop and present the engineering drawings to be submitted as part of the permit application.[111] The licensed engineer who coordinated the design of the dust collection system for US Ink likely would have evaluated the drawings to ensure compliance with IBC (2009) requirements.

In the absence of a federal combustible dust standard, states must rely on their own regulations. New Jersey code officials would need authority under the New Jersey UCC to enforce provisions that oversee the design of dust collection equipment, which would

107 "Notice and Order of Penalty, US Ink Corp/Sun Chemical Corporation," February 20, 2014.

108 New Jersey first adopted the IBC in 2003 and adopted more recent revisions over the years; the last edition was adopted in 2010. New Jersey model code adoptions are summarized on the website (http://www.state.nj.us/dca/divisions/codes/codreg/pdf_regs_former/nj_model_code_adopt_5_7_12.pdf).

109 US Ink Preconstruction Air Permit, Operating Certificate PCP100002.

110 International Code Council, *International Building Code*, 2009 Edition (Country Club Hills, IL: ICC, 2009), Chapter 4, "Special Detailed Requirements Based on Use and Occupancy," Section 415.6.1.

111 N.J.A.C. 5:23-2.15.

require a revision of the UCC. Such revisions are needed to require companies in New Jersey that use such equipment (such as US Ink) to follow minimum design standards intended to protect workers and the public.

The New Jersey DCA promulgates New Jersey UCC regulations[112] and also provides administrative guidance and technical assistance to local departments in the state. Specifically, the DCA provides training[113] and licensing to building code officials throughout the state, administered by the Bureau of Code Services, Division of Codes and Standards.[114] Additional training on engineering design standards for processes involving combustible dust will be needed for local building code officials if their authority is expanded to inspect this type of process equipment.

Furthermore, training is needed to ensure that facilities handling combustible dusts receive the appropriate occupancy classification. US Ink was not accurately classified as an H-2 occupancy that handled combustible dust. The initial building permit identified the US Ink facility as an F-1 and S-1, which are for factory and storage occupancies. However, according to the IBC, F and S occupancies are not required to follow NFPA standards for combustible dust hazards. The DCA should provide training to local building officials on hazardous materials, such as combustible dusts, to ensure that the correct classification is assigned and appropriate building requirements are followed.

8.0 KEY FINDINGS

As a result of the US Ink investigation, the CSB makes the following findings:

1. **A flammable mixture consisting of hydrocarbons and combustible dusts accumulated in the ductwork during the start up of US Ink's dust collection system. The mixture spontaneously ignited leading to a series of events that caused a flash fire, burning 7 workers.** US Ink/Sun Chemical Corporation did not obtain building, fire, or electrical permits for the construction and installation of the new dust collector. In addition, the East Rutherford Building Department does not have a strict permit, code notification, and enforcement process to ensure compliance with the New Jersey UCC.
2. **The original design of the dust collection system was intended strictly for dust collection but was modified before commissioning to include a housekeeping function. This also caused insufficient flow rate and contributed to an accumulation of a flammable mixture in the duct system.** Although the design, construction, and installation of the new dust collector required capital project approval at the corporate level, US Ink/Sun Chemical Corporation did not provide adequate oversight of, and communications (including discussions on the possible implications of the presence of vapors from heated combustible liquids) with, contractors for the dust collection system project.

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112 N.J.A.C. 5:23-1.2.

113 DCA provides training on NFPA codes.

114 N.J.A.C. 5:23-5.2.

3. **System controls, such as temperature and pressure indicators, were not installed for operators to monitor the mixing tanks and dust collection system during start up. This led to the overheating of the flammable dust mixture which accumulated in the ductwork, and ignited above T-306.** The mix tank dust pickup design, which continuously drew air through powder and vapor in the tank headspace, led to the accumulation of dust and condensable vapor in sections where other duct branches joined the main ductwork (duct main), providing fuel for the duct fire that initiated the sequence of events.

4. **US Ink/Sun Chemical Corporation did not provide adequate oversight into the planning, design, installation and commission of the dust collection system. As a result, safety management elements such as a Process Hazard Analysis and Management of Change procedures were not conducted.** The original design of the dust collection system was intended strictly for dust collection but was modified before commissioning to include a vacuum cleaning function, with insufficient flow rate that restricted air movement and contributed to an accumulation of hazardous materials in the duct system.

5. **No processes were in place to confirm adequate start up or commissioning of the dust collection system. As a result, the blockage of the ductwork went undetected and design flaws were not revealed until after the flash fire occurred.** The dust collection system design did not ensure adequate minimum conveying velocity in all dust branches, resulting in plugged ducts and a deposited mixture of carbon black, Gilsonite, clay, and oil within a few days of start-up and accumulating dust fuel in the ducts for the resulting fire. In addition, the use of combustible rubber hoses for ducts and powder chutes contributed to the duct fire and explosion.

6. **US Ink's hazard communication, emergency response plan, and other incident prevention programs did not reinforce an understanding of the potential hazard associated with flammable vapors entering the dust collection system and mixing with the combustible dust.** No local temperature and pressure indicator monitored the mixing tanks and dust collection system. This situation likely led to the mixing temperature exceeding safe limits by a margin sufficient to cause the already self-heated vapors of oil and ink dust powder to ignite the accumulated materials in the ductwork above T-306.

7. **US Ink/Sun Chemical Corporation did not obtain construction permits for the installation of the new dust collection system.** Because of the lack of adequate commissioning or confirmation of adequate performance at start-up, the design flaws were not revealed until the dust explosion. In addition, the dust collection system was not systematically monitored and maintained; no processes were in place to detect the duct plugging that occurred.

8. **No federal agency or state agency in New Jersey regulates combustible dust hazards.** The hazard communication and emergency response plan and other incident prevention programs did not reinforce an understanding of the potential hazard severity associated with dust produced by the new dust collection system. For example, no automatic fire alarm system was in place in the other areas of the pre-mix room, as required by NFPA 72.

9. **A comprehensive OSHA federal regulation specific to combustible dust is needed because the reliance on industry to voluntarily comply with fire protection and engineering standards is insufficient to control combustible dust hazards.** The New Jersey DCA conducts training for internal personnel and local building code officials on some of the NFPA standards in the New Jersey UCC but does not provide training on combustible dust hazards or relevant NFPA standards that address combustible dust.
10. **OSHA did not include the NAICS code for printing ink manufacturing (325910), the industry classification code for US Ink, to its list of industries in the Combustible Dust NEP. OSHA inspectors refer to this list as guidance on inspections for combustible dust hazards in their region.** A comprehensive federal regulation specific to combustible dust is necessary because the reliance on industry to voluntarily comply with consensus standards and fire codes is insufficient to control combustible dust hazards. OSHA did not include printing ink manufacturing (NAICS Code 325910), the industry classification code for US Ink, in its Combustible Dust NEP when it was issued in 2007 or reissued in 2008.
11. **The New Jersey Uniform Construction Code (UCC) adopts the International Building Code, which does reference fire protection and engineering standards for facilities that handle combustible dusts, such as NFPA 654. However, the UCC exempts certain process equipment that could apply these provisions.**
12. **The New Jersey Department of Community Affairs conducts training for local building code officials on some of the NFPA standards in the New Jersey UCC but does not provide training on relevant NFPA standards that address combustible dust hazards.**

9.0 REITERATED RECOMMENDATION

U.S. OCCUPATIONAL SAFETY AND HEALTH ADMINISTRATION

The absence of a general industry safety standard for combustible dust remains an important safety issue because catastrophic dust incidents continue to occur throughout industry. Therefore, the CSB reiterates the recommendation originally issued to OSHA in the 2006 Combustible Dust Hazard Study.

2006-01-I-H R1 Issue a standard designed to prevent combustible dust fires and explosions in general industry. Base the standard on current National Fire Protection Association (NFPA) dust explosion standards (including NFPA 654 and NFPA 484) and include at least the following:

- Hazard assessment
- Engineering controls
- Housekeeping
- Building design
- Explosion protection
- Operating procedures
- Worker training

001327

10.0 RECOMMENDATIONS

As a result of its investigation of this accident at the US Ink facility, the CSB makes a number of safety recommendations.

U.S. OCCUPATIONAL SAFETY AND HEALTH ADMINISTRATION

2013-01-I-NJ R1 Add **North American Industry Classification System (NAICS)** Code 325910, Printing Ink Manufacturing, to the list of industries in Appendix D-1 or Appendix D-2 of Combustible Dust **National Emphasis Program (NEP)**, Directive CPL 03-00-008.

2013-01-I-NJ R2 Communicate with all OSHA Area Offices to encourage appropriate application of the following existing provisions of the Combustible Dust NEP, Directive CPL 03-00-008:

- Paragraph IX, Section A2, indicates that area offices may add to their Combustible Dust NEP establishment lists those facilities in their jurisdictions with a Standard Industrial Classification System code, NAICS code, or both (other than those listed in Appendices D-1 and D-2 of the Combustible Dust NEP directive) if those facilities have a known pattern of combustible dust hazards.
- Paragraph IX, Section B4, indicates that if a fatality or catastrophe investigation is performed at a facility because of a combustible dust deflagration or explosion, the inspector shall use the guidelines in Fatality/Catastrophe Investigation Procedures, Directive CPL 02-00-137, and in the Combustible Dust NEP, Directive CPL 03-00-008.

NEW JERSEY DEPARTMENT OF COMMUNITY AFFAIRS

2013-01-I-NJ R3 Revise the exemption for "manufacturing, production, and process equipment" under the New Jersey Uniform Construction Code (N.J.A.C 5:23-2.2) to require that equipment involved in processing, handling, or conveying combustible dust comply with the design and operating requirements of the current edition of the International Building Code.

2013-01-I-NJ R4 Develop and implement training for local code officials on the National Fire Protection Association (NFPA) standards referenced in the New Jersey adoption of the International Building Code (IBC) for occupancies with a high hazard classification (Group H); specifically, include training on equipment that handles combustible dust and the hazards involved.

2013-01-I-NJ R5 Promulgate a regulation that requires all occupancies handling hazardous materials to inform the local enforcement agency of any type of construction or installation of equipment at an industrial or manufacturing facility. Also require local enforcement agencies to evaluate the information to determine whether a construction permit is required.

001328

US INK/SUN CHEMICAL CORPORATION

2013-01-I-NJ R6 At the US Ink East Rutherford facility, install automatic fire alarm systems consistent with NFPA 72 (the National Fire Alarm Code) in manufacturing areas (such as mixing) where heat generation could occur.

2013-01-I-NJ R7 Revise the Capital Appropriations/Asset Request (CAR) form procedure for new installations and modifications to existing equipment to require at a minimum the following:

- Process hazard analysis (PHA)
- Management of change (MOC)
- Review of engineering drawings for permits
- Safety management of contractors
- Training of plant operators based on applicable dust collection system guidelines and standards, including NFPA 91 and NFPA 654

2013-01-I-NJ R8 Develop and implement a management of organizational change protocol to allow for the transfer of knowledge and information to new personnel, at a minimum including initial and refresher training in the following:

- Safety and health procedures
- Lessons learned from previous incidents
- Technical information for equipment
- Routine plant operation

CSB Investigation Reports are formal detailed reports on significant chemical accidents and include key findings, root causes, and safety recommendations. CSB Hazard Investigations are broader studies of significant chemical hazards. CSB Safety Bulletins are short general interest publications that provide new or noteworthy information on preventing chemical accidents. CSB Case Studies are short reports on specific accidents and include a discussion of relevant prevention practices. All reports may contain safety recommendations if appropriate. CSB Investigation Digests are plain-language summaries of Investigation Reports.

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No part of the conclusions, findings, or recommendations of the CSB relating to any chemical accident may be admitted as evidence or used in any action or suit for damages. See 42 U.S.C. § 7412(r)(6)(G). The CSB makes public its actions and decisions through investigation reports, summary reports, safety bulletins, safety recommendations, case studies, incident digests, special technical publications, and statistical reviews. More information about the CSB is available at www.csb.gov.

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U.S. Chemical Safety and Hazard Investigation Board
Office of Congressional, Public, and Board Affairs
2175 K Street NW, Suite 400
Washington, DC 20037-1848
(202) 261-7600

U.S. CHEMICAL SAFETY AND HAZARD INVESTIGATION BOARD

INVESTIGATION REPORT

FINAL

WEST FERTILIZER COMPANY FIRE AND EXPLOSION

(15 Fatalities, More Than 260 Injured)

WEST FERTILIZER COMPANY

WEST, TX

APRIL 17, 2013

KEY ISSUES:

- REGULATORY OVERSIGHT
- HAZARD AWARENESS
- EMERGENCY PLANNING AND RESPONSE
- FERTILIZER GRADE AMMONIUM NITRATE STORAGE PRACTICES
- LAND USE PLANNING AND ZONING

REPORT 2013-02-I-TX

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Dedication

This report is dedicated to the 12 emergency responders and 3 members of the public who lost their lives as a result of the explosion at the West Fertilizer Company on April 17, 2013.

Morris Bridges

Perry Calvin

Jerry Dane Chapman

Cody Frank Dragoo

Kenneth Harris

Adolph Lander

James Matus

Judith Ann Monroe

Joseph Pustejovsky

Cyrus Adam Reed

Mariano C. Saldivar

Kevin William Sanders

Douglas Snokhous

Robert Snokhous

William Uptmor, Jr.

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Acronyms and Abbreviations

°C	degrees Celsius
°F	degrees Fahrenheit
AC	air conditioning
AFG	Assistance to Firefighters Grant
AHJ	Authority Having Jurisdiction
AN	ammonium nitrate
ANFO	ammonium nitrate/fuel oil
ANSI	American National Standards Institute
API	American Petroleum Institute
ARA	Agricultural Retailers Association
AS	ammonium sulfate
ATF	Bureau of Alcohol, Tobacco, Firearms and Explosives
CDC	Centers for Disease Control and Prevention
CDP	Center for Domestic Preparedness
CDT	central daylight time
CEPP	Chemical Emergency Preparedness Program
CERCLA	Comprehensive Environmental Response, Compensation, and Liability Act
CFATS	Chemical Facility Anti-Terrorism Standards
CFR	Code of Federal Regulations
CMU	concrete masonry unit
COI	chemical of interest
CSAT	Chemical Security Assessment Tool
CSB	U.S. Chemical Safety and Hazard Investigation Board
CTG	Continuing Training Grant
DHS	U.S. Department of Homeland Security
DOL	U.S. Department of Labor
DOT	U.S. Department of Transportation
DWC	Division of Workers' Compensation
EDT	eastern daylight time
EHS	extremely hazardous substance
EMPG	Emergency Management Performance Grant
EMS	emergency medical services
EMT	emergency medical technician

EO	Executive Order
EPA	U.S. Environmental Protection Agency
EPCRA	Emergency Planning and Community Right-to-Know Act
ERDC	Engineer Research and Development Center
ERG	Emergency Response Guidebook
ERP	Emergency Response Plan
EU	European Union
FAST	firefighter assist and search team
FEMA	Federal Emergency Management Agency
FFFIPP	Fire Fighter Fatality Investigation and Prevention Program
FGAN	fertilizer grade ammonium nitrate
FP&S	Fire Prevention and Safety
FR	Federal Register
FRS	Facility Registry Service
g/cm^3	grams per cubic centimeter
GAO	U.S. Government Accountability Office
GPD	Grant Programs Directorate
HAZMAT	hazardous material
HAZWOPER	Hazardous Waste Operations and Emergency Response
HCS	Hazard Communication Standard
HUD	U.S. Department of Housing and Urban Development
HSE	UK Health and Safety Executive
HSNTP	Homeland Security National Training Program
HVAC	heating, ventilation, and air conditioning
IAFC	International Association of Fire Chiefs
IAFF	International Association of Fire Fighters
IAP	Incident Action Plan
IBC	International Building Code
IC	incident commander
ICC	International Code Council
ICS	Incident Command System
ICT	Insurance Council of Texas
IFC	International Fire Code
IME	Institute of Makers of Explosives
ISO	Insurance Services Office

IST	inherently safer technology
K-Mag	potassium magnesium
LEPC	Local Emergency Planning Committee
LNG	liquefied natural gas
MOU	memorandum of understanding
MSDS	Material Safety Data Sheet
NAICS	North American Industry Classification System
NEIC	National Earthquake Information Center
NERRTC	National Emergency Response and Rescue Training Center
NEW	net explosive weight
NFA	National Fire Academy
NFPA	National Fire Protection Association
NIMS	National Incident Management System
NIOSH	National Institute for Occupational Safety and Health
NOX	nitrogen oxide
NPD	National Preparedness Directorate
NTED	National Training and Education Division
NVFC	National Volunteer Fire Council
NYC	New York City
OSHA	Occupational Safety and Health Administration
OTSC	Office of the Texas State Chemist
PHMSA	Pipeline and Hazardous Materials Safety Administration
PPC	Public Protection Classification
PPE	personal protective equipment
PRV	pressure relief valve
PSI	pounds per square inch
PSM	Process Safety Management (standard)
PVC	polyvinyl chloride
Q&A	question and answer
RCRA	Resource Conservation and Recovery Act
RDPC	Rural Domestic Preparedness Consortium
RFI	request for information
RMP	Risk Management Plan
SAA	State Administrative Agency
SAFER	Staffing for Adequate Fire and Emergency Response

SARA	Superfund Amendments and Reauthorization Act
SBA	Small Business Administration
SDS	Safety Data Sheet
SERC	State Emergency Response Commission
SFFMA	State Firefighters' and Fire Marshals' Association
SFMO	State Fire Marshal's Office
SIC	Standard Industrial Classification
SOP	standard operating procedure
SPCC	spill prevention, control, and countermeasures
TAC	Texas Administrative Code
TCEQ	Texas Commission on Environmental Quality
TCFP	Texas Commission on Fire Protection
TDI	Texas Department of Insurance
TEEX	Texas A&M Engineering Extension Service
TFI	The Fertilizer Institute
TGAN	technical grade ammonium nitrate
TIESB	Texas Industrial Emergency Services Board
TNT	Trinitrotoluene
TR	technical report
TRANSCAER	Transportation Community Awareness and Emergency Response
TRI	Toxics Release Inventory
TX	Texas
U.K.	United Kingdom
USFA	U.S. Fire Administration
USGS	U.S. Geological Survey
VFD	volunteer fire department
WFC	West Fertilizer Company
WFD	West Fire Department
WIS	West Intermediate School
WISD	West Independent School District
WMS	West Middle School
WVFD	West Volunteer Fire Department

1.0 Executive Summary

1.1 Overview

On April 17, 2013, a fire and explosion occurred at the West Fertilizer Company (WFC), a fertilizer blending, retail, and distribution facility in West, Texas. The violent detonation fatally injured 12 emergency responders and three members of the public. Local hospitals treated more than 260 injured victims, many of whom required hospital admission. The blast completely destroyed the WFC facility and caused widespread damage to more than 150 offsite buildings. The WFC explosion is one of the most destructive incidents ever investigated by the U.S. Chemical Safety and Hazard Investigation Board (CSB) as measured by the loss of life among emergency responders and civilians; the many injuries sustained by people both inside and outside the facility fenceline; and the extensive damage to residences, schools, and other structures. Following the explosion, WFC filed for bankruptcy.

The explosion happened at about 7:51 pm central daylight time (CDT), approximately 20 minutes after the first signs of a fire were reported to the local 911 emergency response dispatch center. Several local volunteer fire departments responded to the facility, which had a stockpile of between 40 and 60 tons (80,000 to 120,000 pounds) fertilizer grade ammonium nitrate (FGAN), not counting additional FGAN not yet offloaded from a railcar.

More than half of the structures damaged during the explosion were demolished to make way for reconstruction. The demolished buildings include an intermediate school (552 feet southwest of the facility), a high school (1,263 feet southeast), a two-story apartment complex with 22 units (450 feet west) where two members of the public were fatally injured, and a 145-bed nursing home (500 feet west) where many of the seriously injured civilians resided. A middle school (2,000 feet southwest) also sustained serious but reparable damage. Section 3 describes the incident and its consequences in detail.

The CSB investigated the factors that contributed to the detonation of FGAN. Section 4 describes the properties of FGAN and posits three scenarios that could lead to its detonation under the conditions present during the WFC fire. CSB concluded that the construction of the bins and other building materials as well as the lack of an automatic sprinkler system plausibly contributed to the detonation. Section 6 describes inherently safer approaches to FGAN use and storage that reduce the risk of an FGAN detonation.

The total insurance-related losses from the explosion are estimated to be around $230 million and federal disaster assistance is estimated to exceed $16 million. WFC was only insured for $1 million, which fell far short of the incident's damage. Section 5 presents CSB's analysis of the policies and regulations that led to this as well as to the failure of the insurer to identify the risks posed by FGAN. A few years prior to the incident, WFC was dropped by one insurer for failing to address safety concerns identified in loss control surveys. The company that insured WFC at the time of the incident did not appear to have conducted its own safety inspections of the facility.

CSB's analysis of the emergency response, found in Section 7, concludes that the West Volunteer Fire Department did not conduct pre-incident planning or response training at WFC, was likely unaware of the potential for FGAN detonation, did not take recommended incident response actions at the fire scene, and did not have appropriate training in hazardous materials response.

CSB found several shortcomings in federal and state regulations and standards that could reduce the risk of another incident of this type. These include the Occupational Safety and Health Administration's Explosives and Blasting Agents and Process Safety Management standards, the Environmental Protection Agency's Risk Management Program and Emergency Planning and Community Right-to-Know Act, and training provided or certified by the Texas Commission on Fire Protection and the State Firefighters' and Fire Marshals' Association of Texas. CSB's complete analysis is presented in Section 8.

The location of the WFC relative to the surrounding community exacerbated the offsite consequences, leading CSB to assess whether other FGAN storage facilities could pose significant offsite risks. CSB's analysis shows that the risk to the public from a catastrophic incident exists at least within the state of Texas, if not more broadly. For example, 19 other Texas facilities storing more than 10,000 pounds of FGAN are located within 0.5 miles of a school, hospital, or nursing home, raising concerns that an incident with offsite consequences of this magnitude could happen again. Section 9 explores the connection between land use planning and offsite consequences.

1.2 Federal and State Response

In response to this incident, President Barack Obama issued Executive Order (EO) 13650, "Improving Chemical Facility Safety and Security" to coordinate federal actions to reduce the risks of another incident of this type.[1] Details and updates on the status of the EO are included in Section 8.1.

Early investigation activities focused on law enforcement efforts to determine if there was a criminal element to the incident. Responding governmental agencies included the U.S. Bureau of Alcohol, Tobacco, Firearms and Explosives (ATF) National Response Team, Texas State Fire Marshal's Office (SFMO), U.S. Occupational Safety and Health Administration (OSHA), Texas Commission on Environmental Equality, U.S. Federal Emergency Management Agency (FEMA), and U.S. Environmental Protection Agency (EPA). In addition, multiple state and local law enforcement and emergency response organizations responded to the scene.

1.2.1 Joint SFMO/ATF Investigation

Immediately following the incident, ATF deployed to West at the invitation of SFMO and assumed control of the WFC site to conduct a joint investigation of the immediate cause and origin of the fire and explosion and determine whether the initiating fire was intentionally set. The two agencies retained

[1] Executive Order 13650. "Improving Chemical Facility Safety and Security," August 1, 2013. *See*: https://www.whitehouse.gov/the-press-office/2013/08/01/executive-order-improving-chemical-facility-safety-and-security (accessed on December 8, 2015).

control of the scene for about four weeks, interviewing witnesses, excavating the WFC site, and reconstructing the electrical system. To date, law enforcement has not made a final determination of the cause of the fire and ensuing explosion. Three possible scenarios remain under consideration: (1) faulty electrical wiring, (2) short circuit in an electrical golf cart, and (3) intentional act of arson.[2]

1.2.2 CSB Response

CSB investigators from both the Washington, DC, and Denver, Colorado, offices deployed on April 18, 2013, supported by a contingent of contractors that included blast modeling, structural, urban search and rescue, and fire and explosion experts. The joint ATF-SFMO control of the site as a crime scene limited CSB site access and delayed CSB investigator execution of evidence-gathering protocols, chemical testing, and witness interviews. Despite the limited access in the initial stages, driven by the criminal investigation, CSB continued with its investigation.

The investigation of the WFC incident analyzed several root causes and considered multiple contributing causes. Investigative teams partnered with urban search and rescue experts and fire and explosion consultants to survey damage to residences, schools, the nursing home, and other structures. The teams also conducted interviews with eyewitnesses, WFC managers, and hourly workers and gathered physical evidence for further laboratory testing and analysis.

Key Findings

The CSB's analysis includes findings on the technical causes of the fire and explosion; regulatory changes that could have resulted in safety enhancements to the facility; the failure of the insurer to conduct safety inspections or provide an adequate level of coverage; shortcomings in emergency response, including pre-incident planning or response training of the volunteer fire fighters; and deficiencies in land use planning that permitted the City of West to encroach upon the WFC over the years. Section 10 presents the CSB's key findings on the WFC incident.

Recommendations

As a result of the investigation of the WFC fire and explosion, CSB developed recommendations and directed them to the following recipients:

- Environmental Protection Agency (EPA).
- Occupational Safety and Health Administration (OSHA), U.S. Department of Labor.
- Federal Emergency Management Agency (FEMA), U.S. Department of Homeland Security.
- International Codes Council.
- Texas Department of Insurance.
- Texas Commission on Fire Protection.
- State Firefighters' and Fire Marshals' Association of Texas.
- Texas A&M Engineering Extension Services (TEEX).

[2] *See*: http://www.tdi.texas.gov/news/2013/news201320.html (accessed on December 22, 2015).

- El Dorado Chemical Company (EDC).
- West Volunteer Fire Department (WVFD).

Section 11 contains the complete set of recommendations.

2.0 Background

2.1 West Fertilizer Company

The West Fertilizer Company (WFC) was located in the city of West, Texas. The city is approximately 80 miles south of Dallas, Texas, and has a population of about 2,800.[3] The WFC stored and distributed fertilizers, chemicals, grains, and various other farming supplies. At the time of the incident, stockpiles of about 40 to 60 tons of FGAN were estimated to be onsite, and about 30 tons detonated. Table 1 shows the WFC inventory at the time of the explosion and fire.

Table 1. WFC Fertilizer Inventory in April 2013

Fertilizer Name	Amount (in tons)
FGAN (fertilizer building)	40 to 60
FGAN (railcar)	100
Anhydrous ammonia	17
Potash[4]	45
Diammonium phosphate[5]	70
Diammonium phosphate and potash	25
Ammonium sulfate[6]	60 to 70
Zinc sulfate[7]	17.5

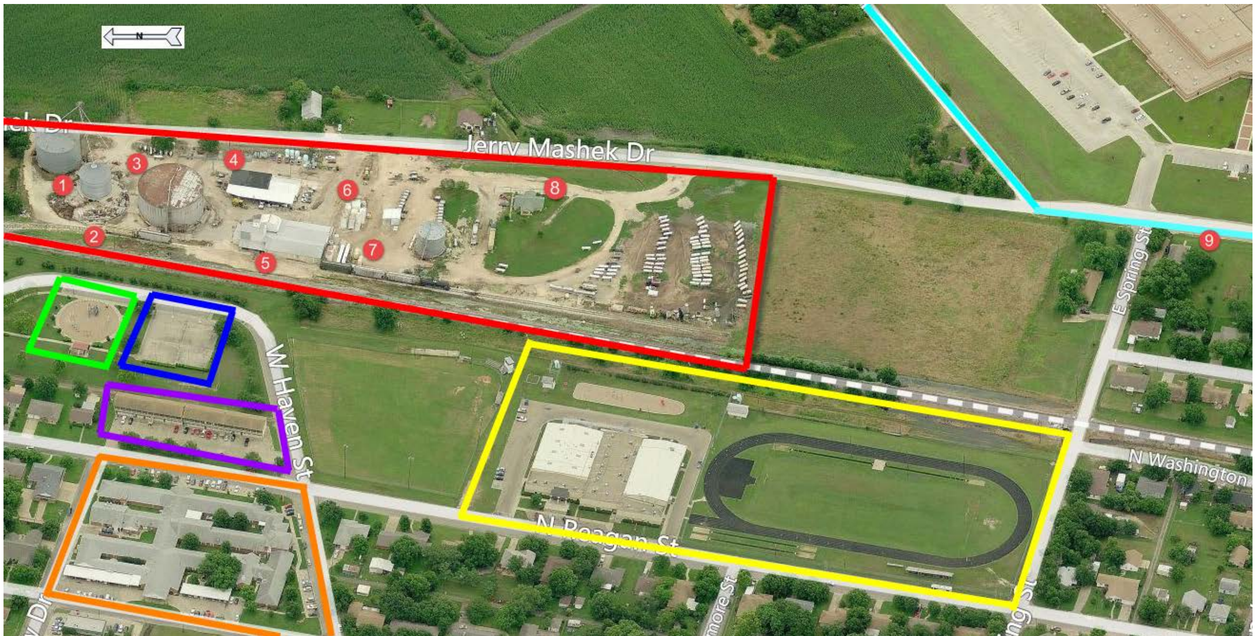
The fertilizer building was constructed in 1961, and business operations started in 1962. Photographs from 1972 show the closest residence about 265 feet from the WFC property. In addition, a baseball field

[3] The 2010 U.S. Census data indicate that the population of West, Texas, is 2,807. *See*: http://www.census.gov/2010census/popmap/ (accessed on December 8, 2015).
[4] Potash is an agricultural fertilizer and is a source of soluble potassium (K).
[5] Diammonium phosphate (DAP), $(NH_4)_2HPO_4$, is one of a series of water-soluble ammonium phosphate salts that can be produced when ammonia reacts with phosphoric acid.
[6] Ammonium sulfate, $(NH_4)_2SO_4$, is an inorganic salt with a number of commercial uses. The most common use is as a soil fertilizer.
[7] Zinc sulfate, $ZnSO_4$, is an inorganic compound and is a colorless solid that is a common source of soluble zinc ions.

was 58 feet from the property. In 1972, the town nursing home and the nearest group of homes were constructed about 500 feet away.[8]

Over the years, growth in the city of West led to the development of land closer to the WFC property line, including a park (less than 150 feet), an apartment complex, the nearest aggregation of homes (about 370 feet), West Intermediate School (a little more than 200 feet), and West High School (about 500 feet). Sections 3.4.2 through 3.4.7 provide additional details on the property damage resulting from the explosion.[9] Figure 1 shows the WFC facility before the fire and explosion in relation to the nearby community, including details on the site and the location of various structures.

[8] This information was determined using Image 272-37A provided by McLennan County and distances calculated using Google Earth (accessed on June 6, 2013).
[9] Calculated using Google Earth (accessed on June 6, 2013).



WFC Facility Legend		Figures in Report
1	Grain Silos	2
2	Location of Overturned FGAN Railcar (post-explosion)	15
3	Corn Silo	-
4	Office/Chemical Storage	-
5	Fertilizer Building	3-5, 7
6	Liquid Fertilizer Tanks	16
7	Anhydrous Ammonia Pressure Vessels	6, 17, 21
8	Scale House	-
9	Nearest Fire Hydrant	-

City of West Legend		Figures in Report	Approximate Distance from Seat of Blast to Fenceline (Feet)
(red)	West Fertilizer Company	2-8, 12	0
(cyan)	West High School	30	1157
(yellow)	West Intermediate School	23-29	552
(blue)	Basketball Court	20	249
(green)	Playground	19	366
(purple)	West Terrace Apartment Complex	36	454
(orange)	West Rest Haven Nursing Home	33-35	629

Figure 1. 2013 Overview of WFC Facility (Source: Bing Maps)

2.1.1 Facility Operations Description

The West, Texas, site consisted of two companies owned by the same family. Adair Grain, Inc., bought and sold grain while the WFC sold fertilizer, farming chemicals (pesticides and herbicides), and basic farm equipment (such as barbed wire, baling twine, and fencing). The WFC also rented farming equipment (fertilizer spreading equipment, tillage equipment) and spread fertilizer on farmland when needed, and its daily activities were largely based on season and weather.

Adair Grain bought grain (milo[10] and corn) from farmers and stored it in four onsite silos (shown in Figure 1 and Figure 2). Adair Grain received grain from farmers' trucks and deposited it into pits (Figure 3). An auger then transferred the grain from these pits, depositing it into the grain bin.

Figure 2. Grain Silos (Source: WFC Insurer)

[10] Milo, also called grain sorghum, is a major feed grain for cattle.

Figure 3. West View of Fertilizer Building (Source: Bing Maps)

The WFC operated two buildings and a number of tanks (shown in Figures 1 and 3). One building served as a chemical warehouse, shop area, and office space. Most chemicals purchased by farmers were stored in that building. Such chemicals included Roundup®, Sevin®, and additives to make pesticides adhere to plants (such as Weedmaster® and Grazonnext®) and were stored in containers ranging in size from 2 to 300 gallons.

The WFC also owned the fertilizer building, constructed in the 1960s, where dry fertilizer was stored (Figure 4). Fertilizers stored in that building included diammonium phosphate, ammonium sulfate, potash (potassium chloride), potassium magnesium sulfate (K-Mag), and FGAN. A seed room was located at the north end of this building (Figure 5).

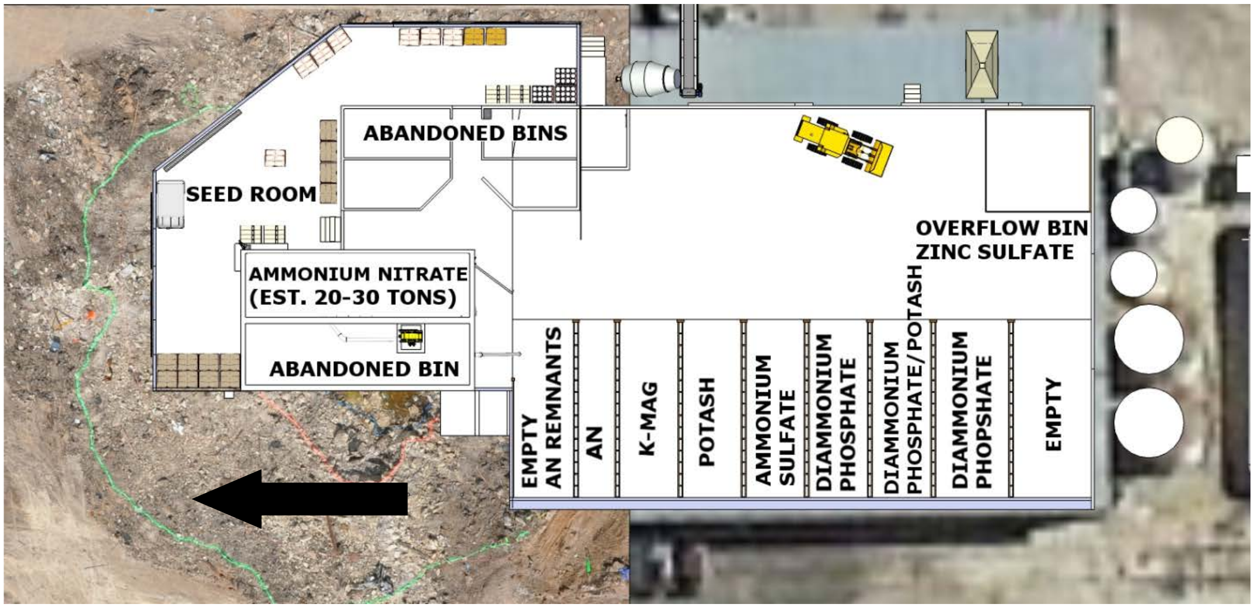


Figure 4. Fertilizer Building Overview (Source: Atlas Engineering)

Figure 5. Southwest View from Northeast Corner of Fertilizer Building (Source: WFC Insurer)

The WFC facility had two 12,000-gallon anhydrous ammonia[11] (NH_3) storage vessels, located to the south of the fertilizer building, for distribution and sale of the product to farmers (Figure 6). The

[11] Anhydrous ammonia is a colorless and extremely water-soluble gas at room temperature, with a strong irritating odor. Ammonia gas is lighter than air, but under certain conditions, ammonia vapor can settle close to the ground during a leak, forming a white cloud. Ammonia can be compressed into a liquid under pressure, and within a concentration in air range of 15 to 28 percent, it is flammable. This is known as the lower explosive limit (LEL) and upper explosive limit (UEL), respectively. Ammonia exposure at lower concentrations can irritate the skin, eyes, and respiratory system, and at high concentrations, exposure can result in pulmonary edema and death.

anhydrous ammonia was primarily trucked into the facility, but delivery by rail was also possible. Although anhydrous ammonia is used in the manufacture of AN, the WFC stored it onsite solely for sale to consumers as liquid fertilizer. Adjacent to the anhydrous ammonia tanks, liquid fertilizer was stored outside in several vertical tanks. This type of fertilizer included a urea ammonium nitrate (UAN) solution or liquid phosphate, and could be blended to meet specific farmer needs. One outside tank was normally full of water to mix with chemicals or liquid fertilizer.

No products were manufactured onsite; the WFC was essentially a distribution center for suppliers such as Mosaic, BASF, Agri-Phos, El Dorado Chemical Company (EDC), and CF Industries. EDC and CF Industries are the only manufacturers of FGAN in the United States. The WFC mixed and sold bulk fertilizer components or unaltered products such as pure FGAN and ammonium sulfate. Farmers came to the WFC and bought fertilizer that was weighed in a hopper, blended in a mixer, and distributed by conveyor belt (the mixer and conveyor belt can be seen in Figure 7). The WFC also delivered and applied fertilizer or chemicals to a farmer’s fields if needed.

Figure 6. Anhydrous Ammonia Storage (Source: WFC Insurer)

Figure 7. West View from East of Fertilizer Building (Source: WFC Insurer)

2.1.2 Facility Layout and Materials of Construction

The fertilizer building (Figure 4) was a wood-framed structure with a concrete floor, at an elevation about 3 feet above grade. The building was constructed piecemeal over the years, starting with the original construction in 1961. The seed room was fabricated in the early 1980s, with a roof constructed of wooden rafters topped with plywood and covered with asphalt shingles. The only trench or drain in the building was in the cattle trough, which was used to collect fertilizer slurry when it became moist. A series of ladders were positioned adjacent to the elevator.

FGAN was stored in two plywood bins along the west wall of the building and in one primary FGAN bin at the north end of building. The primary FGAN bin was normally no more than half full while the fertilizer bins on the west wall could be filled to the top of the containment. In the northeast corner of the building, an abandoned bin had been used to store fertilizer in the past but was unused at the time of the incident.

The primary FGAN bin was constructed differently than the bins on the west wall. The bins on the west wall were composed of three walls rising to a height of about 10 feet and an open front. The primary bin was constructed by attaching plywood sheets to the inside of the exterior beams of the structure. The interior walls were also constructed of 6-inch beams with plywood attached. The main bin was estimated to be 8 feet wide, 20 feet long, and 30 feet high. A large hinged door covered the south end of the bin, with a 3-foot opening at the bottom. Holes were cut in the bin to provide air circulation, and a set of holes on the west wall allowed the bin to overflow into a smaller adjacent bin.

The door to the bin was normally closed when the bin was filled, and it could be opened to provide access

Figure 8. Plywood Bin Wall, Post-Explosion (Source: CSB)

after the inventory was reduced so that the fertilizer was not resting against the door. The bin was just wide enough (8 to 10 feet) to allow a front-end loader to drive in to access and gather the remaining FGAN. Like the west bins, the primary FGAN bin had plywood sheets (including some particle boards) and a wooden frame for support (shown post-explosion in Figure 8). The primary bin also had metal rods connected at opposite sides of the bin, providing internal stiffening support.

About 2 years before the WFC explosion, the northeast corner of the north wall of the primary FGAN bin failed, and employees erected steel and concrete reinforcement around the bottom of the northeast corner to provide support and hold up the bin. As a result, the WFC never completely filled the primary bin to avoid another failure.

A seed room,[12] fabricated in 1980 and located at the north end of the fertilizer building served as the warehouse for seeds sold to consumers. Asphalt shingles covered the roof of the seed room of the fertilizer building. The seed room also stored more than 700 bags of zinc sulfate on the day of the fire and explosion. The zinc sulfate and seeds were stored in bags on pallets, with about 40 to 50 bags per pallet, stacked to a height of about 3 to 4 feet on each pallet. The seed room also contained two pallets of lawn and garden fertilizer (bagged at the WFC), twine, bailing wire, and fencing materials. At the west end of the seed room, 8 to 10 pallets of out-of-season seeds were segregated in an area cooled by an air

[12] The seed room was used for storage of seed, bagged fertilizer, equipment, and vehicles, including a riding lawnmower, a golf cart, and a fork lift. It was constructed as an addition to the main fertilizer building in the early 1980s.

conditioner. The east end of the seed room stored twine and netting. At the time of the incident, the room held a relatively low inventory of seeds (approximately 30 percent of the room's capacity, or 3,000 bags of out-of-season seeds).

2.1.3 Unloading of Fertilizer

Historically, suppliers delivered bulk fertilizer product by truck or rail, but immediately before the incident, most shipments arrived by truck. All bulk fertilizer was transferred into the bins (located as shown in Figure 4), using the same conveyor belt system described in the previous section. Delivered fertilizer was first deposited into a loading pit. An uncovered 20-inch-wide rubber conveyor belt then transported the product into the fertilizer building. The belt was cupped to hold the fertilizer, which was transferred from this conveyor belt to a bucket elevator (pictured post-explosion in Figure 9).

Figure 9. Elevator System Recovered from Blast Debris (Source: CSB)

The elevator lifted the fertilizer to the cupola (the highest structure) and deposited it into polyvinyl chloride (PVC) pipes, which in turn conveyed the fertilizer to either the main FGAN bin or a horizontal conveyor belt for distribution to the bins along the west wall. A valve was used to gravity-feed material to either the large FGAN bin by way of PVC piping (approximately 20 feet long by 1 foot in diameter) or through an approximately 40-foot downpipe toward the horizontal conveyor belt in the main portion of the building. A piece of PVC piping could be added to the downpipe to direct product from the horizontal conveyor belt and to direct FGAN to the two FGAN overload bins on the west wall. The horizontal conveyor belt transported product to the bins in the southern portions of the building. A 6- to 8-foot "kicker" conveyor belt transferred the fertilizer from the horizontal conveyor belt to its final destination in any of the west wall bins. Electric motors powered the conveyor belts. Every fertilizer product used the same conveyor system process for filling the respective bins.

Workers used a front-end loader to move the fertilizer within the fertilizer building. For a blended fertilizer product, the operator would place a load of each product in a predetermined quantity into the weigh hopper. After all of the ingredients were weighed, the product was sent via a conveyor belt to a mixer, which had the appearance of a stationary concrete mixer. The mixed product was deposited on a conveyor belt and loaded into a truck or spreader. A yellow auger next to the conveyor mixed seed with fertilizer. Zinc sulfate could also be added to fertilizer.

2.1.4 Housekeeping

Because unloading operations in the fertilizer building created a dusty environment, the first task of the day in the fertilizer building was cleaning the floor after work during the previous day and evening. To address these conditions during operating hours, the WFC used fans to control the dust during unloading, and on some occasions, workers added a vegetable oil coating to the ammonium phosphate to reduce the dust.[13] An employee reported to CSB that some products were dustier than others and that floor sweeping compound was also applied to the fertilizer building floor on very wet days. When mixing fertilizer, operators usually added phosphate to the hopper and mixer first to eliminate any moisture.

The employees reported that because FGAN tends to absorb moisture and dissolve, the WFC used air conditioning to cool and remove moisture from the primary FGAN bin. After the FGAN bin was emptied, it was swept to remove moisture. On damp or humid days, operators minimized handling FGAN unless necessary because it would “melt” and become lost product.

When the fertilizer became damp and began to “sweat” onto the floor, it was swept into a trench (cattle trough) on the east side of the fertilizer building. The liquid captured as slurry in the trough was then pumped into a liquid fertilizer tank for disposal. Employees reported that the plywood walls between the bins “stayed pretty clean” and did not require any housekeeping.

After a shipment of one type of fertilizer was unloaded, no cleaning process was used to clear the conveyor belt before the next load was transferred. During the unloading process, the fertilizer occasionally spilled because the conveyor belts got off track or ripped. In such cases, operators attempted to separate the products as best they could, but intermixing and cross-contamination nonetheless would occur. The fertilizer in the west bins was occasionally changed out, and if the product became damp and moist, it might have been emptied out with a “drier” product such as K-Mag placed into that bin. The K-Mag would dry out the bin, and afterward, the bin could revert to storage space for another product. Occasionally, the bin walls developed holes or cracks, and when that occurred, either new wood walls were put in place to replace the old ones or caulk was used to fill the holes.

[13] Ammonium phosphate was the only product at the WFC with an oil coating.

3.0 Incident Description

On April 17, 2013, at approximately 7:29 pm, citizens reported signs of smoke and fire at the West Fertilizer Company (WFC) facility to the local 911 dispatch center. Within 20 minutes, a massive explosion occurred, killing 15 people and sending a blast wave through the town that damaged or destroyed many buildings and homes. The fire was witnessed from several vantage points by different individuals associated with the West Police Department, Dallas Fire-Rescue Department, and volunteer fire departments (VFDs) from West, Abbott, Bruceville-Eddy, Mertens, and Navarro Mills. These accounts assisted CSB in determining how the events of the day transpired.

3.1 West Police Department

One of the first responders to the incident was a West Police Department officer who was on routine patrol that evening. The officer reported that he smelled smoke as he was driving through the city park[14] but was not able to identify the exact location of the smoke until he encountered a concerned citizen who advised him that smoke was venting from the highest portion of the WFC building. The officer advised the dispatch center of the smoke and requested that the West Volunteer Fire Department (WVFD) be dispatched to the WFC facility. Once the officer arrived on scene, he witnessed flames that were visible through the wall, extending upward from the lower level to the upper level of the northeast corner of the two-story fertilizer storage building. Then he called dispatchers again and asked them to inform the WVFD that the smoke had escalated to a structure fire.

The WVFD contacted the officer via radio and requested that he establish traffic control to prevent citizens from driving over the fire hoses once the fire engines arrived and laid down fire hoses. The officer agreed but notified the WVFD that he needed to evacuate the city park first. As the officer proceeded to the city park, the responding West firefighters drove past him, heading toward the facility. Once the officer reached the city park, he used his public address system to order an evacuation of the park. After the park was evacuated, he left the area to establish traffic control on the north end of the fertilizer facility. There was no traffic control at the south end toward West High School (WHS), so the officer asked a nearby resident to assist by using his truck to block that intersection. At this time, the officer contacted the police chief and another officer who had called to determine whether he needed assistance. The officer asked the police chief to establish traffic control by the West Intermediate School (WIS) and requested that the other officer relieve the resident who was helping near the high school.

Numerous citizens began parking their cars at WHS to watch the fire. The WVFD truck left the WFC facility and headed toward the police officer. The manager of the WFC arrived on scene to assist the WVFD. Via radio traffic, the officer learned that the entire fertilizer storage building was engulfed in flames, and shortly thereafter he saw and felt the explosion. The officer was briefly disoriented and then unsuccessfully attempted via radio and cell phone to notify the dispatch center of the explosion. An

[14] The city park consisted of the basketball court and the playground.

injured member of the public and an injured firefighter approached the officer, who assisted them. The possibility of further explosions or toxic releases was a concern because of the anhydrous ammonia pressure vessels on the south side of the WFC property. On the basis of this information, the officer decided to evacuate homes within a 1-mile radius. Because the officer's patrol car would not start, he proceeded on foot along Jerry Mashek Drive and Main Street to alert people to evacuate (refer to Figure 1 for a map of the area). By the time the officer made his way to Reagan Street, he had become aware that other emergency responders had initiated the evacuation of the northern portion of the city.

3.2 West Volunteer Fire Department (WVFD)

Emergency dispatchers paged the WVFD, and firefighters responded to the scene with two fire engines, two initial attack apparatus or brush trucks,[15] and a water tender truck[16] at various times. Dispatchers also paged mutual aid personnel from neighboring counties, including Abbott, which responded. Many of the firefighters also responded by using their personally owned vehicles (POVs). According to eyewitness accounts, the fire intensified very quickly and was described as a rolling fire that moved from the northeast end of the fertilizer building (in the seed storage area north of the office) toward the southern end of the building.

Five firefighters arrived on scene in two fire engines at different times. The first fire engine arrived on scene and staged east of the burning structure while one of the brush trucks staged to the north of the first fire engine. Four other firefighters directed water (using two 1.5-inch hoses) from the first fire engine's internal tank onto the fire through the northeast doorway of the bagged fertilizer room, where fire was present. Once the second fire engine arrived on scene, the two firefighters from that fire engine began laying 1,000 feet of 4-inch hose line from the fire hydrant near the high school (1,600 feet away) toward the fertilizer facility. After laying all of the hose lines from the second fire engine, they discovered that the hose was approximately 700 feet short of the length needed to effectively fight the fire. After assessing the situation, one firefighter arranged to take the first fire engine, which had a better pump with greater pressure capabilities and additional hose that would allow him to continue to reverse-lay the lines.[17] However, rather than resuming where the first fire engine ran out of hose, the firefighter went back to the fire hydrant near the high school to connect the first engine to the hydrant without laying the additional length of hose needed to supplement the hose that had already been laid from the second

[15] Initial attack fire apparatus as defined in NFPA 1901 is fire apparatus with a permanently mounted fire pump of at least 250 gallons per minute (gpm) capacity, water tank, and hose body whose primary purpose is to initiate a fire suppression attack on structural, vehicular, or vegetation fires and to support associated fire department operations. Normally, most initial attack fire apparatus are constructed on commercial-style chassis. *NFPA 190:1 Standard for Automotive Fire Apparatus*, 2016 Edition. Quincy, MA: NFPA, 2016.

[16] A water tender is the National Incident Management Systems (NIMS) approved term for a wheeled vehicle carrying water for fire suppression.

[17] In firefighting, reverse lay refers to the nozzle end of the hose being laid from the fire to a water source. This method is used when the pumper must first go to the fire location to size it up before laying supply line, and it is the most expedient way to lay hose if the apparatus must stay close to the water source.

engine. He saw flames (40 to 50 feet high) coming out of the cupola atop the fertilizer storage building and out of the door on the northeast corner of the building. Before the firefighter could make his way back to the end of the hose run, the explosion occurred. Before the explosion, the WVFD assistant chief arrived at the WFC facility, spoke with the police officer on scene, and advised him to begin evacuating nearby homes. He also made a radio request to the dispatch center, asking for a ladder truck to set up at the West Terrace Apartments in case a fire started there, but a ladder truck was not available. The WVFD chief and assistant fire chief were assessing the situation just before the explosion and were considering a total evacuation, even though neither believed that the FGAN would explode.[18]

On the basis of interviews that CSB conducted after the incident, the WVFD came to understand that it did not have enough water to effectively fight the fire.[19] Accordingly, the WVFD was considering the appropriate course of action—possibly standing down, letting the structure burn, and focusing on evacuation.

3.3 Abbott, Bruceville-Eddy, Mertens, and Navarro Mills Volunteer Fire Departments

On the evening of the incident, a group of volunteer firefighters from neighboring city fire departments (including Bruceville-Eddy, Mertens, and Navarro Mills), who were taking an Emergency Medical Technician (EMT)–Basic class at the West Emergency Medical Services (EMS) building, responded to the fire. The West EMS facility is located a few blocks west of the WFC facility.[20] When these volunteer firefighters heard the sirens activated in the city, they immediately made their way to the site. In addition, an ambulance responded with two EMTs and a volunteer firefighter. According to interviews that CSB conducted with emergency responders, radio and cell phone capabilities at the scene were limited after the explosion. Following the explosion, officials established two different staging areas. The first staging area, at the high school football field about 0.25 miles from the blast site, was used as a triage area for injured residents. Injured personnel and residents were relocated from the football field to the second staging area, at the community center about 1 mile away.[21] After the explosion at approximately 8:15 pm, additional volunteer firefighters from the neighboring cities of Abbott, Bruceville-Eddy, Mertens, and Navarro Mills responded to the WFC facility. Figure 10 shows the WFC explosion as it unfolded.

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[18] Section 7 of this report provides further details on how the evacuation occurred.
[19] Employees and emergency responders should ***not*** fight AN fires past the incipient stage. Further details on responding to AN fires is available in Section 7.5 and Section 7.6 of this report.
[20] State Fire Marshal's Office. "Firefighter Fatality Investigation," Investigation FFF FY 13-06 (West, TX).
[21] Clements, Bruce. Texas Department of State Health Services, "The Texas Public Health Response to the West Fertilizer Plant Explosion," October 8, 2013.

Figure 10. Video Stills of WFC Fire and Explosion (Source: Member of the Public)

3.4 **Consequences**

3.4.1 Fatalities and Injuries

The violent explosion at the WFC facility fatally injured 12 emergency responders and 3 members of the public. All of the fatalities except one resulted from fractures, blunt force trauma, or blast force injuries sustained at the time of the explosion. Two fatally injured members of the public lived at a nearby apartment complex while the third resided at the nursing home and died from injuries brought on by the trauma of the explosion shortly after the incident. According to the Waco-McLennan County Public Health District's report, [22] the incident resulted in more than 260 injured victims, including emergency responders and members of the public.[23] Hill County (Hill Regional Hospital and Lake Whitney Medical Center) and McLennan County (Hillcrest Baptist Medical Center and Providence Health Center) hospitals received 81 percent of patient visits, with 104 injury visits at Hillcrest Baptist Medical Center, 82 visits at Providence Health Center, 41 injury visits to Hill Regional Hospital, and 1 injury visit at Lake Whitney Medical Center.[24] The injuries ranged from relatively minor wounds (such as contusions, abrasions, and lacerations) to more serious injuries (such as fractures, closed head injuries, traumatic brain injuries, and skin burns). The majority of patients were treated and released after their initial visit to a hospital, medical center, or mobile medical unit. Figure 11 categorizes all injury types sustained by the 252 patients injured directly by the explosion; many patients received multiple types of injuries. The Waco-McLennan County Public Health report also identified the location where 76 percent of the reported 252

[22] Waco-McLennan County Public Health District. "A Public Health Report on Injuries Related to the West (Texas) Fertilizer Plant Explosion," June 24, 2014.
[23] The number of injured victims includes patients who were treated after the explosion and sustained injuries during clean-up or by debris in the neighborhood.
[24] Waco-McLennan County Public Health District. "A Public Health Report on Injuries Related to the West (Texas) Fertilizer Plant Explosion," June 24, 2014: 7.

injuries occurred, outside or inside of a structure. More than half of the injured patients reported being inside a structure (55 percent), and the rest said they were outside (13 percent) or inside of a vehicle (8 percent). The locations cited by the injured also reflected the most common types of injuries. Patients who were inside a structure were twice as likely to suffer abrasions, contusions, and lacerations. People who were outside or inside of a vehicle were eight times more likely to have hearing loss or tinnitus, tympanic membrane rupture, or inhalation injuries. The majority of the injured were within 1,500 feet of the blast, although some were more than 2,000 feet from the explosion; people who were hospitalized were closer to the center of the blast than those who were not admitted. Notably, eye injuries—and traumatic brain injuries and concussions—were equally distributed among the injured, regardless of location.[25] Detailed information regarding the cause of nonfatal injuries was not collected and analyzed. Possible causes of injuries include being struck by primary fragment projectiles, by secondary fragments from remote structures and vehicles, or directly by the blast wave.

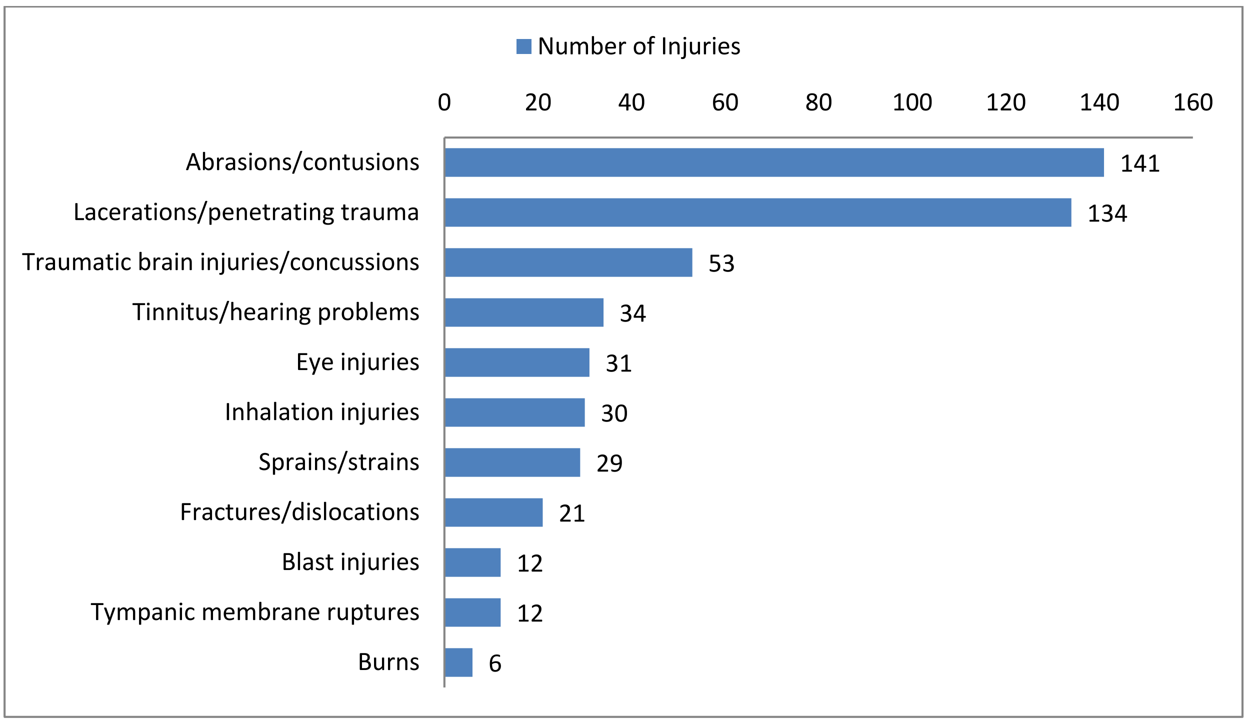

Figure 11. Number of Nonfatal Injuries, by Injury Type (Source: Waco-McLennan County Public Health District)[26]

During the investigation, CSB noted two potential scenarios that could have led to more severe consequences. First, if the fire had started during the middle of a normal school day instead of the

[25] Waco-McLennan County Public Health District. "A Public Health Report on Injuries Related to the West (Texas) Fertilizer Plant Explosion," June 24, 2014.

[26] Waco-McLennan County Public Health District. "Public Health Report: Injuries Related to the West (Texas) Fertilizer Plant Explosion," April 2013 (issued on June 24, 2014).

evening and if all other conditions remained unchanged (specifically, if onsite WFC employees were unable to extinguish the fire), students would have been present at the intermediate and high schools. Had the schools evacuated, students likely would have assembled in areas such as the gymnasium and multipurpose rooms within the schools (and in other pre-designated areas outside of the schools) before the evacuation to conduct a head count. Given the short time that elapsed before the explosion, many students and staff members might have been injured in the 20 minutes from the first discovery of a fire until the explosion. Second, a railcar loaded with more than 100 tons of FGAN toppled during the explosion but did not detonate. If the contents of the railcar had detonated, the damage, injuries, and fatalities would have been significantly worse. These scenarios are important to consider because throughout the United States, there are many facilities that, like WFC, are located near public structures such as schools.[27]

3.4.2 Property Damage

The West incident caused considerable property damage, including the complete destruction of the WFC facility (Figure 12). An initial estimate by the Texas Department of Insurance set total property damage resulting from the explosion and fire at $100 million. CSB hired a consulting firm[28] to perform an assessment of the structural and property damage caused by the fire and explosion. The assessment involved a thorough examination of damage to the WFC facility and to the community structures and facilities.[29] As of the publication of this report, neither the owners of the WFC nor the city of West has decided whether the WFC facility would be rebuilt. Currently, the local farmers are using fertilizer from another fertilizer facility in Leroy, Texas, seven miles east of the city of West.

[27] Section 5.4 provides further details on the location of schools in relation to FGAN facilities throughout Texas.
[28] ABSG Consulting Inc. *See*: http://www.absconsulting.com/ (accessed on June 26, 2015).
[29] Sites examined included the West Intermediate School (WIS), West High School (WHS), West Middle School (WMS), West Rest Haven nursing home, and the park.

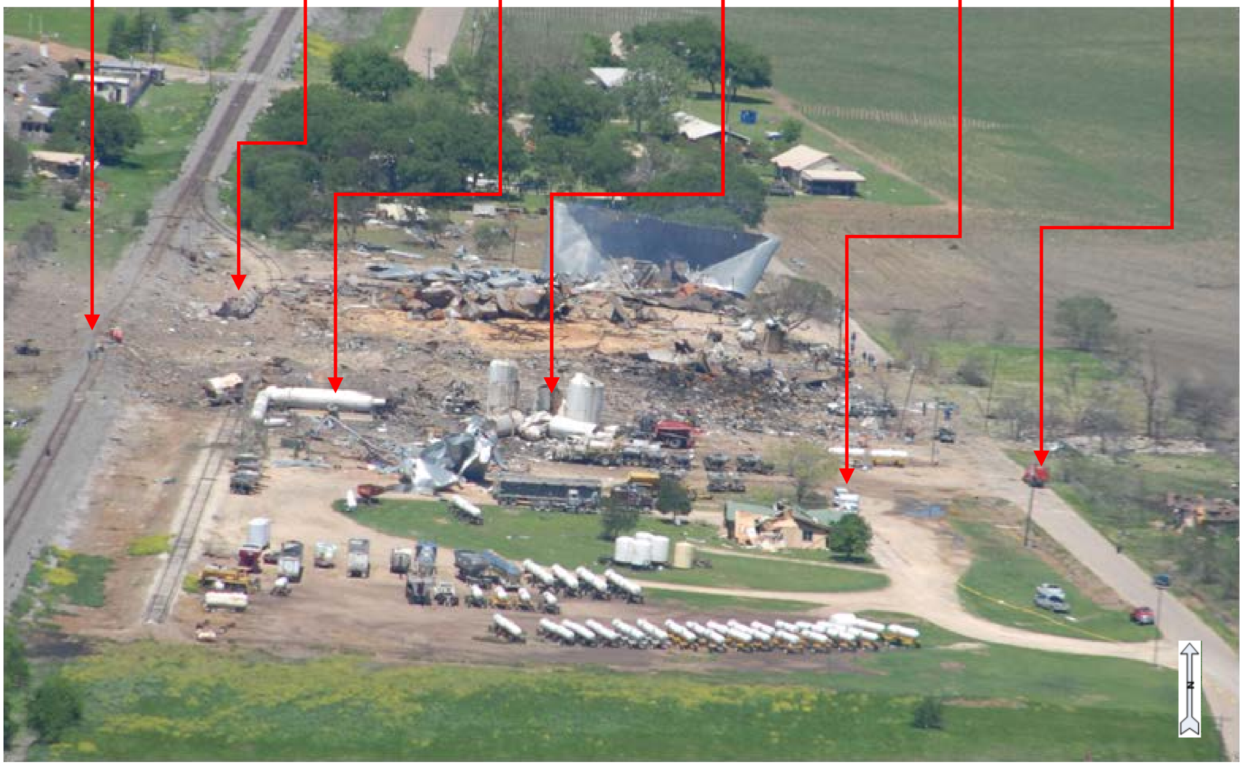

Figure 12. Overview of Damage to WFC Facility (Source: Texas Civil Air Patrol)

The explosion, overpressure, and debris completely destroyed a WVFD brush truck, water tender, and fire engine (Figure 13). The water tender was located southeast of the crater and likely moved about 6 inches south as a result of the blast overpressure. The explosion propelled the door from the water tender to the east. A large farm truck south of the fertilizer storage building and toward the scale house moved about 6 inches south of its original location because of the blast wave (Figure 14). All of the POVs belonging to responding volunteer firefighters who parked onsite were damaged or destroyed in the explosion. In addition, the explosion overturned and destroyed the railroad car loaded with FGAN, approximately 190 feet to the north of the crater (Figure 15).

Figure 13. Damaged WVFD Water Tender (Source: ABS Consulting)

Figure 14. Farm Truck South of Crater, Near the Scale House (Source: ABS Consulting)

Figure 15. Railcar Loaded with FGAN, Destroyed and Overturned by Explosion (Source: CSB)

The explosion completely demolished the scale house; the roof and all four walls failed. The explosion flattened the chemical storage and office building east of the fertilizer storage building—all that remained was a stack of metal debris where the building once stood. The explosion also destroyed the corn silo north of the fertilizer storage building. In addition, the blast heavily damaged the above-ground vertical liquid fertilizer storage tanks. As shown in Figure 16, the liquid level during the explosion in the tank to the left is clearly visible by the crease at the top of the tank where the deformation begins. The tank on the right in Figure 16 clearly shows a large debris impact that folded and crushed the tank.

Figure 16. Liquid Fertilizer Tank Damage (Source: CSB)

The two 12,000-gallon anhydrous ammonia pressure vessels were approximately 30 percent full of ammonia at the time of the explosion. As shown in Figure 17, the anhydrous ammonia pressure vessels were south of the crater. The pressure relief valves (PRVs) on the northern anhydrous ammonia pressure vessel still had their weather caps on and consequently did not relieve the pressure. The weather caps were missing on the PRVs in the middle of the southern anhydrous ammonia pressure vessel.[30] Two additional liquid fertilizer storage tanks sat parallel to the railroad track southwest of the anhydrous ammonia pressure vessels. The blast of the explosion also damaged the tracks on the railroad between the WFC property and the park. The blast was sufficiently powerful to shift the tracks more than 2 feet to one side, creating a prominent curve in the tracks (Figure 18).

Figure 17. Anhydrous Ammonia Pressure Vessels (Source: CSB)

[30] The condition of the anhydrous ammonia pressure vessels is discussed in further detail in Section 3.4.2.1 of this report.

Figure 18. Damaged Railroad Tracks Adjacent to WFC Facility (Source: CSB)

The explosion damaged a playground and basketball court in a park located a few hundred feet west of the WFC facility (Figure 19). The blast destroyed equipment on the playground, including damaging the basketball goal posts on the basketball court (Figure 20). In addition, the trees in the vicinity of the park showed evidence of scorching,[31] likely from the fireball when the explosion occurred. The trees were directly downwind of the anhydrous ammonia pressure vessels and were not within the smoke plume from the fire. Pre-explosion video of the fire shows the smoke traveling with the wind but crossing the playground equipment to the north of the basketball courts.

Figure 19. Damaged Playground Equipment (Source: ABS Consulting)

[31] The ABS damage assessment did not include making a determination about whether the trees were scorched by the fire or by another source.

Figure 20. Damaged Basketball Goal Post at Park (Source: ABS Consulting)

3.4.2.1 WFC Anhydrous Ammonia Vessels

The two 12,000-gallon anhydrous ammonia vessels were located at the south end of the storage building, about 150 feet from the site where the initial fire and smoke were observed. Each vessel was more than 46 feet long, with two affixed PRVs set to vent the tanks to the atmosphere if the pressure inside the tanks exceeded predetermined set points, estimated by one employee as between 250 and 300 pounds per square inch (psi). Both sets of PRVs were fitted with orange plastic caps intended to protect the devices from rain and dirt. The vessels shared a common pipeline that allowed switching between the tanks on occasion, but under normal operation, the connecting pipe was kept in a closed position.

CSB observed the intact PRVs on top of the vessels (Figure 21) on May 28, 2013, although the polyvinyl chloride (PVC) protective caps were no longer in place on the PRVs of the southernmost tank. The absence of detectable residue of this protective material on the PRV suggested that it was exposed to fire to the degree that it melted. The caps were not found during any post-incident salvage or recovery activities. During salvage operations, a crane with lift bucket reportedly struck the PRV for the northernmost tank, knocking it to the ground where it was found.

Figure 21. Anhydrous Ammonia Tank PRV, Post-Incident (Source: CSB)

From interviews with employees who were knowledgeable about the frequency of deliveries and volumes in the tanks, CSB learned that the site received as many as four deliveries of anhydrous ammonia per day under normal operating conditions with good weather and that each vessel was at 30 percent capacity, or about 7,200 gallons, at the time of the fire and explosion. After the incident, technicians removed all remaining contents in both vessels.

When hazardous materials technicians in fully encapsulated personal protection equipment initially entered the area of the anhydrous ammonia vessels after the site was secured, they observed a leaking valve at the east end of the tanks. In light of a buildup of ice around the valve, it is thought that the material leaking was liquid anhydrous ammonia. Notably, anhydrous ammonia stored under pressure contains latent heat. As the liquid is released, it cools rapidly and interacts with moisture in the atmosphere and can freeze on the pipe and adjacent vessel. However, the vessels did not catastrophically fail on the night of the incident. The CSB considers this to be a near-miss of potentially significant consequence.

3.4.3 West Independent School District

The WFC built its facility in 1962, before much of the surrounding community developed. In 1923, the West Independent School District (WISD) (Figure 22) built the West Middle School (WMS), which at the time served as the high school for the city of West. The WMS campus added a building in 1957 that served as supplementary classrooms and library space. The WISD also built West Elementary School (WES) in the early 1960s. WIS was built around 1985, and WHS was constructed in 2000, after the WFC facility was built. Four schools were in close proximity to the facility, including WIS (552 feet southwest of the facility), WHS (1,263 feet southeast of the facility), WMS (2,000 feet southwest of the facility), and WES (4,867 feet southwest of the facility).[32]

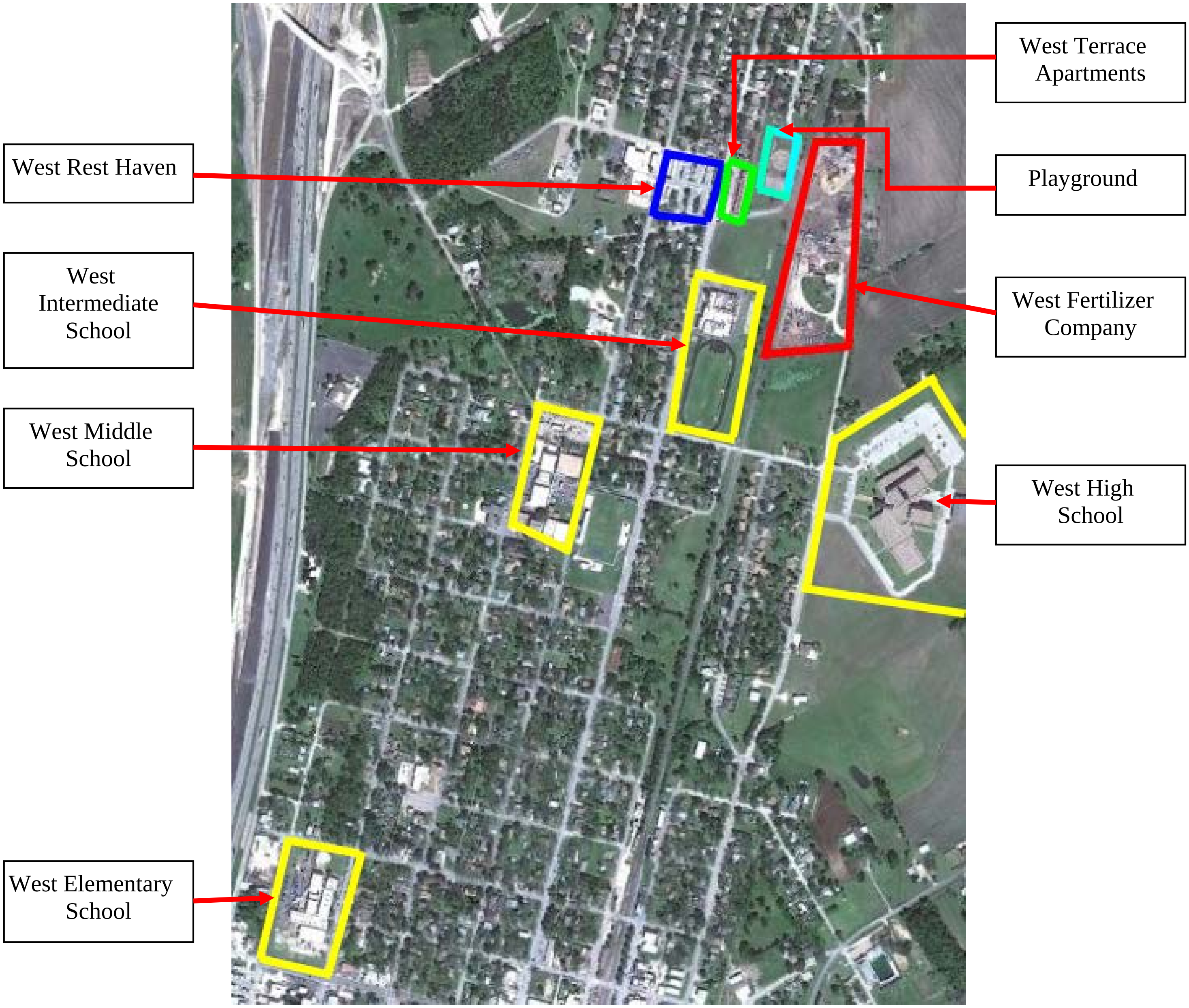

Figure 22. Proximity of WFC Facility to Schools and Other Public Structures (Source: Google Earth)

[32] The growth of the community around the WFC facility is discussed in further detail in Section 9 of this report.

The overpressure from the explosion's blast wave caused most of the damage, although some fires started post-explosion, including those at WIS and many nearby homes. At the time of the incident, school was not in session, which limited the number of fatalities and injuries to members of the public (including students, teachers, and other staff members). However, if the explosion had occurred during normal school hours, the number of injuries and fatalities from the blast wave could have been much higher. Table 2 indicates the projected number of students and staff members who would have been affected and could potentially have been injured or killed by the blast if school had been in session. If all enrolled students had been in school that day, approximately 1,486 students would have been present and vulnerable. Of this total, 665 students would have been at WIS and WHS, which suffered the most severe damage. If the explosion had occurred during school hours and all staff members had been present that day, approximately 191 staff members would have been vulnerable. Of this total, 86 staff members would have been at WIS and WHS. Because of the breadth of damage at the schools, the WISD decided to demolish WIS, WHS, and all WMS facilities except for the gymnasium and the 1923 building. The WISD also demolished select portions of the 1967 annex and the entire cafeteria at WMS. Appendix A includes a discussion of the details of WISD plans to restore and rebuild the school system. For a more complete understanding of the magnitude of the injuries and fatalities that the WFC incident could have caused, this report considers in greater detail the extent of damage at the schools.

Table 2. Estimated Number of Students and Staff During School Hours

School	Grades	Estimated Number of Students Enrolled	Estimated Number of Staff Members
West Intermediate School	4-5	246	22
West Middle School	6	320	40
West High School	7-12	419	64
West Elementary School	K-3	501	45
Total Occupants		**1,486**	**171**

3.4.3.1 Damage Assessment of the West Intermediate School

The original WIS was a pre-engineered metal building consisting of lightweight steel frames, cold-formed girts,[33] and purlins[34] supporting lightweight metal decks. The gymnasium and cafeteria were also pre-engineered metal buildings. The remainder of the school was constructed of precast concrete tilt-up load-bearing walls that supported open webbed steel joists and a metal roof deck with a built-up roof. Figure 23 shows the building room layout in the school evacuation plan and highlights in yellow some classrooms with extensive damage. A considerable amount of debris accumulated in the hallway outside of rooms 11 and 12 (Figure 24). An interior doorframe blocked the hallway; the acoustic ceiling had collapsed; and numerous obstacles would have made exiting the building difficult for students and staff. In addition, the original metal school building just south of this location was involved in a fire after the explosion at the WFC facility, so students and staff members also would have been exposed to smoke and heat. The acoustic ceiling, light fixtures, and other debris were thrown onto all of the desks in the interior of classroom 12 (Figure 25). Moreover, the window on the north facade failed violently, and a large shard of glass (approximately 3 inches long) was embedded in the assignment poster on the south wall of the classroom (Figure 26).

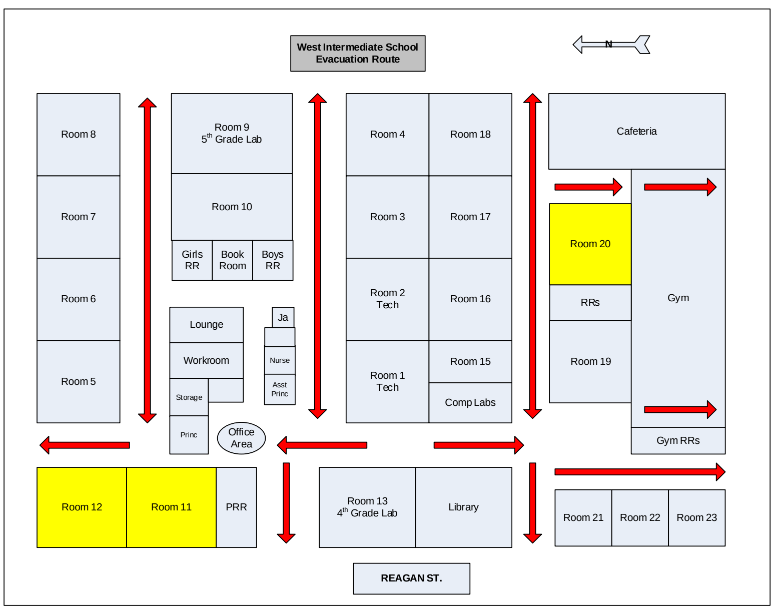

Figure 23. WIS Room Layout in Evacuation Plan (Source: CSB)

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[33] A horizontal structural member that spans columns or posts in framed construction and is used to support cladding. *Dictionary of Construction, Surveying and Civil Engineering* (2012).

[34] A horizontal roof member that runs parallel to the ridge and spans the roof trusses and is used to support the roof covering. *Dictionary of Construction, Surveying and Civil Engineering* (2012).

Figure 24. WIS North Hallway, Looking Toward Northeast Exit Door (Source: ABS Consulting)

Figure 25. Glazing Hazard in WIS Room 12 (Source: ABS Consulting)

Figure 26. Embedded Glass in Assignment Poster in WIS Room 12
(Source: ABS Consulting)

The pre-engineered portion of the school in the northeast corner was heavily damaged by blast overpressure and was also fully engulfed in flames. At the time of the physical survey, blast damage to this portion of the building could not be evaluated because of the magnitude of the fire and associated heat; however, Figure 27 does provide a view looking east down the hallway of this part of the school after the fire.

Figure 27. Interior of Burned Northeast Section of WIS
(Source: ABS Consulting)

The WFC explosion heavily damaged the WIS gymnasium (Figure 28). There was evidence that some of the built-up roof over the gymnasium burned; however, the level of heat damage to the roof was minor compared to the damage from blast overpressure. The north half of the gymnasium roof failed. Within the gymnasium, the blast heavily damaged the pre-engineered frames, which were unstable as a result. The roof purlins were moderately deformed, with the exception of the failure that occurred on the north half of the frame spans. Furthermore, the windows from the south facade of the gymnasium failed, and the overpressure propelled them over the south bleachers and onto the gym floor. The explosion also heavily damaged the roof in the cafeteria to the south of the gymnasium.

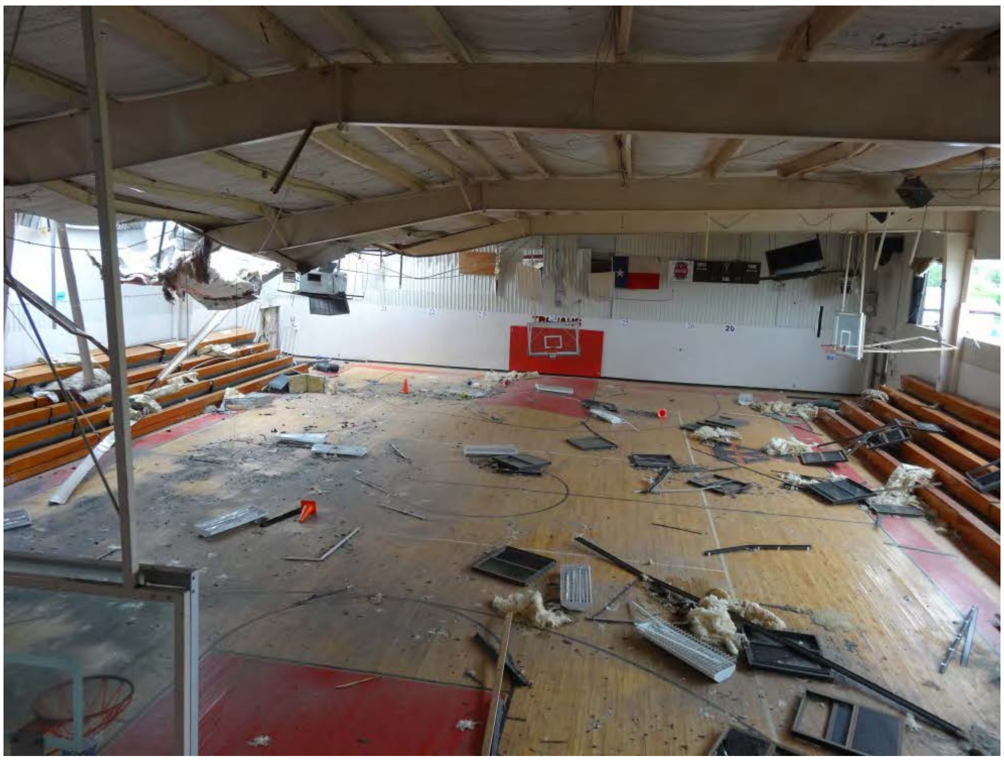

Figure 28. WIS Gymnasium (Source: ABS Consulting)

The interior of classroom 20 also sustained significant damage (Figure 29). The acoustic ceiling, light fixtures, and insulation were blown down onto the floor by a combination of the roof motion and the air blast entering through the heating, ventilation, and air conditioning (HVAC) duct after the explosion displaced the rooftop air conditioner. After the incident, the entire contents of the ceiling plenum were found on top of the desks. If the explosion had occurred during school hours, any students or staff members in the room would have been covered in this debris and would have had to climb over (or through) it to reach the exit. In addition, there was evidence that overpressure entered the room through the HVAC opening and was of sufficient magnitude to cause the door latch to fail. The damage to WIS decreased as the distance from the explosion source increased from the northeast to the southwest. WIS also housed the technical department where all of the school servers were kept. The servers and the data stored on them were lost in the explosion and fire.

Figure 29. WIS Classroom 20 (Source: ABS Consulting)

3.4.3.2 Damage Assessment of West High School

WHS was constructed of concrete masonry unit walls supporting open webbed steel joists and a metal deck with built-up roofing and gravel ballast.[35] The building room layout (on the basis of the school evacuation plan) shows that the school was organized into two wings (Figure 31). The north wing contained the activities area, including the two gymnasiums, two weight rooms, boy's athletics locker room, girl's athletics locker room, and band hall. The south wing included the classrooms as well as a large lecture hall. Between the two wings were the entry hall, administrative offices, common areas, kitchen, and (to the rear) auditorium. A pre-engineered maintenance building sat directly behind the school to the east.

[35] Small gravel placed on a built-up roof to protect the roof from ultraviolet light, heat, and weather and to protect the roof membrane from degradation.

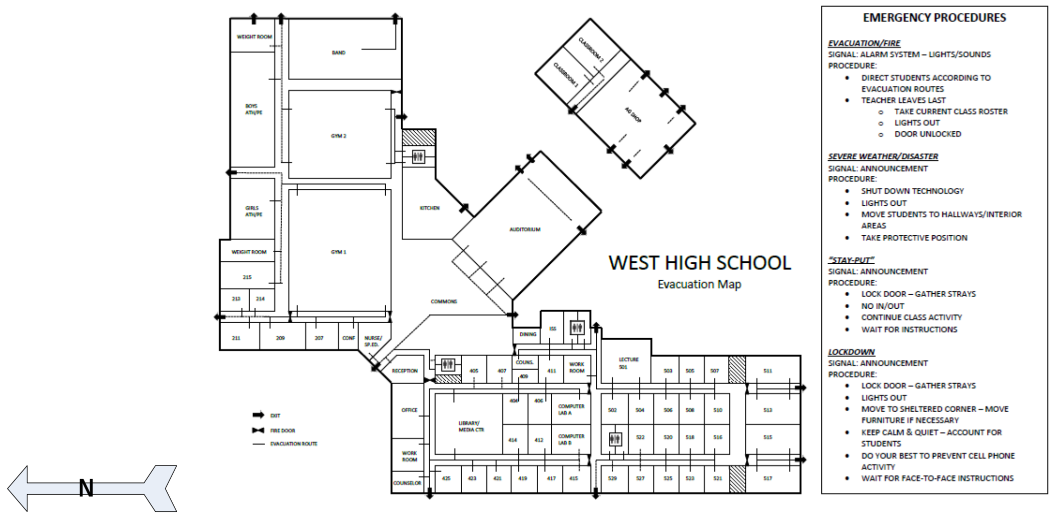

Figure 30. WHS Evacuation Map (Source: WISD)

The WHS auditorium was a steel frame structure with masonry infill walls. After the WFC explosion, some of the masonry veneer on the exterior was loose near the northeast corner. Inside the auditorium, large areas of the hanging ceiling were unstable, and the supporting structure was compromised, especially one area of the ceiling (between the seating and the stage), which was near collapse because of the failed hanger connections. Viewed from underneath, evidence of damage to the ceiling was observable at light fixtures, and evidence of cracking and separation was visible near the walls. However, the severity of the damage and compromise to the ceiling hangers became fully evident when they were inspected from the catwalks above the auditorium.

3.4.3.3 Damage Assessment of West Middle School

WMS was the school third farthest from the WFC site, and although it sustained less damage than WIS and WHS, it was nonetheless severely damaged in the explosion. WMS resided at the site of the original WHS, constructed in 1923. The athletic field east of WMS was the site employed for triage and evacuation of the wounded after the explosion (Figure 31).

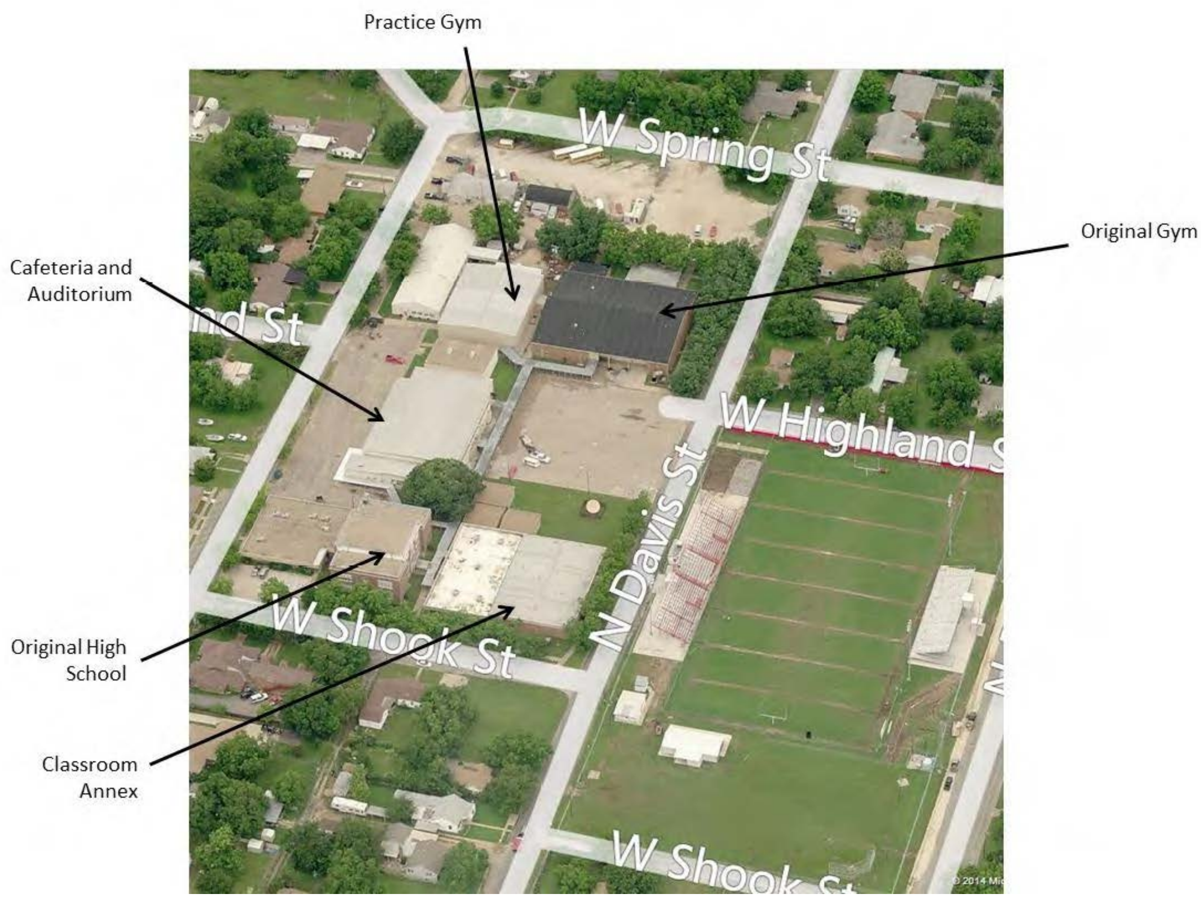

Figure 31. WMS Layout (Source: Bing Maps)

The practice gymnasium was a lightweight pre-engineered metal building with a brick facade. The pre-engineered frames buckled after the explosion, resulting in a small permanent deformation of the roof purlins. In addition, the overpressure damaged the roof purlins and frames. An external assessment of the cafeteria and auditorium indicated damage to the ceiling components. Many of the windows on the west facade were unbroken. The original high school classroom building at WMS was constructed in 1923. The windows facing north toward the WFC facility were broken, but only some of the remaining windows had failed. The building originally was not air conditioned and had a high tin ceiling, but at a later date, a new drop ceiling was installed to accommodate central air conditioning. After the explosion, the new drop ceiling failed, but the original tin ceiling was still in place, and some of the windows were broken. Window hazards thus were low to moderate, and the damage to the exterior appeared to be superficial. The classroom annex building roof structures were open web steel joists supporting a built-up roof on metal deck. The roof structure showed no observable damage; however, the suspended ceiling failed because of the motion of the roof (Figure 32).

Figure 32. Classroom Annex Interior Hallway and Ceiling Damage at WMS
(Source: ABS Consulting)

3.4.3.4 Damage Assessment of West Elementary School

WES was the campus farthest from the WFC site and sustained very minimal damage. WES received minor renovations, such as removing and replacing damaged ceilings, replacing damaged windows, and performing general interior clean-up.[36]

3.4.4 West Rest Haven Nursing Home

The explosion also destroyed the West Rest Haven nursing home, located west and within 600 feet of the WFC facility, at the corner of North Reagan Street and West Haven Street (Figure 33). Since 1967, the nursing home had provided residents with routine care and also treated patients with Alzheimer's disease, diabetes, and hypertension, among many medical conditions. Approximately 20 of the 155 staff members and 130 patients[37] were in the nursing home during the explosion. All were evacuated with the assistance of the nursing home staff and neighborhood volunteers, yet 72 patients sustained injuries. The level of severity of the injuries varied from cuts caused by broken glass and building materials to broken bones. An 87-year-old man succumbed to a stress-related heart attack; however, his death was not a direct result of the explosion.

Before the explosion, the nursing home's medical director came to the Reagan Street entrance and directed the charge nurse to begin evacuating residents to the other side of the facility in response to the ongoing fire at the WFC facility. As the charge nurse began the evacuation process, the explosion occurred. During the post-blast evacuation, staff members and volunteers removed many bedridden

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[36] *See*: http://www.restorewestisd.com/plans.html (accessed on December 22, 2015).
[37] The nursing home had a capacity of 145 individual licenses.

residents from the building through the windows instead of the hallways out of concern that the structure would collapse. The residents were moved from the back of the nursing home to the front during the fire, evacuated after the explosion to a helicopter pad and football field, and eventually moved to the community center. The 72 injured residents were transported to Providence Health Center and Hillcrest Baptist Medical Center to receive treatment. After the residents were treated and released, they were relocated to various nursing homes in the neighboring cities of Waco, Midway, Hewitt, Clifton, and Hillsboro. Uninjured residents were also relocated to these nursing homes.

Within 2 months of the incident, 14 of the West Rest Haven nursing home residents died, a figure cited as unusually high by the facility's administrator,[38] and since the incident, approximately 50 patients have died. According to information the nursing home provided to CSB in May 2015, almost all of the 80 living patients who formerly resided at West Rest Haven tentatively planned to return to the nursing home once the new construction was complete.

Figure 33. Damage to Reagan Street Entry of West Rest Haven (Source: ABS Consulting)

[38] *See*: http://www.dallasnews.com/news/west-explosion/human-toll/20130617-some-say-west-blast-rushed-nursing-home-patients-deaths.ece (accessed on December 22, 2015).

3.4.4.1 West Rest Haven Nursing Home Disaster and Evacuation Plan

West Rest Haven followed a disaster and evacuation plan that include policies and procedures[39] to meet all potential types of emergency and nonemergency situations, including fires, disasters, explosions, toxic fumes, train derailments, broken gas mains, auto and truck collisions, and fire drills. The plan included detailed evacuation procedures in the event of a fire as well as shelter-in-place procedures for events such as severe weather. Depending on the location of the fire, patients could be evacuated to another portion of the building rather than being completely removed from the premises. The disaster and evacuation plan also contained transportation and sheltering agreements if needed during an emergency evacuation of the facility. The plan also provided guidance to the facility's operators on responses to a derailed train or ruptured tank cars containing potentially hazardous liquids and on steps to shelter in place if the facility were exposed to hazardous gas or vapors.[40] West Rest Haven scheduled monthly fire drills to meet the requirement to conduct fire drills during each of the three work shifts. In addition, the nursing home held a mock disaster drill approximately 3 months before the explosion, employing a scenario that assumed a toxic gas release from the WFC facility.

3.4.4.2 Damage Assessment of West Rest Haven Nursing Home

The West Rest Haven nursing home was irreparably damaged (Figure 33), leading the city to completely demolish the structure 3 months after the incident.[41] The nursing home was constructed of load-bearing wood stud walls (with brick veneer) and wood trusses that spanned the wings from exterior wall to exterior wall (east to west). The nursing home's emergency exit plan (Figure 34) shows the floor plan and room layout. The explosion most heavily damaged the eastern-most corridor of the building. As a result of the explosion, the roof trusses collapsed, and the east wall failed. The eastern rooms were heavily damaged and subjected to flying wall debris and window fragments in addition to failing drywall, insulation, and light fixtures from the ceiling. Investigators observed high glazing hazards, including glass shards that penetrated the wall opposite the windows. The ceilings, insulation, and interior contents of rooms were lying on beds and blocking doorways, posing hazards to any occupants of these rooms. In addition, the air blast would have infiltrated the rooms through the failed windows. Pieces of broken glass littered the inside of the nursing home, with the exception of hallway corridors that were shielded from windows by interior partitions. The great rooms, lobby, and patient rooms were also subjected to significant hazards from broken shards of glass.

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[39] The disaster and evacuation plan also includes policy and procedures for severe weather, bomb threats, water shortages, electrical power outages, loss of comfort heating, heat and humidity, and floods.
[40] West Rest Haven Inc. "Disaster and Evacuation Plan."
[41] *See*: http://video.dallasnews.com/Damaged-West-nursing-home-razed-3-months-after-blast-24951515?freewheel=90850&sitesection=dallasnews_nws_non_non&VID=24951515#.Uv58DMKYbIU (accessed on January 4, 2016).

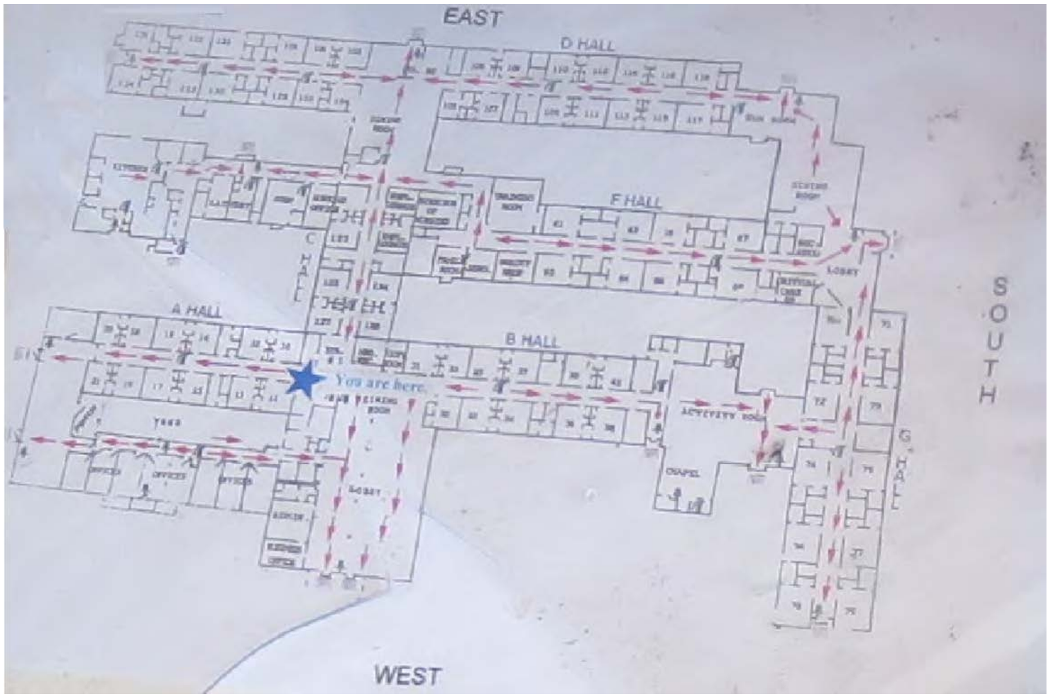

Figure 34. Emergency Exit Floor Plan for the West Rest Haven (Source: CSB)

The blast also inflicted significant damage to the western portion of the nursing home, and the great rooms, such as the lobby, were hit particularly hard because of the large spans of the overhead trusses that failed and collapsed onto the furniture. In addition, hallways in this area presented many hazards, including hanging light fixtures, failed ceiling joists, and collapsed drywall and insulation on the floors. Moreover, the debris field of the nursing home contained secondary fragments from massive pieces of the WFC facility's concrete foundation and also significant masses of earth. Observations indicated that a large piece of the WFC foundation, measuring 16 inches wide by 16 inches tall and 36 inches long (Figure 35, right) impacted room 79, traveling through the roof and the exterior wall (Figure 35, left). This debris fragment was calculated at a weight of approximately 800 pounds and had sufficient momentum after the impact to exit the nursing home, strike the ground, and then travel an additional 60 feet before coming to rest just to the west of North Davis Street.

Figure 35. Crater and Debris (left) from Fragment (right) of WFC Facility Foundation that Impacted West Rest Haven (Source: ABS Consulting)

On April 4, 2014, the city of West broke ground at 503 Meadow Drive, a block away from the original site, on the new 120-bed West Rest Haven nursing home (with 75,000 square feet), which opened in summer 2015.[42] The estimated construction cost is $11 million. West Rest Haven did not receive any grants or federal money to rebuild the facility.

3.4.5 West Terrace Apartment Complex

The West Terrace Apartment Complex, a 22-unit apartment complex built in 1979 and owned by J&B Realty Ltd., was 450 feet due west of the epicenter of the explosion. Two members of the public were fatally injured at the apartment complex. One of the victims was most likely standing on the east side of the complex and watching the fire shortly before the explosion occurred. The second victim was most likely inside her lower-level one-bedroom apartment. The apartment building had four vacant units that were being used for storage. At the time of the explosion, a member of the cleaning staff was just finishing servicing one of the recently vacant units; she was injured in the blast while exiting the apartment building and walking down the stairs to her car. This worker's mother accompanied her on the job that day and was in the just-serviced unit, waiting for her daughter to return with the car, when the explosion occurred; however, the worker's mother was not injured. Four residents of the apartment

[42] *See*: http://dfw.cbslocal.com/2014/04/04/groundbreaking-symbolizes-hope-in-west-one-year-later/ (accessed on April 4, 2014).

complex were treated at Hillcrest Baptist Medical Hospital, and two residents were treated at Providence Health Center for injuries sustained. The explosion completely destroyed West Terrace. The roof and walls of the building completely failed (Figure 36).

Figure 36. West Terrace Apartment Complex East Façade (Source: CSB)

3.4.6 Private Residences

According to the Texas Department of State Health Services, the fire and explosion affected many of the homes within a 2-mile radius of the WFC facility. West had a total of 700 homes, and 350 of those were impacted— with 142with homes damaged beyond repair,[43] 51 homes suffering major damage, 27 homes incurring minor damage, and 130 homes otherwise affected.[44] CSB consultants examined damage to 190 single-family residential buildings within a radius of 3,500 feet of the explosion crater[45] and documented broken windows, facade damage, and nonstructural and structural component (e.g., wall and roof system) failures (Figure 37). The damage assessments were performed in the majority of the cases by inspecting the perimeter of the property. Access to home interiors was limited because owners either were not present or were unwilling to grant access.

[43] Not all homes that were damaged beyond repair have been rebuilt.

[44] Clements, Bruce. Texas Department of State Health Services, "The Texas Public Health Response to the West Fertilizer Plant Explosion," October 8, 2013. *See*: http://www.astho.org/Preparedness/DPHP-Materials-2013/WestTexasExplosion/ (accessed on January 18, 2016).

[45] CSB contractors assessed damage that was measured to 3,500 feet from the WFC site, but damage occurred beyond that distance.

Figure 37. Example of Damage to Single-Family Residential Structure (Source: ABS Consulting)

According to the city of West, 259 building permits were issued as of October 2014. Of those, 79 were for building new homes, 117 for remodeling homes, and 63 for making miscellaneous repairs (such as fence, shed, and carport restoration).

3.4.7 Infrastructure Damage to the City of West

The explosion at the WFC facility damaged the West city infrastructure; it ruptured water lines, deformed sewer manholes, damaged water storage tanks, further rendered wells unusable, cracked walls of a pump house, and caused the loss of water supply to the community. Access to water was restored gradually as the affected infrastructure was repaired. As a result of the explosion, FEMA assisted the city in repairing some of the damaged infrastructure listed in Table 3, such as water facilities and water lines.

Table 3. Infrastructure Repaired with FEMA Funding

Affected Infrastructure	**Cost to Repair Damage**
Well 4, Ground Storage Tank	$365,000

Well 4, Pump Station Door and Window	$2,000
Davis Street Water Line	$74,000
Walnut Street Sewer Manhole	$9,200
Total	$450,200

The West water system is fed by a 12-inch supply line from the city of Waco at a pump station 11 miles south of West. The pump station supplies 700 gallons per minute, with a storage capacity of 167,000 gallons. Water pressure for homes is usually 48 to 50 psi; however, on the morning after the incident, water pressure was measured at less than 20 psi because of damaged water lines. In response to the abnormal water pressure, the city issued a boil water order. West used two water wells to supply water to the community. The first well had a capacity of 250,000 gallons; however, it had been out of service for about 7 years at the time of the explosion. The second well also had a capacity of 250,000 gallons and was removed from service in January 2013 for rehabilitation.[46] This well also was damaged as a result of the explosion but has since been repaired and was back online as of September 1, 2014. The city also has an above-ground water tower with a storage capacity of 150,000 gallons; the tower was nearly drained by the post-explosion fire department response.[47] According to CSB interviews conducted with the Abbott Fire Department, West had a history of improperly working water hydrants and consistently low water pressure. Abbott firefighters had previously responded to fires in West and were unable to get hydrants to work adequately. The city had installed the above-ground water tower before the WFC incident to address the issue of low pressure.

According to the Mayor of West, “The city generates its revenue in three ways—water and sewer rates, property tax, and sales tax.” During the first 2 months after the explosion, West experienced a loss of income (65 percent of water and sewer revenue and 30 percent of property tax values).[48] As of June 2013, the city of West indicated that the fire and explosion at WFC had cost the city $17 million in actual damages; however, the total cost-to-date may be greater as additional demolition, renovation, and construction projects continue throughout the city. On April 15, 2014, the State of Texas provided additional disaster grant assistance[49] to the city of West in the amount of $4,853,500 to fund the disaster recovery work on the water plants, water tank rehabilitation, wastewater outfall interceptor, and disaster zone infrastructure repairs.[50] The first infrastructure project (costing $400,000) was completed in August 2014 and involved installation of a new well and upgrading of a storage tank located by the new nursing home.

[46] State Fire Marshal’s Office. “Firefighter Fatality Investigation,” Investigation FFF FY 13-06 (West, TX).
[47] *Ibid*.
[48] *See*: http://www.cityofwest.com/wp-content/uploads/2012/12/June-2013.pdf (accessed on December 22, 2015).
[49] The State of Texas provided an initial $3.2 million disaster grant in August 2013.
[50] The State of Texas. Office of the Governor, “Letter to the City of West,” April 15, 2014.

4.0 Incident Analysis

4.1 Fertilizer Grade Ammonium Nitrate (FGAN)

4.1.1 The Fertilizer Industry

The Fertilizer Institute defines fertilizer as a "collection of elements needed for plants to grow well."[51] The application of fertilizer to soil provides nutrients for plants to enhance fertility and the production of crops. The primary nutrients for plant nutrition are nitrogen (N), phosphorous (P), and potassium (K). Nitrogen is considered the most important of the three nutrients because it is critical to the formation of protein, which composes the tissue of most living things. Although nitrogen exists in the composition of air, it does not exist in a form that plants can readily absorb. Accordingly, farmers apply fertilizers containing nitrogen compounds to their soils to enhance crop production.

Nitrogen is most readily available for plants in its inorganic forms, such as ammonium (NH_4^+) or nitrate (NO_3^-) ions. It is applied to crops in different forms such as dry granules, liquid, or injection into the soil as a gas. The largest source of nitrogen by volume in commercial fertilizer is anhydrous ammonia, which is applied directly to crops.[52] Other important nitrogen fertilizers include aqueous ammonia (NH3), ammonium sulfate ($(NH_4)_2SO_4$)), ammonium thiosulfate ($H_8N_2O_3S_2$), calcium nitrate ($Ca(NO_3)_2$), sodium nitrate ($NaNO_3$) and FGAN. FGAN, the substance in the fertilizer involved in the West Fertilizer Company (WFC) explosion, is primarily used on pastureland, hay, and fruit and vegetable crops. FGAN is most commonly used in the Southeast and Midwest in the United States, and the largest AN consumers are Missouri (20 percent), Tennessee (14 percent), Alabama (10 percent), and Texas (8 percent).[53]

4.1.2 AN Properties

AN (NH_4NO_3) is a salt compound produced by neutralizing nitric acid (HNO_3) with anhydrous ammonia (NH_3). The AN manufacturing process involves several steps, including solution formation and concentration; solids formation, finishing, screening, and coating; and product bagging, bulk shipping, or both. AN is marketed in different forms depending on its use, but it is primarily manufactured for use in fertilizers or as a precursor in the manufacture of explosives. Liquid FGAN can be sold as a fertilizer or may be concentrated to form a dry solid product. This solid product may be used for fertilizer or fertilizer blends or may be incorporated as part of an explosive. Pure solid AN is a white or grey odorless material that is marketed in several different forms, such as prills, grains, granules, or crystals. Prills are the most commonly produced form and take the shape of spherical pellets. High-density prills are used for FGAN;

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[51] The Fertilizer Institute. *Fertilizer 101, Nourish, Replenish, Grow*. Washington, DC: The Fertilizer Institute, 2010: 13.

[52] *See*: https://www.tfi.org/safety-and-security-tools/get-know-fertilizer-retailer/infographics/ammonium-nitrate-infographic (accessed on November 18, 2015).

[53] *Ibid.*

low-density porous prills are generally considered technical grade ammonium nitrate (TGAN) or explosive grade ammonium nitrate, both of which are used in the manufacturing of explosives. Chemically, however, these prills are identical; the difference is that small quantities of coatings and stabilizers are added to FGAN to prevent caking and degradation.

4.1.3 AN Hazards

Under normal conditions, pure solid AN is a stable material; it usually is not sensitive to mild shock or other typical sources of detonation (such as sparks or friction). However, AN exhibits three main hazards in fire situations:

1. Uncontrollable fire.
2. Decomposition with the formation of toxic gases.
3. Explosion.[54]

These hazards arise in part because AN is an oxidizer. This classification is demonstrated both by the U.S. Department of Transportation (DOT), which categorizes AN as a Class 5.1 oxidizer,[55] and by OSHA, which describes it as an oxidizer in its Explosives and Blasting Agents standard, 29 CFR 1910.109.[56] Significantly, AN is classified as an "explosive" when the prills are produced with more than 0.2 percent carbonaceous material. Carbonaceous material is a substance rich in carbon, such as a hydrocarbon. OSHA defines "oxidizer" as a chemical that "initiates or promotes combustion in other materials, thereby causing fire either of itself or through the release of oxygen or other gases."[57] As an oxidizer, AN can increase the flammability or explosibility (or both) of other combustible substances when it decomposes after exposure to heat. As AN decomposes when in contact with heat or fire, the reactions can release gases such as nitric acid (HNO_3), ammonia (NH_3), nitrogen oxides (NO, NO_2), nitrous oxide (N_2O), nitrogen, oxygen, and water vapor, depending on the heat and pressure. Some by-products can be toxic when emitted.

During fires, AN presents serious risks of explosion beyond those attributed to its oxidizing properties and ability to decompose and emit toxic gases. When AN is contaminated with organic carbon-containing materials or certain inorganic chemicals, its behavior can become dangerously unpredictable,

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[54] Resources Safety, Division of Mines and Petroleum. *Safe Practice: Safe Storage of Solid Ammonium Nitrate*. East Perth, Western Australia: Government of Western Australia, 2013. *See*: http://www.dmp.wa.gov.au/documents/Code_of_Practice/DGS_COP_StorageSolidAmmoniumNitrate.pdf (accessed on August 4, 2015).

[55] U.S. DOT. "Hazardous Material Table," 49 CFR 172.101. *See*: http://www.phmsa.dot.gov/portal/site/PHMSA/menuitem.6f23687cf7b00b0f22e4c6962d9c8789/?vgnextoid=d84ddf479bd7d110VgnVCM1000009ed07898RCRD&vgnextchannel=4f347fd9b896b110VgnVCM1000009ed07898RCRD (accessed on August 4, 2015).

[56] *See*: https://www.osha.gov/pls/oshaweb/owadisp.show_document?p_table=STANDARDS&p_id=9755 (accessed on January 13, 2016).

[57] OSHA. *See*: https://www.osha.gov/dsg/hazcom/ghoshacomparison.html (accessed on August 4, 2015).

especially when the AN is confined and in the presence of fire or high heat.[58] Thus, when AN is combined with contaminants, its explosive sensitivity increases sharply, and the result can lead to detonation.[59] Examples of contaminants include organic chemicals, acids, and flammable and combustible materials.[60]

4.1.3.1 Decomposition of AN

AN has a melting point between 311°F and 337°F (155°C and 169°C). It begins to rapidly decompose at a significant rate soon thereafter.[61] When it is exposed to high heat and pressure, AN experiences endothermic (heat-absorbing) and exothermic (heat-producing) reactions simultaneously, causing the compound to split into its constituent molecules and also transforming it from solid state to molten, or liquefied, state. When AN decomposes or breaks down under thermal conditions, at least seven unique reactions can occur at varying temperatures, with different heat outputs and rates of reaction.[62] Some reactions can produce toxic and detonable by-products. All of the reaction pathways begin with the AN splitting into gaseous ammonia (NH_3) and nitric acid (HNO_3), although that step is usually not explicit.

In the following main exothermic reaction (Eq. 1), which can occur in conditions up to 482°F (250°C), AN yields nitrous oxide and water:

$$NH_4NO_3\,(s) \rightarrow N_2O\,(g) + 2\,H_2O\,(g) \quad \text{(Eq. 1)}$$

Above 482°F (250°C), a reversible endothermic reaction (Eq. 2) takes place at a significant rate, splitting the AN to form ammonia and nitric acid:

$$NH_4NO_3\,(s) \leftrightarrow NH_3\,(g) + HNO_3\,(g) \quad \text{(Eq. 2)}$$

This endothermic reaction is accompanied by a number of exothermic reactions between gaseous ammonia (NH_3) and nitric acid (HNO_3) that vary by degree, depending on reaction conditions. As previously described, AN is in a liquid or molten state, which is aerated with off-gases such as nitrogen oxides (NO, NO_2), water vapor, and nitrous oxide (N_2O). This bubbly liquid is much more sensitive to detonation than solid prills or unaerated liquid. Depending on the rate of these endothermic and

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[58] Greiner, Maurice. "Ammonium Nitrate: Hazards and Handling." *Fertilizer Progress* January/February (1983): 26–38.

[59] Sun, J. et al. "Catalytic effects of inorganic acids on decomposition of ammonium nitrate." *Journal of Hazardous Materials* B127 (2005): 204–210.

[60] The OSHA Explosives and Blasting Agents Standard, 29 CFR 1910.109)(i)(5)(i)(a), lists examples of combustible materials or other contaminating substances, including animal fats, baled cotton, baled rags, baled scrap paper, bleaching powder, burlap or cotton bags, caustic soda, coal, coke, charcoal, cork, camphor, excelsior, fibers of any kind, fish oils, fish meal, foam rubber, hay, lubricating oil, linseed oil, or other oxidizable or drying oils, naphthalene, oakum, oiled clothing, oiled paper, oiled textiles, paint, straw, sawdust, wood shavings, or vegetable oil.

[61] CF Industries. "FGAN." Material Safety Data Sheet Number 004. *See*: http://www.cfindustries.com/pdf/Amtrate_AN_Fertilizer_SDS_NA_FINAL.pdf (accessed on August 4, 2015).

[62] U.S. Department of the Army. *Department of the Army Technical Manual, Ammunition, General*, TM 9-1300-214. Washington, DC: U.S. Department of Defense, September 1984.

exothermic reactions, detonation can occur. Conditions other than heat and pressure, such as pH levels and the presence of impurities, can also influence the rate of reaction.[63]

The decomposition of AN can be controlled to the extent that the main exothermic reaction (Eq. 1) can be used to produce hospital-grade nitrous oxide.[64] However, if the rate of reaction is uncontrolled (which happens, for example, when FGAN is exposed to fire), other reactions can occur as AN decomposes and melts. As the temperature rises over 482°F (250°C), liquid AN becomes less dense and contains many small bubbles of gaseous decomposition products and their reactants, primarily water vapor and nitrous oxide. At 500°F (260°C), liquid AN becomes much more sensitive to shock because these bubbles act as "hot spots" that focus the shock or magnify the energy input. Many tests have shown the direct correlation between temperature and sensitivity in molten AN.[65] In other words, molten AN becomes more sensitive as the temperature under which it is kept rises.

Although the exact sequence of chemical reactions is variable, the primary end products of the detonation process are consistently water, nitrogen (N_2), and oxygen (O_2). As reactions involving nitric acid (HNO_3) and ammonia (NH_3) (Eq. 2) produce these end products, heat is released, which adds energy to a detonation. The nitrous oxide (N_2O) production process (Eq. 1) combines all of the internal fuel (hydrogen) with the oxygen from nitric acid to form water, so no additional oxidation can take place in the pure AN during the detonation reaction. The difference between the uncontrolled detonation reaction and the nitrous oxide reactions is the rate of the reaction and the formation of the triple bond in N_2 and the double bond in O_2, which are exothermic and therefore add to the energy yield during detonation. The following formula (Eq. 3) describes this overall decomposition reaction from the intermediate reactions where AN yields nitrogen, oxygen, and water:

$$NH_4NO_3\,(s) \rightarrow N_2\,(g) + \tfrac{1}{2}\,O_2\,(g) + 2H_2O\,(g) \quad \text{(Eq. 3)}$$

When mixed with AN, many combustible contaminants—including organic materials, fuels, and finely divided materials (e.g., flour, seed or grain dusts, asphalt or fuel oil, or very small metal flakes)—will provide additional fuel that can combine exothermically with the oxygen produced during detonation. Thus, for explosive uses, AN is nearly always combined with a fuel source. This approach increases the energy of the intended explosion and also reduces the toxicity of the end products by reducing nitrogen

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[63] Lees, F.P., and M.L. Ang (eds.). *Safety Cases Within Control of Industrial Major Accident Hazards (CIMAH) Regulations*, Chapter 9. Butterworth-Heinemann, 1984; January 1, 1989: 160.

[64] Asia Industrial Gases Association. *Safe Practices for the Production of Nitrous Oxide from Ammonium Nitrate*, AIGA 080/13. Singapore: Asia Industrial Gases Association, 2013. *See*: http://www.asiaiga.org/docs/AIGA%20080_13%20Safe%20practices%20for%20the%20production%20of%20nitrous%20oxide%20from%20ammonium%20nitrate.pdf (accessed on November 19, 2015).

[65] Van Dolah, R.W. et al. *Explosion Hazards of Ammonium Nitrate Under Fire Exposure*. Washington, DC: U.S. Department of the Interior, Bureau of Mines, 1966. *See*: http://www.osmre.gov/resources/blasting/docs/USBM/RI6773ExplosionHazardsAmmoniumNitrateUnderFireExposure.pdf (accessed on December 22, 2015).

oxide (NO_x) production. Nitrogen oxides are produced, for example, by the following reaction (Eq. 4), which shows AN yielding nitrogen, water vapor, and nitrogen oxides:

$$4NH_4NO_3\,(s) \rightarrow 2NO_2\,(g) + 8H_2O\,(g) + 3N_2\,(g) \quad \text{(Eq. 4)}$$

An example of fueling AN to produce a blasting agent is the addition of fuel oil at around 6 percent by weight to produce ammonium nitrate/fuel oil (ANFO). ANFO may be used for mining and other purposes. Moreover, the military uses a mixture of fuel-rich trinitrotoluene (TNT), AN, and sometimes aluminum to produce a more effective explosive than TNT alone.[66]

4.1.4 Previous Incidents Involving FGAN

AN-related explosions have occurred ever since large-scale AN production began in the late 19th century.[67] One of the earlier notable explosions involving FGAN took place in Oppau, Germany, in 1921, when workers fired explosives into a caked mixture of fertilizer to loosen 4,500 tons of ammonium sulfate (AS) and FGAN. The explosion killed 500 to 600 people, injured an additional 2,000 more, and caused as much as $1.7 million (US) in property damage, destroying 80 percent of the city.[68] Today, that property damage would equate to more than $22 million.[69]

Since then, a number of other FGAN incidents have occurred that involved a major fire, explosion, or both. This report highlights the following four incidents involving FGAN because they provide important information about the behavior of FGAN when exposed to fire:

- Cherokee incident (1973). A fire in the storage building of FGAN producer Cherokee Nitrogen resulted in an FGAN detonation in Pryor Creek, OK. Of the 14,000 tons of FGAN in storage, only a few tons were involved. The detonation was believed to have been underneath a front-end loader parked in an area with FGAN on the floor and might have been initiated by one of the loader's components exploding. It was theorized that contamination of the FGAN with flammable fluids in the loader occurred before the detonation. The detonation occurred 25 minutes after the fire was discovered but did not propagate into the main pile.[70]
- Cory's Warehouse incident (1982). A fire in a warehouse storing wooden furniture, charcoal, and more than 3,000 tons of bagged FGAN and mixtures based on FGAN produced some deflagration of the FGAN but no detonation.[71] Several small explosions occurred but were thought to be due

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66 *Ibid*.
67 Barbrauskas, Vytenis. "Explosions of Ammonium Nitrate Fertilizer in Storage or Transportation Are Preventable Accidents." *Journal of Hazardous Materials* 304, 5 (2016): 134–149.
68 *See*: http://www.aria.developpement-durable.gouv.fr/wp-content/files_mf/FD_14373_oppau_1921_ang.pdf (accessed on December 19, 2015).
69 The CPI Inflation calculator. *See*: http://data.bls.gov/cgi-bin/cpicalc.pl?cost1=1%2C700%2C000&year1=1921&year2=2014 (accessed on December 30, 2014).
70 Freeman, R. "Cherokee Ammonia Plant Explosion." *Chemical Engineering Progress* 71, 11 (1975).
71 A deflagration occurs when a combustion wave propagates at a velocity less than the speed of sound. A detonation is a combustion wave that propagates at a velocity greater than the speed of sound. Detonations create high-pressure shock waves that can cause damage at large distances from the source.

to reactions between sodium nitrate and charcoal. More than 1,000 people were evacuated, and controlling the fire took 6 hours.

- EDC incident (2009). A fertilizer distribution facility in Bryan, Texas, caught fire and completely burned. Firefighters withdrew and evacuated the area. Unlike the West fire, the Bryan AN-related fire produced light-colored smoke as burning progressed, indicating that the fire was ventilated. No explosion occurred, and after the fire, much of the FGAN was still there. Some of the FGAN melted, spread away from the pile, and then re-solidified in a dark mass. The FGAN remaining in the pile had a black crust on it, but beneath that crust, the prills appeared to be unaffected.[72]
- East Texas Ag Supply incident (2014). A fertilizer warehouse in Athens, Texas, caught fire and burned. The warehouse was near the center of town, and the first responders evacuated the area as rapidly as possible. No explosion occurred. The walls of the structure were masonry, but the bins and roof structure were wood.[73]

A more comprehensive list of FGAN incidents involving fires and explosions is provided in Appendix B.

4.1.5 Historical Knowledge of AN Fire and Explosion Hazards

Over the years, the explosibility and fire hazards of AN have been the subject of a number of research papers. Some of those papers were first published through the U.S. Department of Agriculture (USDA),[74] U.S. Bureau of Mines,[75] and other sources abroad. In 1945, a USDA-archived publication discussed in detail the properties of pure AN, based on worldwide research conducted up to that date.[76] The paper notes the following:

- Under favorable conditions of pressure, rapid heating, and retention of heat, AN may be exploded partially from heat alone near 300°F.
- AN can detonate if subjected to a very strong initial impulse.
- Six factors influence the sensitivity of AN toward an explosion: temperature, strength of initial impulse, density, packing, particle size, and moisture content of the material.

Later, the Bureau of Mines (U.S. Department of the Interior) published reports on its investigation of the detonation of AN.[77] Some of the key findings of a 1966 Bureau of Mines report indicated the following:

- No transition to detonation of AN occurred in numerous burning experiments.

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[72] CSB conducted an assessment of the Bryan, Texas, incident.
[73] CSB collected information after the Athens, Texas, incident.
[74] Davis, R.O.E. "Explosibility and Fire Hazard of Ammonium Nitrate Fertilizer," no. 719. Washington, DC: U.S. Department of Agriculture, 1945.
[75] Van Dolah, R.W. et al. "Explosion Hazards of Ammonium Nitrate under Fire Exposure," R. I. 6773. Pittsburgh: Bureau of Mines, 1966.
[76] *See*: https://ia601703.us.archive.org/1/items/explosibilityfir719davi/explosibilityfir719davi.pdf (accessed on January 6, 2016).
[77] In 1961, the Manufacturing Chemists' Association asked the Bureau of Mines to investigate the potential explosion hazards of AN under the conditions of fire exposure that could occur in storage and transportation incidents.

- The critical diameter (minimum diameter to sustain detonation) of AN was quite small when just below the melting point.
- Initiation of prills by oxygen-acetylene gas detonation was shown to be unlikely.
- Detonations were achieved with fuel added in vessels with restricted vents.
- The initiation of detonation in AN from fire exposure in normal storage is quite improbable.
- The chance of modern AN detonating as the result of fire has been considered to be small or even nonexistent.
- The initial shock need not have an amplitude adequate for immediate initiation of detonation.
- Failure to detonate at a small scale should not be interpreted as meaning that the material is incapable of detonation.
- An acetylene-oxygen mixture in a 3-inch tube failed to detonate hot pulverized AN prills. No attempt was made to initiate detonation in foaming liquid AN by using a gas mixture.
- Large fire tests with bagged AN showed that heat penetrated less than 2 inches into the prills and that a crust formed, preventing liquid from penetrating the prills.[78]

The Bureau of Mines conducted a large-scale study (also in 1966) to determine distances for safe storage of AN. Cardboard tubes 1 meter in diameter were used as the donors and acceptors (the donor is detonated conventionally, and the acceptor, which is placed at a test-determined distance from the donor, either detonates or fails in each test). ANFO was the donor, and the acceptors were ANFO and straight AN. The tests were well documented and were of sufficient scale to produce reliable results. One of the findings was that sheet metal covering the donor increased the distance where sympathetic detonation (a follow-on detonation induced by the explosive effects of an initiating explosion) occurred. In a case with ANFO as the acceptor, a sympathetic detonation was produced over a 50-foot gap. With straight AN, the maximum gap was 19 feet. Without the metal, the gap was 12 feet for AN. The Bureau of Mines also conducted tests at smaller diameters, but no detonation was initiated in AN.

One significant finding was that "strong evidence exists that the apparent insensitiveness of AN results largely from a manifestation of critical diameter effects," highlighting the importance of scale. When evaluating test results, small-scale tests are not reliable indicators of large-scale behavior.

In December 1997, EPA published an alert, "Explosion Hazard from Ammonium Nitrate," with the following recommendations:[79]

- Avoid heating AN in a confined space (e.g., consider that processes involving AN should be designed to avoid this possibility).
- Avoid localized heating of AN, which potentially leads to development of high-temperature areas.
- Ensure that AN is not exposed to strong shock waves from explosives.

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[78] Van Dolah, R.W. et al. "Explosion Hazards of Ammonium Nitrate under Fire Exposure," R. I. 6773. Pittsburgh: Bureau of Mines, 1966.
[79] *See*: http://nepis.epa.gov/Exe/ZyPDF.cgi/P100BH59.PDF?Dockey=P100BH59.PDF (accessed on November 19, 2015).

- Avoid contamination of AN with combustible materials or organic substances, such as oils and waxes.
- Avoid contamination of AN with inorganic materials that can contribute to its sensitivity to explosion, including chlorides and some metals, such as chromium, copper, cobalt, and nickel.
- Maintain the pH of AN solutions within the safe operating range of the process, in particular avoiding low pH (acidic) conditions.

This alert was later expanded in August 2013 as a joint EPA, OSHA, and ATF advisory, "Chemical Advisory: Safe Storage, Handling, and Management of Ammonium Nitrate." A June 2015 revision refers explicitly to AN prills.[80]

4.2 Factors Contributing to the Massive Fire and Explosion at the WFC

Because of the unpredictable behavior of FGAN in fire situations, the scenario that contributed to the detonation at the WFC might never be precisely determined; however, several detonation scenarios are plausible. CSB identified two factors or conditions that likely contributed to the intensity of the fire and detonation: (1) the contamination of FGAN with materials that served as fuel and (2) the nature of the heat buildup and ventilation of the FGAN storage space. These factors and scenarios for how the FGAN behaved on the night of the incident are based on the physical evidence that remained, blast analysis commissioned by CSB, U.S. Army Corps of Engineers crater analysis of the WFC explosion, eyewitness accounts, and previous research on FGAN incidents and testing.

4.2.1 Contamination of the FGAN Pile

In fire situations, the behavior of FGAN is unpredictable, in part because of the number of endothermic and exothermic decomposition reactions that take place with increasing temperature. FGAN decomposition reactions beyond the first step have yet to be uniquely defined, and subsequent decomposition reactions of FGAN can only be assumed.[81] When contaminants are added to AN, the decomposition reactions become increasingly more complex.[82] Possible sources of contamination in an FGAN storage area can include ignitable liquids, finely divided metals or organic materials, chloride salts, carbons, acids, fibers, and sulfides. These contaminants can increase the explosive sensitivity of FGAN.

[80] EPA, OSHA, and ATF. "Chemical Advisory: Safe Storage, Handling and Management of Solid Ammonium Nitrate Prills." *See*: http://www2.epa.gov/sites/production/files/2015-06/documents/an_advisory_6-5-15.pdf (accessed on December 7, 2015).

[81] Cagnina, Stefania; Rotureau, Patricia; and Carlo Adamo. "Study of Incompatibility of Ammonium Nitrate and its Mechanism of Decomposition by Theoretical Approach." *Chemical Engineering Transactions* 31 (2013). *See*: http://www.aidic.it/lp2013/webpapers/141cagnina.pdf (accessed on December 7, 2015).

[82] *Ibid*.

The molten FGAN at the WFC likely came in contact with contaminants that were stored in the fertilizer warehouse or were produced during the fire that preceded the explosion. Seed materials, zinc, and other organic products, including the wood-constructed bins, were present near the FGAN storage area or could have come in contact with molten FGAN. During the fire, soot from the smoke and also collapsing wood and roofing material might have mixed with the FGAN pile.

The presence of possible contamination in the FGAN pile can be evidenced by changes in the smoke observed in the WFC fire before the explosion. The earliest sign of the WFC fire was white smoke streaming from vents in the elevator cupola on top of the fertilizer warehouse that stored the FGAN. Light-colored smoke is evidence of a well-ventilated fire, which would be typical of the early phase of a structure fire before it depletes the oxygen in the room. The initial smoke observed at the WFC was from the incipient fire, now believed to have started in the seed room. Shortly after authorities were notified, the smoke darkened and became opaque, indicating large quantities of soot[83] or hydrocarbons burning (Figure 38). Such soot can be the result of a ventilation-limited fire or a soot-producing fuel such as plastic or asphalt, which produces large amounts of soot even in well-ventilated fires.[84] The fact that smoke was observed coming from the same room that held the FGAN bin suggests that the bin was burning at that time. It is likely that soot or molten asphalt began accumulating on the AN shortly after the fire spread to the roof and the FGAN bin. The soot provided a source of fuel as it contaminated the surface of the pile. Soot also greatly increases the absorption of radiant heat from a fire.[85]

Figure 38. Initial Light Smoke (left) Followed by Dark Plume (right)
(Source: Member of the Public)

[83] Soot is finely divided carbon deposited from flames during the incomplete combustion of organic substances.
[84] Fire Development and Behavior Indicators. *See*: http://cfbt-us.com/pdfs/FBIandFireDevelopment.pdf (accessed on November 19, 2015).
[85] Glassman, Irvin and Yetter, Richard. *Combustion*. Burlington, MA: Academic Press, 2009: 458.

4.2.2 Heating and Ventilation

As the fire progressed, the available oxygen in the building was depleted as it was consumed in the fire. Although the fertilizer warehouse structure had some ventilation louvers in the cupola at the top, ventilation at ground level was limited to only a few louvered vents and the normal infiltration that exists around doors. The limited ventilation increased the quantity of soot in the smoke and the potential contamination of the FGAN pile. The path of the fire from the seed room to the main structure is unknown, but an opening, perhaps resulting from an interior wall or the roof burning, seems to have allowed hot smoke and later flame to flow from the seed room into the main structure and out the cupola. Initially, no flames were visible at the cupola, but as the fire progressed, videos and photographs taken before the explosion show the fuel-rich smoke generated by the burning material inside the structure. Subsequently, asphalt roof shingles ignited and began burning vigorously.

With limited ventilation inside the structure, a hot layer of smoke likely would have developed in the upper portion of the room containing the FGAN bin. Because cooler air settles below warmer air, the air temperatures would have remained relatively cooler inside the bin. The ground-hugging nature of the evolving smoke plume, as evidenced in Figure 39, is a characteristic of partially cooled smoke, perhaps cooling as it passed through the elevator structure before it exited the cupola. Because the elevator likely was filled with opaque black smoke, radiant heat from the fire on the FGAN pile would be reduced because the opaque black smoke shielded the pile from the heat.

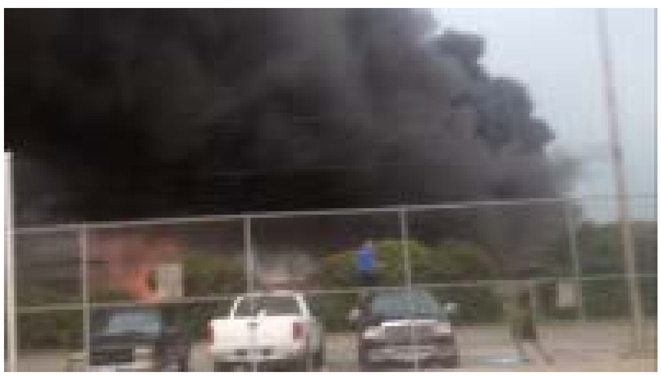

Figure 39. Dark and Heavy Smoke, Rich in Soot
(Source: Member of the Public)

At some point around 5 to 6 minutes before the detonation, the character of the fire changed, according to eyewitness accounts and photographic evidence (Figure 40). This change was most likely caused by increased ventilation through an opening low in the building, possibly when the fire burned through the seed room doors or the roof. The fire also might have been enhanced by oxidizing gases from the heated FGAN pile.

Figure 40. Photographs from 7:42 pm (left) and 7:45 pm (right), Showing Transition to Lighter Smoke and Larger Flame, Before Detonation at Approximately 7:51 pm (Source: Member of the Public)

The additional ventilation caused a marked decrease in dark smoke and probably was accompanied by a major increase in heat radiation inside the fertilizer building because of increased oxygen availability to the burning wood and other fuels. With the dark smoke inside of the structure reduced, radiant heat would reach the surface of the FGAN in the bin, and the increased airflow through the building would greatly increase the radiant heat flux by raising the temperature of the burning wood. The surface of the FGAN, covered with soot or molten asphalt, would absorb the heat flux and cause a very rapid heating of the surface of the FGAN pile. The very hot and contaminated surface of the pile was then sensitive to detonation.

If the building had been well ventilated, the ventilation-limited phase of the fire would not have been as prolonged, reducing the amount of soot and creosote on the pile. In this scenario, the increased intensity of the fire would heat the FGAN pile. The lighter color smoke would allow more heat to be reflected, and the liquid FGAN might have run off as it developed. CSB collected data on similar incidents at the facilities in Bryan, Texas, and Athens, Texas. These incidents demonstrate that an FGAN pile can experience a major structure fire without detonating. The plumes of smoke at the Bryan facility (Figure 41) and Athens facility indicated cleaner-burning fires with less soot production. One source of the difference in the fire plumes might be the level of ventilation inside of the structure, as described to CSB investigators by the Athens fire chief. Some materials, such as asphalt and polyvinyl chloride (PVC), will produce dark plumes even when burning in the open air, but if that smoke production is outside of the structure, no contamination of the FGAN will occur.

Figure 41. Plume of Smoke from AN Fire in Bryan, Texas
(Source: College Station Fire Department)

4.3 Detonation Scenarios

CSB found that contamination (likely from the storage of nearby combustibles or the combustible materials used to construct the FGAN bins and building) and the lack of ventilation were contributing factors that ultimately led to the detonation. However, the exact behavior of the FGAN—specifically how the contaminants, decomposition by-products, ventilation issues, or a combination of those conditions led to the explosion—may never be known.

Previous studies indicated that a detonation of modern FGAN prills under normal standard storage conditions when exposed to fire (unconfined storage without the potential for pressure buildup) was highly unlikely based on a number of factors. Therefore, the three scenarios in this section are considered plausible, but large-scale testing is needed to estimate their relative likelihood. One of the three scenarios (or a combination) is considered plausible as an explanation of event sequences:

- Scenario 1: Detonation from the top of the FGAN pile.
- Scenario 2: Detonation in heated FGAN along exterior wall exposed to fire.
- Scenario 3: Detonation in elevator pit that spread to main FGAN bin.

4.3.1 Scenario 1: Detonation from the Top of the FGAN Pile

Based on the location of the pile and the properties of the bin along with the circumstances of other fire-induced incidents, one possible scenario is that a period of contamination with soot and other organics (possibly including molten asphalt and plastic dripping from the burning composite shingle roof and PVC drop pipe from the elevator mechanism) was followed by about 5 to 6 minutes of intense radiant heating from the flames above and adjacent to the main FGAN bin. During this time, a layer of very hot, contaminated, and sensitive liquid FGAN could have built up on the pile. The foaming FGAN likely produced oxidizing gases, and those mixed with flammable smoke to produce a detonable gas cloud over the FGAN pile in the main bin and possibly in an adjoining bin linked to the main bin through a series of holes cut in the partition between the bins. The cloud consisted of powerful oxidizers that would be expected when FGAN undergoes thermal decomposition—such as NO_2, O_2, and HNO_3 as wells as fuel-rich smoke and pyrolysis[86] products off-gassing from the molten FGAN. The gas cloud then might have ignited from above, undergoing a gas-phase deflagration-to-detonation transition (DDT) in the confinement of the bin. This transition could have been enhanced by the passage of the burning front through the openings between the main and secondary bins, which possibly contained a few hundred pounds of FGAN, in a process known as hot gas injection.[87] Given the powerful oxidizers and mixture of fuels possible in this environment, a direct gas-phase DDT in the partial containment of the main bin by itself might be another possible initiator. This gas detonation then initiated an explosive train on the surface of the pile (Figure 42), moving through the contaminated and sensitive low-density foam, into the mixture of high-density foam and prills beneath, and then into the ambient prills composing the bulk of the pile.

[86] Pyrolysis is the chemical decomposition of a substance by heat.
[87] Byers, Kenneth J. "Pressure Piling and Other Issues Affecting Flameproof Enclosures." Redbank, Australia: Testing and Certification Centre, SIMTARS, 1996.

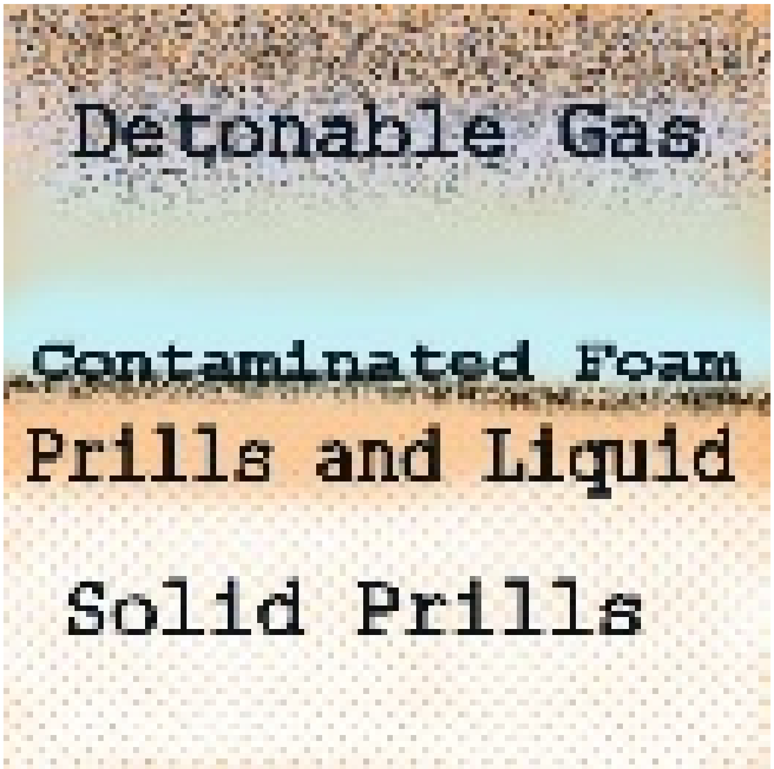

Figure 42. Potential Explosive Train Layers on AN Pile Before Detonation (Source: CSB)

In tests using 1-meter (diameter) cardboard tubes, ambient temperature FGAN has been detonated by a 10-centimeter layer of ANFO at the end of the tube, initiated by a flat shock wave.[88] If a large portion of the surface of the AN pile was detonated by a gas explosion and if the sensitized layer detonated, then the minimum diameter for unconfined FGAN prills (around 1 meter) would be exceeded, and the detonation could potentially proceed through the pile in a complete detonation. In many historical accidents, only part of the AN detonates because of the inability of the detonation wave to spread from a small detonation source into the main pile.[89] This type of incomplete or partial detonation does not seem to have occurred at the WFC; the crater and blast damage indicate a complete detonation of the main pile, however it is unknown how much of the FGAN burned prior to the explosion.

Falling material from a roof collapse has been proposed as a possible initiator in previous accidents, but subsequent testing of falling objects and high-speed projectiles entering solid and molten FGAN did not support this scenario. Although tests have shown that high-velocity impacts (such as those from high-

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[88] Winning, C.H. "Detonation Characteristics of Prilled Ammonium Nitrate." *Fire Technology* 1, 1 (1965): 23.
[89] Freeman, R. "Cherokee Nitrogen Co., Pryor OK." *Chemical Engineering Progress* 71, 11 (1975).

caliber bullets) can detonate molten FGAN, the low velocities of falling objects do not appear to provide the energy density needed to detonate even sensitized FGAN.[90]

Fragments from a fire-induced explosion—such as the materials that might be produced in a hot steel roller with FGAN trapped inside—are another potential initiation source at the top of the pile but likely would not create the large flat shock wave required to fully detonate FGAN. No known vehicles or pressure tanks were close enough to the bin to produce high-speed fragments or a strong shock wave on the top of the FGAN pile. A golf cart was in the seed room, and fire extinguishers and an air conditioner could have failed from overpressure due to overheating, but they were separated from the FGAN bin by the substantial walls of the bin and are unlikely to have produced high-speed fragments. As other researchers have noted, the common element linking recent fire-induced FGAN detonations is some level of confinement.[91] At the WFC building in West, the confinement was the wooden bin, whereas in the transportation accidents in Mexico and Romania cited in the reference, the confinement was the semitrailer. The confinement provided by a wooden bin or a trailer would not allow sufficient pressure to build up to support a solid-phase DDT[92] but could allow the gases escaping the heated FGAN to accumulate over the pile. Additional field testing of this possibility would be useful.

4.3.2 Scenario 2: Detonation in Heated FGAN Along Exterior Wall Exposed to Fire

Another possible scenario is that the detonation at the WFC facility was initiated along one of the exterior walls of the bin. The north and east sides of the bin were exposed to the fire and could have been heated through the walls. No evidence indicates that the bin failed during the fire, although that cannot be ruled out, so the side of the FGAN pile likely would have no direct contact with flame, but some heat could have penetrated through the wall of the bin—more heat if the exterior wall adjacent to the seed room was penetrated and fire entered the space between the exterior sheathing and the plywood bin lining. Figure 43 shows some of the features of the fire on the north side of the structure a few minutes before detonation. The structure above the bin had lost its siding and was burning with good air flow. Flames were appearing through the siding outside the bin, indicating that the wooden exterior sheathing and roofing were beginning to burn. The seed room was just a burning frame, and most of its roof had burned and collapsed.

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[90] Van Dolah, R.W. et al. *Explosion Hazards of Ammonium Nitrate Under Fire Exposure*. Washington, DC: U.S. Department of the Interior, Bureau of Mines, 1966. *See*: http://www.osmre.gov/resources/blasting/docs/USBM/RI6773ExplosionHazardsAmmoniumNitrateUnderFireExposure.pdf (accessed on November 19, 2015).

[91] Nygaard, E.C. "Large Scale Testing of Ammonium Nitrate." *4th EFEE World Conference of Explosives and Blasting* 4(1), 2007.

[92] Van Dolah, R.W. et al. *Explosion Hazards of Ammonium Nitrate Under Fire Exposure*. Washington, DC: U.S. Department of the Interior, Bureau of Mines, 1966. *See*: http://www.osmre.gov/resources/blasting/docs/USBM/RI6773ExplosionHazardsAmmoniumNitrateunderFireExposure.pdf.pdf (accessed on December 22, 2015).

Figure 43. North Side of Structure Approximately 3 Minutes Before Detonation, with Dark Foreground Objects Associated with the Bin Complex North of Fertilizer Building (Source: Member of the Public)

Even with some heating of the pile through the bin wall, it is difficult to envision a potential detonation source; FGAN does not normally detonate when heated except under severe confinement.[93] Contamination also would be less likely in the FGAN exposed to heat along the exterior seed room wall, but some liquid AN, contaminated by soot and roofing components, on the pile surface might have penetrated along the heated wall of the bin if the temperature was high enough or the wall was partially breached. A small amount of wood from the bin also might be nitrated by nitric acid off-gassing from the heated FGAN to form nitrocellulose, but such a reaction has not been observed in testing, and no research papers supporting such a scenario were found. The WFC facility had a concrete floor that would have prevented heating of the pile from the bottom. Bin failure, preceded by leakage of the FGAN or FGAN liquid onto burning material such as seed or plastic cannot be ruled out. Because the bin floor was well above the floor of the seed room, the falling material would have some momentum and could produce

[93] Arthur D. Little, Inc. *Study of Ammonium Nitrate Materials*. Springfield, VA: National Technical Information Service, 1952: 1–49. *See*: http://www.dtic.mil/dtic/tr/fulltext/u2/786334.pdf (accessed on November 19, 2015).

significant pressure under ideal conditions. Whether this situation could lead to a detonation is an open question.

4.3.3 Scenario 3: Detonation in Elevator Pit That Spread to Main FGAN Bin

Another possible detonation scenario focuses on the elevator pit near the FGAN bin. A fiberglass lid covered the pit, and the floor sloped away from the pit to prevent runoff from entering it, but the fire might have melted the cover, and FGAN remnants could have been in the pit. The typical elevator mechanism would not provide any areas for strong confinement leading to high pressures, nor does it seem plausible that a small detonation in the pit could have initiated the main FGAN pile. If the detonation began in the pit, then the most feasible mechanism would be a collapse of the west wall of the bin, spilling FGAN into a mixture of burning rubber from the melted elevator belt and residual FGAN in the bottom of the pit. The mass of the falling FGAN, combined with the strong confinement of the concrete pit walls, might have provided the conditions for a solid phase DDT beginning in the bottom of pit and spreading into the main pile. The likelihood of sufficient FGAN near the door, where the pit was located, seems quite low. Liquid FGAN, if it somehow leaked into the pit, would have been under confinement conditions similar to those for liquid in the bin, with no obvious areas where pressure could build. The elevator itself is a belt with cups protected by a sheet metal box open at the top and bottom. The belt that brought the material in from the unloading pit outside provides no obvious containment other than the rollers, which are often hollow metal. Unlike the rollers above the bin, these rollers would have been shielded from the heat of the main fire but could have been heated by a fire (if it existed) in the pit.

Molten and contaminated FGAN on the floor, initiated by an explosion from a burning loader, was suspected in the 1973 Cherokee FGAN storage explosion, but no known source of an initiating detonation existed at the WFC, and the detonation at Cherokee did not propagate into the main pile. The circumstances of the two accidents were too different to draw any firm conclusions about the role of molten AN in the detonations.

Other fires involving FGAN (such as the fires in Bryan, Texas, and Athens, Texas) did not result in detonation, even though the fires totally consumed the structures housing the FGAN bins and the roofs collapsed. This evidence demonstrates the unpredictable behavior of FGAN exposed to fire. Possible differences between the fire incidents and the WFC are ventilation of the fire, which determines the degree of contamination from smoke products; level of confinement in the bin; and degree of direct heating on the FGAN pile.

4.4 **Forensic Testing of West Fertilizer Company Samples**

On the day before the explosion, the WFC sold 8,000 pounds of an FGAN/AS blend of fertilizer to a farmer in Abbot, Texas. The farmer told CSB investigators that the fertilizer he received, which he estimated was about 75 percent FGAN and 25 percent AS, was dustier than usual during spreading. After the incident, the Office of the Texas State Chemist (OTSC) retained a portion of the fertilizer and provided a sample to CSB for further testing.

The OTSC is part of the Texas A&M University System and administers the requirements of the Texas Feed and Fertilizer Control Service. The OTSC regulates the sale of fertilizer and also conducts laboratory testing of FGAN to ensure that it meets quality guidelines for fertilizer. The OTSC conducted testing of the samples and shared the results with CSB. The OTSC spectral analysis found no activated carbon or any evidence of contamination of the FGAN sample. According to the report, the testing concluded that the sample was a mixture of FGAN and AS. The OTSC ran a nitrogen analysis in the state's combustion laboratory; this is a routine test run by the OTSC to check the concentration of nitrogen in fertilizers. The OTSC determined that the amount of nitrogen contained in the FGAN/AS sample mixture had nitrogen percentages that ranged from 34.33 to 34.61 percent.[94]

The laboratory also conducted tests to determine the particle size distribution of the prills in the farmer's FGAN/AS sample. Results verified that the FGAN/AS samples had high concentrations of fines (smaller broken-down prills). Approximately half (50 to 55 percent) of the farmer's sample consisted of particles smaller than 200 micrometers (0.2 millimeters). Operating under the assumption that the farmer's sample was a blend of FGAN and AS prills, the laboratory obtained a control sample of FGAN and AS mixed in 70:30 portions, respectively. The control sample contained 10 percent particles smaller than 200 micrometers. Although the farmer's sample included a larger than usual number of fines, the particle sizes in this sample are not necessarily representative of the FGAN in the main bin at the WFC because of the addition of AS to the farmer's mixture. Mechanical action such as blending might have taken place when creating the FGAN/AS mixture, reducing the particle size, and further breakage might have occurred during transit.

CSB investigators collected samples of the fertilizer remaining at the WFC facility and the OTSC and in March 2015 commissioned a forensics laboratory to characterize the composition of eight samples by semi-quantitative analysis. Samples 1 through 5 were categorized as solidified and pulverized fertilizer collected from various bins (Figure 44); sample 6 was collected from the FGAN railcar on the WFC property that was the least disturbed by the explosion and firefighting efforts (Figure 45); and samples 7 and 8 were collected from the FGAN mixture purchased by the farmer on the day before the incident (Figure 46). According to shipment records, the railcar contained pure FGAN manufactured by CF Industries. The railcar arrived at the WFC site in early April 2013. At the time of the incident, the WFC had not yet unloaded the railcar. The WFC also received truckloads of EDC pure FGAN product in early April 2013. CSB is unable to conclude whether the CF Industries or EDC product, or a mixture of both, was present in the FGAN main bin at the WFC facility at the time of the explosion.

[94] The percent of nitrogen (34 percent minimum) is typical for a high-density FGAN prill.

Figure 44. Solidified Fertilizer Collected from WFC Property (Approximate Location Unknown) (Source: Forensic Laboratory)

Figure 45. FGAN Prills Collected from a Railcar on WFC Property (Source: Forensic Laboratory)

Figure 46. Farmer's Sample of FGAN and AS Blend (Source: Forensic Laboratory)

The laboratory used infrared spectroscopy and electron microscopy methods to determine the elemental compositions of each sample. Results of this testing confirmed the presence or absence of AN and other salts in some of the samples. Four of the eight samples (1, 2, 3, and 5) contained no FGAN (Table 4). The sample collected from the railcar (no. 6) was determined to contain wholly AN with 36 percent[95] nitrogen and had a prill density of 1.59 grams per cubic centimeter (g/cm^3).[96] The railcar sample consisted of prilled particles with a polyolefin coating, which is commonly applied to reduce caking.[97] Magnesium nitrate or magnesium oxide is also occasionally used as an additive to FGAN prills during the manufacturing process.[98] The purpose of the additive is to act as a desiccant (absorbs moisture) and also to protect against the breakdown of prills at higher temperatures.[99] CSB concluded that the chemical composition of the FGAN obtained from the rail car (no. 6) was typical of FGAN prills commonly used for fertilizer and for creation of fertilizer blends.

Table 4. Forensic Testing Results of Fertilizer Samples Collected from the WFC and the OTSC

No.	Sample Location (if known)	Sample Description	Detected Compounds	FGAN Detected
1	Unknown	White and pink encrusted and prilled layers	AS, magnesium phosphate (with iron), potassium sulfate	No
2	Ammonium phosphate/potassium chloride bin	White prilled particles, pink fragmented particles, and grey encrusted particles	AS, ammonium phosphate, and possibly potassium chloride	No
3	Space between FGAN and potassium chloride bins	Dark pink fragments	Ammonium phosphate, sulfate, alkali salts of fluoride, trace iron	No
4	Backside of diammonium phosphate bin	White powder with red streaks	AN, AS, chlorides, ammonium phosphate, and trace amounts of potassium chloride	Yes

95 FGAN prills typically contain about 34 percent nitrogen. The 36 percent nitrogen result in the sample is likely attributed to the percent error in the analytical method used. The laboratory conducted a linear regression analysis to determine the percentage error in the determination of elemental sulfur in the FGAN/AS samples compared to a control sample, and it estimated the error to be within +/- 0.3 percent of the sample. The laboratory concluded that the percentage error estimates would be similar for oxygen and nitrogen in the samples that underwent electron dispersive spectroscopy (EDS) methods.

96 FGAN is a higher-density prill in the range of 1.72 g/cm^3.

97 According to the FGAN Safety Data Sheet (SDS) from CF Industries, the FGAN prills contain a 0 to 0.2 percent proprietary polyolefin conditioning agent.

98 Ammonium nitrate particulate fertilizer and method for producing the same. *See*: http://www.google.com/patents/US5720794 (accessed on November 25, 2015).

99 U.N. Industrial Development Organization. *Fertilizer Manual*, 3rd Edition. The Netherlands: Kluwer Academic Publishers, 1998: 227.

5	Backside of ammonium sulfate bin	Sample containing gravel and pebbles (separated before analysis)	AS, sulfates, and chlorides	No
6	Railcar	White prilled particles	Prilled AN coated with polyolefin	Yes
7	Farmer AS/FGAN mixture	White prilled particles (partially agglomerated from wetting)	AN, AS, sulfate, extractable polyolefin	Yes
8	Farmer AS/FGAN mixture	White prilled particles	AN, AS, sulfate, extractable polyolefin	Yes

The FGAN/AS mixture purchased by the farmer on the day before the incident was the only available sample representative of materials stored in the fertilizer building before the incident. In addition to the testing conducted by the OTSC to determine the percentage of nitrogen and quantity of fine in these samples, CSB commissioned additional laboratory testing of the prills contained in the FGAN/AS mixture (samples 7 and 8 in Table 4) in October 2015. Because the FGAN sample from the railcar on the WFC property remained relatively undisturbed during the fire and explosion, the laboratory also selected a prill from that sample (no. 6 in Table 4) for comparison.

An image from a macroscopic examination of an individual prill from sample items 6, 7, and 8 is shown in Figure 47. Item 6, which was collected from the railcar, had a smooth and uniform coating-like texture, whereas evidence items 7 and 8, which were sampled from the farmer's mixture, had an uneven surface made up of an agglomeration of amorphous (formless) and semicrystalline particles.

Figure 47. Physical Comparison of Samples (20x) (Source: Forensic Laboratory)

Under a microscope, the polyolefin coating was visually apparent on the surface of the item 6 prill. Through infrared spectral analysis, the laboratory was able to chemically identify the external prill coating as a polyolefin. However, the external polyolefin coating on the surface of sample items 7 and 8 could not be identified through the same analysis. To determine whether a coating had been present, the laboratory quantitatively extracted residues from the prills in a solvent that could be analyzed through infrared spectra analysis. Although direct surface scans of items 7 and 8 did not reveal the presence of the coating, solvent extracts indicated the presence of a polyolefin. This coating could have been applied to the prills at some point in time but was no longer acting as a prill coating on the observed sample items 7 and 8.

4.5 **Blast and Impact Analysis**

CSB commissioned a consultant firm to survey the property damage to the WFC and the surrounding community. On the basis of information obtained from the survey, the consultants characterized the force of the blast and estimated the energy produced during the explosion. Using indicators from the observed damage to residences and community structures, the consultants applied a guideline[100] from the U.S. Army Corps of Engineers and created a three-dimensional model to predict the blast overpressure and determine the explosive weight that was best explained by the physical damage observed in West, Texas.

The computational models and calculations expressed the AN explosive energy estimation normalized against the explosive power of TNT,[101] a high-explosive compound commonly used to quantify blast loads. A TNT equivalence calculation provides an approximation of explosive energy in pounds of TNT. Several TNT equivalent equations are used in industry that employ actual and estimated explosion parameters such as heat capacity, weight of explosive charge, and explosion percent efficiency. Many of the parameters are specific to the material involved. TNT equivalent values are a rough approximation of explosive effects, and the variability of TNT equivalence (20 to 40 percent) might be a result of the ways that it is calculated based on pressure, impulse, crater size, or other damage measures.[102]

The blast modeling consultants estimated the range of potential explosive yields from the WFC explosion to be equivalent to a range of 20,000 to 40,000 pounds of TNT, based on the blast damage indicators recorded and analyzed from 20 lightweight metal buildings, the deformed basketball goalposts, and the condition of the apartment complex and nursing home.

To further refine a specific explosive weight most consistent with all of the observed damage, the consultants used another modeling tool that incorporates a number of different blast prediction methodologies, including the development of a computational fluid dynamic simulation to characterize the shock wave as it wrapped around structures and other obstacles during the explosion. The CSB-

[100] U.S. Army Corps of Engineers. “Estimating Damage to Structures from Terrorist Bombs Field Operations Guide,” ETL 1110-3-495. Washington, DC: U.S. Army Corps of Engineers, 1999.
[101] One ton of TNT has an explosive energy of 4.184 gigajoules.
[102] National Assessment Group. “Ammonium Nitrate Detonability Review and Assessment, Final Report.” Prepared for the Technical Support Working Groups, For Official Use Only. Kirtland AFB, NM: September 2, 2011: 7.

commissioned blast experts determined that the explosive energy of the WFC explosion that is most consistent with the observed damage is 25,000 pounds (12.5 tons) of TNT. With an estimated 30 tons of FGAN in the main WFC bin at the time of the blast, the 12.5-ton TNT equivalent is based on a 42 percent efficiency of the material that contributed to the explosive energy. Because the quantity of FGAN consumed in the fire before the explosion was not determined, the exact quantity of FGAN that contributed to the explosion remains unknown.

The ATF National Response Team also requested that the U.S. Army Engineer Research and Development Center (ERDC) conduct an assessment of the WFC explosion damage and then estimate the equivalent explosive yield of the blast. The ERDC team arrived in West on April 29, 2013. As part of the site study, the ERDC team conducted a detailed survey of the crater left by the explosion (Figure 48), using survey and three-dimensional scanning equipment to verify critical dimensions. The shape of the crater was asymmetric, with an apparent diameter of 75 feet and a depth of nearly 8 feet (Figure 49).

Figure 48. Ground-Level View of WFC Explosion Crater (Source: CSB)

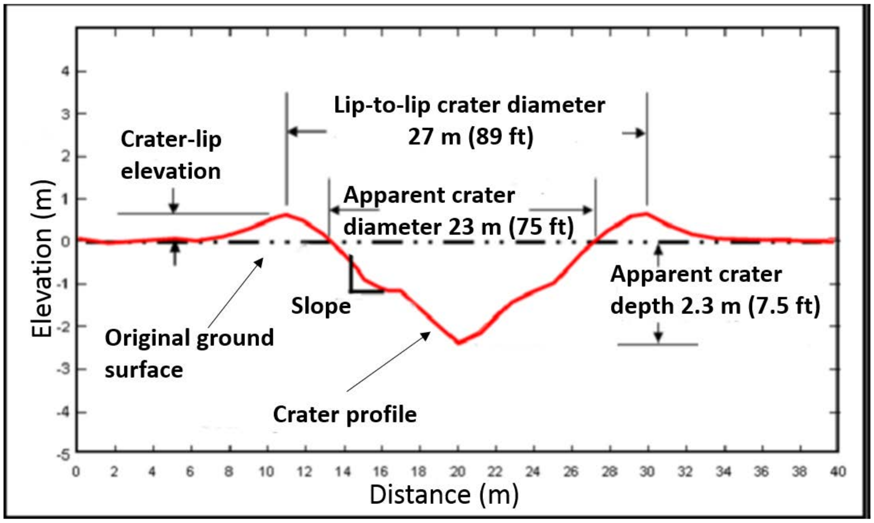

Figure 49. WFC Explosion Crater Profile Measurements (Source: Army Corps of Engineers)

The ERDC team compared the field crater measurements with experimental data for blast craters and other sources to produce an estimate of the net explosive weight of the FGAN. The experimental data also took into consideration the near-surface geology (soil type and underlying rocks) surrounding the explosion, which has an effect on the crater depth and size. The ERDC team compared the crater dimensions and soil types from the WFC explosion with similar experimental data to estimate the explosive weight of FGAN. The final report on this analysis concluded that this method entails a degree of uncertainty because none of the experimental data included the type of soil with limestone found in Texas.[103] In addition, the experimental charge was C-4, which might have a different explosive or cratering efficiency than FGAN. The ERDC team made assumptions to account for the lack of available data and, on the basis of the crater analysis, estimated the WFC explosion to be within the range of 10,000 to 21,500 pounds of TNT.

The center of the crater was almost directly under the WFC facility's main FGAN bin, which was likely the source of fuel for the explosion. This main bin contained an estimated 20 to 30 tons of FGAN at the time of the incident; however, the blast analyses from consultants hired by CSB and from the Army Corps of Engineers indicate that the quantity of FGAN that contributed to the explosion could have been smaller, based on the observed damage. To demonstrate the location of the crater in reference to the fertilizer storage building and the main FGAN bin, CSB commissioned a structural engineering firm to create a three-dimensional rendering of the fertilizer facility over the crater location (Figure 50).[104] Figure 51 shows an elevation view of the fertilizer building, with the underlying crater.

[103] The soil at the WFC consists of limestone with varying amounts of chalk and clay. This soil type is consistent with what **would** be expected in West, Texas.

[104] Crater and building location are estimated to be within +/- 2 feet, based on global positioning information.

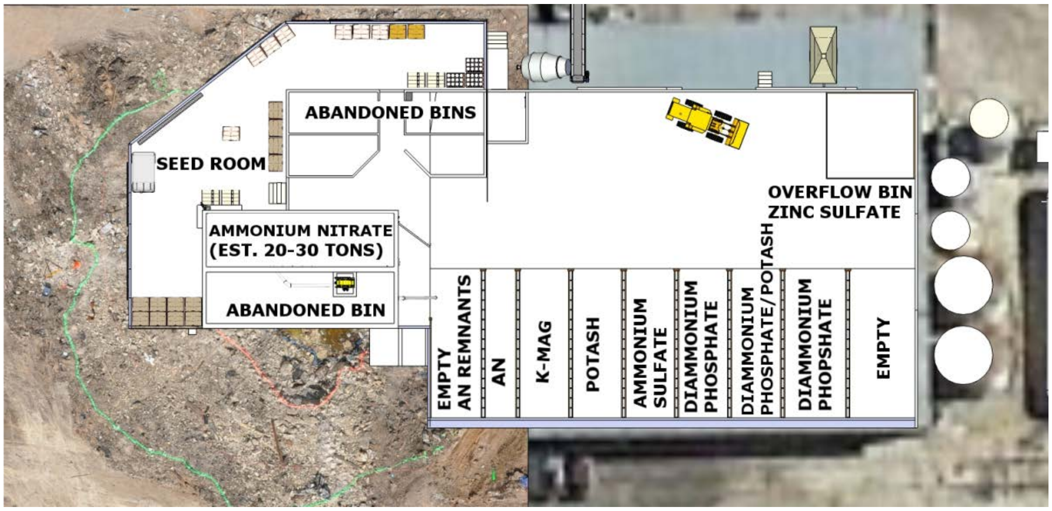

Figure 50. Overhead View of WFC Bins, with Crater Underlay (Source: Atlas Engineering)

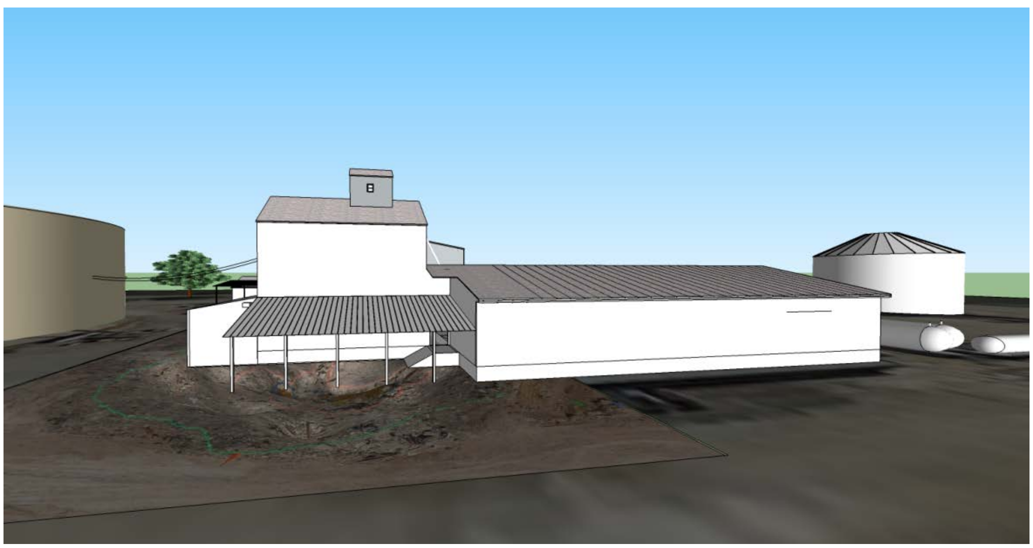

Figure 51. Elevation View of Fertilizer Building, with Crater Depth (Source: Atlas Engineering)

4.5.1 Seismic Data

According to the United States Geological Survey (USGS), the WFC explosion registered as an earthquake of magnitude 2.1 on the Richter scale. The Lake Whitney seismic station in Meridian, Texas, about 25 miles west-northwest of the WFC site, recorded seismic signals from the April 17, 2013, explosion. ATF concluded that there were two separate explosions, “one smaller and one larger,” based on eyewitness accounts and seismic evidence.[105] After conversations with USGS seismologists, CSB later learned that a system error occurred, and only one event was recorded at the Lake Whitney station. According to USGS, seismic signals resulting from the WFC explosion were recorded on nine seismic stations within a range of 25 to 360 miles. Using the onset time of the seismic energy at these stations and the known location of the explosion, the USGS National Earthquake Information Center estimated that the time of the explosion was 7:50:38 pm local time. According to USGS, the seismic data recording shows both energy that propagated through the earth as well as later-arriving energy that propagated through the air (Figure 52). USGS concluded that the event was a single large explosion, but it could not rule out the possibility of multiple closely timed explosions.

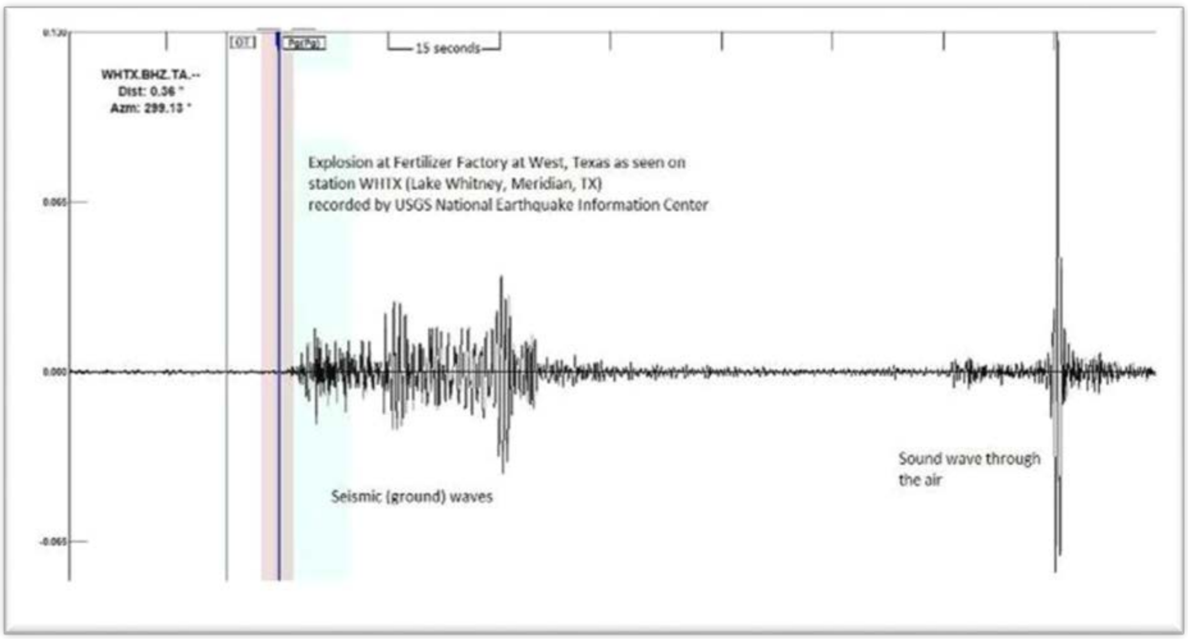

Figure 52. Data Recorded at Lake Whitney Station, WHTX, and Seismograph by the USGS National Earthquake Information Center (Source: USGS)

5.0 Commercial Property and Liability Insurance

The West Fertilizer Company (WFC) had commercial property insurance to cover losses (such as building damage, damage to product, or loss of income due to property damage) from certain loss events, such as fires. The company also held a commercial liability insurance policy to protect itself against claims for bodily injury while onsite or while operating company automobiles. CSB examined available documentation of the WFC's insurance coverage and inspections from 2007 until the April 2013 explosion. The WFC was insured by two different insurance companies, Triangle Insurance Company,

[105] ATF. "ATF Press Conference Video," May 16, 2013, minute 12:45. *See*: http://www.youtube.com/watch?v=OpLjSvcRqzU (accessed on November 19, 2015).

Inc. (Triangle) and the United States Fire Insurance Company (U.S. Fire). Triangle issued policies that included coverage for property damage, business interruption, bodily injury, and automobile accidents from 2007 to the end of 2009. In late 2009, Triangle decided not to renew the insurance policy because of the WFC's lack of compliance with loss control recommendations. The WFC insurance policy expired on December 31, 2009. Thereafter, the WFC obtained similar coverage from U.S. Fire in January 2010 and renewed it in 2011, 2012, and 2013. The U.S. Fire insurance policy was in effect at the time of the 2013 explosion.

5.1 Triangle Insurance Coverage and Audits (2006–2010)

Triangle conducted an initial onsite survey of the WFC facility in 2006 and provided insurance coverage from 2007 until 2010. The WFC had a $1 million commercial general liability policy and $2 million in coverage to cover onsite property and business losses. In 2009, Triangle gave notice to the WFC that it was not renewing the policy because of the WFC's lack of compliance with loss control recommendations issued by Triangle following several onsite audits. Triangle conducted annual loss control surveys at the WFC facility from 2006 through 2009, and it issued a number of recommendations for suggested improvements to WFC operations. The Triangle loss control surveys included an evaluation of WFC automobiles and drivers, storage and application of dry and liquid fertilizers, grain and feed milling, and anhydrous ammonia.

CSB investigators requested and reviewed insurance documentation from Triangle, including risk profiles, insurance audit reports, and communications from Triangle to the WFC. In 2006, Triangle performed an initial survey of the WFC facility before issuing coverage. Triangle loss control specialists made four recommendations to the WFC for safety improvements, including replacing missing guards on augers and conveyors and addressing visual damage to one of the grain bins. Triangle's overall risk assessment categorized the facility as average, with housekeeping, maintenance, and grounds in average to fair condition. During the anhydrous ammonia survey, Triangle noted the close proximity of the WFC facility to schools, residences, and businesses and also documented concerns about the ammonia risk management plan (RMP) being out of date (discussed in Section 8.4.2.4). Triangle assigned a representative to work with the WFC to update and improve the RMP submission.

In 2007, Triangle conducted another loss control survey and submitted 10 recommendations to the WFC; 4 of the 10 recommendations were restated from the 2006 survey because they remained unresolved. The loss control specialist identified several safety and compliance issues, including:

- A corroded 440-volt wire ran from the pole on the north side of the plant through the bulk fertilizer facility to the anhydrous ammonia tank area on the south side of the facility.
- An aluminum ground wire showed noticeable signs of corrosion from the fertilizer. The loss control specialist noted that the wire could lose its ability to ground, potentially causing shock and fire hazards (Figure 53).
- Several temporary lighting sockets needed to be wired in permanently to reduce the potential for electrical shocks and fire hazards.

About 2 months later, the WFC responded to some of the Triangle recommendations and reported that 3 of the 10 recommendations were resolved, including replacing guards and repairing an electrical cord on an auger. The remaining seven recommendations, including the exposed 440-volt wire, remained outstanding. The Triangle loss control specialist's overall opinion of risk, documented from this survey, was fair; housekeeping received a fair rating; and maintenance received a fair to poor rating.

Figure 53. Exposed 440-Volt Electrical Wiring Identified in 2007 Survey
(Source: Triangle Insurance Company)

In September 2008, a loss control specialist from Triangle conducted another renewal survey and made 14 recommendations, including several outstanding recommendations from the previous year. During this survey, Triangle identified additional damaged electrical wires at the facility in need of repair (Figure 54). The WFC submitted a completed recommendation form to Triangle later that month, stating that seven recommendations were addressed or in the process of being settled.

Figure 54. Damaged Electrical Cord Identified in 2008 Insurance Survey
(Source: Triangle Insurance Company)

In August 2009, Triangle identified six additional recommendations during the annual loss control survey. One recommendation was restated and designated as “critical” for a lack of safety chains on towing equipment. The Triangle consultant also noted that the WFC “seems to be resistant” to implementing a training program to address the frequency of vehicle and mobile equipment accidents. Triangle documented a large quantity of temporary exposed wiring in the WFC facility that needed to be run in conduits. When evaluating WFC safety programs in 2009, Triangle noted that the company had no positive safety culture and that “written programs are incomplete and outdated, there is no structured safety program.” In addition, Triangle found no accident investigation program and no evidence that the WFC held regular safety meetings for employees. The following excerpt from the 2009 survey indicates Triangle concerns:

> They need a SCMP (Safety and Compliance Management Programs) person to help them with safety issues, permits, etc. To my knowledge they have not had a safety meeting since we started insuring them in 2006…I have a concern with the wiring at both grain operation & the dry fertilizer plant. Only about 10% is run in conduit. The rest consist of a heavy flexible 4-wire cable, the type you would normally use to put outside on poles but it is not protected from cuts & abrasion.[106]

In September 2009, the loss control specialist stated in an internal Triangle email that “because of losses and non-compliance of recommendations, Triangle should non-renew Adair Grain, Inc./West Fertilizer Co. in West, Texas.”[107] In September 2009, Triangle sent notification to the WFC that all policies would not be renewed for the following year. In 2010, the WFC retained U.S. Fire for insurance coverage.

[106] Triangle Insurance Company Documentation, Loss Control Survey at Adair Grain/WFC. August 2009.
[107] Triangle Representative. “Adair Grain,” email message to manager, Underwriting Services Triangle, September 14, 2009.

5.1.1 Triangle Loss Control Surveys That Did Not Include FGAN Hazards

CSB reviewed the WFC loss control survey documentation and the Triangle "Loss Control Best Practice Manual" for insurance inspectors and found no focus on FGAN fire and explosion hazards between 2006 and 2009. In the 2006 survey and subsequent surveys, Triangle documented the presence of ammonium nitrate (AN) onsite for security concerns and answered, "Yes" to the question, "Does the account meet state regulations for the storage and transportation of product?" Although no state-specific regulations for AN storage existed at the time, the survey did not include federal regulations, such as the OSHA Explosives and Blasting Agents standard (29 CFR 1910.109, discussed in Section 8.2), or industry consensus standards, such as National Fire Protection Association (NFPA) 400, *Hazardous Materials Code* (addressed in Section 8.6.1). Triangle guidance included a description of combustible and noncombustible bulk fertilizer storage buildings for informational purposes, but Triangle did not provide guidelines or requirements for specific storage practices, such as separation from potential contaminants, materials of construction, or mechanism for fire and explosion prevention. Other survey focus areas, such as grain milling and anhydrous ammonia, included a more detailed review of federal requirements, such as the OSHA Grain Handling Facilities Standard (29 CFR 1910.272) for the prevention of grain dust explosions and the EPA Risk Management Program rule for anhydrous ammonia storage. In November 2013, Triangle updated the best practice manual to include compliance with federal regulations in addition to state regulations for fertilizer storage and transportation.

5.2 **U.S. Fire Insurance Coverage and Audits (2010–2013)**

U.S. Fire started providing insurance to the WFC in 2010 and renewed coverage for 2011, 2012, and 2013. The WFC was insured by U.S. Fire at the time of the April 2013 incident. The WFC general liability policy had a maximum limit of $1 million, and the commercial property insurance policy had a limit of about $4.45 million, which included all buildings and equipment on the WFC property. In 2013, the WFC held U.S. Fire coverage for commercial property, general liability, inland marine,[108] and commercial automobile.

According to the insurance policy documentation for the WFC, U.S. Fire offered policyholders a loss control service that included onsite surveys of the facility to provide:

- Safety information and educational material to minimize loss costs.
- Initial survey and evaluation.
- Specific suggestions for improving loss control practices.
- Consultation and training to help management understand hazards associated with operations.
- Follow-up surveys.

[108] Commercial inland marine insurance covers property in transit or property that is movable or portable and is not at a fixed location.

CSB requested additional information from U.S. Fire related to the WFC insurance policy, including claims, audits and inspections, and training requirements for U.S. Fire loss consultants. CSB also requested documentation of U.S. Fire's onsite inspections at the WFC facility over the time period it was insured. To date, U.S. Fire has not provided CSB with the requested documentation. Outside counsel for U.S. Fire indicated to a CSB investigator that the $1 million policy amount did not necessitate much onsite activity, such as audits or inspections, during the time that the WFC was insured. [109]

5.3 Insurance Claims and Other Aid after the Explosion

The Texas Department of Insurance (TDI) regulates the business of insurance in Texas and provides resources for people and businesses to obtain insurance in the state. In response to the WFC explosion, TDI assisted in securing the scene and mobilizing a disaster response program to assist consumers with filing insurance claims related to the incident. The Texas State Fire Marshal's Office (SFMO) and the Division of Workers' Compensation are units within TDI. The total insurance-related losses due to the explosion are estimated to be in the range of $230 million.[110] Many of the residents in the area did not have home or rental insurance. Those individuals relied on aid from FEMA, Salvation Army, and American Red Cross operations. FEMA received a total of 1,108 applications for assistance as a result of the fire and explosion at the WFC facility.[111] Nearly 6 months after the incident, FEMA[112] reported providing federal disaster assistance exceeding $16 million to eligible survivors. This sum included more than $9 million in federal disaster loans from the U.S. Small Business Administration (SBA), nearly $840,000 in individual assistance grants from FEMA, and more than $6.2 million in FEMA Public Assistance funding.[113] Low-interest disaster assistance loans from the SBA[114] were also available to homeowners, renters, businesses of all sizes, and private nonprofit organizations whose property was damaged or destroyed by the incident. On the basis of data provided by FEMA, 580 applications were submitted for individuals or families that had homeowners, homeowners with small business loans, and mobile home insurance. FEMA verified losses totaled about $9,052,308. The real property FEMA verified losses amounted to about $8,145,750. The personal property FEMA verified losses totaled roughly $906,557. Although all losses related to the fire and explosion totaled nearly $250 million, the

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[109] Outside Counsel for U.S. Fire, conversation with CSB Investigator, January 20, 2015.

[110] Texas House of Representatives, 84th Texas Legislative Session. Testimony on House Bill 2470. *See*: http://www.house.state.tx.us/video-audio/committee-broadcasts/ (accessed on January 6, 2016).

[111] Official data provided by FEMA.

[112] FEMA—under the authority of Section 408 of the Robert T. Stafford Disaster Relief and Emergency Assistance Act, 42 U.S.C. § 5174, and Title 44 of the Code of Federal Regulations (CFR)—may provide financial assistance and, if necessary, direct services to eligible individuals and households that, as a direct result of a major disaster, have necessary expenses and serious needs and are unable to meet such expenses or needs through other means.

[113] *See*: http://www.fema.gov/news-release/2013/10/07/federal-disaster-assistance-tops-16-million-west-texas (accessed on January 6, 2016).

[114] The SBA serves as the Federal government's primary source of money for the long-term rebuilding of disaster-damaged private property. These disaster loans cover uninsured and uncompensated losses and do not duplicate benefits of other agencies or organizations.

WFC carried a policy from U.S. Fire at the time of the incident with a limit of only $1 million for bodily injury and offsite property damage.

5.4 FGAN Facilities in Texas and the Potential for Offsite Consequences

Under the Texas Commercial Fertilizer Rule (described in Section 8.7.1), facilities that sell or offer to sell FGAN or FGAN-containing materials must obtain annual registrations from the Office of the Texas State Chemist (OTSC) to do business. The OTSC collects information on each facility storing more than 10,000 pounds (5 tons) of AN in Texas. According to the OTSC list of facilities as of September 2014, 80 facilities statewide stored AN in quantities exceeding 10,000 pounds. Of those 80 facilities, 43 stored FGAN, and 37 stored technical grade ammonium nitrate (TGAN). In October 2015, the OTSC reported 40 FGAN facilities in Texas.[115] Of those 40 facilities, only nine (23 percent) are located in jurisdictions with an adopted fire code.

CSB found that West, Texas, is not the only town in the state with FGAN storage in close proximity to residential areas, schools, and hospitals. In fact, some of these occupancies are directly adjacent to, or across the street from, FGAN storage. Because the WFC operated in close proximity to schools, residences, and a nursing home, CSB plotted the 40 FGAN storage facilities in Google Earth™ to determine whether FGAN storage facilities are also in close proximity to residential areas, schools, or other large population clusters.

CSB found that 19 (48 percent) of the facilities storing more than 10,000 pounds of FGAN are located within 0.5 miles of a school, hospital, nursing home, or a combination of those occupancies. Of the 40 FGAN facilities, 33 (83 percent) of the FGAN storage facilities are located within 0.25 miles of a residence or apartment building.[116] The WFC facility was about 550 feet (0.16 miles) from the closest school, which sustained catastrophic damage as a result of the explosion, which could have resulted in additional loss of life had the school been in session at the time of the incident. CSB identified one other school in Texas that is 529 feet (0.12 miles) from an FGAN storage facility, even closer than the school destroyed in West, Texas (Figure 55). Of the 40 FGAN storage facilities, 16 (40 percent) are within 0.5 miles of an elementary school, secondary school, or high school (Figure 56).

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[115] CSB noted that two new FGAN facilities registered with the OTSC between September 2014 and October 2015 and that five facilities were listed in September 2014 that did not register to sell FGAN in October 2015.

[116] The closest structures with obvious characteristics of a private residence were selected for this measurement using Google Earth and Google Street View.

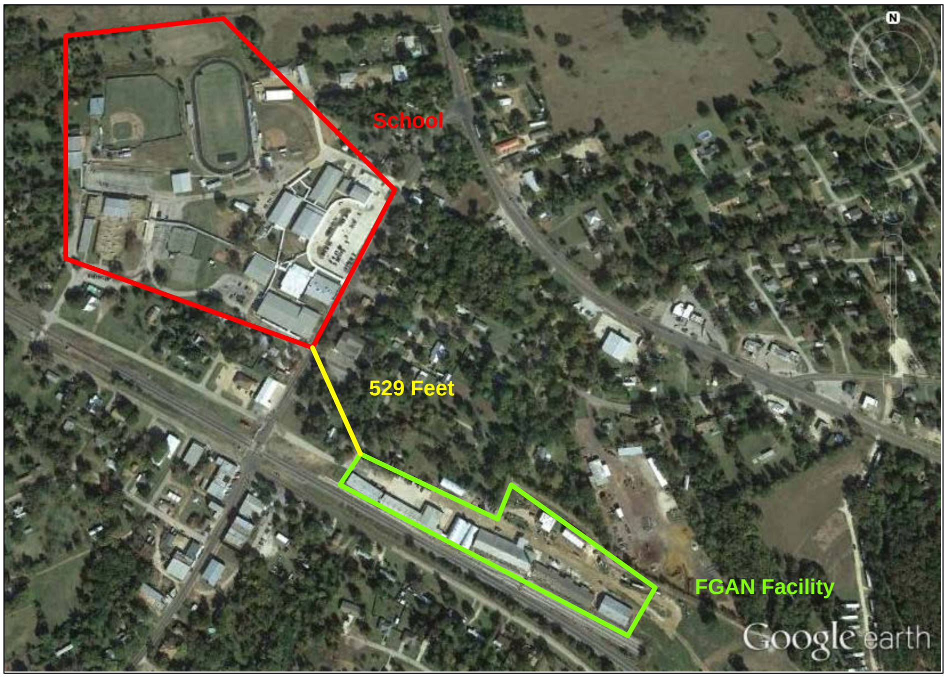

Figure 55. Overhead View of a School Approximately 529 Feet from an FGAN Storage Facility (Source: Google Earth)

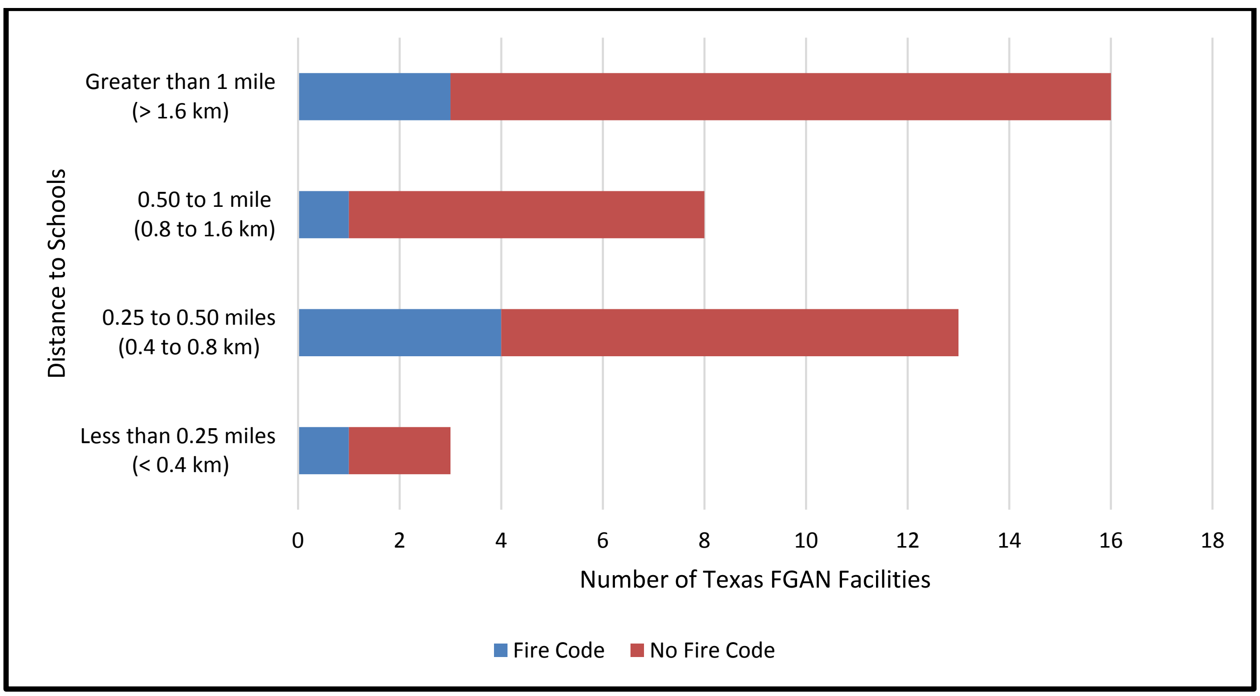

Figure 56. Breakdown of FGAN Storage Facilities (10,000 pounds or more) Within 1 Mile of a Texas School (Source: CSB)

The West Rest Haven nursing home was located about 600 feet from the WFC facility and sustained irreparable damage as a result of the blast. CSB measured distances between Texas FGAN storage facilities and nearby hospitals and nursing homes and found that 38 percent of the facilities are within 1 mile of a nursing home or hospital. In one case, a fertilizer facility is adjacent to a 50-bed hospital and a residence, also a few blocks from a school (Figure 57).

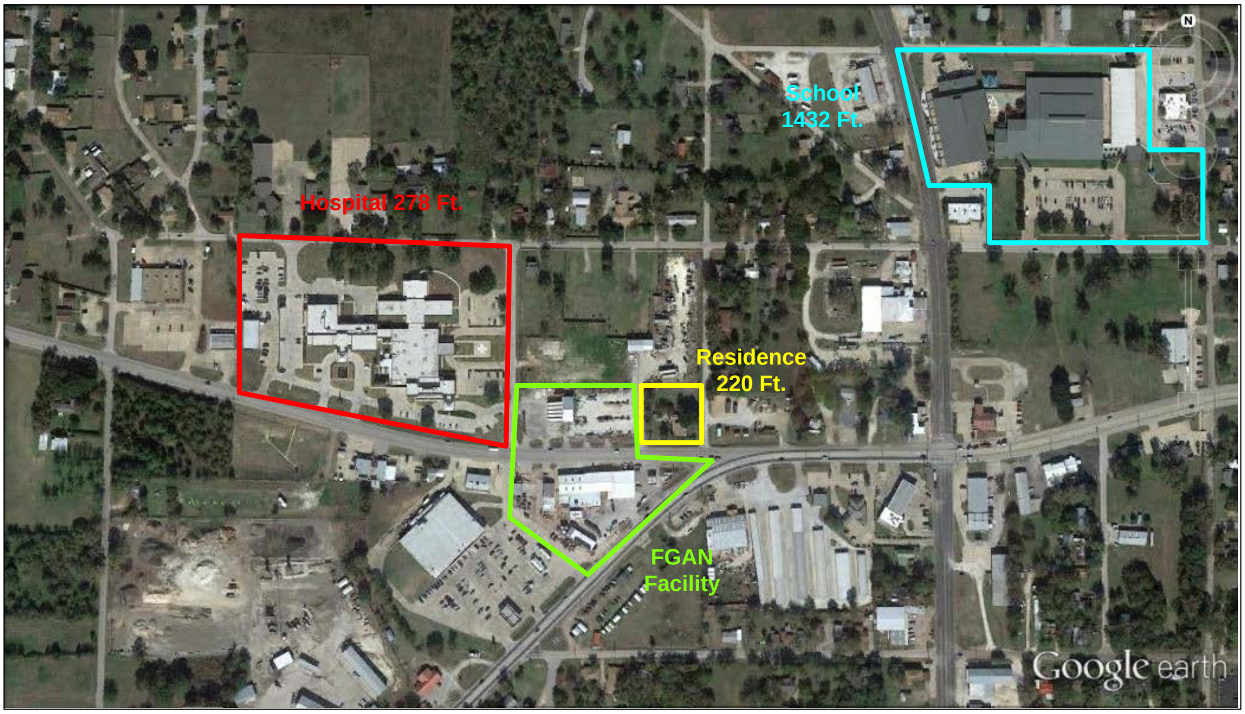

Figure 57. Overhead View of a Texas FGAN Storage Facility near a Hospital, Residence, and School (Source: Google Earth)

Findings from the analysis of the proximity of FGAN storage facilities to various community structures show that the risk to the public from a catastrophic incident exists throughout the state of Texas. Injury data published by the Waco-McLennan County Health Department supported the conclusion that people within 1,500 feet (or 0.28 miles) from the blast epicenter were the majority of those injured in the WFC fire and explosion, particularly those who were inside a structure at the time of the blast.[117]

5.5 Limits of Insurance Coverage in Texas

Property and liability insurance companies can complement government oversight of industry by identifying hazards and reducing losses through the insurance process. In some ways, insurance can

[117] Waco-McLennan County Public Health District. "Public Health Report: Injuries Related to the West (Texas) Fertilizer Plant Explosion," April 2013 (issued on June 24, 2014).

augment government standards and safety monitoring.[118] The insurance industry provides coverage for losses at established premiums but also has an incentive to reduce and manage risks. Insurers perform functions of risk reduction and risk management by using tools such as auditing and inspecting their clients, managing loss prevention efforts, analyzing loss histories, identifying causes of accidents, and teaching clients how to avoid premium increases (or how to secure premium reductions).[119] Insurance reinforces existing government regulations by expecting that policyholders comply with existing requirements. This approach can be effective at reducing risk and preventing incidents because annual insurance audits can be more frequent than state or federal enforcement inspections, such as those by SFMO or OSHA. Texas law does not require facilities that store FGAN to obtain commercial general liability or property insurance; however, the WFC voluntarily obtained insurance. The WFC's $1 million general liability policy with U.S. Fire did not include excess or umbrella coverage for the consequences of serious incidents, such as bodily injury and property damage. If the WFC is found responsible for this incident in civil cases, its insurance would not be sufficient to pay the full amount of insurance claims for the catastrophic consequences caused by the blast.

Texas law requires some businesses to have liability insurance for operations that potentially pose a lower level of public risk than the WFC incident (Table 5). Air conditioning and refrigeration contractors, mold assessors, and plumbers are some of the businesses or services subject to commercial general liability requirements in Texas. For amusement ride owners and operators, Texas set the minimum requirements for insurance at $1.5 million per occurrence and requires proof of insurance to operate an amusement ride. For an amusement park ride to operate in the state, the ride must be inspected at least annually by the insurer.[120] The ride also must meet the standards for coverage and have an adequate amount of insurance coverage.[121] Operators of amusement park rides annually must file copies of the inspection certificate and insurance policy with the TDI Commissioner. The Texas amusement ride regulation also requires operators of coin-operated rides and bounce houses to obtain liability insurance. However, FGAN storage facilities such as the WFC facility can operate next to schools, residential areas, and hospitals with little or no general liability insurance. Adequate levels of coverage would likely prompt rigorous onsite loss control audits by insurers.

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[118] Ben-Shahar, Omri, and Kyle D. Logue. "Outsourcing Regulation: How Insurance Reduces Moral Hazard," *Michigan Law Review* 111:2 (2012); University of Michigan Law and Economics Research Paper No. 12-004; University of Chicago Institute for Law and Economics Olin Research Paper No. 593. *See*: http://ssrn.com/abstract=2038105 (accessed on January 6, 2016).

[119] *Ibid.*

[120] Texas Occupations Code, § 2151.101, "Regulations of Amusement Rides: Requirements for Operation." *See*: http://www.statutes.legis.state.tx.us/Docs/OC/htm/OC.2151.htm (accessed on August 4, 2015).

[121] *Ibid.*

Table 5. Minimum Insurance Requirements in Texas[122]

Business/Operation	Minimum Amount
Amusement ride operators	$1.5 million
Elevator/escalator contractors	$1.5 million[123]
Mold assessors and remediators	$1 million[124]
Electricians	$600,000[125]
Residential appliance installers	$600,000[126]
Plumbers	$300,000[127]
Tow truck operators	$300,000[128]
Structural pest control providers	$300,000[129]
Used automotive parts recyclers	$250,000[130]
Air conditioning service providers	$200,000[131]

Previous incidents in Athens, Bryan, and West have demonstrated the risk imposed by FGAN facilities on Texas communities and the public. In the absence of a state fire code, there is limited state oversight to ensure that facilities are addressing conditions that could potentially lead to an incident similar to the WFC fire and explosion.

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[122] *See*: http://www.dallasnews.com/news/west-explosion/headlines/20130508-texas-makes-bounce-house-operators-carry-liability-coverage-but-not-plants-like-west-fertilizer.ece (accessed on January 6, 2016).
[123] *See*: https://www.tdlr.texas.gov/elevator/Elevapp.pdf (accessed on January 6, 2016).
[124] Texas Administrative Code Licensing Requirements. *See*: http://txrules.elaws.us/rule/title25_chapter295_sec.295.309 (accessed on January 6, 2016).
[125] *See*: http://www.tdlr.texas.gov/electricians/forms/ElectricianCOI.pdf (accessed on January 6, 2016).
[126] *See*: http://www.tdlr.texas.gov/electricians/forms/ELC012 Residential Appliance Installation Contractor License Application.pdf (accessed on January 6, 2016).
[127] *See*: http://www.tsbpe.state.tx.us/common/CertificateofInsuranceForm-fillablefeb2012.pdf (accessed on January 6, 2016).
[128] Administrative Rules of the Texas Department of Licensing and Regulation, § 86.400, "Insurance Requirements—Tow Truck Permits." 33 TexReg 2940. New section adopted, effective April 15, 2008.
[129] Texas Occupations Code, § 1951.312, "Liability Insurance." *See*: http://www.statutes.legis.state.tx.us/Docs/OC/htm/OC.1951.htm (accessed on January 6, 2016).
[130] *See*: https://www.tdlr.texas.gov/parts/aprrules.htm#8740 (accessed on January 6, 2016).
[131] Proof of insurance is required only with an initial application for licensure, a change in license assignment (new company), or a request by the Department of Insurance.

Triangle conducted annual inspections at the WFC facility and identified conditions that could result in potential losses, such as fires and worker injuries. Although Triangle did not focus specifically on hazards related to FGAN storage, it offered recommendations to the WFC to correct conditions, such as electrical hazards, that could result in a fire. CSB did not receive any documentation that U.S. Fire continued performing similar audits and inspections at the WFC facility after Triangle's nonrenewal.

It is not common for states to have prescriptive requirements for insuring specific industries. However, TDI does impose liability insurance and inspection requirements for amusement park rides and establishes minimum liability insurance coverage for certain operations and services, as listed in Table 5. CSB identified other FGAN storage facilities located in close proximity to community structures; however, the level of insurance carried by these facilities remains unknown. In response to the WFC incident, TDI conducted a voluntary survey of 95 Texas fertilizer facilities in June 2013 and requested the names of the companies that insure those facilities against general liability, property, and workers' compensation losses. TDI received 12 responses to the 95 inquiries. Although the number of responses does not suggest that the remaining fertilizer facilities are uninsured, there is no way to determine whether these facilities have insurance policies that incorporate audits and inspections to focus on safe FGAN storage and handling conditions.

On March 5, 2015, House Bill 2470 proposed amendments to the Texas Commercial Fertilizer Rules to require proof of liability insurance coverage for annual registration, similar to the requirements for amusement park rides. The bill proposed to amend the Texas Agriculture Code to require public liability insurance to produce, store, transfer, blend, or sell FGAN or FGAN-containing materials upon applying for a permit under the Texas Commercial Fertilizer Rules.[132] However, this bill did not pass the state legislature.

Without insurance and inspection requirements for FGAN facilities, operators can sell bulk quantities of fertilizer with little or no insurance coverage. The process of obtaining insurance could encourage both agricultural insurers and insured parties to assess current risks and to increase the awareness and rigor of insurance audits to ensure that companies are safely storing FGAN in accordance with guidance released as part of Executive Order 13650 (addressed in Section 8.1), OSHA standards, and industry consensus standards such as NFPA 400. Minimum coverage requirements will spur more realistic risk analysis by insurers that write coverage for FGAN bulk storage retail facilities. By providing agricultural businesses the guidance to identify and address FGAN hazards when underwriting and conducting annual loss control inspections, insurers can play a role in ensuring that FGAN facilities mitigate hazardous conditions.

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[132] The required liability insurance policy proposed by HB 2470 afforded bodily injury and property damage protection in an amount determined by TDI to compensate a person who incurred damages as a result of FGAN operations. The bill also directed TDI to coordinate with the Texas State Fire Marshal, Department of Health Services, Office of the Texas State Chemist, and other agencies to study the risk exposure for FGAN activities to determine the appropriate requirements for a liability insurance policy.

5.6 Insurance Services Office Rating

The Insurance Services Office (ISO)[133] is an independent commercial enterprise and insurance industry advisory company that provides information, evaluation, and underwriting on safety and risk management related to community fire protection and building code effectiveness, serving insurance companies and other fire safety organizations. ISO adopts a public protection classification (PPC) system to develop fire insurance premiums for residential and commercial properties.[134]

ISO obtains information on municipal fire protection efforts in communities throughout the United States. Those data are then analyzed and evaluated for communities, using a standardized method and criteria known as the Fire Suppression Rating Schedule (FSRS). The FSRS assigns a PPC rating (from 1 to 10) to fire departments in each community. Class 1 represents exemplary public protection, and Class 10 indicates that the area's fire suppression program does not meet ISO minimum criteria. ISO develops a split classification; for example, 5/9. The first class (Class 5 in the example) applies to properties within 5 road miles of a fire station and within 1,000 feet of a fire hydrant. The second class (Class 9 in the example) applies to properties within 5 road miles of a fire station but farther than 1,000 feet from a hydrant. ISO generally assigns Class 10 to properties farther than 5 road miles from a fire station.

To determine a community's PPC, ISO conducts a field survey, with ISO staff members visiting the community to observe and evaluate features of the fire protection systems. Using the FSRS, ISO objectively evaluates three major areas: fire department,[135] water supply,[136] and fire alarm and communication systems.[137] When ISO allocates a high class rating to a fire department, ISO works with the affected fire department and the city to make improvements to the fire department, water system, and/or fire and alarm communication systems. Once these improvements are completed, the city then requests a new ISO reclassification. ISO reevaluates the city and then notifies the fire department of the new PPC rating. If a lower rating is received, the city notifies all homeowners and business owners to inform their insurance carriers to adjust their policies based on the new classification.

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[133] *See*: http://www.isomitigation.com/index.php/about-iso (accessed on January 7, 2016).

[134] Insurance companies often rely on information from ISO about a community's fire protection services to evaluate claims and damages.

[135] A review of the fire department accounts for 50 percent of the total classification. ISO focuses on a fire department's first-alarm response and initial attack to minimize potential loss. Here, ISO reviews items such as engine companies, ladder or service companies, distribution of fire stations and fire companies, equipment carried on apparatus, pumping capacity, reserve apparatus, department personnel, and training.

[136] A review of the water supply system accounts for 40 percent of the total classification. ISO reviews the water supply that a community uses to determine the adequacy for fire suppression purposes. It also considers hydrant size, type, and installation as well as the inspection frequency and condition of fire hydrants.

[137] An ISO review of the fire alarm system accounts for 10 percent of the total classification. The review focuses on the community's facilities and support for handling and dispatching fire alarms.

5.6.1 Impact of the City of West Class 5 ISO Rating on the West Fertilizer Company

According to the West Fire Department, ISO rated the city of West at Class 5 before April 17, 2013. The pre-incident ISO classification and PPC rating of the West Volunteer Fire Department (WVFD) placed the city of West among the top 25 percent of all Texas communities (Figure 58). The average classification rating for communities and fire departments in Texas is Class 7.

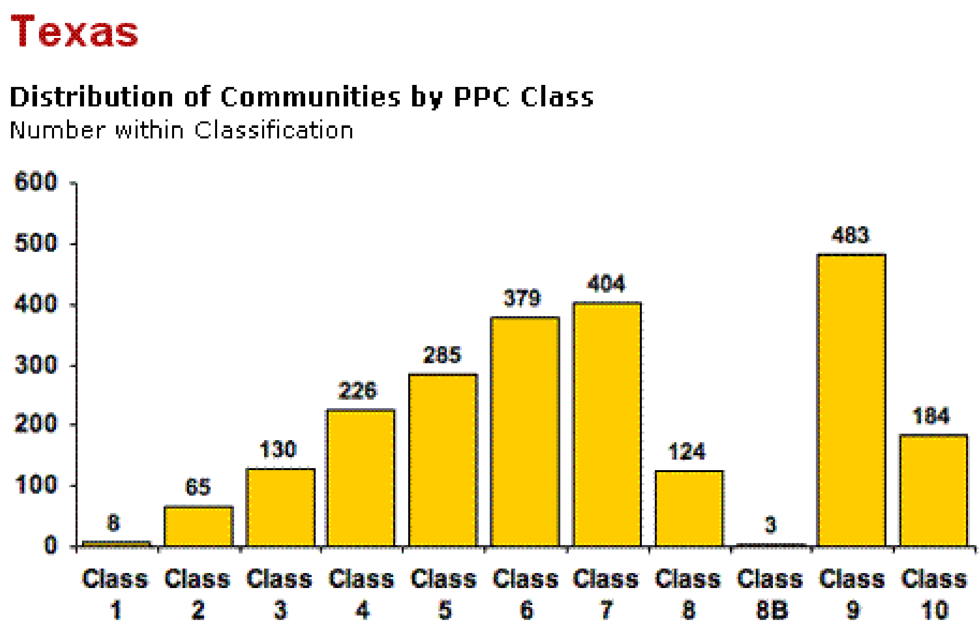

Figure 58. Distribution of ISO Class Ratings for Cities and Communities in Texas (Source: ISO)[138]

On the national scale, the average PPC for cities, fire departments, and communities in the United States is Class 7 (the same as the average for Texas). The current ISO rating of the WVFD places the city of West among the top 30 percent of all communities nationwide (Figure 59).

[138] *See*: http://www.isomitigation.com/index.php/ppc-program/how-the-ppc-program-works/facts-and-figures (accessed on December 20, 2015).

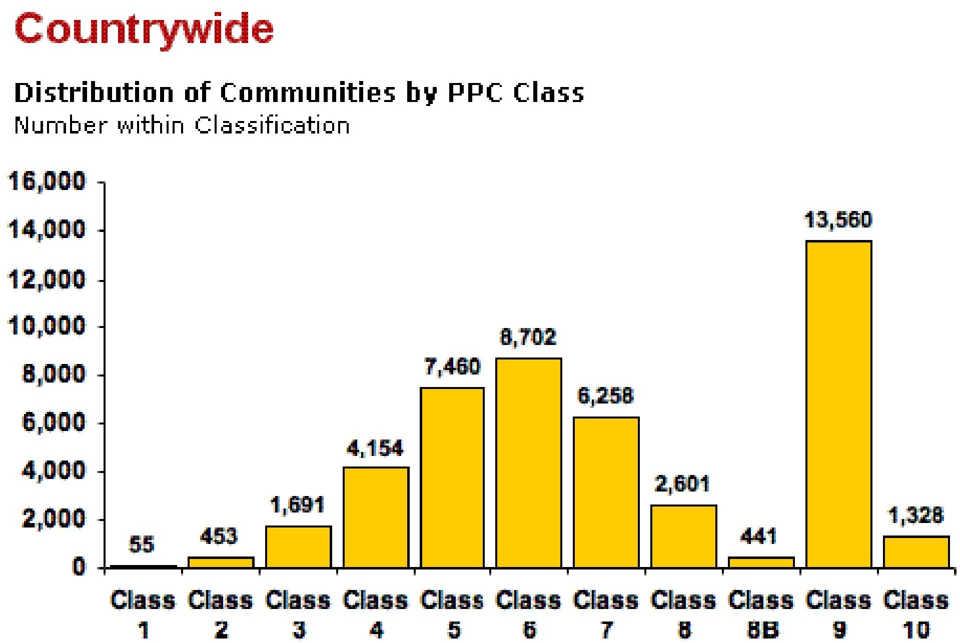

Figure 59. Distribution of ISO Class Ratings for All U.S. Cities and Communities (Source: ISO)[139]

Firefighters who responded to the WFC fire reported difficulty in extending their 4-inch fire hoses to the nearest fire hydrant, which was located at West High School, more than 1,500 feet from the burning fertilizer plant. A surviving firefighter testified that the emergency responders had to use one of their fire trucks as a connector line to reach the nearest fire hydrant at the high school. After dropping all of the hose lines on the engine, they discovered that they were about 700 feet short of the length needed to effectively fight the fire. Some of the volunteer firefighters then arranged to take the engine with hose and continue to string lines. One of the firefighters subsequently returned to the hydrant near the high school to attempt to establish a connection from the hose line to the fire hydrant. The explosion occurred just as the firefighter arrived at the fire hydrant, and he survived the explosion, although with severe injuries.

The WFC plant was not incorporated into the West city limits,[140] so an ISO assessment of the city of West did not capture the fertilizer plant as a high-risk facility. An ISO evaluation of the WFC plant would have increased the city's ISO rating and would have compelled the insured residents[141] and industrial facilities to carry higher homeowners and industrial hazard insurance premiums.[142] The WFC

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[139] *Ibid.*
[140] Section 9 discusses land use planning and zoning.
[141] If the WFC plant had been included in the ISO rating, the city of West would have had a higher classification score, with an increased insurance premium for homeowners in West because of the proximity of the fertilizer plant to residential neighborhoods.
[142] The rating directly impacts the premiums that insurance companies charge for commercial and industrial facilities as well as homeowner's coverage. A lower ISO rating means a lower price for insurance coverage.

had insurance coverage of $1 million, without any prior evaluation from ISO. If ISO had evaluated the fertilizer plant, insurance underwriters would have charged a higher premium for the WFC plant based on the level of risks and hazards associated with the chemicals and operations at the WFC facility. Also, the ISO rating system would have revealed the distance from the nearest fire hydrant to the fertilizer plant, which would have increased the PPC rating. To obtain lower ISO PPC ratings, the city of West would have had to make adjustments by installing and regularly maintaining fire hydrants with ISO-minimum water flow rates closer to the fertilizer plant to enable ease of reach during emergencies.[143]

6.0 Inherently Safer Technology

FGAN has certain risk characteristics that can make it inherently dangerous under some conditions. Ammonium nitrate (AN) by itself is a powerful oxidizer; when mixed with fuel oil, it can be used as an industrial explosive when exposed to fire or shock. Traditional safety practices to control FGAN fire and explosion hazards through procedures, hazard awareness, and emergency response are important. However, applying the concept of inherently safer technology (IST) or inherently safer design (ISD) can substantially reduce risk.

IST and ISD are recognized approaches for decreasing risk by permanently reducing or eliminating the hazards associated with materials and operations used in an industrial process.[144] Trevor Kletz, an acknowledged expert on IST and chemical process safety, defined IST as the avoidance of hazards rather than the control of hazards by adding protective equipment.[145] Inherently safer processes can be achieved by strategies such as:

- Substituting dangerous chemicals or processes with safer alternatives.
- Simplifying processes.
- Minimizing the quantity of a chemical on hand or in a process.
- Moderating the operating conditions of a process.

Before the widespread adoption of IST, plant designs in the chemical industry tended to address reduction of risk by relying on layers of protective equipment, procedures, and alarms.[146] IST is preferable to adding layers of protection because, while this approach might reduce the likelihood or impact of an event, the inherent hazards remain.[147] The concept of IST can be derived from a list of strategies for

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[143] To qualify for rating credit, fire hydrants must be capable of delivering a minimum of 500 gpm for 30 minutes.
[144] Center for Chemical Process Safety. *Inherently Safer Chemical Processes—A Life Cycle Approach*, Second Edition. New York: John Wiley & Sons, 2009.
[145] Kletz, Trevor A., and Paul Amyotte. *Process Plants: A Handbook for Inherently Safer Design*. Boca Raton, FL: CRC Press, 2009.
[146] Kletz, Trevor, and Paul Amyotte. *Process Plants: A Handbook for Inherently Safer Design*, Second Edition. Boca Raton, FL: Taylor & Francis, 2010.
[147] *Ibid*.

reducing risk (Figure 60). IST is most effective when implemented during the earliest stages of the process design, but it can be applied at all stages of a life cycle (design, operation, shutdown, and demolition).[148]

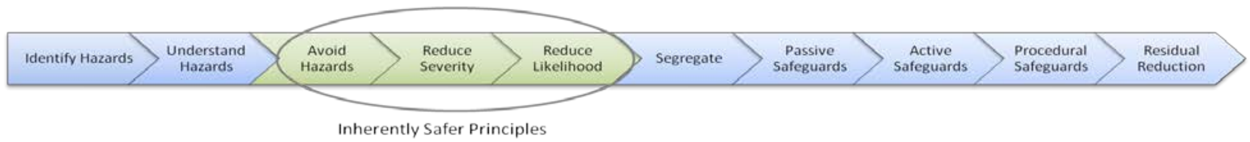

Figure 60. Risk Control Hierarchy (Source: CCPS)[149]

Table 6 lists some IST approaches that can be applied to FGAN.

Table 6. Inherently Safer Approaches for Handling FGAN[150]

Inherently Safer Strategy	**Description**	**Examples**
Substitution	Replacing a hazardous material with a safer option	Use a fertilizer with less explosive potential than FGAN
Minimization	Reducing the quantity of a hazardous material used in a chemical process	Store FGAN in purpose-built buildings holding smaller quantities of materials, well separated from one another and from potential sources of contamination
Moderation	Using a hazardous material under the least hazardous conditions	Store FGAN in bins constructed of materials impervious to the effects of AN and in areas where electric service is not required
Limitation of effects (a form of moderation)	Changing designs or reaction conditions rather than adding protective equipment	Construct FGAN storage bins to minimize the consequence of a possible explosion
Simplification	Eliminating process complexity to provide fewer opportunities for error and equipment failure	Limit the types of FGAN blends sold to minimize the need for staff to handle FGAN.

[148] National Research Council. *The Use and Storage of Methyl Isocyanate (MIC) at Bayer CropScience*. Washington, DC: The National Academies Press, 2012.
[149] Center for Chemical Process Safety. *Inherently Safer Chemical Processes—A Life Cycle Approach*, Second Edition. New York: John Wiley & Sons, 2009: 3, 27.
[150] *Ibid*.

Once all hazards associated with a chemical process are identified and understood, IST can be applied in the design phase or to existing processes. According to Kletz, the concepts of IST are not sharply defined and can merge into each other, depending on how they are applied.[151] Although not always feasible or cost-effective, substitution is often the most desired approach for reducing hazards because it involves replacing a hazardous material with a safer alternative. Minimization to reduce the quantity of a hazardous chemical stored or used within a process can often have a dramatic effect on risk, albeit usually only locally. The concept of moderation usually involves processing or storing chemicals under conditions that are less likely to add to or exacerbate risk—such as lower temperatures and pressures, removal of potential catalysts and sources of ignition, or use of materials of construction that minimize heat exposure near FGAN. In addition, the concept of simplification involves modifying procedures to reduce the likelihood of operator error and designing processes that require little or no operator actions to render the process safe in the event of a loss of control. The implementation of one or more of the inherently safer options, if feasible, can eliminate or minimize hazards instead of controlling them.

IST might not eliminate all risks associated with a process, and some apparently inherently safer options might introduce new hazards that are of greater concern than those eliminated. For example, a reduced quantity of a hazardous chemical at a plant can lead to greater risk in transportation systems or at the originating plant. Elimination of large FGAN inventories at facilities similar to the West Fertilizer Company (WFC) is impractical because farmers rely on large quantities of fertilizer for their crops. Lower inventories could potentially introduce new hazards from the larger number of FGAN shipments needed to supply storage facilities. Accordingly, before implementation, IST options must be thoroughly analyzed and assessed, considering all risks and not only the interests of an individual facility.

In terms of reducing the fire and explosion hazards associated with storage and handling of FGAN, two inherently safe measures are described in the rest of this section: (1) modify or substitute for the formulation of FGAN, making it less susceptible to fire or explosion, and (2) modify the conditions in which FGAN is stored to eliminate the possibility of a large fire and explosion.

6.1 Alternative Formulations of FGAN

An alternative formulation of FGAN could reduce the potential for a detonation under fire conditions. However, more testing is necessary to ensure that these formulations are safer in bulk quantities, agriculturally compatible, and environmentally acceptable. In response to the 1947 FGAN explosion in Texas City, Texas, and to subsequent AN-based bombings across the United States,[152] researchers have

[151] *Ibid*.

[152] Past AN-based bombings in the United States include the 1970 University of Wisconsin bombing, the 1990 Internal Revenue Service building bombing and other attempted bombings in California, the 1995 Murrah Federal Building bombing in Oklahoma City, and the 1996 attempted bombing of the FBI fingerprint database complex in Clarksburg, West Virginia.

explored several options for inerting or desensitizing FGAN to lower the detonation sensitivity of the material. One method introduced in 1968 claimed to render FGAN inert with the addition of 5 to 10 percent monoammonium phosphate and diammonium phosphate.[153] However, in 1995, a test showed that the mixture was detonable with a larger charge diameter than the initially presented charge.[154]

In 1997, the International Fertilizer Development Center conducted a study for ATF to study the feasibility, practicability, and impact of making nitrate-based fertilizer chemicals inert. The study concluded that it is not feasible to inert AN without adversely affecting its effectiveness and efficiency as a fertilizer.[155] In 1998, the National Research Council (NRC) released a report that addressed existing studies for inerting AN. The NRC examination concluded that FGAN with altered prill porosity, dilutants, or chemical additives could still be detonable[156] and that no current technology would reduce the risk without seriously affecting the utility of AN as a fertilizer.[157] The NRC recommends further examinations of the impacts of alternate formulations on agricultural suitability, costs to the end-user and environmental impacts of additives or inertants.[158] Large quantities of inert materials mixed with AN might not be practical because of the cost and the reduction in fertilizer effectiveness. Adding a percentage of another chemical to AN can make it safer, but farmers might need to buy and transport more fertilizer to deliver the same quantity of nitrogen to their crops.[159] CSB has reviewed documentation and publications that describe a few of those alternatives to AN based on the addition of inert chemicals (Table 7).

Table 7. Examples of AN Fertilizer Alternatives

Name	**Method**	**Claims**

[153] Porter, S.J. "Method of desensitizing fertilizer grade FGAN and the product contained," U.S. Patent 3,366,468, 1968.
[154] National Research Council. *Containing the Threat from Illegal Bombings: An Integrated National Strategy for Marking, Tagging, Rendering Inert, and Licensing Explosives and Their Precursors*. Washington, DC: National Research Council, 1998: 106. *See*: http://www.nap.edu/openbook.php?record_id=5966&page=106 (accessed on June 26, 2014).
[155] *See*: https://www.atf.gov/file/57516/download (accessed on January 20, 2016).
[156] National Research Council. *Containing the Threat from Illegal Bombings: An Integrated National Strategy for Marking, Tagging, Rendering Inert, and Licensing Explosives and Their Precursors*. Washington, DC: National Research Council, 1998: 106. *See*: http://www.nap.edu/openbook.php?record_id=5966&page=106 (accessed on June 26, 2014).
[157] *Ibid*.
[158] *Ibid*.
[159] Thompson, Steve. *Dallas News*. Quoting Bob Best, Pentagon scientist: "There are safer alternatives to FGAN fertilizer. But a safer form?" *See*: http://watchdogblog.dallasnews.com/2013/10/there-are-safer-alternatives-to-ammonium-nitrate-fertilizer-but-a-safer-form.html/ (accessed on June 26, 2014).

Sulf-N® 26[160] (ASN 26)	FGAN fused with ammonium sulfate[161]	The addition of ammonium sulfate dampens the role of FGAN combustion.[162]
Ferti-Safe[163]	Fly-ash-coated and gypsum-coated fertilizer	Detonation potential can be reduced or eliminated.
Calcium ammonium nitrate (CAN)	Mixture of FGAN and limestone (calcium carbonate) or dolomite (calcium magnesium carbonate)	Some tests revealed less oxidizing capability than FGAN. CAN is less prone to thermal decomposition than FGAN.

Honeywell has developed a fertilizer called Sulf-N 26 (later marketed by J.R. Simplot Company as ASN 26), claimed to be inherently safer than FGAN. Sulf-N 26 is made of nitrogen and sulfur[164] by fusing FGAN with ammonium sulfate (AS), a fire retardant. For the patent, tests were conducted according to United Nations Recommendations on the Transport of Dangerous Goods.[165] The test method is designed to measure the potential for a solid substance to increase the burning rate or burning intensity of a combustible substance when the two are thoroughly mixed. The mixture of FGAN fused with AS did not burn in the test, and the mixture was not classified as an oxidizer. Sulf-N 26 contains significantly less nitrogen than FGAN (26 percent compared to 34 percent).[166] This nitrogen level can be an issue for some farmers as the effective absorption rate of nitrogen is vitally important to plants. Sulf-N 26 also contains higher quantities of sulfur, which farmers can need for certain types of crops and soils but not for others. Further examination is necessary to fully assess the use of Sulf-N 26 as an inherently safer alternative to FGAN. Notably, a 50/50 mixture of AS and FGAN was involved in the 1921 Oppau, Germany, explosion.

Researchers from the University of Kentucky developed a technology called Ferti-Safe to desensitize FGAN by coating it with an ash-like coal combustion by-product.[167] They developed the technology with the intention of preventing the malicious use of FGAN for explosive devices. The Ferti-Safe formulation

[160] Sulf-N 26 was not commercially available at the time of the WFC incident.
[161] Honeywell. "Honeywell Sulf-N 26." *See*: http://sulfn26.com/ (accessed on June 26, 2014).
[162] *Ibid*.
[163] Ferti-Safe was not commercially available at the time of the WFC incident.
[164] Honeywell. "Honeywell Sulf-N 26." *See*: http://sulfn26.com/ (accessed on June 26, 2014).
[165] United Nations. Recommendations on the Transport of Dangerous Goods, Manual of Tests and Criteria, ST/SG/AC.10/11/Rev2, Section 34, Classification Procedures, Test Methods and Criteria Relating To Oxidizing Substances of Division 5.1, Test O.1: Test for Oxidizing Solids, 1995.
[166] Bomgardener, Melody M. "Safer Fertilizer," *Chemical and Engineering News*, December 6 (2011). *See*: http://cen.acs.org/articles/89/web/2011/12/Safer-Fertilizer.html (accessed on May-June 2015).
[167] Taulbee, D. et al. *Reducing the Explosion Potential of Ammonium Nitrate Fertilizer*, Final Report to the National Institute of Hometown Security, Lexington, KY (2012).

involves coating FGAN with gypsum (calcium sulfate) and fly ash.[168] Both coating options are claimed to be effective in stopping an explosion of a blend of ammonium nitrate/fuel oil (ANFO).[169]

Calcium ammonium nitrate (CAN) contains 26 percent nitrogen and about 25 percent inert calcium carbonate. Formulations of CAN have been used in Europe and other countries since the 1920s, but it is not manufactured in the United States. European safety data sheets state that CAN is not capable of self-sustaining progressive thermal decomposition.[170]

The scope of most existing studies on alternative forms of FGAN is focused on reducing or eliminating the security threats associated with using FGAN to construct improvised explosive devices with the addition of fuel oil, but such studies do not focus on FGAN used in agricultural operations. Although some of the available information on these options suggests that they might be inherently safer, only limited testing has been performed to characterize the behavior of the alternatives in fire situations similar to that at the WFC.

FGAN is vital to the nourishment of crops across the country, and alternative formulations must also be capable of meeting agricultural fertilizer needs. Because of the lack of scientific literature to show that alternative formulations of bulk FGAN can resist detonation in fires, CSB concludes that FGAN detonations can currently best be avoided through better compliance with storage practices and the application of inherently safe building design and storage.

6.2 Inherently Safe Building Design and Storage

In the United States, FGAN storage practices at facilities similar to the WFC have not significantly changed over time. Before the fires in Bryan, Athens, and West, these Texas FGAN facilities had similar construction, with combustible materials and construction and limited fire safety features. CSB visited another EDC facility in Itasca, Texas, in 2013 and also noted combustible construction for the storage facility and bins. Findings from the WFC incident demonstrate that inherently safer concepts can be applied to storage practices to significantly reduce the risk of a fire or explosion. Modifying existing facilities or constructing new storage facilities with inherently safe options—such as facility set-back distances and the use of noncombustible construction materials—can reduce such risks.

Because FGAN behavior is unpredictable in fire conditions, the most immediately effective strategy for reducing risk in existing and future FGAN storage facilities is to use inherently safer building design options to avoid creating the hazardous conditions that can contribute to a large uncontrollable FGAN fire and detonation. CSB concluded that the storage of combustible materials near FGAN storage piles and the use of combustible bins likely facilitated the spread of the FGAN-related fire to other bins and nearby

[168] Fly ash is a fine particle residue of coal combustion.
[169] Taulbee, D. et al. *Reducing the Explosion Potential of Ammonium Nitrate Fertilizer*, Final Report to the National Institute of Hometown Security, Lexington, KY (2012).

[170] *See*: http://www.eurochem.ru/wp-content/uploads/2012/08/SDB_27_KASweiss_0124_EU.pdf (accessed on January 7, 2016).

combustibles. The combustibles also likely acted as a fuel during the fire; the soot, creosote, and other contaminants from the burning wood materials mixed with the surface of the FGAN, potentially increasing its energy and sensitivity to detonation.

By eliminating wood and other combustibles as construction materials for FGAN bins and storage facilities and also for the storage of nearby combustible materials, the possibility of contaminating FGAN during a fire or smoldering event is greatly reduced. However, organic materials (such as packing materials or seeds) that are commonly present with the storage of bulk fertilizer will increase the likelihood of an explosion and will make the FGAN explosion more energetic. Certain inorganic contaminants, including chlorides and some metals (such as aluminum powder, chromium, copper alloys, cobalt, and nickel), can also sensitize FGAN, increasing the likelihood of detonation.[171] Current OSHA requirements in the Explosives and Blasting Agents standard in 29 CFR 1910.109(i) do not prohibit the use of wooden FGAN storage bins; instead, OSHA requires bins that are protected against FGAN impregnation (as noted in Section 8.2). The installation and use of concrete or metal[172] storage bins would reduce the potential for a fire to spread throughout the facility and to other piles of FGAN or nearby combustible materials.

It is also inherently safer to store FGAN in places where sources of ignition are not present. For example, a storage building without electric service eliminates the one of the possible sources of ignition and is thus inherently safer.

In July 2009, an FGAN-related fire at the EDC fertilizer storage facility in Bryan, Texas, burned the facility to the ground, but the FGAN did not explode. The fire forced an evacuation of more than 80,000 residents in the Bryan area and students at the Texas A&M College Station campus. EDC rebuilt the facility, originally a wooden structure, with concrete bins surrounded by a concrete dome (Figure 61). EDC's insurance company required the use of concrete construction materials instead of wood to minimize the fire risk.

[171] EPA. "EPA Chemical Advisory: Safe Storage, Handling, and Management of Solid Ammonium Nitrate Prills." *See*: http://www2.epa.gov/sites/production/files/2015-06/documents/an_advisory_6-5-15.pdf (accessed on November 30, 2015).

[172] Galvanized iron, copper or copper alloys, lead, and zinc are not recommended metals for AN storage.

Figure 61. Reconstructed EDC Facility in Bryan, Texas (Source: CSB)

Use of concrete bins or external metal hoppers instead of wooden structures is considered an inherently safer option for FGAN storage. According to Kletz, the IST concept of moderation entails storing or transporting a hazardous material in a less hazardous manner.[173] In this case, eliminating the presence of the combustibles removes an obvious and principal source of fuel and heat that contribute to detonation. Replacing bins with structures made of concrete instead of combustible materials also limits the quantity of FGAN available to support combustion by confining it to the bin and preventing the acceleration of a fire. It is well recognized that wood is not a preferred material of construction for buildings or bins storing FGAN, and untreated wooden bins should never be used to store FGAN because of the oxidizing properties of FGAN that will increase the burning temperature and rate of burn of the structure itself, facilitating the spread of a fire. Concrete or compatible metals should be used to avoid contamination during fires. The Health and Safety Executive in the United Kingdom states that FGAN storage "should be constructed of a material that does not burn, preferably concrete."[174]

In March 2014, CSB responded to OSHA's request for information (RFI) (at 78 *Federal Register* 73756) on future possible revisions to OSHA safety standards, including the Explosives and Blasting Agents standard in 29 CFR 1910.109(i) and the Process Safety Management standard in 29 CFR 1910.119. In response to the RFI, CSB urged OSHA to consider revising existing standards to provide more explicit requirements for the storage and handling of FGAN, including prohibiting wooden or combustible FGAN storage bins.[175] In May 2015, the NFPA issued a new edition of NFPA 400-2016, *Hazardous Materials Code* (Chapter 11, "Ammonium Nitrate"), which prohibits combustible construction materials for new FGAN storage facilities and establishes requirements for automated fire detection, fire suppression, alarm activation, and evacuation plans for existing facilities with combustible construction. CSB recommends that OSHA revise its standards to include requirements similar to those in NFPA 400-2016 for FGAN storage facilities to reduce the likelihood of a detonation when FGAN is exposed to fire.

7.0 Emergency Response

The FGAN explosion at the West Fertilizer Company (WFC) facility killed 15 people and caused more than 260 injuries. Of the 15 fatalities, 12 were first responders (firefighters and emergency services) personnel who responded to the fire—eight volunteer firefighters, with five from the West Volunteer Fire Department (WVFD), two from the City of Abbott Fire Department, and one from the Mertens and

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[173] Kletz, Trevor, and Paul Amyotte. "Attenuation." *Process Plants: A Handbook for Inherently Safer Design*, Second Edition. Boca Raton, FL: CRC Press, 2010: 103.

[174] Health and Safety Executive (HSE). *Storing and Handling Ammonium Nitrate*. United Kingdom: Health and Safety Executive, 2004. *See*: http://www.hse.gov.uk/pubns/indg230.pdf (accessed on January 6, 2016).

[175] CSB. "CSB Comments on the OSHA Proposed Rule: Process Safety Management and Prevention of Major Chemical Accidents." *See*: http://www.regulations.gov/#!documentDetail;D=OSHA-2013-0020-0074 (accessed on November 30, 2015).

Navarro Mills Fire Department; an off-duty career firefighter (captain) from the City of Dallas Fire Department; an emergency medical technician (EMT) from West; and two good Samaritans who supported the emergency response at the fertilizer plant.[176] One of the deceased volunteer firefighters who responded to the fire was also an employee of the WFC.

CSB developed this section of our report to provide information to fire departments across the country by evaluating the key factors that contributed to the firefighter fatalities and to share lessons learned so that similar events can be avoided in the future. Accordingly, to determine what went wrong, CSB used emergency response documents, interviews, and video footage to analyze in detail the actions that were taken before and during the approximately 20 minutes that elapsed from the first call for assistance until the explosion occurred.

This analysis is not focused only on volunteer firefighters; it demonstrates the need for effective pre-incident planning and firefighter training. Firefighters are expected to make risk assessments and decisions under time pressure with limited visibility during an actual response to a fire, which is almost impossible without adequate training.

Although this analysis indicates that the emergency responders involved in this incident accepted an extremely high level of risk that resulted in multiple deaths, CSB recognizes that they were attempting to develop a plan of action for a fire scenario that none of them had prior practical experience with.

7.1 Firefighter Response

The chain of events—from the time the volunteer firefighters and other emergency responders arrived at WFC until the time of the explosion—can never be precisely known. On the basis of interviews with surviving firefighters and the evaluation of the incident scene, CSB was able to assess the emergency response process on April 17, 2013. On the evening of the incident, the emergency responders who were initially dispatched to the fire arrived at the scene at different times. CSB obtained a street surveillance camera video recording and also camera footage from the inside of a neighboring hardware store in West.[177] The surveillance recording indicated that four emergency response vehicles were en route between 7:37 pm and 7:51 pm, when the explosion occurred, as shown in the timeline of events in Figure 62.

[176] One of these Good Samaritans was familiar with the equipment used by the WVFD and volunteered to assist the second, who was in the area tending to cattle and offered his help to the firefighters. These two deceased Good Samaritans were made honorary volunteer firefighters at the memorial for the fallen West, Texas, firefighters and other emergency responders held in Waco, Texas, on April 25, 2013.

[177] The convenience store and street surveillance camera are located about a mile from the WFC facility at the intersection between East Pine Street and North Roberts Street.

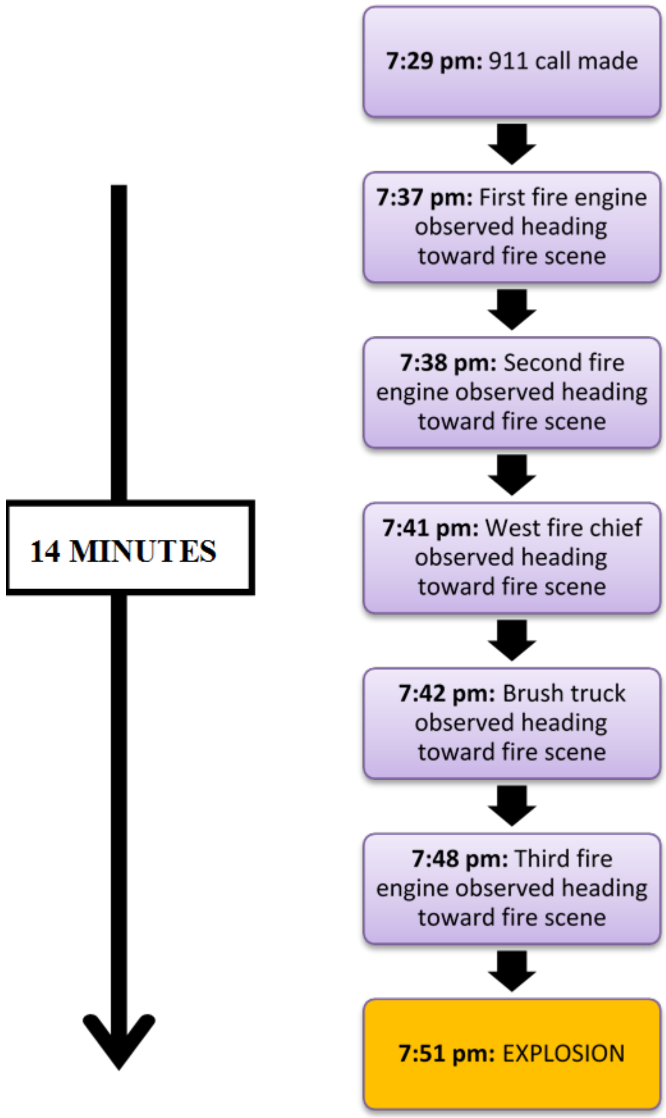

Figure 62. Timeline of Events for Emergency Response to WFC Facility (Source: CSB)

Emergency responders were notified and dispatched to the scene at about 7:29 pm on April 17. The firefighters arrived on scene over a span of about 14 minutes, as recorded on surveillance footage of emergency vehicles en route to the WFC site that night.[178] In the video footage, the WVFD fire chief can be observed driving the water tender toward the incident scene at about 7:41 pm. Firefighters were dispatched to the scene of the emergency without anyone's knowledge of how long the fire had been

[178] Because the WVFD is a volunteer-based service, it should be noted that the volunteer firefighters were not at the station at the time of the incident. Several firefighters were at home, attending to other personal activities or participating in an EMT training class.

burning or smoldering before being noticed.[179] Upon arrival, they concentrated their efforts initially on the incident scene, preparing to suppress flames that were visible at the northeast portion of the storage structure. Without a robust incident pre-planning process in place, without adequate hazardous materials awareness training, and with no previous FGAN-related fire emergency training or drills, the firefighters had no expectation of a possible FGAN explosion. The firefighters were advised by the career fire captain that they did not have the resources to combat the growing fire and should concentrate on cooling the liquid anhydrous ammonia tanks located near the burning building to prevent the tank from rupturing or venting. However, they had not established that stream of water when the explosion occurred because they had to shut off the attack lines while the pumpers were repositioned.[180]

7.2 Key Contributing Factors to Emergency Responders' Fatality

CSB identified the following seven key factors that contributed to the fatalities of firefighters and other emergency responders in West:

1. Lack of incident command system.
2. Lack of established incident management system.
3. Lack of hazardous materials (HAZMAT) and dangerous goods training.
4. Lack of knowledge and understanding of the detonation hazards of FGAN.
5. Lack of situational awareness and risk assessment knowledge on the scene of an FGAN-related fire.
6. Lack of pre-incident planning at the WFC facility.
7. Limited and conflicting technical guidance on AN.

7.2.1 Lack of Incident Command System

CSB found that none of the responding emergency response personnel trained and certified in the National Incident Management System (NIMS) process formally assumed the position of Incident Commander (IC) who would have been responsible for conducting and coordinating an incident command system (ICS). Senior emergency response personnel at the WVFD arrived at the scene of the WFC incident at different times and did not delegate an IC to be in charge of the incident. Also, there was no record that arriving firefighters conducted an initial incident size-up or risk assessment to determine initial actions (offensive or defensive) that would be most suitable in responding to the incident based on the situation and available resources without putting emergency personnel at risk.

Despite multiple responders having ICS training, none of them reportedly established command or took control of the fire ground. On the basis of a review of radio communications and interviews with surviving firefighters, CSB found no clear messaging or discussion among the responding firefighters on who should assume the role of the designated IC. Without a delegated IC officially taking control of the

[179] CSB was unable to determine how long the fire had been burning before the firefighters were notified.
[180] NIOSH Fire Fighter Fatality Investigation and Prevention Program. *See*: http://www.cdc.gov/niosh/fire/ (accessed on December 28, 2015).

fire ground operations, no ICS was established. Consequently, no senior emergency response personnel or IC was responsible for coordinating the various response activities carried out by individual firefighters on the scene. The West fire chief arrived on scene at about 7:41 pm and did not critically assess the conditions on the ground before the explosion 10 minutes later, at about 7:51 pm. The fire chief and assistant chief provided support and advisory functions but did not actively engage in fire ground function or take control of the fire ground; no record indicated that the West fire chief took command of the incident upon his arrival.[181] Without direction to the contrary, the firefighters immediately took offensive action against the flames coming from the doors on north end of the east side of the structure. CSB interviews with surviving firefighters indicated that before the arrival of the fire chief, the other senior firefighters who had reached the incident scene about six minutes earlier had not delegated senior personnel with the training and expertise needed to formally assume responsibility as the IC. The firefighters had not reached a conclusion about how to establish a best approach and how to respond to the fire when the explosion occurred. Despite being trained for the ICS and NIMS process, none of the certified firefighters had prior practical experience in establishing incident command or coordinating and maintaining control of any previous emergency that merited the same approach as an FGAN-related fire scene.

7.2.2 Lack of Established Incident Management System

CSB found that the emergency response personnel who responded to the WFC incident did not take time to set up, implement, and coordinate an effective incident management system plan that would have ensured evacuation of the nearby residents. Because no formal IC was in charge of the incident, none of the firefighters took responsibility for formally establishing and coordinating an effective incident management system.

Witness testimonies revealed that emergency alert systems for the public were not activated before the explosion, although McLennan County had such systems in place.[182] Many of the injuries might have been avoided or might have been less severe if an immediate evacuation had occurred. When the fire was first detected by a police officer, he ordered people in the parks near the facility to evacuate, and he blocked off roads. In addition, employees from the nursing home took the initiative as part of their company emergency response policy to move occupants to the back of the building for fear of smoke or an ammonia release. However, without a formal evacuation order to the entire affected community, many of the residents were left unaware of the risk and chose to watch the fire from inside their homes or vehicles or from the street, placing them within range of the high-pressure blast wave and in the line of flight of debris. In a study conducted after the WFC incident of FGAN-related fires worldwide since

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[181] NIMS requires that the ICS should be established by the first arriving NIMS qualified personnel. Best practices indicate that the fire chief does not need to be on the scene of a fire before the ICS can be established.
[182] See Section 8.5 of this report.

1970, the majority of detonations occurred within 60 minutes of the initial fire report.[183] Because this elapsed time to detonation might be shorter than the response times for emergency operations and potential firefighting, a 'let-it-burn' approach with a precautionary evacuation of the surrounding neighborhood is appropriate.[184]

An incident management system is intended to provide a standard approach to management of emergency incidents. The U.S. Department of Homeland Security (DHS) established NIMS in 2004.[185] NFPA 1561 (2014 Edition) indicates, "[T]he incident management system shall provide structure and coordination to the management of emergency incident operations to provide for the safety and health of emergency services organization responders and other persons involved in those activities."[186] DHS developed the NIMS program to standardize the incident management process by facilitating coordination of an emergency among all responders (including all levels of government and public, private, and nongovernmental organizations) so that they work together seamlessly and manage incidents involving threats and hazards (regardless of cause, size, location, or complexity) to reduce loss of life, property damage, and harm to the environment. To achieve this objective, FEMA, an organization within DHS, developed a NIMS training program.[187] All federal emergency responders, including firefighters, are required to receive NIMS training.[188] Presidential Policy Directive 5, which established the NIMS training program, applies to all federal agencies, and non-federal entities, although not required to participate, are encouraged to do so.[189]

NFPA 1500 (*Standard on Fire Department Occupational Safety and Health Program*, 2013 Edition[190]) and NFPA 1561 (*Standard on Emergency Services Incident Management System and Command Safety*, 2014 Edition[191]) emphasize the need to use effective incident management systems at all emergency

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[183] Marlair, G., et al. Comments about the paper entitled "Lessons to be Learned from an analysis of ammonium nitrate disasters in the last 100 years," by Pittman et al., *Journal of Hazardous Materials* 280 (2014).
[184] *Ibid.*
[185] *See*: https://www.fema.gov/national-incident-management-system (accessed on December 28, 2015).
[186] NFPA. *NFPA 1561: Standard on Emergency Services Incident Management System and Command Safety*, 2014 Edition. Quincy, MA: NFPA, 2014.
[187] The NIMS training program specifies National Integration Center and stakeholder responsibilities and activities for developing, maintaining, and sustaining NIMS training. The NIMS training program outlines responsibilities and activities that are consistent with the National Training Program, as mandated by the Post-Katrina Emergency Management Reform Act of 2006. This program integrates with FEMA training offered through the Emergency Management Institute (EMI) and USFA. *See*: http://www.fema.gov/pdf/emergency/nims/nims_training_program.pdf (accessed on December 28, 2015).
[188] *See*: https://www.fema.gov/national-incident-management-system/training (accessed on December 28, 2015).
[189] To compel non-Federal entities seeking grants, FEMA does require its grant recipients to verify that they are "NIMS-compliant." However, there is no requirement for fire services not receiving federal grants to participate in NIMS. *See*: https://www.fema.gov/pdf/emergency/nims/nims_training_program.pdf (accessed on December 28, 2015).
[190] NFPA. *NFPA 1500: Fire Department Occupational Safety and Health Program*, 2013 Edition. Quincy, MA: NFPA, 2013.
[191] NFPA. *NFPA 1561: Standard on Emergency Services Incident Management System and Command Safety,* 2014 Edition. Quincy, MA: NFPA, 2014.

scenes. In most cases, this process is known as the ICS, with the primary objective of managing the incident. NFPA 1561 defines an incident management system as "a system that defines the roles and responsibilities to be assumed by responders and the standard operating procedures to be used in the management and direction of emergency incidents and other functions."

CSB concluded that despite multiple personnel in the WVFD being trained and certified to initiate and manage the NIMS process, none of the certified firefighters who responded to incident was designated to assume or assumed the role of IC to initiate and coordinate the ICS and incident management plan as stipulated in the NIMS process. If the West firefighters had executed a planned, tested, and practiced ICS and incident management plan, the number of injuries and casualties sustained by both responders and neighboring residents could have been reduced.

7.2.3 Firefighter Training

Firefighters must cope with extraordinary situations and circumstances that threaten their personal safety. To improve execution and reduce the threat of injury or loss of life, it is vital for both volunteer and career firefighters to receive thorough training and information supporting effective decision making. CSB's investigation of the WFC incident revealed that no standardized training requirement applies to volunteer firefighters across the nation.[192]

The NFPA has found that, in general, career firefighters have more funding from their local municipalities and thus are often better trained and better equipped compared to volunteer or hybrid fire departments across the country.[193] In some communities, volunteer firefighters receive training in formal or informal settings; however, this training hinges on the state and regulatory authority, and the level and type of this basic and specialty training are not standardized. Some VFDs provide training programs equal to those of paid departments, but most volunteer firefighters either pay out of pocket or raise funds to pay for any additional specialty training. Such specialty training can address wildland firefighting, technical rescue, swift water rescue, HAZMAT response, vehicle extrication, and firefighter assist and search teams.

CSB found that since there is no federal agency regulating municipal fire departments, some volunteer firefighters in less populated areas or rural communities rarely receive any major type of course training, and most of their initial training is usually on-the-job experience.[194] In addition, some volunteer

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[192] Career firefighters have a standardized basic minimum training requirement.

[193] In its report *A Third Needs Assessment of the U.S. Fire Service*, the NFPA found that compared to their big city counterparts, fire departments in smaller communities were more likely to report that many firefighters had not had formal training in various activities and did not have sufficient PPE. *See*: http://www.nfpa.org/~/media/files/research/nfpa-reports/fire-service-statistics/2011needsassessment.pdf?la=en (accessed on December 28, 2015).

[194] Many volunteer firefighters near special or large manufacturing and storage facilities do receive training from the facility staff. This observation is particularly true when the volunteers include employees of the facility.

firefighters receive EMT[195] and fire academy training.[196] After completing the EMT and fire academy training, most firefighters are required to earn state certification. To maintain additional professional competency, some volunteer firefighters become state certified, but they must meet the same levels of requirements as those that apply to career firefighters.

For example, in Texas, the general requirements for volunteer fire protection personnel certification programs are the same as those for paid personnel. Certification for paid fire protection personnel in Texas is mandatory, but for volunteer fire protection personnel, participation in a certification program is voluntary and not enforced.[197] Texas does not require volunteer firefighters to receive a minimum level of training on how to respond to fires involving hazardous materials. In some cases, volunteer firefighters receive first-level certification, which gives an overview of fire suppression and rescue techniques, including HAZMAT and jaws-of-life training.

NFPA 1001 *(Standard for Fire Fighter Professional Qualifications*, 2013 Edition[198]*)* provides recommended basic and minimum training requirements that all firefighters are expected to complete to respond to fire emergency calls. Once the basic training requirement has been met, the subsequent level of training differs between paid career and volunteer firefighters. In Texas, paid career firefighters are required to complete about 500 hours of training certification over four levels—introduction, basic, immediate, and advanced—through an academy-type program. Training and certification for volunteer firefighters are provided through the State Firefighters' and Fire Marshals' Association of Texas (SFFMA).[199] The SFFMA sets up standards for training and certification, but local jurisdictions are left to decide how many firefighters should be sent for particular training and the level of certification needed to protect their respective localities. For example, VFDs in rural areas and sparsely populated communities might require their firefighters to be certified only at the introductory level because few

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[195] Some firefighters are mandated to receive certification as an EMT. The general EMT-Basic training requires about 100 hours of classroom or field instruction, usually involving some hours of practice in a hospital or ambulance. At the end of the training, EMT-Basic students must take and pass an examination. Firefighters seeking additional training may enroll in the EMT-Intermediate class or the Advanced EMT class, which includes an additional 1,000 hours of education in advanced medical emergency response and care. *See*: http://work.chron.com/certifications-need-become-firefighter-17338.html (accessed on December 28, 2015).

[196] The fire academy training program prepares firefighters for state firefighter certification. The fire academy program involves the completion of classes in the fire science program. Other courses administered in the fire academy program for entry-level firefighters address building codes, emergency medical procedures, and prevention techniques. In addition, the programs train students to fight fires with standard equipment, such as fire extinguishers, ladders, axes, and chainsaws. *See*: http://work.chron.com/certifications-need-become-firefighter-17338.html (accessed on December 28, 2015).

[197] *See*: http://www.tcfp.texas.gov/certification/certification_overview.asp (accessed on December 28, 2015).

[198] NFPA. *NFPA 1001: Standard for Fire Fighter Professional Qualifications*, 2013 Edition. Quincy, MA: NFPA, 2013.

[199] According to its website, the SFFMA was established in 1876 to support fire and emergency service providers in Texas and beyond. The SFFMA offers support to more than 1,200 fire departments, 22,000 individual members, 80 industrial fire brigades, and EMS and international departments. *See*: http://www.sffma.org/web/SFFMA/About_Us/SFFMA/About.aspx?hkey=84e079d0-75c2-47df-b9e9-7ae03d5685dd (accessed on December 28, 2015).

buildings are in the area. In contrast, other towns or communities (such as West) that are near a chemical plant might require their firefighters to receive HAZMAT training and certification.

7.2.4 Firefighter FGAN Knowledge and Lack of HAZMAT Training

CSB determined that lack of knowledge and understanding of FGAN detonation hazards at the WFC facility contributed to the emergency responder fatalities. Interviews with surviving firefighters indicated that they did not have sufficient time and information to properly assess the WFC facility and evaluate the behavior of the FGAN-related fire. Because the firefighters did not have adequate knowledge of the FGAN hazard, they focused their emergency response efforts on the anhydrous ammonia tanks. The lack of adequate HAZMAT training and the lack of FGAN firefighting guidance contributed to the deaths of the emergency responders.

A joint NFPA-USFA survey revealed that an estimated 36 percent of U.S. fire departments involved in HAZMAT responses have not provided formal training in those duties to all involved personnel.[200] CSB reviewed the training and experience of the firefighters who were fatality injured in the WFC incident and found that all of the responding firefighters had minimum training and certifications for responding to fire emergencies, especially training through FEMA courses.[201] In addition, very few of the volunteer firefighters involved in this explosion, including surviving officers, had received HAZMAT training. Only two of the deceased volunteer firefighters had taken the HAZMAT awareness course, which is the introductory basic level for HAZMAT training and includes recognition and use of the *Emergency Response Guidebook* (ERG) as well as notification protocols.[202] Table 8 shows the age, rank, function at the scene, and training and experience levels of the victims.

Table 8. Training and Experience Information of the Fatally Injured Firefighters[203]

Victim	Rank	Age	Years of Experience	Training	Function on Scene
1	Firefighter	48	15 years with WVFD	Landing zone safety, propane emergency response, fire and emergency management services emergency response, HAZMAT awareness, ladder practices, hose handling, live burns, basic self-contained breathing apparatus (SCBA), Introduction to Incident	Dispatched to incident site by WVFD

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[200] NFPA, USFA. "Four Years Later: A Second Needs Assessment of the U.S. Fire Service." *See*: www.usfa.fema.gov/downloads/pdf/publications/fa-303-508.pdf (accessed on December 28, 2015).
[201] *See*: https://training.fema.gov/is/crslist.aspx?all=true (accessed on December 28, 2015).
[202] NIOSH. "9 Volunteer Fire Fighters and 1 Off-Duty Career Fire Captain Killed by an Ammonium Nitrate Explosion at a Fertilizer Plant Fire–Texas." *NIOSH Report on Death in the Line of Duty.* Report Number F2013-11. *See*: http://www.cdc.gov/niosh/fire/pdfs/face201311.pdf (accessed on December 28, 2015).
[203] *Ibid*.

Victim	Rank	Age	Years of Experience	Training	Function on Scene
				Command System (ICS-100),[204] ICS for Single Resources and Initial Action Incidents (ICS-200),[205] National Incident Management System (NIMS): An Introduction (IS-700),[206] National Response Framework: An Introduction (IS-800b)[207]	
2	Career Fire Captain (off duty)	52	31 years with career fire department	31 years as a career firefighter from Dallas (Training status unknown)	Responded voluntarily to assist WVFD
3	Firefighter	26	2 years at mutual aid VFD	ICS-100, ICS-200, IS-700a, NIMS Multiagency Coordination System (MACS) Course (IS-701a),[208] NIMS Public Information Systems (IS-702a),[209] NIMS Resource Management (IS-703a)[210]	Dispatched for mutual aid
4	Firefighter	37	17 years at mutual aid VFDs[211]	Emergency vehicle operations, basic auto extrication, compressed air foam systems,[212] basic firefighting, ICS-100, ICS-200, IS-700a, IS-800.b, HAZMAT I & II,[213] Various training classes offered by TEEX and other departments since 1996.[214]	Responded in privately owned vehicle (POV); dispatched for mutual aid
5	Volunteer Captain	29	10 years at mutual aid VFD	Training status unknown	Attending EMT class nearby. Dispatched for mutual aid; responded in POV

[204] *See*: https://training.fema.gov/is/courseoverview.aspx?code=IS-100.b (accessed on December 28, 2015).
[205] *See*: https://training.fema.gov/is/courseoverview.aspx?code=IS-200.b (accessed on December 28, 2015).
[206] *See*: https://training.fema.gov/is/courseoverview.aspx?code=IS-700.a (accessed on December 28, 2015).
[207] *See*: https://training.fema.gov/is/courseoverview.aspx?code=IS-800.b (accessed on December 28, 2015).
[208] *See*: https://training.fema.gov/is/courseoverview.aspx?code=IS-701.a (accessed on December 28, 2015).
[209] *See*: https://training.fema.gov/is/courseoverview.aspx?code=IS-702.a (accessed on December 28, 2015).
[210] *See*: https://training.fema.gov/is/courseoverview.aspx?code=IS-703.a (accessed on December 28, 2015).
[211] Training information provided to the CSB by victim's family.
[212] *Ibid.*
[213] *Ibid.*
[214] *Ibid.*

Victim	Rank	Age	Years of Experience	Training	Function on Scene
6	EMT, Firefighter	33	1 year at mutual aid VFD	Training status unknown	Attending EMT class nearby. Rode in city ambulance
7	On E-1 Firefighter	41	2 years with WVFD	Basic auto extrication, emergency driving, landing zone safety, ICS-100, IS-700a	Responded on Engine 1
8	Firefighter	50	13 years with city VFD	Fire and EMS emergency vehicle response, landing zone safety, ground cover (basic and intermediate), EMS emergency vehicle response, vehicle extrication, propane ER, fire and EMS ER, Intro to IC, HAZMAT awareness, fire emergency vehicle response, ladder practices, hose handling, live burns, basic SCBA, ICS-100, ICS-700a, IS-800b	Drove the brush truck
9	Volunteer Captain	50	18 years with WVFD	Basic firefighting, propane emergency response, ICS-100, IS-700a	Responded in POV
10	Firefighter	29	3 years with WVFD	Firefighting phase 1, emergency driving, basic auto extrication, landing zone safety, SCBA and smokehouse training, ICS-100, ICS-200b, Intermediate ICS for Expanding Incidents **(**ICS-300),[215] Advanced ICS (ICS-400),[216] IS-700a, IS-701a, IS-702a, IS-703a, NIMS Communication and Information Management (IS-704), NIMS Intrastate Mutual Aid: An Introduction (IS-706),[217] IS-800b	Drove in Engine 1

Texas provides voluntary certification for HAZMAT technicians and HAZMAT ICs through the Texas Commission on Fire Protection (TCFP).[218] The TCFP was established under Texas Government Code, Chapter 419, to develop and enforce recognized professional standards for individuals and the fire service.[219] In addition, the TCFP provides education and assistance to the fire service and enforces

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[215] Intermediate ICS for Expanding Incidents (ICS-300) provides training and resources for personnel who require advanced knowledge and application of the ICS. This course expands on information covered in the ICS-100 and ICS-200 courses. *See*: http://training.fema.gov/emiweb/is/icsresource/trainingmaterials.htm (accessed on December 28, 2015).

[216] The Advanced ICS **(**ICS-400) course provides training and resources for personnel who require advanced application of ICS. This course expands on information covered in ICS-100 through ICS-300. *See*: http://training.fema.gov/emiweb/is/icsresource/trainingmaterials.htm (accessed on December 28, 2015).

[217] *See*: https://training.fema.gov/is/courseoverview.aspx?code=IS-706 (accessed on December 28, 2015).

[218] *See*: http://www.tcfp.texas.gov/certification/certification_requirements.asp (accessed on December 28, 2015).

[219] *See*: http://www.statutes.legis.state.tx.us/Docs/GV/htm/GV.419.htm (accessed on December 28, 2015).

statewide fire service standards. The TCFP is responsible for certification, training approval, and testing and compliance.[220]

CSB evaluated the curriculum manual used for HAZMAT certification for firefighters in Texas and found that FGAN explosion hazards were not covered at all. In fact, the manual mentioned FGAN twice under United Nations (UN)/DOT hazard classes and divisions of hazardous materials and weapons of mass destruction (WMD)—as a Class 1, Division 1.5 insensitive explosive[221] and as a Class 5, Division 5.1 oxidizing substance[222]—in the 349-page document.[223]

Nationally, CSB found that the curriculum used for HAZMAT training does not fully address the hazards and severity of FGAN-related fires and explosions. A review of the U.S. Fire Administration (USFA) National Fire Academy HAZMAT field course outlines confirmed that they place little emphasis on emergency response to storage sites containing dangerous reactive chemicals and oxidizers such as FGAN. Conversely, HAZMAT shipping and transportation are covered in detail in the courses. A review of one firefighter training reference manual, *Fundamentals of Firefighter Skills*, compiled by the International Association of Fire Chiefs (IAFC) and the NFPA, indicated that very little guidance is provided to firefighters regarding responses to HAZMAT incidents involving reactive chemicals. Chapter 29 ("Hazardous Materials: Recognizing and Identifying the Hazards") of the second edition of the *Fundamentals of Firefighter Skills* reference manual includes in-depth information on various HAZMAT transportation methods and containers but does not consider storage and warehousing for these materials. FGAN is not mentioned in the entire chapter.[224]

CSB concludes that the current training resources at the local, state, and federal levels do not provide sufficient information for firefighters to understand the hazards of FGAN. It is therefore essential for firefighter and emergency response training institutions to collaborate with fire departments to develop and implement a realistic process for ensuring that hazard response knowledge, once attained, does not become unused and obsolete.[225]

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[220] TCFP. *See*: http://www.tcfp.texas.gov/about/mission_and_goals.asp (accessed on December 28, 2015).

[221] AN is mentioned as FGAN fertilizer and fuel oil mixtures (ANFO), an example of a very insensitive explosive with a mass explosion hazard (blasting agent) under Division 1.5 (Explosives). Chapter 6, "Hazardous Materials Awareness." *United Nations/Department of Transportation (UN/DOT) Hazard Class and Division of Hazardous Materials and Weapons of Mass Destruction (WMD), Class 1*. Section 601: 3. *See*: http://www.tcfp.texas.gov/manuals/curriculum_manual/chapter_6.pdf (accessed on December 28, 2015).

[222] AN is mentioned as an example of a Division 5.1 oxidizing substance under U.N./DOT Hazard Class 5. Chapter 6, "Hazardous Materials Awareness," Section 601: 4. *See*: http://www.tcfp.texas.gov/manuals/curriculum_manual/chapter_6.pdf (accessed on December 28, 2015).

[223] TCFP. Chapter Six, "Hazardous Materials." *Certification Curriculum Manual*, effective on June 1, 2010. Based on NFPA 472 (2008 Edition). *See*: http://www.tcfp.texas.gov/manuals/curriculum_manual/chapter_6.pdf (accessed on December 28, 2015).

[224] NFPA, IAFC. *Fundamentals of Fire Fighter Skills*, 2nd Edition. Burlington, MA: Jones & Bartlett Publishers, 2008.

[225] Hazard response knowledge must be retained, and an effective retraining process must be put in place to prevent the loss of its organizational value.

7.2.5 Lack of Situational Awareness and Risk Assessment Knowledge

Although many firefighter training courses provide overviews of initial fire scene size-up, assessment, incident planning, and execution, CSB found that none of the firefighter HAZMAT field training courses provide sufficient information on firefighter situational awareness and risk assessment that could help them make informed decisions while at the fire scene.[226,227] The firefighters who initially responded to WFC did not have the tools to effectively perform the situational awareness and risk assessment that would have enabled them to make an informed decision to not fight the fire. Situational awareness in firefighting involves the capability to "read" the scene of a fire or emergency, including changes in the behavior of a fire. Effective situational awareness supports prompt decision making to either evacuate the scene of a fire or continue fighting the fire by taking a defensive or offensive stance. Chapter 4 of NFPA 472 (*Standard for Competence of Responders to Hazardous Materials/Weapons of Mass Destruction Incidents*, 2013 Edition) provides guidance on situational awareness competencies for responder-level personnel.[228]

In fires involving HAZMAT, it is not always possible for firefighters to obtain needed information before acting, but they might be able to characterize a HAZMAT incident based on initial information acquired from the emergency call center and dispatcher; emergency response manuals and guides; knowledge base on the response area; and visual, auditory, and olfactory (odorous) clues. In some cases, the fire department's standard operating procedures (SOPs) and the level of training of the emergency response crew might be insufficient to respond at the incident scene to changing events and scenarios that were not planned for or anticipated—hence, the need for effective training on situational awareness and risk assessment.

Clearly written SOPs would afford fire department trainees the opportunity to read and understand the operational procedures of their fire department. The NIOSH Alert, "Preventing Injuries and Deaths of Fire Fighters," emphasizes the need for departments to establish and adhere to the firefighting policies and procedures stipulated in the SOPs.[229] NFPA 1500 (*Fire Department Occupational Safety and Health Program*, 2013 Edition[230]) emphasizes the need for development of a risk management plan, including risk identification of actual and potential hazards. In addition, it states that "fire departments shall prepare and maintain policies and standard operating procedures that document the organizational structure, membership, roles and responsibilities, expected functions, and training requirements." NFPA 1500 also

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[226] NFPA, IAFC. *Fundamentals of Fire Fighter Skills*, 2nd Edition. Burlington, MA: Jones & Bartlett Publishers, 2008.

[227] Texas Commission on Fire Protection. Chapter Six, "Hazardous Materials." *Certification Curriculum Manual*, effective on June 1, 2010. Based on NFPA 472 (2008 Edition). *See*: http://www.tcfp.texas.gov/manuals/curriculum_manual/chapter_6.pdf (accessed on December 28, 2015).

[228] NFPA. *NFPA 472: Standard for Competence of Responders to Hazardous Materials/Weapons of Mass Destruction Incidents,* 2013 Edition. Quincy, MA: NFPA, 2013.

[229] *See*: http://www.cdc.gov/niosh/docs/2005-132/pdfs/2005-132.pdf (accessed on December 28, 2015).

[230] NFPA. *NFPA 1500: Fire Department Occupational Safety and Health Program,* 2013 Edition. Quincy, MA: NFPA, 2013.

provides guidance on the procedures to initiate and manage operations at the scene of an emergency incident. Moreover, NFPA 1561 (*Standard on Emergency Services Incident Management System and Command Safety*, 2014 Edition) states that "SOPs shall include the requirements for implementation of the incident management system and shall describe the options available for application according to the needs of each particular situation."[231]

Firefighting environments are inherently unpredictable, volatile, and fraught with risk.[232] It is therefore important for decisions to be made in a context of changing priorities, uncertain information, and limited resources. Firefighters must be able to rapidly size up[233] any situation and create scenarios (or what-ifs) to make quick and informed decisions and predict the nature and behavior of a fire. NFPA 472 (*Standard for Competence of Responders to Hazardous Materials/Weapons of Mass Destruction Incidents*, 2013 Edition) offers guidance on competencies for ICs. Scene size-up is essential in any emergency situation, especially for HAZMAT incidents.[234] This approach includes a thorough overall assessment of the scene and the identification of all possible hazards to ensure the safety of the emergency response crew. CSB concluded that training references and guides on emergency response do not address how to effectively respond to AN-related fires.

7.2.6 Lack of Pre-Incident Planning at Facility

The fire department did not have a formal pre-incident planning program for FGAN at WFC. Firefighters responding to the incident were aware of the risks associated with anhydrous ammonia leaking from the tanks and that it could form a toxic flammable cloud that could leave the facility, drift into nearby homes, and potentially explode. Although some responding firefighters knew that FGAN was onsite, they did not anticipate a possible FGAN explosion. Some of the West fire department officials reported that they were aware of the chemicals routinely stored at the WFC, but there was never any formal training to prepare for a fire or chemical emergency. Effective site-specific pre-incident planning for emergency responders is essential to guide initial and subsequent actions while responders are at an emergency. Onsite pre-incident planning might have identified the possible FGAN explosion hazard. CSB did not find evidence of regularly scheduled training exercises to ensure that the WVFD conducted incident pre-planning and facility tours to address fire safety and chemicals onsite.

A pre-incident plan must provide clear information on the magnitude of hazards in a chemical plant or business. A competent incident commander (IC) or designated authority must be capable of executing the pre-incident plan, including analyzing the incident, planning the response, implementing the planned

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[231] NFPA. *NFPA 1561: Standard on Emergency Services Incident Management System and Command Safety,* 2014 Edition. Quincy, MA: NFPA, 2014.
[232] Flin, R. *Sitting in the Hot Seat: Leaders and Teams for Critical Incident Management*. Chichester: Wiley, 1996.
[233] Incident size-up uses ongoing processes of information gathering and analysis that will help the firefighters make quick and informed decisions concerning how better to respond to the incident.
[234] NFPA. *NFPA 472: Standard for Competence of Responders to Hazardous Materials/Weapons of Mass Destruction Incidents,* 2013 Edition. Quincy, MA: NFPA, 2013.

response, evaluating progress, retreating from the incident, and terminating the response. The NFPA [235] provides guidance on developing an effective incident response plan methodology for emergency responders.[236] NFPA 472 (*Standard for Competence of Responders to Hazardous Materials/Weapons of Mass Destruction Incidents*, 2013 Edition[237]) provides guidance on the competencies required for hazardous materials responders (including the IC) involved in pre-incident planning and execution of the plan.

The pre-incident plan also must be effectively communicated to other external emergency units in the surrounding areas for times when these agencies are called on for mutual aid. In addition, a pre-incident plan must be systemic and must include a realistic exit and evacuation strategy, especially when a decision is made to not take offensive action at a hazardous materials incident.

Pre-incident planning must include all of the HAZMAT onsite. Plans must be put in place to address how to effectively respond to an emergency. NFPA 1620 (*Standard for Pre-Incident Planning*, 2015 Edition) states that the pre-incident plan "shall identify and document any special hazards recognized by the authority having jurisdiction that present extraordinary life safety challenges, operations challenges, or other challenges to emergency responders."[238] NFPA 1620 further states that the "pre-incident plan should be the foundation for decision making during an emergency situation and provides important data that will assist the IC in developing appropriate strategies and tactics for managing the incident." This standard also states that the "primary purpose of a pre-incident plan is to help responding personnel effectively manage emergencies with available resources." Pre-incident planning involves evaluating the protection systems, building construction, building contents, and operating procedures that can affect emergency operations.

NFPA 1620 outlines the steps involved in developing, maintaining, and using a pre-incident plan by isolating the incident into pre-incident, incident, and post-incident phases. In the pre-incident phase, for example, the guidance covers factors such as physical elements and site or occupant considerations, protection systems, water supplies, hydrant locations, and special hazard considerations. Building characteristics—including type of construction, materials used, occupancy, fuel load, roof and floor design, and unusual or distinguishing characteristics—should be recorded, shared with other departments that provide mutual aid, and entered into the dispatcher's computer if possible so that the information is readily available if an incident is reported at the noted address.

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[235] The NFPA, a nonprofit standards organization, has been developing standards since 1896 that directly affect fire services at the department level. The NFPA produces more than 300 consensus codes and standards intended to minimize the possibility and effects of fire and other risks. The codes are voluntary standards that industry can adopt and that regulatory agencies can enforce once the codes are signed into law. Standards are an attempt by an industry or profession to self-regulate by establishing minimal operating, performance, or safety criteria. *See*: http://www.nfpa.org/about-nfpa (accessed on December 28, 2015).

[236] CSB referred to the most current edition of the NFPA codes and standards throughout this report.

[237] NFPA. *NFPA 472: Standard for Competence of Responders to Hazardous Materials/Weapons of Mass Destruction Incidents,* 2013 Edition. Quincy, MA: NFPA, 2013.

[238] NFPA. *NFPA 1620: Standard for Pre-Incident Planning,* 2015 Edition. Quincy, MA: NFPA, 2015.

An adequate pre-incident plan must include, at a minimum, specific tested and practiced procedures for responding to an emergency at a given facility; a list of potential HAZMAT such as FGAN, including the quantity of each chemical that may be onsite; details on HAZMAT handling and storage; chemical locations at a particular site; the likely behavior of chemicals in a fire, flood, or other emergency; worst case scenario regarding how these chemicals might behave or interact in an emergency; the Safety Data Sheet (SDS)[239] for each of the HAZMAT; and specific recommendations on how to respond to a fire when these chemicals are involved.

Before the incident, the WVFD did not conduct a pre-inspection for an FGAN-related fire emergency. In most cases, a site-specific pre-incident plan would be developed in partnership with each chemical plant or chemical business in the response jurisdiction. Although WFC reported the quantity and location of each of its hazardous chemicals, including FGAN, to the WVFD, no mechanism ensured that pre-incident drills or inspections were conducted. Although the firefighters in West conducted some onsite anhydrous ammonia drills, none of the drills or training focused on the potential of an FGAN-related fire emergency.

A fire pre-plan would enable firefighters to determine various situations where conditions could dramatically change in a burning structure. This information would enable them to consider the hazards associated with each site. Also, the pre-incident plan could provide this advanced information, which might have aided the WVFD in developing a response strategy or might have facilitated a decision to stand down and allow the structure to burn to the ground if no lives were endangered by doing so. Whether a volunteer fire department (VFD) has pre-incident plans in place often depends on the individual fire department. Currently, no federal agency regulates municipal fire departments in the United States. Although the U.S. Congress funded the National Institute for Occupational Safety and Health (NIOSH) in 1998 to establish the Fire Fighter Fatality Investigation and Prevention Program, NIOSH only investigates on-the-job firefighter fatalities and makes recommendations for improvements to the profession. NIOSH lacks authority to enforce regulations or mandate firefighter training requirements.[240]

7.3 Limited and Conflicting Technical Guidance on FGAN

Firefighters might not have at their fingertips all of the hazard information regarding the chemicals that can be found in their communities. Regardless of the instant availability of information on the hazards of a specific chemical, firefighters are required to respond immediately upon dispatch and are expected to

[239] An SDS is a document developed by the manufacturer of a hazardous chemical product that communicates the hazards of the product. It is required under OSHA's Hazard Communication Standard. Under this standard, all chemical manufacturers, distributors, or importers must provide to downstream users an SDS for each hazardous chemical. Previously, SDSs were known as Material Safety Data Sheets (MSDS); however, in 2012, the name underwent a change when OSHA decided to modify the Hazard Communication Standard to adopt the U.N. Globally Harmonized System.

[240] NIOSH Fire Fighter Fatality Investigation and Prevention Program. *See*: http://www.cdc.gov/niosh/fire/ (accessed on December 28, 2015).

make prompt decisions. To make effective decisions in fire emergencies, some fire prevention and emergency response stakeholders have developed technical manuals and guidebooks. These guidebooks help emergency responders and firefighters to better understand chemical hazards. References include the Emergency Response Guidebook (ERG), SDSs, and NFPA standards.[241] Although firefighting manuals support the prevention of injuries and fatalities, CSB found conflicting information and inconsistencies in various emergency response guidelines.

7.3.1 Emergency Response Guidebook

The ERG is a readily available and widely used guidebook among the emergency response community. Formerly known as the DOT ERG, this document is now jointly produced by DOT, Transport Canada, and the Secretariat of Communications and Transportation (Mexico). The current ERG is designed as a resource for first responders to consult during the initial phase of a dangerous goods or HAZMAT transportation incident. Emergency response personnel (such as firefighters, EMTs, and police officers) in the United States, Canada, Mexico, and other countries use the ERG when responding to transportation emergencies involving HAZMAT. In most cases, firefighters who complete HAZMAT courses, the most basic of which is Awareness Level training, are expected to be familiar with the ERG. Figure 63 shows the 2012 edition of the ERG.

[241] Annex E of NFPA 400 (2013 Edition) also provides AN firefighting guidance. NFPA. *NFPA 400: Hazardous Materials Code*, 2013 Edition. Quincy, MA: NFPA, 2013.

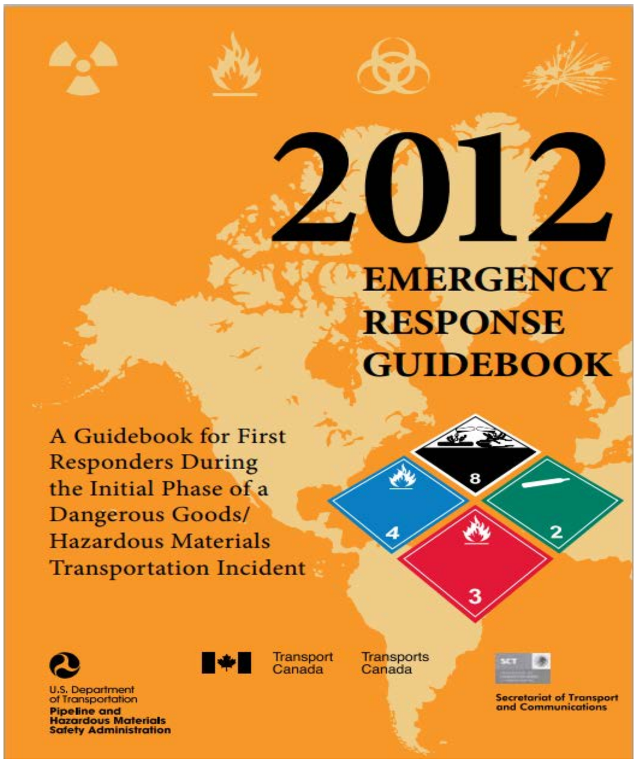

Figure 63. Cover Page of 2012 Edition of ERG (Source: DOT PHMSA)[242]

Most firefighting apparatuses have a copy of the ERG.[243] After the WFC incident, NIOSH investigators found copies of the 2012 ERG in the glove boxes of some of the damaged fire equipment and apparatuses.[244] However, CSB does not have any evidence that indicates whether the West firefighters consulted the ERG on the night of the explosion. The ERG is especially useful in situations when the relevant SDS is not readily available to firefighters.

The ERG gives direction (based on DOT Hazard Classification Criteria) on response to HAZMAT and dangerous goods emergencies during transportation. It does not provide any specific guidance on the

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[242] DOT Pipeline and Hazardous Materials Safety Administration (PHMSA). *See*: http://phmsa.dot.gov/pv_obj_cache/pv_obj_id_7410989F4294AE44A2EBF6A80ADB640BCA8E4200/filename/ERG2012.pdf (accessed on December 28, 2015).

[243] DOT. *The Emergency Response Guidebook: A Guidebook for First Responders During the Initial Phase of a Dangerous Goods/Hazardous Materials Transportation Incident (ERG)*, 2012 Edition. *See*: http://phmsa.dot.gov/staticfiles//PHMSA/DownloadableFiles/Files/Hazmat/ERG2012.pdf (accessed on December 28, 2015).

[244] NIOSH. "9 Volunteer Fire Fighters and 1 Off-Duty Career Fire Captain Killed by an Ammonium Nitrate Explosion at a Fertilizer Plant Fire–Texas." *NIOSH Report on Death in the Line of Duty*. Report Number F2013-11. *See*: http://www.cdc.gov/niosh/fire/pdfs/face201311.pdf (accessed on December 28, 2015).

handling of ammonium fertilizer.[245] In fact, the ERG includes the following commentary under the heading of its 2012 Edition:

> This guidebook will assist responders in making initial decisions upon arriving at the scene of a dangerous goods incident. It should not be considered as a substitute for emergency response training, knowledge or sound judgment. ERG2012 does not address all possible circumstances that may be associated with a dangerous goods incident. It is primarily designed for use at a dangerous goods incident occurring on a highway or railroad. Be mindful that there may be limited value in its application at fixed facility locations.[246]

The current edition of the ERG lists 15 variations of FGAN. Next to each FGAN variant is a guide number that leads to information on the potential hazard and the appropriate emergency response, but the suggested measures are broad and subject to varying interpretations.

On October 1, 2014, CSB provided comments on a DOT request for information (RFI), "Hazardous Materials: Revision of Emergency Response Guidebook" (FR Doc. 2014-20683), which was published on August 29, 2014.[247] CSB commented as follows:

> The ERG is intended for incidents involving the transport of hazardous materials and is limited to the size of the transportation containers involved.[248] However, the CSB has found in several investigations[249] that the ERG manual was used by emergency responders for incidents involving chemical fires, explosions and releases of hazardous materials at fixed facilities. Incidents at fixed facilities may involve larger quantities of hazardous materials as well as additional hazards involving process conditions or other hazardous chemicals stored nearby, resulting in higher risk to emergency responders. The directions regarding response to a chemical release or fire incident intended for transportation may be different when applied to an incident at a fixed chemical or manufacturing facility. For this reason, the CSB suggests that the DOT consider additional language to clarify ERG's use limitations at fixed facilities.

CSB also urged DOT to highlight in bold text on the front cover page of the next edition of the ERG: "Only Intended for Use When Responding to Transportation Incidents." Realizing that emergency

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[245] The ERG provides some information and guidance on handling Division 5.1 oxidizers.
[246] DOT. *The Emergency Response Guidebook: A Guidebook for First Responders During the Initial Phase of a Dangerous Goods/Hazardous Materials Transportation Incident (ERG)*, 2012 Edition: 356. *See*: http://phmsa.dot.gov/staticfiles//PHMSA/DownloadableFiles/Files/Hazmat/ERG2012.pdf (accessed on December 28, 2015).
[247] *See*: http://www.csb.gov/csb-recommends-safety-improvements-to-us-department-of-transportation-emergency-response-guidebook-widely-used-by-firefighters/ (accessed on December 28, 2015).
[248] *See*: http://www.csb.gov/assets/1/7/DOT_ERG__RFI10_1_14.pdf (accessed on December 28, 2015).
[249] Technics, Inc., 2003. *See*: http://www.csb.gov/technic-inc-ventilation-system-explosion/ (accessed on December 28, 2015);
DuPont Belle, 2010. *See*: http://www.csb.gov/dupont-corporation-toxic-chemical-releases/ (accessed on December 28, 2015);
Millard Refrigerated Services, 2010. *See*: http://www.csb.gov/millard-refrigerated-services-ammonia-release/ (accessed on December 28, 2015);
AL Solutions, 2010. *See*: http://www.csb.gov/al-solutions-fatal-dust-explosion/ (accessed on December 28, 2015).

responders will continue to reference the ERG for incidents involving HAZMAT releases at fixed facilities, CSB suggested that DOT consider adding guidance such as the information that first responders should obtain and reference when responding to an incident at a fixed facility, such as the company SDSs and submitted Tier II information.[250] CSB advised that such guidance also should be in the front section of the ERG (for example, on pages 1 and 2). In addition, CSB suggested that DOT move the user's guide from page 356 to page 1 or 2 of the next ERG edition to provide users with earlier guidance.

CSB also urged DOT to take the following actions:

- Review and revise the ERG to remove generic and vague information in the emergency response section of Guide 140 and other ERG sections.
- Include a statement that urges emergency responders to reference other sources in addition to the ERG to obtain more detailed instructions when responding to emergency incidents at fixed facilities. First responders should obtain and refer to the company SDSs or submitted Tier II information when responding to an incident at a fixed facility. This information should also be in the introduction of the ERG (for example, on pages 1 and 2).
- Revise the ERG to address the unpredictable behavior of fires involving FGAN and the potential for detonation within a very short time frame. DOT should consider recommending a more conservative response to fires involving FGAN by emphasizing firefighter and resident evacuation when the threat is to human lives rather than property.
- Revise Guide 140 to include a separate discussion of the properties and behaviors unique to FGAN (such as the potential for detonation within a very short time frame) that might differ from those of other oxidizers covered by Guide 140.

On its website, DOT provided a preview of updates for the 2016 Edition of the ERG.[251] The link to the ERG updates provided by DOT showed that the review working group on the ERG had made the following changes:

- Replaced written instructions on page 1 with a flow chart to show how to use the new ERG (2016).
- Expanded the Table of Placards and updated the title to Table of Markings, Labels, and Placards and Initial Response Guide to Use on Scene.
- Expanded the Railcar Identification Chart and the Road Trailer Identification Chart to two pages each.
- Updated Table 1 and Table 3 based on new toxic inhalation hazard (TIH)[252] data and reactivity research.

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[250] Additional information on Tier II information is noted in Section 8.5 of this report.
[251] DOT. "Preview of Updates for the ERG 2016." *See*: http://www.phmsa.dot.gov/pv_obj_cache/pv_obj_id_CDF7F93A3E0C2F808D9EA09C262749DAEF400200/filename/ERG2016_Preview.pdf (accessed on December 28, 2015).
[252] TIH is the abbreviation for toxic inhalation hazard. Under the Hazardous Materials Regulations (HMR), 49 CFR Parts 171–180, TIH materials are gases or liquids that are known (or presumed on the basis of tests) to be so toxic to humans as to pose a hazard to health in the event of a release during transportation. *See*:

- Updated pipeline emergency response information.
- Added information about Globally Harmonized System of Classification and Labeling of Chemicals (GHS) markings.
- Added all new dangerous goods and HAZMAT listed in the U.N. Recommendations on the Transport of Dangerous Goods, 19th Revised Edition.
- Added information on emergency response assistance plans applicable in Canada.

Also, DOT provided a snapshot of the cover page of the 2016 edition of the ERG (Figure 64) on its website.

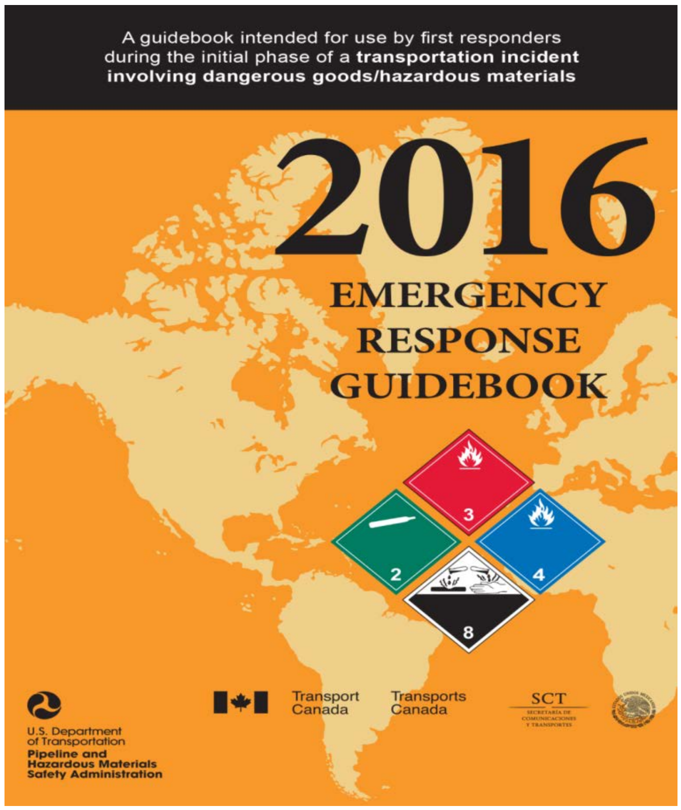

Figure 64. Cover Page of 2016 Edition of ERG (Source: DOT PHMSA)[253]

CSB noticed (from the preview of the 2016 edition of the ERG), that DOT and other authors of the ERG moved the warning statement, "A Guidebook for First Responders During the Initial Phase of a Dangerous Goods/Hazardous Materials Transportation Incident" from the left side of the cover page of the 2012 edition to the top of the cover page, as recommended by CSB. However, DOT and other authors

https://www.federalregister.gov/articles/2004/08/16/04-18705/hazardous-materials-enhancing-rail-transportation-security-for-toxic-inhalation-hazard-materials (accessed on January 20, 2016).

[253] *See*: http://www.phmsa.dot.gov/staticfiles/PHMSA/ImageCollections/Images/ERG2016_Cover.png (accessed on December 28, 2015).

of the ERG did not include the statement "Only Intended for Use When Responding to Transportation Incidents" in bold on the front cover page of the 2016 edition of the ERG, as suggested by CSB in its response to the DOT RFI for the ERG revision.[254] Instead, DOT and other ERG authors modified the statement "A Guidebook for First Responders During the Initial Phase of a Dangerous Goods/Hazardous Materials Transportation Incident" to "A guidebook intended for use by first responders during the initial phase of a **transportation incident involving dangerous goods/hazardous materials**."[255] Note that "transportation incident involving dangerous goods/hazardous materials" is in bold on the cover page of the 2016 edition of the ERG.

7.3.2 Safety Data Sheets

CSB did not find any record that the WVFD consulted the SDS for FGAN and other chemicals present at the WFC facility during the incident. After the incident, CSB reviewed the SDS (that was current at the time of the WFC incident) provided by CF Industries and EDC, the manufacturers of the FGAN used at the WFC. The CF Industries SDS for FGAN (SDS Number 004) provided guidance on FGAN hazards in the December 11, 2012, revision of the SDS.[256] Under the Hazards Identification, Emergency Overview heading (item three, page 1), CF Industries described FGAN:

> Strong oxidizer. Contact with combustible material will increase fire hazard. May undergo detonation if heated under confinement causing pressure buildup or if subjected to strong shocks. Solid AN when sensitized or during decomposition may become unstable and/or explosive. When AN is heated to decomposition it may produce vapor which contains nitrogen oxides (NO_X). AN is an oxidizer and as such may increase the flammability and/or explosiveness of other substances. Use water to control fires involving AN, if water is compatible with burning material. AN itself is non-flammable. AN can cause irritation to eyes and skin and may be an inhalation discomfort in confined locations.[257]

Under the Firefighting Measures heading (item five, page 3), CF Industries noted:

> Flood burning ammonium nitrate fertilizer with large volumes of low pressure water. Do not use salt water, carbon dioxide, dry chemicals or foam extinguishers. Never attempt to smother fire, such as by sealing off, closing a compartment or building doors when fire occurs. Do not add steam. Ammonium nitrate fertilizer does not have the property of spontaneous combustion. Fire fighters should wear approved self-contained breathing apparatus to protect themselves from the

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[254] *See*: http://www.csb.gov/csb-recommends-safety-improvements-to-us-department-of-transportation-emergency-response-guidebook-widely-used-by-firefighters/ (accessed on December 28, 2015).

[255] *See*: http://www.phmsa.dot.gov/staticfiles/PHMSA/ImageCollections/Images/ERG2016_Cover.png (accessed on December 28, 2015).

[256] CF Industries has since removed its December 11, 2012, SDS for FGAN from its website. CF industries replaced the December 11, 2012, SDS for FGAN with a revised and updated SDS for FGAN (April 23, 2013). *See*: http://www.cfindustries.com/pdf/Ammonium-Nitrate-Amtrate-MSDS.pdf (accessed on January 20, 2016). On May 15, 2015, CF Industries published its current SDS for Amtrate FGAN fertilizer, which supersedes every other SDS. *See:* http://www.cfindustries.com/pdf/Amtrate_AN_Fertilizer_SDS_NA_FINAL.pdf (accessed on December 28, 2015).

[257] CF Industries LLC. "Safety Data Sheet, FGAN." SDS Number 004, revised December 11, 2012.

> toxic fumes of decomposing ammonium nitrate, and protective clothing to guard against molten nitrate splashes should also be worn.[258]

This SDS for FGAN referred to NFPA 400 (*Hazardous Materials Code*, 2013 Edition) under its section on handling and storage but not in its section on firefighting measures. Although Chapter 11 of NFPA 400 provided some recommendations for safe storage, handling, and use of AN, it did not include any specific guidelines on FGAN firefighting measures. Annex E of NFPA 400 outlined some general procedures and suggestions on firefighting for FGAN incidents. Section E.2.1 of Annex E of the 2013 edition of NFPA 400 states:

> [S]hould a fire break out in an area where FGAN is stored, it is important that the mass be kept cool and the burning be promptly extinguished. Apply large volumes of water as quickly as possible. If fires reach massive and uncontrollable proportions, fire-fighting personnel should evacuate the area and withdraw to a safe location.[259]

Also, Section E.2.2 of NFPA 400 suggested the provision of as much ventilation as possible to the fire area.[260] Although the FGAN SDS provided by CF Industries contained some useful insights and guidance on how to respond to FGAN-related fires, it did not clearly define "a distance" from which a fire could be "flooded" (one of the special firefighting procedures) and did not specify what "volumes of low pressure water" would be needed.

CSB compared the firefighting measures in the CF Industries and EDC SDS with those in the SDS provided by a similar large technical grade AN (TGAN) manufacturer (Orica)[261] and with those in the current edition of the DOT ERG (Table 9).

Table 9. Comparison of Various AN-Related Firefighting Measures in April 2013

EDC SDS (FGAN)	**CF Industries SDS (FGAN)**	**Orica AN SDS (TGAN)**	**DOT ERG (2012 Edition)**
If confined when an ignition occurs, an explosion may occur.	FGAN may undergo detonation if heated under confinement.	FGAN may explode under confinement and high temperature.	FGAN may explode from heat or contamination.
Flood with water.	Flood fire area from a distance.	Fires should be fought from a protected location.	Flood large fire with water from a distance.

[258] *Ibid*.
[259] NFPA. *NFPA 400: Hazardous Materials Code*, 2013 Edition. Quincy, MA: NFPA, 2013.
[260] *Ibid*.
[261] According to its website, Orica is the largest provider of commercial explosives and blasting systems to the mining and infrastructure markets, a global leader in the provision of ground support in mining and tunneling, and a leading supplier of sodium cyanide for gold extraction. *See*: http://www.orica.com/About-Us#.VlXviHarSUk (accessed on December 28, 2015).

Firefighters should wear proper protective equipment and self-contained breathing apparatus.	For massive fires, use unmanned fire nozzles; if this is impossible, withdraw from area, and let burn.	A major fire may involve a risk of explosion.	For massive fire, use unmanned hose holders or monitor nozzles; if this is impossible, withdraw from area and let fire burn.

These examples of guidance for fighting fires involving FGAN illustrate hazards that were broadly defined and were not clearly communicated to emergency responders. The use of vague and broad terminologies in some of the guidelines compared in Table 9 indicates that the behavior of FGAN under heat and confinement is not clearly understood because no standardized methods are used to communicate the hazards of FGAN and possible firefighting procedures to emergency responders. Also, terms such as "massive," "major," "large," "protected location," and "distance" were not clearly defined in the guidelines. The CF Industries SDS and the ERG suggested "flooding" a fire involving FGAN from a distance, and the Orica SDS suggested fighting such fires from a "protected location." The EDC SDS instructed firefighting personnel to flood with water but did not address the need to extinguish fires from a distance or to evacuate under massive fire situations. In these guidelines, the safe distance or protected location is not clearly defined. Hence, a firefighter must make a judgment to determine which location or area is protected, which distance is safe enough to fight a fire involving FGAN, how much water is needed for flooding, and which fire is massive or major**.** Unfortunately, firefighters are often forced to make these decisions without adequate training, information, preparation, and pre-planning. The WFC incident highlighted the need for greater awareness of FGAN hazards. In response to the 2013 explosion, EDC updated its SDS to include more information about the explosive hazards of AN and information for firefighters. The revised EDC SDS now advises firefighters to fight AN fires remotely because of the risk of explosion. If an AN-containing structure is fully engulfed in flames, firefighters are instructed not to fight the fire and to evacuate the surrounding area to at least a one-half-mile radius.[262]

7.4 Lessons Not Learned and Lessons Learned

7.4.1 Pre-West-Incident FGAN-Related Fires and Explosions: Lessons Not Learned

CSB found that lessons learned from previous firefighter fatalities and emergency responses to FGAN-related incidents were not effectively disseminated to firefighters and emergency responders in other communities where FGAN is stored or used. Had those lessons been applied to the very similar situation

[262] *See*: www.eldoradochemical.com/MSDS_Sheets/EDC/EDC_Products/EDCC_AN_Prill_SDS_Information_Bulletin_Nov_2014.pdf (accessed on December 28, 2015).

in West, the firefighters and emergency responders might have better understood the risks associated with FGAN-related fires.

Although the firefighters in West knew of the hazards associated with the tanks of anhydrous ammonia as a result of previous releases, they were not alert to the explosion hazard from the FGAN inside the warehouse. Although FGAN itself does not burn, the conditions under which AN might detonate when exposed to fire are unpredictable and not clearly understood, and current guidance does not offer consistent advice on how to attempt to guarantee firefighter safety. The deaths of the volunteer firefighters and emergency responders in West was not the first time that firefighters have been killed when responding to FGAN-related explosion incidents.

On April 16, 1947, a ship containing 7,000 tons of wax-coated FGAN[263] exploded in the port of Texas City, Texas, killing 581 people, including all 26 Texas City firefighters who responded to the incident.[264]

The November 29, 1988, Kansas City, Missouri, ammonium nitrate/fuel oil (ANFO) incident, although not directly related to an FGAN fire, is worth mentioning because of its severity, the important lessons learned from the incident, and its implication for emergency response. Six firefighters from the Kansas City, Missouri, fire department were killed in an explosion while they were extinguishing a fire at a construction site.[265] About 40 minutes later, a second explosion occurred, followed by several minor explosions. Investigators later learned that after the first explosion, the battalion chief immediately pulled back and prevented other firefighters from entering the area. A command post was set up at a safe distance, which ultimately prevented more firefighter casualties. The initial fire involved a trailer/magazine containing blasting mixtures of FGAN, fuel oil, and aluminum pellets. One end of the trailer contained approximately 3,500 pounds of ANFO mixture while the remainder of the load was approximately 17,000 pounds of ANFO mixed with 5 percent aluminum pellets. In addition, a second explosion rocked another trailer/magazine loaded with approximately 1,000 30-pound sacks of ANFO mixture with 5 percent aluminum pellets.[266]

Both explosions in Kansas City created large craters where the two trailers had been parked, similar to the impact of the explosion in West. The first trailer explosion produced a swimming-pool-like crater that

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[263] Although the Texas City incident involved a form of wax-coated FGAN that is no longer manufactured for fertilizer purposes and a form of strong confinement (the locked hull of a ship), the lessons of confinement were developed and incorporated into industry guidance after the Texas City incident.

[264] *See*: https://www.txdps.state.tx.us/dem/temo/archives/2013/Vol60No4/Articles/article2.htm (accessed on December 28, 2015).

[265] The Texas City incident is discussed in this section to indicate that firefighters have lost their lives in the past because of a lack of pre-incident planning, inadequate training and information, and erroneous knowledge of the hazards with which they were dealing. The same observation applied to Kansas City, even though it was an ANFO incident; firefighters were not equipped with the right information and had inadequate knowledge of the hazards of the explosive material (ANFO) that they dealt with that evening, and they lost their lives as a result.

[266] USFA. "Six Firefighter Fatalities in Construction Site Explosion; Kansas City, Missouri." Technical Report Series," USFA-TR-024, November 1988. *See*: http://www.usfa.fema.gov/downloads/pdf/publications/tr024.pdf (accessed on January 20, 2016).

was 80 feet in diameter with a depth of 8 feet, connected to a smaller crater that was 20 feet in diameter and 6 feet deep. The second trailer explosion gouged a crater approximately 100 feet in diameter and 8 feet deep, similar in dimensions to the crater resulting from the explosion in West, Texas. The Kansas City incident investigation determined that the firefighters were not told specifically about the contents of the trailer/magazine, although the dispatcher did caution them about explosives on the site. The firefighters did not report any indication of the presence of warning placards on the trailers because there was no requirement by firefighters to report the presence or absence of warning placards over the radio upon their arrival at a scene of a fire. Also, it was not clear whether the firefighters realized that the trailers housed an explosive magazine.[267]

No record of communication among the dispatch official, fire chief, and firefighters indicated that the firefighters knew the contents of the magazine, and the firefighters did not seem alarmed when they arrived at the site. In addition, the fire department was not aware of the presence of the trailers/magazines or their contents before the incident because of a lack of jurisdictional authority. The Kansas City Fire Prevention and Protection Code did not require the city engineer to notify the fire department that blasting permits had been issued, although this provision was changed immediately after the incident. The Kansas City Fire Department had no authority or responsibility to inspect the construction site because it was a state enclave.[268]

Shortly after the Kansas City explosions, the USFA produced a technical report (USFA-TR-024/November 1988)[269] with findings of its investigation and lessons learned. Although the fertilizer-related incidents in Texas City and West did not involve explosives per se, the Kansas City incident further illustrated that the lack of knowledge about the stored HAZMAT and the lack of pre-incident planning by firefighters before their response led to the fatalities. Most of the recommendations based on lessons learned emphasized the need to be properly prepared through pre-incident planning and through the provision of clear information to firefighters and emergency responders dealing with fires involving HAZMAT.

CSB observed that within the last 6 years, three notable FGAN-related incidents in Texas involved emergency responders. Subsequently, CSB reviewed the emergency response activities associated with the FGAN-related fires that occurred in 2009 at the EDC facility in Bryan, Texas, and in 2014 at the East Texas Ag Supply facility in Athens, Texas.

On Thursday, July 30, 2009, at about 11:40 am CDT, a fire broke out at the EDC facility in Bryan. The EDC facility stores FGAN and blends it with other materials to create fertilizer. The fire at the EDC fertilizer plant led to the evacuation of more than 80,000 residents in the Bryan and College Station area.

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[267] An explosive magazine is an enclosed storage structure for holding explosives.
[268] A state enclave is any portion of a state that is completely surrounded by the territory of another state.
[269] USFA. "Six Firefighter Fatalities in Construction Site Explosion; Kansas City, Missouri." Technical Report Series," USFA-TR-024, November 1988. *See*: http://www.usfa.fema.gov/downloads/pdf/publications/tr024.pdf (accessed on January 20, 2016).

Although the storage structure burned to the ground, unlike the incident at the WFC facility, no explosion, loss of life, or major injuries were recorded.

At Bryan, the firefighters were informed that a welder had accidentally heated an FGAN bin and that the chemical was smoldering. The firefighters decided not to fight the fire, evacuated the area, and let the facility burn to the ground, without any explosion. Their knowledge of FGAN and the risks associated with a probable explosion most likely led the Bryan firefighters to decide to evacuate. Figure 65 shows the post-incident aerial view of the EDC facility wooden fertilizer warehouse.

Figure 65. Post-Incident Aerial View of EDC Facility Wooden Fertilizer Warehouse (Source: Bryan-College Station Eagle)

After the incident, the Bryan Fire Department—in conjunction with the emergency management divisions for Brazos County, the city of Bryan, the city of College Station, and Texas A&M University—performed an emergency review and analysis and released an after-action report and improvement plan. These documents were shared with fire departments and emergency response agencies that were involved in the incident response and investigation, including local and regional emergency response agencies—mostly in the Brazos Valley area, where Brazos County, the cities of Bryan and College State, and Texas A&M University are located—and other state agencies that responded to the incident.[270]

The 2009 EDC fire after-action report for Brazos Valley highlighted the need for emergency response departments to reflect on protection, response, and recovery activities that occurred during the EDC incident, despite the fact that the community-wide response to the incident resulted in no loss of life or serious injuries. In addition, the after-action report identified potential strengths to be maintained and built on, noted potential areas for further improvement, and suggested recommendations for corrective and preventive actions based on the incident. The after-action report indicated:

> The Texas Division of Emergency Management provides the National Emergency Response and Rescue Training Center (NERRTC) funding to develop regional plans that will enable local emergency management to rapidly respond to disasters using the region's resources before requesting assistance from State and Federal partners. Within that scope, NERRTC also develops after-action reports on behalf of local, regional and state governments that have been affected by major disasters. As in the case of the EDC fire, lessons learned help recognize needs for plans, policies and procedures revisions to enhance the effectiveness of response (personnel, teams and/or equipment).[271]

Unfortunately, CSB did not find any record that the WVFD requested or received a copy of the Brazos Valley after-action report and improvement plan. In addition, no record suggested that lessons learned from the EDC incident were discussed or shared with firefighters at West.[272] Although circumstances in West might have differed from those in Bryan, if lessons learned had been effectively relayed among the firefighters at West, the volunteer firefighters who responded to the WFC incident possibly could have drawn on the experience of Bryan firefighters to inform response strategies, both in the pre-planning stages and in the response to the incident on the night of April 17, 2013.

7.4.2 Post-West Incident FGAN-Related Fire: Lessons Learned

On May 29, 2014, at around 5:45 pm, a fire involving FGAN occurred at the East Texas Ag Supply facility in downtown Athens, Texas. Emergency dispatchers and the Athens Police Department promptly notified firefighters from the Athens Fire Department (AFD).[273] Emergency response units from the AFD arrived on the scene of the fire at 5:50 pm and found fire and smoke coming from the northwest end of the 3,500-square-foot East Texas Ag Supply facility. This facility was built with masonry bricks and combustible wooden structures, similar to construction at the WFC facility.[274] The AFD chief arrived

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[270] EDC. "2009 El Dorado Chemical Fire After-Action Report for Brazos Valley," August 11, 2009.
[271] *Ibid*.
[272] CSB found that several surviving West firefighters interviewed after the WFC incident did not have adequate information about the EDC incident at Bryan (approximately 100 miles south of West, Texas).
[273] The AFD was organized as a volunteer department in 1911. Currently, the AFD is a fully paid fire department with two stations and 27 firefighters. *See*: http://athenstexas.us/fire.cfm (accessed on December 28, 2015).
[274] Shortly after the April 17, 2013, incident at the WFC facility in West, Texas, an investigative reporter from the Dallas news station (WFAA) entered the Athens facility with a camera crew and revealed that East Texas Ag Supply

about 2 minutes after the first responding units were dispatched to the site of the incident, and he found that the fire had self-ventilated at the northwest end. On the basis of his observation of the enormous scope of the fire and the possibility of detonation of FGAN in the engulfed building, the fire chief promptly decided to let the East Texas Ag Supply facility burn to the ground instead of attempting to fight the fire.[275] He ordered his firefighters to retreat from the scene and began an extensive evacuation of the downtown Athens, Texas, area. The Athens Police Department coordinated the evacuation of the nearby residential areas, setting up an initial three-block evacuation perimeter, which was later expanded to five blocks.[276] Fortunately, no injuries were associated with this incident. On June 2, 2014, the State Fire Marshal's Office (SFMO) completed its investigation of the East Texas Ag Supply facility incident and released its findings, ruling and classifying the source of the fire as undetermined.[277]

The East Texas Ag Supply facility was a privately owned business with annual revenues estimated between $10 million to $20 million and a work force of approximately nine employees. The East Texas Ag Supply facility was an FGAN and potash fertilizer storage facility, and it was registered under Standard Industrial Classification Code 5191 (Farm Supplies) and North American Industry Classification System (NAICS) Code 424910 (Farm Supplies Merchant Wholesalers).[278] On the day of this incident, the East Texas Ag Supply facility received approximately 70 tons of FGAN (total) and 100,000 pounds of potash, which were stored inside the building when the fire occurred.

CSB gathered information concerning the East Texas Ag Supply incident from the emergency responders and the facility and also conducted an interview with the AFD fire chief. According to the incident statement provided to CSB, the Athens, Texas, fire chief stated:

> We allowed the fire to mitigate itself, with research showing that some such facilities had burned out with no explosions. We had learned a lot from West and had already removed other products that could cause contamination and had made the owner remove his diesel tractor from within the building and to keep it off site when not in use. We feel this was a major deterrent from having a detonation.[279]

Figure 66 and Figure 67 show photographs of the East Texas Ag Supply facility during the fire incident.

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was receiving and storing the same substance thought to have been involved in the explosion in West. *See*: http://www.wfaa.com/story/news/local/investigates/2014/08/18/14029198/ (accessed on December 28, 2015).

[275] According to the Athens, Texas, fire chief, the initial plan of action was to engage the fire at the incipient stage, but by the time he arrived on scene, the chief knew that the fire was well past the incipient stage and that the quantity of water needed to squelch the fire at that stage was beyond the capabilities of the equipment on hand. He gave the order for his men to cease firefighting based on his early observations and to begin evacuation activities.

[276] The City of Athens police chief was in charge of the evacuation and the control of traffic. The police chief set the initial evacuation perimeter at three blocks from the facility based on the immediate resources available to the police chief at that time; the perimeter subsequently was expanded to five blocks. Police and fire personnel conducted the evacuation notification by using their public address systems and going door to door.

[277] *See*: http://www.tdi.texas.gov/news/2014/news201443.html (accessed on December 28, 2015).

[278] After the WFC incident in West, the city of Athens, Texas, received a lot of attention because of the presence of a fertilizer storage facility downtown that was similar to and older than the WFC facility. Wooden bins were used for storage of AN at the East Texas Ag Supply facility.

[279] The fire incident statement was provided to CSB via email on October 3, 2014, by the Athens, Texas, fire chief.

Figure 66. Dark Grey Smoke[280] Originating from East Texas Ag Supply Facility in Downtown Athens, Texas (Source: Athens Fire Department)

[280] However, this smoke was not as black as the smoke from the WFC fire (see Section 4 of this report).

Figure 67. Dark Smoke Combined with Flames at East Texas Ag Supply Facility in Athens, Texas[281] (Source: Athens Fire Department)

In an interview, the fire chief reported that the AFD conducted extensive pre-planning, visited the East Texas Ag Supply fertilizer storage facility on multiple occasions, and instructed the owner of the facility to repair anything that seemed to be hazardous or noncompliant with the International Fire Code, which the city of Athens adopted in 2009. SFMO officials had also visited the facility previously on at least two occasions and compelled the owner of the East Texas Ag Supply facility to fix old broken machinery that was onsite.[282] In addition to these visits from SFMO, AFD officials often toured the facility to randomly inspect loading and unloading operations and to take note of other fire safety issues, including the location and spacing of exits within the facility. Pre-incident assessment of the facility indicated that the fertilizer storage bins were old and constructed of double layer plywood, each about 10 feet from the ceiling of the 35- to 40-foot-tall building, with three of the bins used to store FGAN. Similar to the WFC facility in West, the East Texas Ag Supply facility had no sprinkler systems, and the building was

[281] At the East Texas Ag Supply facility incident in Athens, Texas, the flame appeared to be the normal yellow color of many wood and other combustibles burning in normal air. Unlike the WFC incident, there was no detonation of FGAN; hence, no evidence of brighter (higher-temperature) white flame was observed before the detonation at West (see Section 4 of this report).

[282] In addition to the actions taken by the city of Athens before the East Texas Ag Supply fire on May 29, 2014, the SFMO—as part of its endeavors to share the lessons learned from the West, Texas, AN explosion—went to all 66 counties with businesses that had 10,000 pounds or more of AN. The statewide tour started on December 12, 2013, and was completed on December 17, 2014. Local first responders, LEPC members, local officials, business staff, and citizens were invited to the public meetings organized by the SFMO. On April 3, 2014, the SFMO visited Athens, Texas (Henderson County) to enlighten the public on the hazards of FGAN. *See*: http://www.tdi.texas.gov/fire/fman.html (accessed on December 28, 2015).

constructed with masonry brick walls on three sides, covered with an asphalt shingle roof. Figure 68 shows the East Texas Ag Supply facility, including its masonry brick walls completely burned to the ground.

Figure 68. East Texas Ag Supply Facility's Masonry Brick Walls, Engulfed by Fire and Smoke (Source: Athens Fire Department)

The Athens community has two community alert systems, CodeRED and FIRST Alert. The CodeRED community alert system was developed to notify residents of any emergency. The FIRST Alert system is directed from the Henderson County 911 dispatch center.[283] The protocol for use of the CodeRED system indicates that during any emergency situation or a fire incident, the fire chief or a designee (usually the police chief) would give the order for the CodeRED notification. Once a CodeRED order is given, the designee or authorized emergency staff member is expected to make a recorded speech, which is then broadcast over the Internet and to all landline telephones in the city. The process also notifies mobile phone subscribers. The CodeRED system was not deployed during the East Texas Ag Supply incident to notify Athens residents.[284] However, the CodeRED alert system was used the following day (May 30, 2014) to notify the community about the post-incident status of the East Texas Ag Supply facility and the conditions surrounding that facility.

The Athens, Texas, fire chief compared the city's situation to that in West and stated that the AFD conducted additional research and identified how best to respond to any emergency situation that could

[283] Athens, Texas, is located in Henderson County, about 70 miles southeast of Dallas, Texas.

[284] On the day of the incident, there was no clear communication on the designation of the appropriate party to make the outgoing emergency notification message. The fire chief maintained that because he was occupied with command firefighting operations, the task of making the announcement should have been transferred to the Athens Police Department (police chief); unfortunately, this was not the case. Moving forward with the post-incident critique, the fire chief indicated that standardizing the designation of who makes the announcement would be better defined for future community notifications.

arise because of the East Texas Ag Supply facility. In West, the WFC plant was primarily a fertilizer facility, with anhydrous ammonia tanks, carts, loaders, insecticides, and other potential contaminants for FGAN. On the basis of the aftermath of the WFC explosion in West, Henderson County reviewed its existing local emergency planning committee (LEPC) process. About a year before the Athens fire incident, the natural disaster planning LEPC was expanded, with the fire chief as its chair, to address emergencies arising from human activities or industrial facilities.

Although the cause of the Athens fire incident has not been determined, the city of Athens initiated reforms aimed at protecting the city from another incident in the future. On May 29, 2015, a year after the fire at the East Texas Ag Supply facility, the city passed an ordinance that banned the bulk storage of FGAN in Athens. The ordinance included a mandatory reporting process for facilities with limited quantities of hazardous chemicals such as FGAN so that they would report the quantities of the hazardous chemicals in their facilities, thereby enabling VFDs to conduct inspections at such facilities.[285] CSB investigators conducted a teleconference with the city of Athens fire chief on June 24, 2015. The fire chief stated that the East Texas Ag Supply facility had been torn down and will not be rebuilt within the Athens city limits. In addition, Athens is now considering efforts aimed at monitoring other hazardous chemicals (similar to FGAN) that are currently stored by facilities within the city limits.[286]

7.5 Other Post-Incident Investigation Reports Related to Firefighting

After the fire and explosion at the WFC facility, several other agencies conducted investigations of the incident. EPA and OSHA conducted their investigations for violations of environmental and workplace safety and health laws, while the Texas SFMO and NIOSH conducted their investigations on the firefighters and the emergency response at the WFC facility. The ATF investigation of the WFC incident is ongoing.

7.5.1 Texas State Fire Marshal's Office (SFMO)

The SFMO [287] served as the lead Texas investigatory agency for the WFC incident, working in collaboration with ATF.[288] On May 15, 2014, the SFMO released its line-of-duty deaths investigation of the West, Texas, incident, "Firefighter Fatality Investigation" (Investigation FFF FY 13-06).[289]

The SFMO report described the incident and issued recommendations focused on the emergency response to the WFC incident, including the conditions that led to the fire and explosion. The report indicated that the firefighters at West were not prepared for what they faced on the night of April 17, 2013. Also, the

[285] Section 8.7.3 of this report discusses the Athens City ordinance in detail.
[286] Section 8.7 of this report addresses state and local regulatory developments (post-West, Texas, and Athens, Texas, incidents).
[287] *See*: http://www.tdi.texas.gov/fire/documents/fmohistory.pdf (accessed on December 28, 2015).
[288] Section 1.2.1 of this report addresses the ATF investigation.
[289] *See*: http://www.tdi.texas.gov/reports/fire/documents/fmloddwest.pdf (accessed on December 28, 2015).

SFMO highlighted that the emergency responders were victims of a "systemic deficiency in the training and preparation" of the WVFD, attempting to put out a fire that was beyond its incipient stage[290] and could no longer be extinguished. The report also included findings related to training and operational best practices for firefighters. On page 47, the SFMO report identified training deficiency as a key finding:

> The State of Texas has not adopted minimum training standards for volunteer fire departments; however, all fire department members must be properly trained and qualified to perform their assigned duties. Members who are authorized to work in high-level assignments (rank) must be trained and evaluated in performing those duties. All members must be periodically re-evaluated to ensure that they are capable of performing their assigned duties safely and effectively.[291]

The SFMO firefighter fatality report on the WFC incident further proposed several recommendations based on training of firefighters, including establishment of "realistic training and educational requirements for all positions and ranks and a promotional process that ensures that ranking members demonstrate a progressive knowledge, skill, and ability to perform their assigned duties and responsibilities according to their position in the organization." The SFMO report concludes by recommending that "fire departments should develop standard operating guidelines and appropriate training involving those critical findings specific to incident command, strategy and tactics, and firefighter safety."[292]

The SFMO report findings and recommendations are similar to those of CSB in this report with regard to the emergency response in West. Section 7.2 of this report describes in detail pre-incident planning, fire scene risk assessment, and development of a clearly defined incident command structure for emergency situations.[293]

7.5.2 NIOSH Findings and Recommendations

In 1998, the U.S. Congress funded NIOSH to establish the Fire Fighter Fatality Investigation and Prevention Program, which investigates on-the-job fatalities of firefighters and provides improvement recommendations to the profession.[294] On November 12, 2014, NIOSH released its report on the emergency responder fatalities caused by the WFC explosion.[295] The report, "9 Volunteer Fire Fighters and 1 Off-Duty Career Fire Captain Killed by an FGAN Explosion at a Fertilizer Plant Fire–Texas," identified contributing factors to the firefighter fatalities, specifically failure to recognize hazards associated with FGAN, limited pre-incident planning of the commercial facility, quick spread of the fire

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[290] The term "incipient" has been widely used in the firefighting community and in various fire codes, including NFPA codes. However, CSB believes that it could be easily misinterpreted and imposes on firefighters a responsibility to make a subjective determination regarding the seriousness of a fire.

[291] *See*: http://www.tdi.texas.gov/reports/fire/documents/fmloddwest.pdf (accessed on December 28, 2015).

[292] *Ibid*.

[293] Section 7.1 of this report considers the firefighter response and Section 7.2 discussed details of factors contributing to the firefighter and other emergency responder fatalities in West, Texas.

[294] *See*: www.cdc.gov/niosh/fire (accessed on December 28, 2015).

[295] *See*: http://www.cdc.gov/niosh/fire/pdfs/face201311.pdf (accessed on December 28, 2015).

to uncontrollable size, unexpected detonation of approximately 40 to 60 tons of solid FGAN, emergency responders working within the blast radius at the time of the explosion, and large non-sprinklered wood construction in the commercial structure.[296]

In addition, NIOSH issued recommendations to prevent a similar incident from recurring. Recommendations included pre-incident planning inspections of facilities within the jurisdiction of a fire department; development of a written risk management plan; fire department use of risk management principles at all structure fires, especially for incidents involving high-risk hazards; development, implementation, and enforcement of a written incident management system to be applied during all emergency incident operations; standards for firefighters to wear a full array of turnout clothing and personal protective equipment (PPE) appropriate for the assigned tasks; and firefighter training that meets or exceeds NFPA 1001 (*Standard for Fire Fighter Professional Qualifications*).

CSB concluded that most of the key contributing factors and recommendations cited by NIOSH in its WFC incident investigation report are similar to those of CSB.[297]

7.6 Summary of Incident Emergency Response

CSB found no evidence of pre-incident planning addressing the likelihood of a fire involving FGAN at the WFC facility. As a result, the firefighters who responded to the WFC fire did not take the time to critically assess the situation on the ground before the explosion occurred. Senior emergency response personnel from the WVFD arrived at the scene of the incident at different times, and firefighters who were ICS trained and certified in the NIMS process did not assume the role of IC to establish, implement, and coordinate an incident command structure and incident management system for the fire emergency. The firefighters did not fully understand the hazards of FGAN detonation and consequently shifted their firefighting tactics to strategies to ensure that the anhydrous ammonia tanks onsite did not rupture. Also, the emergency response personnel at West did not take the time to implement an incident management system plan, which would have facilitated the prompt and proper evacuation of the nearby residents.

The volunteers who responded to the WFC facility fire did not have sufficient HAZMAT training to make an informed decision on how best to respond to the fire at the fertilizer facility. Furthermore, lessons learned from previous firefighter fatalities and emergency responses to FGAN-related incidents were not effectively disseminated to firefighters and emergency responders in other communities, such as West, where FGAN is stored or used.

A review of firefighter training courses, information in emergency response guides, manufacturers' manuals, and other information available to emergency responders concerning AN-related fires at incident sites confirms that such materials place little emphasis on how to effectively respond to fire

[296] NIOSH. "9 Volunteer Fire Fighters and 1 Off-Duty Career Fire Captain Killed by an Ammonium Nitrate Explosion at a Fertilizer Plant Fire–Texas." *NIOSH Report on Death in the Line of Duty.* Report Number F2013-11. *See*: http://www.cdc.gov/niosh/fire/pdfs/face201311.pdf (accessed on December 28, 2015).

[297] *Ibid.*

incidents involving the handling and storage of FGAN and might altogether be insufficient to enable firefighters to recognize the potential magnitude of an FGAN explosion. The commonly used emergency response guides and manuals contain inconsistent information regarding the best response to FGAN-related fires. In a fire situation, an FGAN explosion could occur at any time, and without knowing how long an AN-related fire has been burning, firefighters might not be aware of how much time they have to make informed emergency response decisions before an explosion occurs. That is why in the DECIDE model widely used by HAZMAT responders, after it is determined that HAZMAT is present, the next step is to estimate likely harm, without intervention.[298] Above all, the conditions under which FGAN might detonate when exposed to a fire are unpredictable and not clearly understood, and current guidance does not offer best practices to protect firefighters from FGAN fire and detonation hazards.

7.7 Firefighter Training Grants and Programs

7.7.1 Need for Training

CSB found that currently no federal requirements compel municipal fire departments to develop site-specific pre-incident plans with businesses and chemical plants that process and store HAZMAT such as FGAN. To implement any reform in nationwide inspection of businesses and facilities storing hazardous chemicals, determining the number of fire departments and firefighters in the United States (especially in rural communities such as West, Texas) is important. In addition, it is important to understand how prepared fire departments and firefighters should respond to fires involving FGAN. Part of being prepared is being properly trained on the hazards surrounding a community.

7.7.1.1 U.S. Firefighter Statistics

CSB conducted a review of firefighter statistics across the country at the time of the WFC fire and explosion. The review indicated that the majority of the nation's firefighters are volunteers and that 85 percent of fire departments are composed of volunteer firefighters. In addition, the NFPA estimated the number of firefighters in the United States in 2013 at more than a million, including 345,600 career firefighters (31 percent of the total) and 786,150 volunteer firefighters (69 percent of the total).[299] Approximately 95 percent of all volunteer firefighters serve in local fire departments that protect fewer than 25,000 people.[300] More than half of these volunteer firefighters support small rural departments that protect fewer than 2,500 residents, such as the WVFD in West, Texas.[301] At the end of 2012, an estimated 30,100 fire departments operated in the United States. Of these, 2,610 (9 percent of all departments) were composed of only career firefighters; 1,995 (7 percent) relied on mostly career

[298] Ludwig Benner. "D.E.C.I.D.E in Hazardous Materials Emergencies." *See*: http://www.henrycoema.org/EMA/HazMat_Training_Materials_files/DECIDE.pdf (accessed on January 8, 2016).
[299] *See*: http://www.nfpa.org/research/reports-and-statistics/the-fire-service (accessed on December 28, 2015).
[300] *Ibid*.
[301] *Ibid*.

firefighters; 5,445 (18 percent) were supported by a mostly volunteer firefighting force; and 20,050 (67 percent) depended entirely on volunteer firefighters.[302] Despite the fact that the majority of the nation's firefighters are volunteers and that 85 percent of fire departments are composed of volunteers, no federal requirements mandate that VFDs work with businesses and chemical plants that process and store HAZMAT (such as FGAN) to develop site-specific pre-incident plans.

7.7.1.2 U.S. On-Duty Firefighter Fatalities

Over the last few decades, the fire service industry has made notable advancements, including building code improvements, incorporation of sprinkler systems in commercial and industrial buildings, and development of improved personal protective gear and technologically advanced apparatus. In addition, several laws and programs have been implemented to improve firefighter health and safety in the United States.[303,304,305] Despite these laws and improvements, many firefighters are injured or killed while on duty each year. The USFA has recorded the number of firefighter fatalities and conducted an annual analysis since 1977, noting almost 4,500 on-duty firefighter fatalities in the United States in the last 35 years.[306] By the end of 2013, 101 firefighter fatalities were reported for the year nationally, including those in West, Texas; four Houston Fire Department firefighters who died while responding to a hotel fire on May 31, 2013; and 19 firefighters from the Prescott Fire Department who lost their lives while responding to a wildland fire in Arizona on June 30, 2013. The NFPA also publishes its own annual study detailing on-duty firefighter fatalities in the United States.[307] The annual number of fatalities for volunteer firefighters is substantially higher than the annual number of fatalities for career firefighters (Figure 69).

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302 NFPA, Fire Analysis and Research Division. "US Fire Department Profile 2012." *See*: http://www.kolb.net/FireReports/2013/US_DeptProfile2012.pdf (accessed on December 28, 2015).

303 Fabio, A. et al. "Incident-level risk factors for firefighter injuries at structural fires." *Journal of Occupational and Environmental Medicine*, 44(11) (2002): 1059–63.

304 NFPA. *NFPA 1500: Standard on Fire Department Occupational Safety and Health Program*. Quincy, MA: NFPA, 2013.

305 Moore-Merrell, L. et al. *Contributing Factors to Firefighter Line-of-Duty Injury In Metropolitan Fire Departments in the United States*. Emmitsburg, MD: USFA, 2008.

306 *USFA*. *See*: http://www.usfa.fema.gov (accessed on December 28, 2015).

307 NFPA. "U.S. Fire Service." *See*: http://www.nfpa.org/research/fire-statistics/the-us-fire-service (accessed on December 28, 2015).

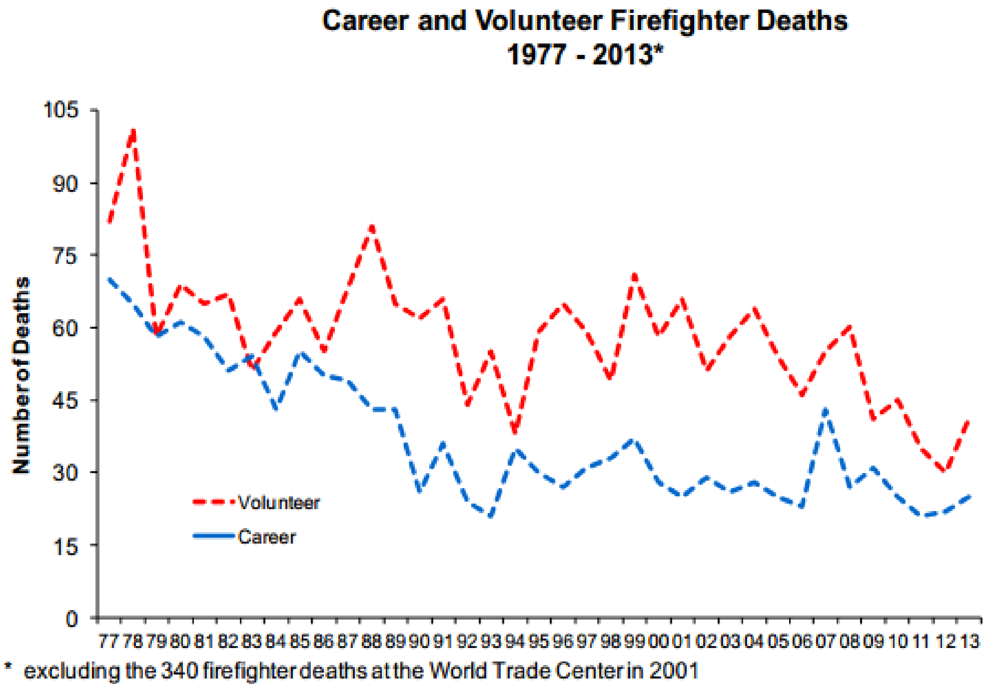

Figure 69. Comparison of Volunteer and Career Firefighter Deaths (1977–2013) (Source: NFPA)[308]

This discrepancy could be due to a number of factors, such as the larger population of volunteer firefighters (more than 67 percent of all firefighters nationwide) or the lack of standardized training requirements for volunteers. Of the 82 firefighter fatalities in 2012, 39 were volunteer firefighters (47.6 percent of the total), and 32 were career firefighters (39 percent of the total); in addition, four part-time wildland firefighters, three contract wildland firefighters, two paid on-call firefighters, one part-time (paid) firefighter, and one industrial firefighter lost their lives (1.2 percent of the total). CSB believes that adequate training is essential to reduce on-the-job firefighter fatalities, especially among volunteer firefighters who are not required to complete the same level of training as career firefighters.

7.8.1.3 U.S. Volunteer Firefighter Statistics

A VFD is a fire department composed of volunteers, usually residents or nearby citizens, who perform fire suppression and other related emergency services for a local jurisdiction or community. The U.S. Department of Labor (DOL) classifies volunteer firefighters as firefighters who receive either no compensation or nominal fees (up to 20 percent of the compensation that a full-time firefighter would receive in the same capacity).[309] DOL allows volunteer firefighters to receive benefits such as worker's compensation, health insurance, life insurance, disability insurance, pension plans, length-of-service

[308] *See*: http://nysfma.org/diyFiles/FirefighterFatalitiesinttheUS2013.pdf (accessed on December 28, 2015).
[309] Dodge, G., and M. Mullarkey. *Managing Volunteer Firefighters for FLSA Compliance: A Guide for Fire Chiefs and Community Leaders*. Fairfax, VA: International Association of Fire Chiefs, 2006.

awards, and property tax relief. DOL also states that volunteer firefighters may be paid nominal fees on a per-call or per-shift basis or on the basis of various service requirements, but they may not be compensated based on productivity (such as receiving an hourly wage).

Career firefighters are fully compensated for their services. Some volunteer firefighters might serve in a hybrid fire department that relies on both full-time and volunteer firefighters. In this approach, career firefighters can regularly staff a station for rapid response with needed apparatuses, and the volunteers can provide supplementary staffing and staff apparatuses before, during, and after an incident or while full-time career personnel are out of service for training. Moreover, volunteer firefighters can sometimes compose a group of part-time or on-call firefighters who have other occupations when not engaged in occasional firefighting.

The West volunteer firefighters held other (full-time) jobs and were not financially compensated for their time. Some VFDs compensate their firefighters as employees during the time that they are responding to or attending to an emergency scene and possibly during training. An on-call firefighter can also volunteer time for other nonemergency duties, such as training, fundraising, and equipment maintenance. In addition to fundraising, fire departments and emergency response services often seek alternative sources to support and fund their daily operations and long-term plans. Federal and state funding is available through grants from DHS and FEMA to assist emergency responders and fire departments in addressing EMS and firefighter-related needs such as training and equipment procurement and maintenance. National programs that support the need for emergency preparedness, including firefighter training, are discussed in the next section of this report.

7.7.2 National Firefighter Training Funds and Programs

7.7.2.1 U.S. Department of Homeland Security (DHS)

DHS was formed after the terrorist attacks of September 11, 2001, as part of a national effort to safeguard the United States against terrorism. The mission of DHS includes preventing terrorism and enhancing security, managing U.S. borders, administering immigration laws, securing cyberspace, and ensuring disaster resilience. DHS also provides the coordinated comprehensive federal response in the event of a terrorist attack, natural disaster, or other large-scale emergency while working with federal, state, local, and private sector partners to ensure a swift and effective recovery effort. DHS builds a ready and resilient nation through efforts to accomplish the following:

- Bolstering information sharing and collaboration.
- Providing grants, plans, and training to homeland security and law enforcement partners.
- Facilitating rebuilding and recovery.[310]

Although the scope of DHS is expansive, it contains many components, including FEMA, where much of the federal funding flows to various FEMA programs that assist in elements of national resiliency, such as

[310] *See*: http://www.dhs.gov/building-resilient-nation (accessed on December 28, 2015).

rebuilding and recovering after a disaster (such as the West, Texas, incident) or encouraging emergency response preparedness training.

Federal Emergency Management Agency (FEMA)

FEMA was created in 1979 in an effort to coordinate the federal government's role in preparing for, preventing, mitigating the effects of, responding to, and recovering from all domestic disasters, whether natural or man-made, including acts of terror.[311] On March 1, 2003, FEMA became part of DHS, and FEMA's Office of National Preparedness was given responsibility for helping to ensure that the nation's first responders were trained and equipped to deal with WMD along with other types of disasters. FEMA supports preparedness by developing policies; ensuring that adequate plans are in place and are validated; defining the necessary capabilities required to address threats; providing resources and technical assistance to state, local, tribal, and territorial partners; and integrating and synchronizing preparedness efforts throughout the nation.

DHS and FEMA achieve their mission of ensuring disaster resiliency partly by providing funding and support to various federal programs that are tasked with preparing the nation to respond to various hazards, such as community exposure to chemicals and hazardous materials. Fire departments use the programs to assist in developing a well-organized, equipped, and trained function for the communities they serve. CSB reviewed the nationwide funding mechanisms available to career and VFDs through DHS and FEMA. Volunteer firefighters similar to those who responded at West have access to these firefighting resource funds if they can demonstrate that they have a need for it. CSB examined whether federal and state funds could be allocated to fire departments to assist them in obtaining the training that firefighters need to address fires and explosions involving HAZMAT such as FGAN.

Grants

It is important to understand the process for allocating grants to emergency responders such as fire departments. First, this section discusses the application process for a DHS FEMA grant. Second, the FEMA Grant Programs Directorate (GPD), the program that administers these grants once they receive proposals from applicants for funding is discussed. Third, the DHS FEMA preparedness (non-disaster) grants are described. Fourth, the Assistance to Firefighter Grants (AFG) Program is discussed in detail and in relation to funding in Texas. Specifically, the AFG, Staffing for Adequate Fire and Emergency Response (SAFER) grants, and the Fire Prevention and Safety (FP&S) grants are examined.

DHS FEMA Grants Application Process

Often federal grant funding flows to the local level through the states. However, some states provide direct funding for emergency medical services (EMS), especially in rural areas. On the other hand, some states have no funding for local programs. Most SFMOs and EMS bureaus offer technical assistance to

[311] *See*: http://www.fema.gov/about-agency (accessed on December 28, 2015).

local agencies and subsidized training programs to first responders.[312] A large portion of the federal grant budget is passed to the states through formula or block[313] grants. The states then decide how to use the grant money. However, some direct federal grant programs are for fire departments and EMS agencies such as the AFG.[314] Direct grants are given specifically to the applying agency, but pass-through grants[315] require the state to apply to the federal government and then distribute grant money to agencies that request it. Project grants are the most common form of federal grant. Depending on the program requirements, EMS organizations gain access to the funds through a competitive bidding process. Application for a project grant does not guarantee an award, and the amount received by grantees is not predetermined by a formula.[316] Although most DHS components possess some programs that support grants,[317] FEMA has the majority of programs and funding.[318]

FEMA Grant Programs Directorate (GPD)

The purpose of FEMA GPD is to strategically and effectively administer and manage FEMA grants to ensure critical and measurable results for customers and stakeholders. The mission is to manage federal assistance to measurably improve capability and reduce the risks that the nation faces in times of man-made and natural disasters. The focus of GPD is to provide customer service to all grantees as well as internal and external partners; establish and promote consistent outreach and communication with state, local, and tribal stakeholders; ensure transparency in the grant process; and enhance the nation's level of preparedness and the public's capability to prevent, protect, mitigate against, respond to, and recover from all hazards. GPD also holds program management responsibility for the suite of preparedness grants that included, and continue to include, the following goals and objectives:

- Review, negotiate, award, and manage the FEMA preparedness grant portfolio.
- Provide subject matter expertise in response to regional office and stakeholder inquiries.
- Develop grant guidance.
- Formulate risk methodology to support grant allocations.
- Analyze investments.
- Manage budget execution and formulation.

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[312] FEMA and USFA. "Funding Alternatives for Emergency Medical and Fire Services." FA-331, April 2012.
[313] A block grant does not involve competition. The federal government distributes funds to the states based on an established formula.
[314] The AFG Program is discussed in further detail in the *Assistance to Firefighters Grant Program* Section of this report.
[315] Funds issued by a federal agency to a state agency or institution that are then transferred to other state agencies, units of local government, or other eligible groups, per the award eligibility terms.
[316] FEMA and USFA. "Funding Alternatives for Emergency Medical and Fire Services." FA-331, April 2012.
[317] DHS supports a wide variety of financial assistance, including post-disaster relief and resilience, preparedness, boating safety, cybersecurity, research, university centers of excellence, and assistance to firefighters.
[318] *See*: http://www.dhs.gov/dhs-financial-assistance (accessed on December 28, 2015).

- Provide the driving force for grant management initiatives through the strategic delivery of policy, training, systems, and data analysis.[319]

The GPD carries out its mission through three divisions, including the GPD Front Office, Grant Operations Division, and Preparedness Grant Division.[320] The FEMA grants that pertain to firefighter training and emergency response are discussed in the *Preparedness (Non-Disaster) Grants* and *Assistance to Firefighters Grant Program* Sections of this report.

Preparedness (Non-Disaster) Grants

FEMA provides state and local governments with preparedness program funding in the form of Non-Disaster Grants to enhance the capacity of state and local emergency responders to prevent, respond to, and recover from a WMD terrorism incident involving chemical, biological, radiological, nuclear, and explosive (CBRNE) devices and cyber attacks.[321] The Emergency Management Performance Grant (EMPG) Program is a preparedness grant that provides more than $350 million to assist local, tribal, territorial, and state governments in enhancing and sustaining all-hazards emergency management capabilities.[322] Either the State Administrative Agency (SAA) or the state's Emergency Management Agency (EMA) is eligible to apply directly to FEMA for EMPG Program funds on behalf of state and local EMAs.[323] The fiscal year (FY 2015) EMPG Program will focus on planning, operations, equipment acquisitions, training, exercises, construction, and renovation to enhance and sustain the all-hazards core capabilities of state, local, tribal, and territorial governments.[324] The period of performance for the EMPG Program is 24 months. In FY 2015, the EMPG Program allocated $20,163,325 to the state of Texas.[325]

Assistance to Firefighters Grant Program

Within FEMA, the AFG Program consists of three types of grants[326] that support improvements in training, staffing, and safety within fire departments. These grants include the AFG, FP&S grants, and SAFER grants:

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[319] *See*: https://www.fema.gov/grant-programs-directorate (accessed on October, 23, 2015).
[320] The Preparedness Grant Division includes the Preparedness (Non-Disaster) Grants.
[321] *See*: https://www.fema.gov/preparedness-non-disaster-grants (accessed on October, 22, 2015).
[322] *See*: http://www.dhs.gov/news/2015/07/28/dhs-announces-grant-allocations-fiscal-year-fy-2015-preparedness-grants (accessed on October 22, 2015).
[323] *See*: http://www.fema.gov/media-library-data/1427284579730-8faafd19a62444a974429c3e12d803fa/FY2015EMPG_FAQ.pdf (accessed on December 28, 2015).
[324] *See*: http://www.fema.gov/media-library-data/1438020444107-4db58a4f1c24b3bd0962b8327652df5b/FY_2015_EMPG_Fact_Sheet_Allocations.pdf (accessed on October 22, 2015).
[325] *See*: http://www.fema.gov/media-library-data/1438020444107-4db58a4f1c24b3bd0962b8327652df5b/FY_2015_EMPG_Fact_Sheet_Allocations.pdf (accessed on November 25, 2015)
[326] The AFG Program also includes Assistance to Firefighters Fire Station Construction Grants.

- **AFG**. The primary goal of the AFG Program is to meet the firefighting and emergency response needs of fire departments and nonaffiliated EMS organizations. Since 2001, the AFG Program has helped firefighters and other first responders to obtain critically needed equipment, protective gear, emergency vehicles, training, and other resources needed to protect the public and emergency personnel from fire and related hazards.[327] AFGs are awarded to fire departments, state fire training academies, and EMS organizations.
- **SAFER Grants**. The SAFER Grants were created to provide funding directly to fire departments and volunteer firefighter interest organizations to help them increase the number of trained frontline firefighters available in their communities. The goal of SAFER is to enhance the local fire departments' capabilities to comply with staffing, response, and operational standards established by the NFPA (NFPA 1710, NFPA 1720, or both).[328]
- **FP&S Grants**. The FP&S Grants are part of the AFG Program and support projects that enhance the safety of the public and firefighters from fire and related hazards.[329] The primary goal is to reduce injury and prevent death among high-risk populations. In 2005, Congress reauthorized funding for FP&S Grants and expanded the eligible uses of funds to include firefighter safety research and development.[330]

In FY 2014, the AFG provided more than $300 million in grant money nationwide; of this $300 million, Texas received approximately $6.5 million. The AFG Program issued 2,243 individual grants nationwide, and of those, only 90 grants were to fire departments for the purpose of training firefighters.[331] Moreover, in FY 2014, the AFG Program awarded grant money to 40 firefighting and EMS organizations in Texas to provide aid for much needed resources (Figure 70). Of those 40 Texas organizations, 20 career fire departments, but only 14 VFDs, were awarded funding through the AFG Program. The remaining six organizations include emergency service organizations and one state fire training academy. Notably, an interesting finding is that of the grants awarded in Texas, only one award was specific to training personnel while the majority of the awards were used to fund equipment, PPE, facility modifications, vehicle acquisitions, and wellness and fitness programs.

[327] *See*: http://www.fema.gov/welcome-assistance-firefighters-grant-program (accessed on December 28, 2015).
[328] *See*: http://www.fema.gov/staffing-adequate-fire-emergency-response-grants (accessed on December 28, 2015).
[329] *See*: http://www.fema.gov/welcome-assistance-firefighters-grant-program (accessed on December 28, 2015).
[330] *See*: http://www.fema.gov/fire-prevention-safety-grants (accessed on December 28, 2015).
[331] *See*: http://www.fema.gov/assistance-firefighters-grants-award-year-2014 (accessed on October 21, 2015).

FEMA

Assistance to Firefighters Grant Program (AFG)
FY 2014 Award Recipients
Last Updated: 9/25/2015 - www.fema.gov/firegrants/

Organization	City	State	Program	Award Amount	Activity Breakdown	Award Date
Martindale Volunteer Fire Dept. Co.	Martindale	TX	Operations and Safety	$46,196.00	Personal Protective Equipment ($48,005)	4/24/2015
Northwest Rural Emergency Medical Services Association, Inc.	Tomball	TX	Operations and Safety	$160,572.00	EMS Equipment ($168,600)	4/24/2015
Sulphur Springs Fire Rescue	Sulphur Springs	TX	Operations and Safety	$57,143.00	Modify Facilities ($60,000)	4/24/2015
Devine Volunteer Fire and Rescue Department	Devine	TX	Operations and Safety	$23,982.00	Equipment ($24,056)	5/8/2015
Farmers Branch Fire Department	Farmers Branch	TX	Operations and Safety	$223,773.00	Personal Protective Equipment ($246,150)	5/22/2015
Frankston Volunteer Fire Department	Frankston	TX	Operations and Safety	$80,000.00	Equipment ($45,900) || Personal Protective Equipment ($38,100)	5/22/2015
City of Paris Fire Department	Paris	TX	Operations and Safety	$11,632.00	Equipment ($12,795)	5/29/2015
Commerce Fire Department	Commerce	TX	Operations and Safety	$153,048.00	Personal Protective Equipment ($160,075)	5/29/2015
Texas Engineering Extension Service (TEEX)	College Station	TX	State Fire Training Academy	$265,243.00	Equipment ($265,600)	6/19/2015
Hitchcock Volunteer Fire Department	Hitchcock	TX	Operations and Safety	$160,667.00	Personal Protective Equipment ($167,500)	7/3/2015
Leander Fire Department	Leander	TX	Operations and Safety	$22,719.00	Wellness and Fitness Programs ($6,540)	7/10/2015
San Marcos Fire Department	San Marcos	TX	Regional Request	$707,546.00	Equipment ($778,300)	7/10/2015
Troup Volunteer Fire Dept	Troup	TX	Vehicle Acquisition	$238,096.00	Vehicle Acquisition ($250,000)	7/10/2015
Bonham Fire Department	Bonham	TX	Vehicle Acquisition	$663,713.00	Vehicle Acquisition ($696,898)	7/24/2015
Glenn Heights Fire Department	Glenn Heights	TX	Operations and Safety	$78,858.00	Personal Protective Equipment ($82,800)	7/24/2015
Houston Fire Department	Houston	TX	Operations and Safety	$915,120.00	Training ($1,008,732)	7/24/2015
Itasca Fire Department	Itasca	TX	Vehicle Acquisition	$103,621.00	Vehicle Acquisition ($108,802)	7/24/2015
Burnet County Emergency Services District No. 9	Spicewood	TX	Operations and Safety	$72,000.00	Personal Protective Equipment ($75,600)	7/31/2015
Apple Springs Volunteer Fire Dept	Apple Springs	TX	Operations and Safety	$53,143.00	Personal Protective Equipment ($55,800)	8/14/2015
Mic-County Volunteer Fire Department	Lockhart	TX	Regional Request	$399,637.00	Equipment ($423,600)	8/14/2015
Orange County Emergency Services District #1	Vidor	TX	Operations and Safety	$173,993.00	Personal Protective Equipment ($191,392)	8/14/2015
Anna Fire Department	Anna	TX	Operations and Safety	$28,572.00	Modify Facilities ($30,000)	8/21/2015
Cash Fire Department Assoc. Inc.	Greenville	TX	Operations and Safety	$71,760.00	Equipment ($74,355)	8/21/2015
City of Palestine Fire Department	Palestine	TX	Operations and Safety	$170,667.00	Personal Protective Equipment ($179,200)	8/21/2015
City of Terrell Fire Department	Terrell	TX	Operations and Safety	$246,215.00	Modify Facilities ($65,700) || Personal Protective Equipment ($139,500) || Wellness and Fitness Programs ($53,325)	8/21/2015
eastex freeway volunteer fire department	humble	TX	Operations and Safety	$73,119.00	Equipment ($80,430)	8/21/2015
Elm Mott Volunteer Fire and Rescue	Elm Mott	TX	Operations and Safety	$31,429.00	Equipment ($33,000)	8/21/2015
Kilgore Fire Department	Kilgore	TX	Operations and Safety	$158,364.00	Personal Protective Equipment ($174,200)	8/21/2015
Comanche Volunteer Fire Department	Comanche	TX	Operations and Safety	$116,071.00	Personal Protective Equipment ($121,374)	8/28/2015
Sanger Volunteer Fire Department	Sanger	TX	Operations and Safety	$36,364.00	Equipment ($40,000)	8/28/2015
Tarkington Volunteer Fire Department	Cleveland	TX	Operations and Safety	$62,858.00	Personal Protective Equipment ($66,000)	8/28/2015
Kingsville Fire Department	Kingsville	TX	Vehicle Acquisition	$362,728.00	Vehicle Acquisition ($399,000)	9/4/2015
Muenster Volunteer Fire Department	Muenster	TX	Operations and Safety	$78,572.00	Personal Protective Equipment ($82,500)	9/4/2015
Richland Hills Fire Rescue	Richland Hills	TX	Operations and Safety	$41,214.00	Equipment ($43,274)	9/4/2015
Stafford, City of	Stafford	TX	Operations and Safety	$152,728.00	Personal Protective Equipment ($168,000)	9/4/2015
Quitman Fire & Rescue	Quitman	TX	Operations and Safety	$111,429.00	Personal Protective Equipment ($117,000)	9/11/2015
CITY OF WEBSTER	WEBSTER	TX	Operations and Safety	$23,620.00	Equipment ($24,800)	9/18/2015
Garland Fire Department	Garland	TX	Operations and Safety	$18,730.00	Equipment ($20,400)	9/18/2015
Van Alstyne Fire Department	Van Alstyne	TX	Operations and Safety	$33,387.00	Modify Facilities ($23,500) || Equipment ($10,056)	9/18/2015
Centerville Volunteer Fire Dept., Inc	Centerville	TX	Operations and Safety	$97,381.00	Personal Protective Equipment ($102,250)	9/25/2015
TOTAL				**$6,525,910.00**		

Figure 70. Assistance to Firefighter Grant Program Recipients in Texas (Source: FEMA)

In FY 2014, the awarded SAFER Grants totaled approximately $11.7 million to five fire departments in Texas to increase the number of trained firefighters; of these five departments, only one was a VFD (Figure 71). Similarly, the awarded FP&S Grants totaled approximately $1.5 million to two organizations in Texas, neither of which were fire departments, to support projects that enhance the safety of the public and firefighters from fire and related hazards (Figure 72).

FEMA

Adequate Fire and Emergency Response (SAFER)
FY 2014 Award Recipients
Last Updated: 9/25/2015 - www.fema.gov/firegrants/

Organization	City	State	Program	Award Amount	Award Date
Houston Fire Department	Houston	TX	Hiring	$4,797,650.00	7/10/2015
Fresno Volunteer Fire Department	Fresno	TX	Hiring	$225,792.00	7/17/2015
College Station Fire Department	College Station	TX	Hiring	$758,982.00	8/21/2015
City of Killeen/Fire Department	Killeen	TX	Hiring	$4,443,404.00	9/11/2015
Little Elm Fire Department	Little Elm	TX	Hiring	$1,489,518.00	9/11/2015
TOTAL				$11,715,346.00	

Figure 71. SAFER Grant Award Recipients in Texas (Source: FEMA)

FEMA

Prevention & Safety Grants Awards (FP&S)
FY 2014 Award Recipients
Last Updated: 9/25/2015 - www.fema.gov/firegrants/

Organization	City	State	Program	Award Amount	Award Date
City of Dallas	Dallas	TX	Fire Prevention	$94,412.00	8/28/2015
Scott & White Memorial Hospital	Temple	TX	Fire Prevention	$1,394,953.00	9/11/2015
TOTAL				$1,489,365.00	

Figure 72. FP&S Grant Recipients in Texas (Source: FEMA)

On the basis of the analysis of the FEMA FY 2014 funding allocation to fire departments throughout the nation, it can be concluded that much of the grant monies went toward non training-related support. Given the constraints that many VFDs experience regarding funds to support training, fire departments should express a greater interest in also applying for federal grants for training purposes and not solely for supporting other firefighting-related needs such as equipment. For this reason, FEMA should develop a grant that specifically supports firefighter training needs and cannot be used toward funding other resource needs such as equipment or PPE.

DHS FEMA Programs

A general understanding of the intricate landscape of federal grant programs also enables a better understanding of many of the DHS and FEMA programs specific to training. This section describes the various components and programs that promote preparedness at a national level. First, the FEMA National Preparedness Directorate (NPD) serves as a mechanism for fostering programs and resources. Second, training programs reside within the National Training and Education Division (NTED). Third, the Homeland Security National Training Program (HSNTP) is positioned to create accessible training and specifically addresses national preparedness gaps. Fourth and fifth, the Center for Domestic Preparedness (CDP) and the Rural Domestic Preparedness Consortium (RDPC) are NTED training partners. Sixth, the USFA role as a leader in firefighter training is reviewed. Each is discussed in detail in the rest of this section.

National Preparedness Directorate (NPD)

The NPD is an organizational component of FEMA that provides the doctrine, programs, and resources to prepare the nation to prevent, protect, mitigate, respond to, and recover from disasters while minimizing the loss of lives, infrastructure, and property.[332] A variety of courses in all-hazards emergency planning and response constitutes a key aspect of building a culture of preparedness and involves training at many levels, including:

- State, local, tribal, and territorial elected officials.
- Emergency managers.
- First responders.
- Appropriate whole community members, such as volunteer organizations, Community Emergency Response Teams, Citizen Corps, and bystanders.
- Other emergency responders.

Through the NPD, FEMA has established and delivered effective training and professional education programs and developed a national certification system for overall emergency management competency and expertise. This work is accomplished by the National Emergency Training Center (NETC), CDP, and other training partners.[333]

National Training and Education Division (NTED)

NTED serves the nation's first responder community, offering more than 150 courses to help build critical skills that responders need to function effectively in mass consequence events. NTED primarily serves state, local, and tribal entities in 10 professional disciplines, but has expanded to serve the private sector and citizens as well. Instruction is offered at the awareness, performance, and management and planning levels. Emergency responders attend NTED courses to learn how to apply the basic skills of their profession in the context of preparing, preventing, deterring, responding to, and recovering from acts of terrorism and catastrophic events. Training partners or providers that develop and deliver NTED approved training courses include:

- CDP.
- Counterterrorism Operations Support.
- Louisiana State University.
- New Mexico Institute of Mining and Technology.

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[332] *See*: http://www.fema.gov/national-preparedness-directorate (accessed on December 28, 2015).
[333] *See*: http://www.dhs.gov/topic/plan-and-prepare-disasters (accessed on December 28, 2015).

- Texas Engineering Extension Service.[334]
- Transportation Technology Center, Inc.
- University of Hawaii, National Disaster Preparedness Training Center.

Other training partners, such as the following, have developed or are developing training courses for NTED:

- BCFS Health and Human Services.
- Frederick Community College.
- International Association of Fire Fighters.[335]
- Naval Postgraduate School.
- RDPC.[336]

NTED training partners deliver training at no cost to the individual or to the individual's jurisdiction or agency. In some circumstances, with approval from the SAA state/territory training point of contact, Homeland Security Grant Program (HSGP) funds [337] may be used for overtime and backfill costs for those individuals attending NTED courses.

Training providers have a limited supply of training for each state. Occasionally, a state exhausts the available free training. In these cases, NTED has an Excess Delivery Acquisition Program that allows NTED training partners to charge for course delivery when more sessions of a requested class are needed than the grant funds can accommodate. Select training partners potentially could support training firefighters on the hazards associated with FGAN fires, as discussed in further detail.

NTED courses include multiple delivery methods, specifically instructor-led (direct), train-the-trainers (indirect), customized (conferences and seminars), and web-based deliveries. Instructor-led courses are offered in residence (i.e., at a training facility) or through mobile programs that deliver courses to state and local jurisdictions that request the training. While the GPD, Grant Operations Division manages, administers, and conducts application budget review, creates the award package, approves, amends and closes out awards, the NPD NTED holds programmatic responsibility for the HSNTP Continuing Training Grants (CTG) Program and also maintains the program management function and responsibilities throughout the life cycle of the awarded grant.[338]

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[334] TEEX currently has an 8-hour course delivered in any participating jurisdiction that focuses on training responders to meet the requirements established in NFPA 472, Chapter 4, "Competencies for Awareness Level Personnel," and the OSHA 29 CFR 1910.120 (q)(6)(i) (a–f) First Responder Awareness Level competencies. This course takes an all-hazards approach to HAZMAT incidents. It provides participants with the knowledge to recognize the HAZMAT, protect themselves, notify others, and secure the scene. As part of a DHS FEMA funded HSNTP Cooperative Agreement, this course is available at no direct cost to state, county, and local government agencies.

[335] Section 7.7.3.1 of this report provides additional information about the IAFF.

[336] RDPC is discussed in further details in the *Rural Domestic Preparedness Consortium* Section of this report.

[337] HSGP funds can be used to reimburse the state agency or local jurisdiction for delivery of, and attendance to, the course.

[338] DHS, HSNTP, CTG Program. "Notice of Funding Opportunity." DHS-15-NPD-005-000-01.

Homeland Security National Training Program, Continuing Training Grants

The FY 2015 HSNTP CTG program[339] provides funding via cooperative agreements[340] to training partners to develop and deliver training to prepare whole communities to prevent, protect against, mitigate, respond to, and recover from acts of terrorism and from natural, man-made, and technological hazards. An objective of the program is to create accessible training solutions to address specific national preparedness gaps across the country.

For FY 2015, the total HSNTP funds available under the CTG Program is $11.521 million, to be used for training in the following focus areas:

- Cybersecurity.
- HAZMAT.
- Countering violent extremism.
- Rural training.

The FY 2015 HSNTP CTG Program is an open and competitive funding opportunity, available to entities with existing programs or demonstrable expertise relevant to the focus areas in the funding opportunity announcement—including state, local, tribal, and territorial entities; nonprofit national associations and organizations; nonprofit higher education institutions; and nonprofits such as community and faith-based organizations.

HAZMAT and rural training are two focus areas of interest to this investigation because fire departments with HAZMAT or FGAN facilities in their jurisdiction (or those in rural[341] locations) can apply for this grant since they fall under these focus areas. Within the HAZMAT focus area, departments are required to identify current and emerging national gaps in HAZMAT incident planning, response, and recovery as well as the training solutions to address these gaps. The FY 2015 HSNTP CTG Program prescribed the following standards related to HAZMAT training: NFPA standards, including NFPA 472 (*Standard for Competence of Responders to Hazardous Materials /Weapons of Mass Destruction Incidents*), NFPA 473 (*Standard for Competencies for EMS Personnel Responding to Hazardous Materials/Weapons of Mass Destruction Incidents*), and 29 CFR 1910.120 (Hazardous Waste Operations and Emergency Response). In addition, Executive Order 13650, "Improving Chemical Facility Safety and Security," and published reports from the Chemical Facility Safety and Security Working Group have been incorporated. The proposed training should address the following issues:

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[339] As appropriated by the Department of Homeland Security Appropriations Act, 2015 (Pub. L. 114-4) and authorized by the Implementing Recommendations of the 9/11 Commission Act of 2007 (Pub. L. 110-53) (hereafter the 9/11 Act), and the Homeland Security Act of 2002 (6 U.S.C. § 101 et seq.).

[340] A legal instrument of financial assistance between a federal awarding agency or pass-through entity and a non-federal entity that is consistent with 31 U.S.C. 6302–6305.

[341] The U.S. Census Bureau defines rural areas as all areas not meeting the following definition of a metropolitan area: Metropolitan statistical area (MSA) must include at least one city with 50,000 or more inhabitants or an urbanized area with at least 50,000 inhabitants and a total MSA population of at least 100,000.

- Planning, response and mitigation strategies, defensible critical decision making to save lives and property, and actions for fixed-facility spills and releases.
- Increasing knowledge, skills, and abilities to achieve core capabilities of interdiction and disruption, on-scene security and protection, and operational communications and coordination to enhance a jurisdiction's capability to mitigate and respond to HAZMAT incidents.
- Responder health and safety to prepare for, respond to, and recover from HAZMAT incidents by including on-scene health risk assessments and hazard risk analysis, incident safety and health plans, air monitoring plans, PPE selection and use, and safe work practices.

Many VFDs similar to the WVFD are situated in rural environments where the funding to support training is limited. The required training objectives for the rural training focus area include HAZMAT, mass fatality planning and response, crisis management for school-based incidents, development of emergency operations plans, railcar safety, agroterrorism and food and animal safety, and media engagement strategies for first responders.[342]

Center for Domestic Preparedness

CDP opened in June 1998 as a training center for the nation's emergency responders. The CDP mission is to train emergency response providers from state, local, and tribal governments as well as the Federal government, foreign governments, and private entities, as available. CDP training is also available for international, federal, and private sector responders who may participate if space is available on a fee-for-service basis. The scope of training includes preparedness, protection, and response. CDP provides onsite and mobile training at the performance, management, and planning levels while also facilitating the delivery of training by DHS training partners. DHS fully funds CDP training for state, local, and tribal responders. CDP has three distinct facilities that support training, specifically the Chemical, Ordnance, Biological, and Radiological Training Facility (COBRATF), Advanced Responder Training Complex (ARTC), and Noble Training Facility. The CDP COBRATF offers the only program in the nation featuring civilian training exercises in a toxic chemical agent environment, including biological materials. The advanced hands-on training enables responders to effectively respond to real-world incidents involving chemical, biological, explosive, or radiological materials or other HAZMAT. The ARTC provides responders with a realistic training environment to exercise the skills acquired during training. The CDP Noble Training Facility is the nation's only hospital dedicated solely to preparing the health care, public health, and environmental health communities for mass casualty events related to terrorism or natural disasters.

CDP's federal training partners include agencies such as:

- Emergency Management Institute (EMI).
- National Fire Academy (NFA).
- Federal Law Enforcement Training Centers.

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[342] DHS HSNTP CTP Program. "Notice of Funding Opportunity (NOFO)," DHS-15-NPD-005-000-01.

- Center for Disease Control and Prevention.
- Veterans Administration.
- DHS Office for Bombing Prevention.
- Radiological Emergency Preparedness Program.
- Department of Agriculture.
- DHS Domestic Nuclear Detection Office.
- Health and Human Services Division of Strategic National Stockpile.

Rural Domestic Preparedness Consortium (RDPC)

Rural emergency responders face unique challenges compared to their urban counterparts, such as limited access to funding for fundamental training. These challenges in providing consistent and high-quality training for first responders were recognized by Congress and DHS, which then established RDPC. Led by the Center for Rural Development, RDPC is a DHS-funded program providing training and resources to rural first responders. RDPC develops and delivers relevant all-hazards training specific to rural environments, and courses are offered both in person and online at no cost. To ensure that training directly reflects the needs of rural emergency responders, RDPC convenes a national rural preparedness summit and completes a biannual national survey of rural stakeholders. Data gathered from these activities are used to determine the type of training needs, level of need, and best delivery methods.[343]

U.S. Fire Administration (USFA)

The USFA is currently an entity within FEMA. The USFA was established by the Federal Fire Prevention and Control Act of 1974. [344] The mission of the USFA is to provide leadership, coordination, and support for the nation's fire prevention and control, fire training and education, and EMS activities and to prepare first responders and health care leaders to react to all-hazard and terrorism emergencies. One of USFA's key objectives is to reduce the nation's loss of life from fire while also reducing property loss and nonfatal injury due to fire.[345]

The USFA develops and delivers fire prevention and safety education programs in partnership with other federal agencies, the fire and emergency response community, media, and safety interest groups.[346] The USFA collaborates with public and private groups to promote and improve fire prevention and life safety through research, testing, and evaluation. The USFA manages many of the federal programs related to firefighting, including the National Fire Incident Reporting System, a dataset and collection of statistical

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[343] *See*: https://www.ruraltraining.org/about/overview/ (accessed on October 21, 2015).
[344] The U.S. Congress passed P.L. 93-498, the Federal Fire Prevention and Control Act, in 1974, which led to establishment of the USFA and the NFA. *See*: http://legcounsel.house.gov/Comps/FIREPREV.PDF (accessed on December 28, 2015).
[345] *See*: https://www.fas.org/sgp/crs/homesec/RS20071.pdf (accessed on December 28, 2015).
[346] *See*: http://www.usfa.fema.gov/about/index.html (accessed on December 28, 2015).

information relating to fire incidents, public fire education campaign materials, and information on grants and funding.

The USFA oversees the NFA at the NETC in Emmitsburg, Maryland. The NFA works to enhance the capability of fire and emergency services and allied professionals to deal more effectively with fire-related emergencies. The NFA offers free training courses and programs on campus, online, and throughout the nation.[347]

The USFA offers federal funding and grants directly to local career fire departments and VFDs and unaffiliated EMS organizations to help address a variety of equipment, training, and other firefighter and EMS-related needs. The grants are provided through the Fire Act Grants under the FEMA AFG Program, FP&S Grants, and SAFER Grants, which provide grants for hiring, recruiting, and retaining firefighters.[348] [349] Firefighters often dedicate personal time for training, public education, fundraising, and other nonemergency department-related activities. In addition, they are often members of their local or national firefighter associations.

7.8.2 Texas Firefighting Training Organizations and Programs

CSB reviewed the availability of national firefighter training grants and programs. The review revealed that career and volunteer firefighters and fire departments have access to many federally funded training grants and programs throughout the nation. Moreover, CSB reviewed state-level funding and programs available to Texas firefighters and fire departments in an effort to determine how access to HAZMAT and FGAN-specific training can be increased while also improving training standards for FGAN. Select state resources—such as the Texas Commission on Fire Protection (TCFP), Texas Rural Volunteer Fire Department Assistance Program, SFFMA, and Texas A&M Engineering & Extension Services (TEEX) are discussed further. As a result, CSB issues recommendations to some of these state resources, which are identified in Section 11.

7.7.2.2 Texas Commission on Fire Protection (TCFP)

The TCFP, a state government agency, is one of many state and local agencies that compose the Texas fire protection community. The commission's statutory authority and role within this community is to serve Texas fire departments as follows:

- Provide training guidelines and assistance to the fire service.
- Establish and enforce statewide fire service standards.[350]

[347] *See*: http://www.usfa.fema.gov/training/nfa/ (accessed on December 28, 2015).
[348] *See*: https://www.fema.gov/welcome-assistance-firefighters-grant-program (accessed on December 28, 2015).
[349] The AFG, FP&S Grants, and SAFER Grants are discussed in the *Assistance to Firefighters Grant Program* Section of this report.
[350] *See*: http://www.tcfp.texas.gov/about/compact.asp (accessed on November 13, 2015).

An important TCFP characteristic is its service to regulated organizations, including paid fire departments and those volunteer departments that choose to be voluntarily regulated. The policymaking body of the TCFP is a 13-member board appointed by the governor and confirmed by the Texas Senate. The commissioners adopt policies in accordance with Chapter 419 of the Texas Government Code. Upon adoption by the TCFP, these policies become state administrative laws collected under Part 13 of Title 37 of the Texas Administrative Code (TAC). The TCFP may propose or adopt changes to the TAC. The firefighter advisory committee[351] is responsible for reviewing and commenting on the administrative rules that govern the state's fire service and also assists the TCFP in matters relating to fire protection personnel, volunteer firefighters, fire departments, and VFDs.[352] The advisory committee may submit new curricula (or changes to curricula) for study and review before approval by the TCFP. The commission often creates ad hoc advisory committees to assist in creating and updating curricula, validating test questions, and addressing other related matters. Members of the Texas fire service serve voluntarily on these committees.[353]

The goal of the TCFP compliance program is to ensure the safety of the state's fire protection personnel by inspecting fire departments and other regulated entities to confirm that they are in compliance with state laws and rules. The compliance inspectors also inspect training records to ensure that fire protection personnel are in compliance with the appropriate certification rules for their disciplines. The commission's compliance officers travel to every regulated entity at least once every 2 years to inspect fire protection personnel certifications, training records, breathing air test records, protective clothing, and self-contained breathing apparatus. If a fire department is found to be in violation of a state law or TCFP rule, the Compliance Section compels the department to correct the violation immediately or works with it to develop a plan that will lead to compliance.[354]

The TCFP certification program certifies approximately 32,000 fire protection personnel in Texas. State law requires paid fire protection personnel to be certified by this commission; volunteers and individuals not affiliated with a paid or volunteer department can voluntarily choose to be certified by TCFP. The commission certifies fire protection personnel to multiple levels (basic, intermediate, advanced, and master) in several different disciplines.[355] In addition, TCFP certifies training facilities. When fire departments have unmet training needs, TCFP may take a number of actions:

- Authorize reimbursement for a local government agency for training program expenses.
- Provide staff or educational materials on request to training programs or fire departments.

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[351] The firefighter advisory committee is created by the TCFP enabling statute, Chapter 419 of the Government Code. The TCFP appoints members. *See*: http://www.statutes.legis.state.tx.us/Docs/GV/htm/GV.419.htm#419.023 (accessed on December 28, 2015).
[352] *See*: http://www.tcfp.texas.gov/directory/commission_and_committees.asp (accessed on November 3, 2015).
[353] *See*: http://www.tcfp.texas.gov/directory/commission_and_committees.asp (accessed on November 13, 2015).
[354] *See*: http://www.tcfp.texas.gov/about/compact.asp (accessed on October 27, 2015).
[355] Including structure fire protection, aircraft rescue fire protection, marine fire protection, fire inspector, fire and arson investigation, HAZMAT technician, pumper driver and operator, fire instructor, fire officer, and head of department.

- Establish minimum curriculum requirements for courses in schools operated by state or local governments.
- Provide training assistance to fire departments through the following methods:
  - Purchase and provide training aids to fire departments, temporarily or permanently.
  - Finance training seminars for fire departments.
  - Pay instructor fees to teach specialized courses for fire departments that employ fully paid fire protection personnel.[356]

Although these four elements are cited in the TCFP statute (Section 419.028), the commission is no longer funded for the type of assistance provided by authorizing reimbursements or delivering training. The TCFP funding program that offers this type of training assistance to fire departments was transferred to the Texas A&M Forest Service in 2009.[357] TCFP's Certification Curriculum Manual supplies the curriculum for the training of structural fire suppression personnel, aircraft rescue fire protection personnel, and marine fire protection personnel as well as fire inspectors, fire investigators, HAZMAT technicians, pumper drivers and operators, fire instructors, fire officers, and wildland firefighters.[358] The Certification Curriculum Manual's Hazardous Materials Awareness chapter was updated in June 2015. This chapter of the manual includes course material on Class 5 oxidizing substances and organic peroxides; this class includes AN.[359] The curriculum sets the minimum standards for materials covered in the course; however, instructors decide whether to go into further detail within specific topic areas such as AN.

The TCFP may consult and cooperate with a local governmental agency, other governmental agency, university, college, junior college, or other relevant institutions concerning the development of training schools and associated programs of courses of instruction for fire protection personnel, including the preparation or implementation of continuing education or training programs.[360] The TCFP has entered into a memorandum of understanding (MOU) with TEEX[361] to coordinate each organization's training responsibilities. In addition, the TCFP has an MOU with the Texas A&M Forest Service to coordinate the provision of training assistance and other assistance to firefighting entities. The Texas A&M Forest Service consists of many programs directed to VFDs to enhance the ability of firefighters to protect themselves and the public from fire-related hazards. One such program within the Texas A&M Forest Service that supports volunteer firefighter training is discussed in more detail in the next section.

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[356] *See*: http://www.statutes.legis.state.tx.us/Docs/GV/htm/GV.419.htm (accessed on October 28, 2015), Section 419.028 through Section 419.031.
[357] The Rural VFD Assistance Program in the Texas A&M Forest Service is discussed further in Section 7.7.4 of this report.
[358] *See*: http://www.tcfp.texas.gov/manuals/curriculum_manual.asp (accessed on October 28, 2015).
[359] *See*: http://www.tcfp.texas.gov/manuals/curriculum_manual/chapter_6.pdf (accessed on October 28, 2015).
[360] Section 419.030.
[361] Section 7.7.2.5 discusses TEEX in further detail.

7.7.2.3 Texas Rural Volunteer Fire Department Assistance Program (HB 2604)

In a January 2015 interim report by the Texas Committee on Homeland Security and Public Safety, Chairman Joe Pickett (D-El Paso) submitted recommendations to, and drafted legislation for consideration by, the House of Representatives, 84th Texas Legislature.[362] The committee's report indicates that of the 40 fire departments that represent the authority with jurisdiction for the 43 FGAN facilities across the state, 27 are VFDs; 7 are a combination of paid and volunteer firefighters; and 6 consist only of paid firefighters. A recommendation that stemmed from this finding encouraged the legislature to approve a rider in the Appropriations Bill for Texas A&M Forest Service that addresses funding in the Rural Volunteer Fire Department (Rural VFD) Assistance Program. The purpose of this funding is to provide training for VFDs across the state that are in a jurisdiction with an FGAN facility.[363]

The 77th Texas Legislature passed House Bill 2604 in 2001, establishing the Rural VFD Assistance Program.[364] The primary goal of the VFD Assistance Programs is to enhance the emergency response capabilities of volunteer and combination fire departments with 20 or fewer paid members.[365] The Texas Rural VFD Assistance Program provides funding to rural VFDs for the acquisition of firefighting vehicles, fire and rescue equipment, protective clothing, dry hydrants, computer systems, and firefighter training. This cost-share program is funded by the Texas State Legislature. Beginning on September 1, 2015, the annual grant budget for the program increased to $24.3 million from the previous annual budget of $12.8 million. Cost share assistance for training tuition has increased after changes to the Rural VFD Assistance Program that also took effect on September 1, 2015. The new reimbursement rate is 100 percent of the actual cost of tuition, not to exceed $125 per day up to a maximum of $625 per trainee per school. The annual maximum for training tuition grant assistance per fire department is $12,500.[366] The Texas A&M Forest Service conducted a funding meeting for FY 2015 on March 11, 2015, to determine how grants would be awarded. During this meeting, approximately $1.4 million in grants was awarded to Texas VFDs. Two VFDs in McLennan County, Texas, were approved for funding, and one is the WVFD, approved for $8,000 for a training library (Table 10).[367] All VFDs that apply for state grants,

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[362] *See*: http://www.house.state.tx.us/_media/pdf/committees/reports/83interim/House-Committee-on-Homeland-Security-and-Public-Safety-interim-report.pdf (accessed on October 28, 2015).

[363] *See*: http://www.house.state.tx.us/_media/pdf/committees/reports/83interim/House-Committee-on-Homeland-Security-and-Public-Safety-interim-report.pdf (accessed on October 28, 2015): 22–24.

[364] *See*: http://texasforestservice.tamu.edu/uploadedFiles/FRP/New_-_Local_Capacity_Building/TFS_Assistance_Programs/Historical_Funding_Summaries/2604/HB%202604%20Funding%20Meeting%20Approvals%2003_11_15.pdf (accessed on November 13, 2015).

[365] *See*: http://texasforestservice.tamu.edu/content/article.aspx?id=19857 (accessed on October 28, 2015).

[366] *See*: http://texasforestservice.tamu.edu/uploadedFiles/TFSMain/Preparing_for_Wildfires/Fire_Department_Programs/Local_Volunteer_Fire_Department_Programs/Rural_VFD_Assistance_Program/Special%20Announcement%20--%20Program%20Changes%20FY16(1).pdf (accessed on October 27, 2015)

[367] *See*: http://texasforestservice.tamu.edu/uploadedFiles/FRP/New_-_Local_Capacity_Building/TFS_Assistance_Programs/Historical_Funding_Summaries/2604/HB%202604%20Funding%20Meeting%20Approvals%2003_11_15.pdf (accessed on November 16, 2015).

including matching federal funds, must certify that they have adopted NIMS. Before the WFC incident in December 2012, the WVFD had requested funds through the Rural VFD Assistance Program for a large brush truck, but the request was not approved. The WVFD requested this funding every year thereafter, although it did not meet the NIMS certification requirement.[368]

Table 10. Funds Allocated to WVFD through the Rural VFD Assistance Program

Date Approved	**Equipment/Training Category**	**Approved Amount**
January 2003	Truck Chassis Large	$40,000
May 2004	C/S Structural Gear	$6,000
September 2008	Wildland Gear	$5,700
March 2015	Training Library	$8,000

The SFFMA of Texas was instrumental in the creation of House Bill 2604, which annually distributes grant funding through the Texas Forest Service to fire departments in need. Similar to the TCFP, the SFFMA assists many volunteer firefighters and fire departments in obtaining training.

7.7.2.4 State Firefighters' and Fire Marshals' Association of Texas (SFFMA)

Organized in 1876, the SFFMA is Texas's oldest and largest fire association serving the fire and emergency service responders of Texas. The SFFMA has the support of more than 1,200 fire departments, 22,000 individual members, 80 industrial fire brigades, and EMS and international departments. The association is active in legislative efforts that affect the fire service in Texas.[369] The SFFMA is a fee-based membership organization that offers individual and fire department memberships,[370] and has partnered with the National Volunteer Fire Council (NVFC)[371] to provide joint benefits to their members.

The SFFMA consists of a volunteer firefighter certification program that encourages VFDs to initiate the program in an effort to upgrade training standards. A VFD must be a member of the SFFMA to participate in the certification programs. Through the program, the fire department's selected

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[368] *See*: http://tfsweb.tamu.edu/HistoricalFunding/ (accessed on November 17, 2015).
[369] *See*: http://www.sffma.org/web/SFFMA/About_Us/SFFMA/About.aspx?hkey=84e079d0-75c2-47df-b9e9-7ae03d5685dd (accessed on October 29, 2015).
[370] The fire department membership dues are based on the Federal Census population of the cities and towns that they serve.
[371] NVFC is discussed in further detail in Section 7.7.3 of this report.

certification coordinator is required to attend a free certification workshop at least once every 2 years. The certification workshop is a requirement to maintain the departments' participation status. The certification coordinator validates that all training and certifications meet state criteria; it is the coordinator's responsibility to document the training and ensure that a qualified instructor has conducted the training. To verify that a department holds continual training and correctly maintains its records, the coordinator must submit an annual training summary or progress report.[372] The SFFMA Certification Board sets the criteria for the training curriculum; however, it does not develop topic-specific training modules for firefighters and departments. The SFFMA relies on firefighter training schools, approved training providers, or certified training instructors to administer the training. The SFFMA Program allows individual departments and their members to decide how far they will go in the process. The process levels include NFPA 1403, Introductory; NFPA 1001, Firefighter I; NFPA 1001, Firefighter II; and Master certifications.[373] Currently, the SFFMA does not have an exclusive program that certifies firefighters on HAZMAT or AN; however, part of the certification for the Firefighter I program includes a section on HAZMAT.[374] As part of the minimum standards for firefighter certification, the section designates that trainees recognize the hazard classes and divisions of HAZMAT and WMD[375] and identify common examples of materials and primary hazards in each hazard class or division, such as Class 5 oxidizers.[376]

The SFFMA Texas Industrial Emergency Services Board (TIESB) provides guidance for the Texas Industrial Fire Protection Program. The TIESB works with the Texas Chemical Council and the National Petroleum Refiners Association in reviewing differences among various industries in training needs for all emergencies and loss prevention programs. The TIESB has many objectives, including promoting the development of fire training and loss prevention programs for industrial firefighters or members of the SFFMA and also recommending for each member industry-minimum criteria for maintaining effective fire training, loss prevention, and educational programs.[377] Currently, the TIESB has a certification program for industrial HAZMAT teams and emergency response personnel[378] that establishes minimum criteria for certification but also provides flexibility so that each facility can structure its training programs to address individual needs. The TIESB has formally adopted NIMS, designating it as the incident management system for all members seeking certification of their training programs.[379]

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[372] *See*: http://www.sffma.org/web/SFFMAPages/Certification/2015/Navigating_Cert_2015_Apr.pdf (accessed on November 2, 2015).
[373] *See*: http://www.sffma.org/WEB/SFFMAPages/Certification/Resources/Certification_FAQ.pdf?WebsiteKey=65a2a6d5-cf92-4d26-8251-b69cdeecaa68&hkey=1509bff9-ad5b-411d-904d-9de79e384a6d (accessed on October 30, 2015).
[374] Of the 22 sections in the program, Section 18 covers HAZMAT.
[375] NFPA 472, Section 4.2.1: 2, 3.
[376] *See*: http://www.sffma.org/web/SFFMAPages/Certification/2015/Full_Program_2015_02.pdf (accessed on October 29, 2015): 61.
[377] *See*: http://www.sffma.org/web/SFFMA/Divisions/Industrial/SFFMA/TIESB.aspx?hkey=60a9d6ce-7f4f-4d91-b642-d41585bf3597 (accessed on October 30, 2015).
[378] Training program certification is for HAZMAT Technician, Specialist, and Incident Command levels.
[379] *See*: http://www.sffma.org/web/SFFMAPages/TIESB/Policy_Docs/TIESB010.pdf (accessed on October 30, 2015).

Within Texas, multiple organizations support firefighter standards for training curricula and certification. These organizations work with training partners such as TEEX in the development of course curricula and the implementation of training programs that suit the diverse needs of fire departments.

7.7.2.5 Texas A&M Engineering Extension Services (TEEX)

In 1929, the State Firemen's and Fire Marshals' Association of Texas (SFFMA) selected Texas A&M College as the site for a permanent firefighter training school. In 1931, the Texas Legislature authorized the creation of a Firemen's training school by passing House Bill No. 921. This bill authorized Texas A&M to create, conduct and maintain a Firemen's training school.

A member of The Texas A&M University System, the Texas A&M Engineering Extension Service (TEEX) has more than 80 years of experience in providing professional services with expertise in national and industrial security, emergency preparedness and response, public infrastructure, occupational safety, economic development, and technology assessment and validation. TEEX employees nearly 1,000 experts in various fields and is able to develop training solutions for emergency responders across the state and nationwide. Funding for Texas agencies and fire departments is available from several sources to support TEEX tuition, fees, and other related expenses.

TEEX encourages fire departments to take advantage of federal funding programs such as those in DHS FEMA as well as no-cost training in Texas through the fire extension services, NFA, area schools, and other assistance programs and associations.[380] TEEX tailors need-specific services and training at a number of its facilities and also at customer-specified locations worldwide. TEEX has the ability to offer a full-range of services and delivery methods, including:

- Course design and development.
- Online course delivery.
- Hosting services for eLearning courses.
- Classroom-based instruction.
- Hands-on skills-based instruction.
- National certification testing.
- Technical assistance and technology validation.
- Bilingual training and translation services.

TEEX collaborates with resources within The Texas A&M University System to provide a unique blend of research and technical expertise. The TEEX Emergency Services Training Institute's (ESTI) main training facility is the Brayton Firemen's Training Field. Adjacent to this facility is Disaster City®, which is comprised of 296 acres in College Station, Texas, making it the world's largest, most comprehensive campus for first responders. Each year thousands of students participate in ESTI's hands-on training in firefighting, emergency medical services, hazardous materials, rescue, Incident Command, and

[380] *See*: https://teex.org/Pages/about-us/funding-grants.aspx (accessed on November 6, 2015).

specialized programs. ESTI offers over 200 different courses in more than 130 specialty areas to students from across Texas, the United States and around the world.[381]

In FY15 TEEX/ESTI provided training for some 96,364 students in 3,670 separate classes which accounted for 1.625 million man contact hours. During the course of FY15 training, all 254 Texas Counties were served including 92% of all Texas Communities. TEEX/ESTI also trained students from 81 foreign countries during FY15. TEEX receives General Revenue from the State of Texas to provide outreach or extension training to the States Emergency Responders. In FY15, more than 20,000 responders of the State trained through this program at no cost to them or their department.

Through its accreditation with the National Professional Qualification System (NPQS), or ProBoard, TEEX/ESTI is authorized to offer certification training in compliance with National Fire Protection Association (NFPA) standards.[382]ESTI is currently accredited to provide certifications in 46 individual disciplines. TEEX/ESTI currently leads the nation in the number of ProBoard certifications issued on an annual basis. The certification levels TEEX/ESTI offers include:

- NFPA 1001 Fire fighter I & II.
- NFPA 1002 Driver/Operator Pumper, Aerial, ARFF, Mobile Water Supply.
- NFPA 1003 Airport Firefighter.
- NFPA 1006 Rescue Technician - Rope Rescue I, II; Trench Rescue I, II; Confined Space Rescue I, II; Wilderness Rescue I, II; Vehicle & Machinery I, II; Structural Collapse I, II.
- NFPA 1021 Fire Office I – IV.
- NFPA 1031 Fire Inspector I & II, Plans Examiner I.
- NFPA 1041 Fire Instructor I & II.
- NFPA 1061 Public Safety Telecommunicator I & II.
- NFPA 1081 Fire Brigade - Incipient, Advanced Exterior, Interior Structural, Leader.
- NFPA 472 Hazardous Materials - Awareness; Operations Core; Operations Mission Specific: PPE, Product Control, Air Monitoring & Sampling, Response to Illicit Laboratory Incidents; Technician; Technician w/ Tank Car Specialty; Technician w/ Cargo Tank Specialty; Technician w/ Intermodal Tank Specialty; Technician with Flammable Liquids Bulk Storage Specialty; Incident Commander.

ESTI supports FEMA's HSNTP with the delivery of over twenty different courses across the nation with topics that range from tactical level, Wide Area Search and WMD Defensive Operations to simulation-driven incident management courses to executive-level workshops and seminars. In addition, ESTI provides technical assistance, exercise planning expertise and event review and After-Action Report support to organizations across the nation. Throughout the year, TEEX hosts full-scale operational readiness exercises (OREs) that test a team's entire response capabilities.

[381] *See*: https://teex.org/Pages/about-us/disaster-city.aspx (accessed on December 31, 2015).
[382] *See*: https://teex.org/Pages/Program.aspx?catID=613&courseTitle=Pro%20Board (NPQS) (accessed on December 31, 2015).

TEEX/ESTI provides many DHS FEMA funded training programs that can be delivered online, face to face, or in a combination format. One such training program funded by DHS FEMA involves HAZMAT response; this training is geared toward emergency responders and focuses on the special challenges of dealing with WMDs or a terrorist incident, including knowledge of CBRNE events and responses to incidents involving CBRNE materials. The Standardized Awareness Training course focuses on training responders to meet competency requirements established in NFPA 472, Chapter 4, and in OSHA 29 CFR 1910.120. The course takes an all-hazards approach to HAZMAT incidents and gives participants the knowledge needed to recognize the hazardous material, protect themselves, notify others, and secure the scene. Another training program funded by DHS FEMA addresses incident management and response. These courses facilitate the implementation of the all-hazards multidisciplinary team-based approach outlined in the DHS National Response Framework, which is designed to respond to large-scale or expanding incidents, including those involving HAZMAT.[383] In addition to the in-person training, ESTI offers a variety of web-based training, such as awareness-level courses and those within the innovative Online Recruit Academy. These interactive courses provide emergency responders with a convenient way to complete knowledge-based training at their own pace.

There is an increasing need to provide training to responders who have the potential and will be expected to respond to Industrial Facilities/Industrial Emergencies in their area. There are multitudes of newly-introduced specialized hazards across the United States that First Responder communities have the potential to respond to. The increased potential for incidents to occur in these areas further highlights the need for all response and emergency management personnel be trained on how to properly preplan for, respond to, and mitigate these specialized incidents. Components of this training should address the preplanning, command, safety, operational, logistical, and local resource coordination and public information areas and should focus on assisting local responders in addressing key priorities and a safe outcome for their personnel.

These hazards include emergencies that result from drilling and fracking operations, flammable liquid bulk storage facilities, transportation emergencies (pipelines, rail[384], trucking, maritime, and air), and warehousing or storage of hazardous chemicals and materials such as FGAN. In light of these potential exposures to the response community, TEEX has developed a course entitled, "Industrial Emergencies for Municipal Based Responders" (IEMBR). This is a two-phased course with the awareness-level information contained in Phase I and the hands-on (firefighting and Hazardous Materials Response) contained in Phase II. TEEX is currently reaching out across the State of Texas and providing Phase I IEMBR training to first responders. Due to the complexity of the Phase II response scenarios and the

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[383] *See*: https://teex.org/Pages/Program.aspx?catID=469&courseTitle=Response-Hazardous%20Materials%20and%20Search%20and%20Rescue (accessed on November 6, 2015).

[384] TEEX has also developed and is currently delivering a 24-hour Crude by Rail course. TEEX worked in corporation with rail service providers, owning companies and the response community to develop this course. It provides a detailed look at rail car construction, hazards associated with rail car emergencies, response plans, resource management and responder safety.

need for realistic training props, all Phase II training is conducted at the TEEX/ESTI Brayton Firemen's Training Field. Phase II of the IEMBR course is more costly than Phase I due to the flammable liquid fuels, LPG and firefighting foams that are used as part of the training.[385] There is a critical need to establish a funding mechanism for First Responders to attend IEMBR Phase II training.

7.7.3 National Membership Firefighter Associations

Although several bodies represent the interests of firefighters and emergency responders, the three most prominent labor unions and associations for firefighters in the United States are the International Association of Fire Fighters (IAFF), NVFC, and IAFC. Combined, these three associations have more than a million members across the United States.[386] An important aspect of the mission of each association entails providing training information and resources to members.

7.7.3.1 International Association of Fire Fighters (IAFF)

The IAFF[387] is a labor union that represents career firefighters in the United States and Canada. Established in 1918, the IAFF currently represents a membership of more than 300,000 professional firefighters in more than 3,200 fire departments. The IAFF acts to ensure that adequate resources and tools, including the development and implementation of new training and equipment, are provided to career firefighters and paramedics in all member fire departments.

7.7.3.2 National Volunteer Fire Council (NVFC)

The NVFC is a nonprofit association that represents the interests of fire and emergency services at the national level by providing advocacy, information, resources, and programs to support volunteer first responders. The NVFC serves as the voice of the volunteer firefighter in the national arena and supplies tools, resources, programs, and advocacy for first responders nationwide. The NVFC also conducts national advocacy for first responders, including promoting legislation that benefits the fire and emergency medical services. The NVFC offers information, education, and training for volunteer fire and EMS organizations throughout their respective states.[388]

7.7.3.3 International Association of Fire Chiefs (IAFC)

The IAFC represents the leadership of firefighters and emergency responders worldwide.[389] With a network of more than 10,000 fire chiefs and emergency personnel, IAFC members include experts in firefighting, EMS, terrorism responses, HAZMAT spills, natural disasters, search and rescue operations, and public safety policy. The IAFC was established in 1873 to provide a forum for fire and emergency

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[385] *See*: https://teex.org/Documents/2014-04-firetalk.pdf (accessed December 31, 2015).
[386] *See*: http://www.nfpa.org/research/reports-and-statistics/the-fire-service (accessed on December 28, 2015).
[387] *See*: http://client.prod.iaff.org/#page=AboutUs (accessed on December 28, 2015).
[388] NVFC. *See*: http://www.nvfc.org/ (accessed on December 28, 2015).
[389] IAFC. *See*: http://www.iafc.org/About/?navItemNumber=537 (accessed on December 28, 2015).

service leaders to exchange ideas, develop professionally, and identify the latest products and services available to first responders, including career and VFD chiefs.[390]

8.0 Regulatory Analysis

Multiple federal, state, and local agencies regulate FGAN storage and handling, depending on statutory requirements, which can address worker safety, environmental protection, public safety, national security, and transportation. Requirements for reporting bulk quantities of FGAN also vary. CSB reviewed FGAN safety-related requirements in the United States and found differences in how FGAN facilities are identified and regulated. This section includes a discussion of the requirements for FGAN safety and security as well as voluntary efforts by industry, including:

- President Obama's Executive Order (EO) 13650 (Section 8.1).
- OSHA Explosives and Blasting Agents standard (Section 8.2).
- DHS Chemical Facility Anti-Terrorism Standards (CFATS) (Section 8.3).
- OSHA Process Safety Management (PSM) standard (Section 8.4.1).
- EPA Risk Management Program rule (Section 8.4.2).
- EPA Emergency Planning and Community Right-to-Know Act (EPCRA) regulations (Section 8.5).
- National fire protection standards and Texas fire codes (Section 8.6).
- Post incident state and local regulatory developments (Section 8.7).
- Voluntary industry initiatives (Section 8.8).

Each of these sections includes background and analysis. The sections provide supporting information for the CSB recommendations in Section 11, which includes recommendations to regulatory agencies to revise existing standards so that they include FGAN-specific requirements.

8.1 President Obama's Executive Order 13650

In the aftermath of the West Fertilizer Company (WFC) incident, President Barack Obama issued EO 13650, "Improving Chemical Facility Safety and Security," on August 1, 2013.[391] The EO states that "…measures can be taken by executive departments and agencies with the regulatory authority to further improve chemical facility safety and security in coordination with owners and operators."[392] The EO established the Chemical Facility Safety and Security Working Group, which is co-chaired by the

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[390] According to its website, the mission of the IAFC is to provide leadership to current and future career, volunteer, fire rescue, and EMS chiefs; chief fire officers; and company officers and managers of emergency service organizations throughout the international community, using vision, information, education, services, and representation to enhance their professionalism and capabilities. *See:* http://www.iafc.org/About/index.cfm?navItemNumber=537 (accessed on December 28, 2015).
[391] Executive Order 13650. "Improving Chemical Facility Safety and Security." August 1, 2013.
[392] *Ibid*.

Secretary of Homeland Security, the EPA Administrator, and the Secretary of Labor.[393] Working with multiple governmental agencies, the EO Working Group was tasked with improving operational coordination with state, local, and tribal partners; enhancing federal coordination regarding chemical facility safety and security; improving information collection and sharing; modernizing key policies, regulations, and standards; and identifying best practices.[394]

One of the group's first deliverables, issued in August 2013, was the document, "Chemical Advisory: Safe Storage, Handling, and Management of FGAN."[395] The advisory summarized best practices for AN storage, lessons learned from past AN incidents, hazard information, hazard reduction options, emergency planning activities, emergency response operations, and information resources.[396] In June 2015, the advisory was reissued as "Chemical Advisory: Safe Storage, Handling, and Management of Solid Ammonium Nitrate Prills."[397] This advisory includes a more detailed and reorganized regulatory information section.[398] It has been distributed by government agencies such as EPA and OSHA and by the two U.S. manufacturers of FGAN, CF Industries and EDC.

In addition, in June 2014, the EO Working Group published "Actions to Improve Chemical Facility Safety and Security—A Shared Commitment: Report for the President."[399] That report summarized the EO Working Group's progress, focusing on actions to date, findings and lessons learned, challenges, and high-priority next steps.[400] The report includes an aggressive action plan that details specifically how the EO Working Group has begun to, or will, tackle each of its aforementioned tasks.[401]

8.2 OSHA Explosives and Blasting Agents Standard

The 1971 OSHA Explosives and Blasting Agents standard (29 CFR 1910.109) regulates, in part, the storage, use, and transportation of explosives and blasting agents and specifies safety requirements for various grades of AN. The standard was based on two national consensus standards—NFPA[402] 495 (*Code for the Manufacture, Transportation, Storage, and Use of Explosives and Blasting Agents*, 1970

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393 *Ibid*.
394 *Ibid*.
395 *See*: http://www.ctif.org/sites/default/files/news/files/fed_an_advisory-083013.pdf (accessed on December 28, 2015).
396 *Ibid*.
397 *See*: http://www.epa.gov/sites/production/files/2015-06/documents/an_advisory_6-5-15.pdf (accessed on December 28, 2015).
398 *Ibid*.
399 *See*: https://www.osha.gov/chemicalexecutiveorder/final_chemical_eo_status_report.pdf (accessed on December 28, 2015).
400 *Ibid*.
401 *See*: https://www.osha.gov/chemicalexecutiveorder/ (accessed on December 28, 2015).
402 NFPA codes, standards, and guides are voluntary consensus products that are not enforceable unless adopted into law.

Edition), and NFPA 490 (*Code for the Storage of Ammonium Nitrate*, 1970 Edition).[403] The first nine sections of OSHA's Explosives and Blasting Agents standard, (a) through (h), cover the storage and transportation of explosives and blasting agents. The last two sections, (j) and (k), address small arms ammunition and the manufacture of explosives and pyrotechnics.

AN is covered in the middle of the standard, under section (g) when it is used as a blasting agent[404] and under section (i) when it is stored in the form of crystals, flakes, grains, or prills, including fertilizer grade, dynamite grade, nitrous oxide grade, technical grade, and other mixtures containing 60 percent or more AN by weight.[405] Included in 29 CFR 1910.109(i) are requirements for storage, building construction, ventilation, and fire protection associated with bulk and bagged AN. These requirements cover facilities that store more than 1,000 pounds of AN.[406] At the time of the incident, the WFC facility stored FGAN well in excess of 1,000 pounds.

The standard includes various requirements for the bulk storage of AN.[407] For example, the standard mandates that warehouses have "adequate ventilation or be capable of adequate ventilation in case of fire."[408] Also, storage bins must "be clean and free of materials which may contaminate AN."[409] Bins storing bulk quantities of AN may not be constructed with galvanized iron, copper, lead, or zinc "unless suitably protected," and wooden bins "protected against impregnation by AN" are permitted.[410] The partitions dividing AN storage from other products that would contaminate the AN must be of "tight construction."[411] To avoid potentially dangerous contamination, AN must be in a separate building or must be separated by "approved type firewalls of not less than 1 hour fire-resistance rating from storage of organic chemicals, acids, or other corrosive materials, materials that may require blasting during processing or handling, compressed flammable gases, flammable and combustible materials or other contaminating substances."[412]

While CSB found no evidence to suggest that any detonation of AN in the United States has occurred at a facility compliant with OSHA's 1910.109(i) standard, CSB does find that these requirements do not offer sufficient safeguards concerning the bulk storage of FGAN. This conclusion is evidenced best by the

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[403] *See*: https://www.osha.gov/pls/oshaweb/owadisp.show_document?p_table=FEDERAL_REGISTER&p_id=19509 (accessed on December 28, 2015). The NFPA 490 standard went through several updates. The most recent edition was issued in 2002. In 2010, NFPA incorporated NFPA 490 into a more recently developed standard, NFPA 400 (*Hazardous Materials Code*) (discussed in detail in Section 8.6.1). OSHA, however, has not updated its Explosives and Blasting Agents standard to incorporate the provisions of NFPA 400 because OSHA's legal authority to adopt consensus standards expired in the mid-1970s.
[404] Because it was not pertinent to this investigation, 29 CFR 1910.109(g) is not discussed.
[405] 29 CFR 1910.109(i)(1)(i)(a).
[406] 29 CFR 1910.109(i)(2)(i).
[407] Because bulk storage of FGAN was primarily at issue at the WFC facility, bagged storage is discussed only briefly for the sake of comparison.
[408] 29 CFR 1910.109(i)(4)(i)(a).
[409] 29 CFR 1910.109(i)(4)(ii)(a).
[410] *Ibid*.
[411] *Ibid*.
[412] 29 CFR 1910.109(i)(5)(i)(a).

WFC incident, in which the use of wooden bins (albeit not untreated wooden bins) to store FGAN was allowed under the 1910.109(i) standard. The CSB found that such construction likely facilitated the fire's spread between storage bins.[413] Moreover, the CSB found that even if the wooden bins had been treated (e.g., with coated or clad materials), the incident may have still occurred. This is because, as discussed previously, although coated or clad materials may protect wood against AN impregnation, they are not fire resistant and will still burn. Accordingly, CSB issued public comments on March 31, 2014 when OSHA released a Request for Information (RFI) to CSB and other stakeholders on its Explosives and Blasting Agents standard.[414]

The comments made by CSB pertained in part to the weakness of the provisions in 29 CFR 1910.109(i), particularly with respect to the bulk storage of FGAN.[415] Specifically, CSB expressed concern that, because of certain gaps in 1910.109(i), users are left to decide appropriate safety measures without proper instruction.[416] For example, 1910.109(i) permits the use of wooden bins "protected against impregnation of AN" without defining the word "impregnation."[417] Furthermore, even if the word had been defined, CSB noted that the use of wooden bins is not recommended in other countries, such as the United Kingdom (U.K.), which recommend the use of concrete for bulk AN storage.[418] Moreover, CSB noted in its RFI comments that 1910.109(i) does not provide sufficient fire protection measures with respect to the storage of bulk quantities of FGAN because it requires sprinklers only for bagged AN in amounts exceeding 2,500 tons.[419] CSB concluded that the requirement for sprinklers (or other fire suppression methods) as well as fire detection equipment likely would have helped minimize the severity of the impact of the WFC fire and explosion on the facility and on the surrounding community.[420]

In addition, CSB commented that the title of the standard, "Explosives and Blasting Agents," should be revised so that it is clear that FGAN not used as a blasting agent or explosive is also covered under the standard.[421] As currently titled, the name of the standard might mislead readers to believe that the standard applies only to the explosives industry. Accordingly, CSB recommended that the title be revised to clearly indicate that the standard also applies to the fertilizer industry. Similarly, CSB noted that no scope describing the purpose and application of the standard is listed at the beginning of the standard.[422] Rather, the scope of 29 CFR 1910.109(i) that applies to FGAN appears in the middle of the standard.

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[413] It should be noted, however, that 29 CFR 1910.109(i) did prohibit the configuration and contents of the seed room adjacent to the AN bin.

[414] On December 9, 2013, OSHA issued an RFI on 17 issues regarding revision to the agency's regulatory standards. CSB commented on 15 of the 17 issues in a public comment dated March 31, 2014. The CSB comments are posted on the OSHA website; *see*: http://www.csb.gov/assets/1/16/CSB_RFIcomments.pdf (accessed on December 28, 2015).

[415] *See*: http://www.csb.gov/assets/1/16/CSB_RFIcomments.pdf (accessed on December 28, 2015).

[416] *Ibid*.

[417] *Ibid*.

[418] *Ibid*.

[419] *Ibid*. *See*: 29 CFR 1910.109(i)(7)(i).

[420] *See*: http://www.csb.gov/assets/1/16/CSB_RFIcomments.pdf (accessed on December 28, 2015).

[421] *Ibid*.

[422] *Ibid*.

CSB recommended changing this organization so that the scope is specified early in the document and is easy to locate. CSB concluded that the implementation of such recommendations regarding the standard's title and scope would likely make the standard easier to understand.

In addition to providing comments in response to the OSHA RFI, CSB reviewed guidance documents on FGAN from government and industry sources, finding that the only pre-WFC incident reference to the OSHA standard was in an EPA Chemical Safety Alert, "Explosion Hazard from AN," from December 1997.[423] In a letter to EPA, The Fertilizer Institute (TFI), a major trade association composed of fertilizer industry representatives, contended that the reference was inaccurate and that EPA therefore should remove it from its alert.[424] Specifically, TFI said that the standard "was not applicable to facilities handling AN, unless the facility also handles an explosive or blasting agent."[425] This assertion, however, is incorrect; no part of the standard supports such a reading. As previously mentioned, 29 CFR 1910.109(i) clearly states that it applies to ". . . the storage of AN in the form of . . . prills including fertilizer grade . . ."[426] Nonetheless, CSB finds that additional and well publicized guidance is needed to explain the applicability and provisions of the standard.

Fertilizer industry representatives reported to the Government Accountability Office (GAO) that it was not well known that 1910.109(i) applies to FGAN.[427] While conducting interviews with WFC management and employees, CSB found that WFC personnel knew little about the pertinent section. During these interviews, CSB learned that OSHA conducted its last inspection of the WFC plant[428] in 1985, when the facility was cited for various violations concerning anhydrous ammonia, respiratory protection, and recordkeeping. CSB found no evidence that OSHA cited the WFC for violating any requirement of 1910.109(i) before the April 2013 fire and explosion. It is unknown whether OSHA inspected the facility against this section of the standard.

CSB found that, in addition to WFC personnel, others who would reasonably be expected to know about 29 CFR 1910.109(i) might not have had such knowledge. After the current owners acquired the facility in 2004, third-party safety consultants who visited the facility never referenced 1910.109(i) in their final inspection reports. In fact, in reviewing documentation provided by the WFC, CSB identified only one mention of 1910.109(i)—in a Safety Data Sheet (SDS) provided by one of the WFC's FGAN suppliers, CF Industries, which the WFC received in 2012. The GAO confirmed this observation, noting in its May

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423 *See*: http://nepis.epa.gov/Exe/ZyPDF.cgi/P100BH59.PDF?Dockey=P100BH59.PDF (accessed on December 28, 2015).

424 The Fertilizer Institute. "Fertilizer Grade Ammonium Nitrate: Properties and Recommended Methods for Packaging, Handling, Transportation, Storage and Use."

425 Leason, Chris S., counsel to TFI. Letter to Tawai-David Chung, EPA OSWER, CEPPO, June 27, 1997. At the request of CSB, EPA conducted a search to find its final signed response to TFI's letter. Because of the age of the document, it would only exist in paper form; however, EPA no longer has paper files from that time frame. Thus, EPA's response to this letter is unknown.

426 29 CFR 1910.109(i)(1)(i)(a).

427 GAO. "Chemical Safety: Actions Needed to Improve Federal Oversight of Facilities with Ammonium Nitrate." Washington, DC: GAO, May 2014.

428 Certain structures of the WFC plant had not yet been built at the time of the 1985 OSHA inspection.

2014 report that it reviewed four SDSs from producers of solid FGAN fertilizer and only one mentioned the pertinent section of the OSHA standard.[429] CSB notes as a concern the fact that the fertilizer industry, as recently as 2014, reported that personnel exhibited little recognition of the applicability of 1910.109(i) to FGAN.[430]

With respect to enforcement, CSB found very little history of OSHA using 29 CFR 1910.109(i) to cite fertilizer facilities. Table 11 shows OSHA's record of 1910.109(i) citations and also the citation that OSHA issued against the WFC by Standard Industrial Classification (SIC)[431] code.

Table 11. OSHA 29 CFR 1910.109(i) Citation History

No.	Facility	Inspection Year	Standard Industrial Classification
1.	Coshocton Farm Bureau (Coshocton, OH)	1974	5083: Farm and Garden Machinery
2.	Smith-Douglass Chemical Div. Bo. (Clayton, DE)	1975	5191: Farm Supplies
3.	Jr. Simplot Co. (Bartley, NE)	1975	2875: Fertilizers, Mixing Only
4.	Farmers Union Cooperative Oil (Flandreau, SD)	1975	5541: Gasoline Service Stations
5.	Old Fox Chemical Co, Inc. (East Providence, RI)	1976	2875: Fertilizers, Mixing Only
6.	Drake Chemical Inc. (Lock Haven, PA)	1976	2865: Cyclic Crudes and Intermediates
7.	IMC Chemical Group Inc. Trojan (New Tripoli, PA)	1976	2892: Explosives
8.	Atlas Powder Co. Kinepak (Alvarado, TX)	1977	2892: Explosives
9.	Jacklin-Plant Food Center (Post Falls, ID)	1977	5191: Farm Supplies
10.	Genstar Chemical Inc. (Presque Isle, ME)	1978	2873: Nitrogenous Fertilizers
11.	Nipak Energy Corp. (Krum, TX)	1979	2892: Explosives
12.	Iuka Coop Exchange (Iuka, KS)	1979	5153: Grain and Field Beans
13.	Beaver Explosives Inc. (New Castle, PA)	1980	2892: Explosives
14.	Independent Explosives Co. of Pennsylvania (Pittston Township, PA)	1987	2892: Explosives

[429] GAO. "Chemical Safety: Actions Needed to Improve Federal Oversight of Facilities with Ammonium Nitrate." Washington, DC: GAO, May 2014.
[430] *Ibid.*
[431] SIC is a system for classifying industries according to industry-specific four-digit codes.

15.	Thermex Energy Corp. (Parrish, AL)	1990	2892: Explosives
16.	Kesco, Inc. (Kittanning, PA)	1994	2892: Explosives
17.	Howard Fertilizer Company, Inc. (Orlando, FL)	1997	2875: Fertilizers, Mixing Only
18.	Hall Explosives Inc. (Good Springs-Tremont, PA)	1998	1629: Heavy Construction, Nec.
19.	American East Explosives (Mount Carmel, PA)	1999	2892: Explosives
20.	West Fertilizer Co. (West, TX)	2013	5191: Farm Supplies

As shown in Table 11, 19 inspections resulted in citations, excluding the citation against the WFC. The SIC code for 10 of these citations are clearly nonfarm, addressing mostly explosives; the nine remaining citations are related to farm supplies. It is important to note, however, that these data reflect citations only, not inspections. That is, although the facilities in Table 11 were inspected against, and cited for violations of, 1910.109(i), they do not represent all inspections conducted by OSHA against that section of the standard. It is impossible to determine whether OSHA inspected any other facilities for compliance, but did not cite them. CSB found no evidence of citations from 1999 to 2013.

The OSHA 29 CFR 1910.109(i) citation history in Table 11 is also similar to that of more recent OSHA enforcement data from 2005 to 2013. These data show that no other facility with the same North American Industry Classification System (NAICS)[432] code as the WFC (NAICS Code 424910) received a citation for violating 1910.109(i). The GAO May 2014 report similarly concluded that OSHA rarely issued citations for violations of the standard's requirements for FGAN storage at fertilizer facilities.[433] GAO found that "a citation for a violation of [OSHA's] AN storage regulations was issued as a result of an inspection of a fertilizer facility only once before the explosion in West, Texas."[434]

After the WFC explosion, OSHA issued 24 citations to the WFC on October 9, 2013, including nine citations for serious violations of 29 CFR 1910.109(i).[435] These violations included lack of adequate ventilation, absence of fire-resistive construction, and improper storage and bin pile heights.[436] The agency also cited the WFC for not ensuring that the wooden bins it used to store FGAN were treated to prevent FGAN impregnation.[437] OSHA and the WFC ultimately settled, with the WFC agreeing to pay

[432] NAICS is the standard used by Federal statistical agencies in classifying business establishments for the purpose of collecting, analyzing, and publishing statistical data related to the U.S. business economy.
[433] GAO. "Chemical Safety: Actions Needed to Improve Federal Oversight of Facilities with Ammonium Nitrate." Washington, DC: GAO, May 2014.
[434] *Ibid*.
[435] OSHA. "Citation and Notification of Penalty to Adair Grain," October 9, 2013.
[436] *Ibid*.
[437] *Ibid*.

penalties without admitting guilt about violating the standards under which it was cited, including 1910.109(i).

There is evidence that the WFC owners made efforts to comply with regulations when notified of noncompliance. When the WFC owners acquired the facility in 2004, state and federal regulators found them to be noncompliant with environmental, product quality, and transportation regulations—issues that the owners promptly corrected. For example, Federal EPA inspectors cited the WFC for not refiling its Risk Management Plan (RMP) registration in 2004.[438] This citation prompted the WFC to hire an insurance company to develop a comprehensive RMP for the safe storage of its anhydrous ammonia.[439] Also, Texas Commission on Environmental Quality (TCEQ) inspectors issued a citation to the facility in 2006 for not having an air permit for anhydrous ammonia.[440] The WFC subsequently developed maintenance and inspection programs to prevent anhydrous ammonia releases. As a result of these inspections and citations, the WFC took appropriate corrective actions. The importance of regulatory awareness and notification, therefore, cannot be overemphasized.

8.2.1 OSHA Issuance of Guidance on Explosives and Blasting Agents Standard

In December 2014, the OSHA Directorate of Enforcement Programs issued investigatory and citation guidance to OSHA enforcement personnel on elements of 29 CFR 1910.109. The nine-page guidance document provides additional clarification of the scope of 1910.109(i) and its application to facilities that store FGAN. This document includes specific compliance guidance for the majority of standard provisions and describes conditions that would be considered in or out of compliance. This guidance further clarifies the application of the standard to facilities storing FGAN and provides a list of NAICS industry codes for facilities most likely to manufacture, use, store, handle, or possess FGAN. The list of NAICS codes includes facilities such as the WFC plant and states that particular attention to AN hazards is needed when inspecting these facilities. The guidance also clarifies the standard's definition of "adequate ventilation" and includes the types of ventilation likely to be unacceptable under the regulations as well as a ventilation rate calculation to assess compliance.

Furthermore, the guidance document provides additional clarification on the subject of wood protection against FGAN impregnation. As discussed previously, 1910.109(i) does not specifically define compliant approaches for the treatment of wood to protect against FGAN impregnation. The standard prohibits untreated wood bin construction for FGAN storage. Although OSHA does not recommend the use of treated wood bins, wood with impermeable coating and claddings (such as two-part epoxy coatings, steel sheet cladding, or sodium silicate) are considered acceptable means for protecting wood against FGAN impregnation. OSHA provides additional guidance for varying types of wood construction that might be encountered during field inspections, including citable conditions such as improperly treated wood and

[438] EPA. "Enforcement Case Report to West Chemical & Fertilizer Company," August 14, 2006.
[439] Triangle Insurance Company. Anhydrous Ammonia Supplement for WFC, 2006.
[440] TCEQ. "TCEQ Enforcement Referral to West Chemical & Fertilizer," June 21, 2006.

treated wood that has not been maintained to protect the coating integrity. The guidance also addresses pile heights for clumping and caking conditions and fire prevention.

The 2014 guidance document for 1910.109(i) addressed some of the issues with vague wording that CSB raised in the RFI comments. Some of the requirements listed under the standard, however, do not provide sufficient safeguards to a facility owner storing bulk quantities of FGAN. In the case of the WFC incident, the wood-constructed bins were made of combustible materials and likely facilitated the spread of a fire between storage bins. According to OSHA, AN impregnation of porous combustible materials, such as wood, can accelerate combustion in the event of a structural fire and increase the explosion risk.[441] OSHA permits the use of wood bins and wood construction only if the wood is protected against impregnation. Although coated or clad materials can protect against AN impregnation, they are not fire resistant and will still burn, contributing to the generation of heat during a fire. CSB determined that the wood-constructed bins likely contaminated the AN, ultimately leading to the detonation by increasing AN energy and sensitivity (discussed in Section 4.2.1). Completely eliminating wood and other combustibles as materials for constructing FGAN bins and storage facilities greatly reduces the possibility of contaminating FGAN during a fire or smoldering event.

Although OSHA enforcement guidance and other efforts have provided greater clarity on how 1910.109(i) applies to FGAN facilities, OSHA still needs to revise and update the standard to incorporate the most recent provisions in NFPA 400 (2016 Edition) that address the safe storage of FGAN.

OSHA cannot enforce some of the regulations in the current 1910.109(i) because they contain requirements reserved for the authority having jurisdiction, such as the municipal or state code official for occupancy permits. Moreover, OSHA cannot cite the following requirements in the standard:

- 29 CFR 1910.109(i)(2)(ii): Approval of large quantity storage shall be subject to due consideration of the fire and explosion hazards, including exposure to toxic vapors from burning or decomposing ammonium nitrate.
- 29 CFR 1910.109(i)(2)(iii)(e): The continued use of an existing storage building or structure not in strict conformity with this paragraph may be approved in cases where such continued use will not constitute a hazard to life.

Because the current version of 1910.109(i) has limited enforcement in some areas—and because NFPA 400 (2016 Edition) (discussed in Section 8.6.1.1) includes updated provisions, some in response to the WFC incident, for increasing the safety of AN storage facilities—OSHA should update 1910.109(i) to include requirements similar to the provisions in NFPA 400 (2016 Edition). It also should revise the rules that currently are enforceable only by municipal or state officials.

[441] OSHA enforcement directive on 1910.109(i).

8.2.2 Need for an Emphasis Program

Unfortunately, only after the WFC incident was more attention focused on the hazards of FGAN and the role of applicable regulations. Since the explosion and issuance of the EO, OSHA has worked to increase awareness of FGAN and the scope of 29 CFR 1910.109(i) through the joint agency advisory on safe storage of FGAN, the letter to the fertilizer industry, and the guidance document for compliance officers to assist in enforcing the 1910.109 standard for FGAN facilities. However, enforcement guidance does not provide the resources needed by OSHA to increase the frequency of inspections, although such guidance may help ensure that 1910.109(i) is applied appropriately when OSHA compliance officers happen to inspect facilities that fall under the rule.

A more realistic and immediate approach to confirm that FGAN facilities are complying with the standard would be for OSHA to launch a regional emphasis program (e.g., in Regions IV, VI, and VII[442]) where these types of facilities are more common. A regional emphasis program would include a certain number of annual inspections per year, which would facilitate bringing FGAN facility operators into compliance with both regulatory and industry standards and would reduce the potential for a future event similar to the WFC incident.

Imposing stricter requirements on AN storage and handling could take several years before enactment into federal regulations. OSHA has initiated several national, regional, and local emphasis programs targeted at specific industries or located in specific geographical areas to help prevent hazards. Such emphasis programs have successfully focused inspection and enforcement efforts on specific industries.

A 1910.109(i) emphasis program can include NFPA 400 (2016 Edition) as a guidance document for compliance officers to support recognition of hazardous conditions or issuance of violations when found. It would also prompt improvement of safe FGAN storage and handling practices through increased awareness and would allow OSHA to collect information and data that could support future revisions to current regulations on FGAN.

8.3 **Chemical Facility Anti-Terrorism Standards (CFATS)**

DHS promulgated the CFATS in 2007 to address security issues at high-risk chemical facilities, including those that store certain quantities of FGAN. The rule establishes risk-based performance standards for chemical facility security and requires facilities to prepare vulnerability assessments and security plans to protect the public from a breach of security or an intentional release.

Under CFATS, DHS collects information from facilities that possess designated quantities of chemicals of interest (COIs).[443] In creating the COI list, DHS referenced other established lists that regulate

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[442] These regions include the following states: Alabama, Florida, Georgia, North Carolina, South Carolina, Tennessee, Mississippi, Kentucky, Nebraska, Kansas, Missouri, Iowa, Texas, Oklahoma, Arkansas, Louisiana, and New Mexico.
[443] CFATS § 27.210(a)(1)(i).

chemicals—including the list of chemicals covered under the EPA Risk Management Program, the Chemical Weapons Convention, and DOT—and a list of chemicals with known inhalation hazards. The COI list includes 322 chemicals and also screening threshold quantities for each chemical as it relates to each of the three defined security hazards (release, theft, and sabotage).

Chemical facilities that meet the COI criteria listed in Appendix A of the CFATS rule must complete and electronically submit a Chemical Security Assessment Tool (CSAT) Top-Screen form to DHS. Using the information collected from facility Top-Screen information, DHS assigns a preliminary risk-based tier—from the highest (tier 1) to the lowest "high-risk" level (tier 4) and the "not high-risk" level (tiered out)—based on a basic assessment of the potential consequences in association with the chemical holdings at each facility.[444] Once a preliminary tier is assigned, each facility in tiers 1 through 4 must submit a CSAT Security Vulnerability Assessment to DHS, and DHS uses that assessment to make a final determination of the facility's assessed level of risk. If DHS retains the facility in one of the four high-risk tiers, the facility must submit a site security plan. DHS reviews the plan, conducts an onsite inspection of the facility, and approves the plan if it is deemed adequate relative to the risks inherent in the facility, its chemical holdings, and potential consequences of a security breach.

Since publication of the CFATS rule, DHS has received more than 50,000 Top-Screen forms submitted by chemical facilities. As of September 2015, DHS covers 3,182 high-risk facilities nationwide, and 2,607 of those sites have undergone onsite authorization inspections.

8.3.1 AN Screening Thresholds

FGAN is listed in CFATS Appendix A as a DHS COI. A facility reports to DHS based on possession of AN under three conditions:

1. If a facility possesses 5,000 pounds or more of FGAN with more than 0.2 percent combustible substances, including any organic substance calculated as carbon, to the exclusion of any other added substance in bulk storage, the facility must report. Facilities meeting this threshold must also submit information to DHS on quantity and on method of storage or packaging.
2. If a facility possesses 400 pounds or more of FGAN with more than 0.2 percent combustible substances, including any organic substance calculated as carbon, to the exclusion of any other added substance in transportation packaging, the facility must report.
3. If a facility possesses 2,000 pounds or more of solid FGAN with a nitrogen concentration of 23 percent or higher in transportation packaging, the facility must report.

CSB requested and reviewed CFATS data from all facilities in the United States that submitted information to DHS for storage of FGAN as of March 2014. According to the DHS data, 1,351 facilities in the United States store AN in quantities that exceed the screening thresholds. The majority of those

[444] When determining whether a facility is high risk, DHS primarily focuses on the potential consequences associated with a successful terrorist attack on the facility (including the use of stolen or diverted materials in a separate attack offsite). A threat factor also is incorporated into the risk assessment for facilities with release hazards.

facilities store FGAN for agricultural uses (Figure 73). Based on the NAICS codes submitted with Top-Screen information, 46 percent of the facilities that report to DHS stock FGAN for agricultural purposes such as farm merchandising and wholesale or crop preparation. An additional 6 percent store FGAN for fertilizer mixing.

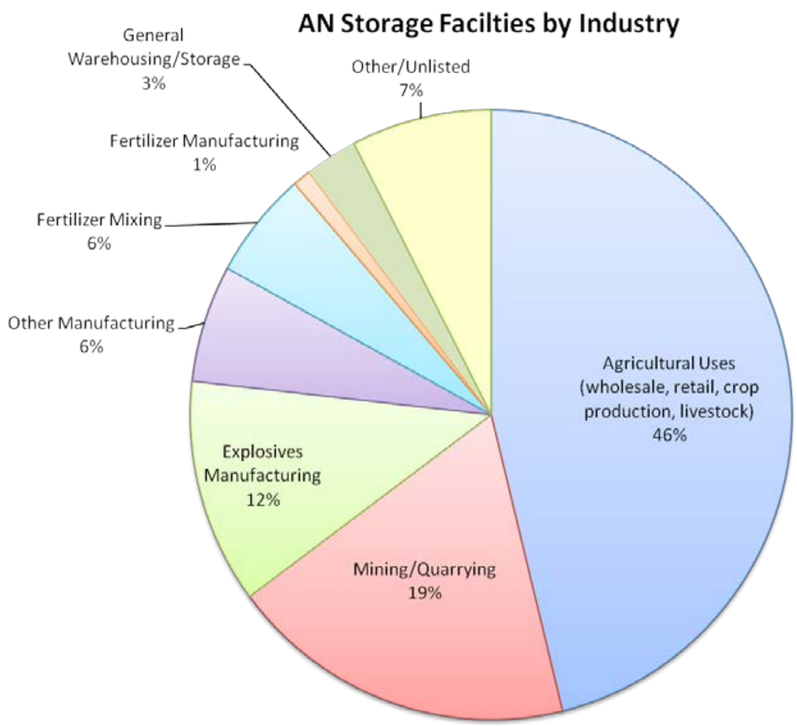

Figure 73. Percentage of AN Storage Facilities by Industry (Source: DHS)

In 2008, DHS filed a reporting extension to agricultural facilities meeting screening thresholds of FGAN for farmers and agricultural end users of FGAN, such as the preparation and application of crops, feed, land, or livestock.[445] However, this extension does not apply to chemical distribution facilities or to commercial chemical application services, such as the WFC. At the time of the April 2013 explosion, the WFC possessed an estimated maximum of 120,000 pounds of FGAN, about 60 times the screening threshold of 2,000 pounds, but did not submit Top-Screen information to DHS as required under the CFATS. Consequently, DHS was unaware that the WFC possessed FGAN until the 2013 explosion. After the incident, the WFC retroactively submitted a Top Screen to DHS upon notification that it was not compliant with the rule, and DHS did not issue a citation to the WFC for originally failing to submit the form. If the WFC had complied with the CFATS, a CFATS inspection or assistance visit might have noted the storage conditions at the WFC facility and prompted change. In addition, DHS engagement

[445] 73 *Federal Register* 1640.

with facility management might have prompted greater engagement by local law enforcement, which in turn might have supported greater involvement by other community emergency services.

8.4 Safety Management Programs

Following a number of major chemical accidents in the United States and abroad in the 1970s and 1980s, Congress amended the Clean Air Act (CAA) in 1990 to require both OSHA and EPA to publish new regulations to help prevent similar accidents. Through Section 304 of the CAA Amendments, Congress directed the Secretary of Labor, in coordination with the EPA Administrator, to promulgate, pursuant to the Occupational Safety and Health Act of 1970, a chemical process safety standard to prevent accidental releases of chemicals that could pose a threat to employees.[446] Also, through CAA Amendments Section 112(r), Congress required EPA to publish regulations and guidance for chemical accident prevention at facilities using substances that posed the greatest risk of harm from accidental releases.[447] The following sections focus on the intertwined regulations that OSHA and EPA developed – the OSHA Process Safety Management of Highly Hazardous Chemicals standard and the EPA Risk Management Program rule.

8.4.1 OSHA Process Safety Management Standard

OSHA's Process Safety Management of Highly Hazardous Chemicals standard (29 CFR 1910.119) (known as the PSM standard) became effective in May 1992.[448] The standard contains requirements for preventing or minimizing the consequences of catastrophic releases of toxic, reactive, flammable, or explosive chemicals.[449] It includes the following 14 elements:

1. Employee participation.
2. Process safety information.
3. Process hazard analysis.
4. Operating procedures.
5. Training.
6. Contractors.
7. Pre-startup safety review.
8. Mechanical integrity.
9. Hot work permits.
10. Management of change.
11. Incident investigation.
12. Emergency planning and response.
13. Compliance audits.

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[446] *See*: https://www.osha.gov/Publications/osha3132.html (accessed December 28, 2013).
[447] *See*: http://www.epa.gov/sites/production/files/2013-10/documents/caa112_rmp_factsheet.pdf (accessed December 28, 2015).
[448] OSHA. "Process Safety Management." OSHA 3132, 2000.
[449] 29 CFR 1910.119.

14. Trade secrets.[450]

The PSM standard states that it applies, in part, to "a process which involves a chemical at or above the specified threshold quantities listed in Appendix A [List of Highly Hazardous Chemicals, Toxics and Reactives] to this section."[451] Notably, FGAN is not on this list.

In deciding which chemicals to regulate under the PSM standard, OSHA reviewed potential "highly reactive and explosive substances," as required by Section 304(b) of the CAA Amendments.[452] OSHA considered information drawn from multiple sources, including EPA, DOT, World Bank, NFPA, the Health and Safety Commission of the U.K., and the states of Delaware and New Jersey.[453] With respect to reactives, OSHA chose to include only those chemicals with the two highest (i.e., most dangerous) reactivity ratings under NFPA 490 because of the significant risk that they posed to workers.[454] These chemicals had reactivity ratings of 3 or 4.[455] FGAN, however, was left off the PSM list, despite having a reactivity rating of 3.[456] Although the agency did consider adding FGAN to the PSM list in the late 1990s, this effort failed due to "resource constraints and other priorities."[457] Thus, FGAN has yet to be regulated under the PSM standard.

Anhydrous ammonia, on the other hand, is on the List of Highly Hazardous Chemicals, Toxics and Reactives, with a threshold quantity of 10,000 pounds. CSB found that, at the time of the incident, the WFC was storing the equivalent of 34,000 pounds of anhydrous ammonia, more than three times the threshold quantity that triggers PSM coverage. CSB also discovered that the WFC had previously stored 54,000 pounds of anhydrous ammonia in 2006 and 2011. Given these facts, the WFC should have complied with the PSM standard because the company stored anhydrous ammonia, at least in 2006, 2011, and 2013, in quantities that exceeded its threshold quantity. However, CSB learned that the PSM standard did not apply to the WFC at the time of the incident because the facility qualified under OSHA's interpretation of the standard's retail facilities exemption.

At the time of the incident, a facility qualified under the retail facilities exemption if the following conditions were met: (1) the facility contained a highly hazardous chemical in a quantity that met or exceeded the threshold quantity for the chemical; (2) the facility used a process[458] covered by the PSM

[450] *Ibid*.
[451] 29 CFR 1910.119(a)(1)(i).
[452] CONSAD OSHA Report, 1988.
[453] 55 *Federal Register* 29150.
[454] CONSAD OSHA Report, 1988.
[455] *Ibid*.
[456] Federal OSHA in discussion with CSB, May 14, 2015.
[457] *See*: https://www.osha.gov/pls/oshaweb/owadisp.show_document?p_table=FEDERAL_REGISTER&p_id=16946 (accessed December 28, 2015).
[458] The PSM standard defines "process" as any activity involving a highly hazardous chemical, including any use, storage, manufacturing, handling, or onsite movement of such chemicals (or any combination of these activities). It also states that, for purposes of this definition, any group of vessels that are interconnected—and separate vessels

standard; and (3) more than 50 percent of the facility's income was derived from direct end users.[459] The WFC facility met all three conditions for its storage of anhydrous ammonia. It stored anhydrous ammonia, a highly hazardous chemical, in quantities that exceeded its threshold quantity. Also, the facility used a process because it stored the anhydrous ammonia, and storage meets the PSM standard definition of a "process." Because the WFC primarily sold its products, including anhydrous ammonia, to farmers (i.e., direct end users), the company met the third condition as well. Thus, the WFC qualified under the PSM standard's retail facilities exemption and was not required to comply with the standard.

If the PSM standard had applied to the WFC for its storage of anhydrous ammonia however, the WFC would have been required to conduct a process hazard analysis (PHA). A PHA must address the following:

- Hazards of the process.
- Identification of any previous incident that had a potential for catastrophic consequences in the workplace.
- Engineering and administrative controls applicable to the hazards and their interrelationships, such as appropriate application of detection methodologies to provide early warning of releases, with acceptable detection methods that might include process monitoring and control instrumentation with alarms and also detection hardware such as hydrocarbon sensors.
- Consequences of a failure of engineering and administrative controls.
- Facility siting.
- Human factors.
- Qualitative evaluation of a range of the possible safety and health effects on employees in the workplace if a failure of controls occurs.[460]

The WFC would have had to address facility siting as part of its PHA. Facility siting refers to the location of the covered process and its proximity to various other components within the facility's property.[461] It does not refer to the site of the facility in relation to the surrounding community.[462] A facility siting analysis at the WFC likely would have identified the close proximity of the facility's FGAN storage warehouse and its anhydrous ammonia storage tanks, thus triggering implementation of necessary safeguards to mitigate the possibility of potentially catastrophic successive incidents involving the two hazardous chemicals. This observation was a critical element of CSB's investigation because evidence indicated that the FGAN explosion damaged the facility's anhydrous ammonia tanks. If more force had been applied to the tanks, their contents could have been released into the neighboring community and

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that are located so that a highly hazardous chemical could be involved in a potential release— must be considered a single process.

[459] OSHA interpretation letter. *See*: https://www.osha.gov/pls/oshaweb/owadisp.show_document?p_table=INTERPRETATIONS&p_id=23885 (accessed December 28, 2015).

[460] *See*: https://www.osha.gov/Publications/osha3132.html (accessed on December 28, 2015).

[461] *See*: https://www.osha.gov/pls/oshaweb/owadisp.show_document?p_table=DIRECTIVES&p_id=1558 (accessed on December 28, 2015).

[462] *Ibid*.

caused even more fatalities and injuries. However, the WFC was not required to conduct facility siting because it qualified for the PSM standard's retail facilities exemption.

CSB communicated its concern about the retail facilities exemption in its March 31, 2014, comments to OSHA's December 9, 2013 RFI.[463] CSB asked OSHA to consider whether the retail facilities exemption should be revised in order to cover facilities such as WFC, which stored bulk quantities of chemicals covered by the PSM standard.[464]

8.4.1.1 Revised Interpretation of the PSM Retail Facilities Exemption

On July 22, 2015, OSHA issued a memorandum, "Process Safety Management of Highly Hazardous Chemicals and Application of the Retail Exemption" (Retail Exemption Memorandum).[465] OSHA noted in the memorandum that the PSM exemption for retail facilities does not define the term "retail facility."[466] However, the agency also said that the preamble to the PSM standard does explain that chemicals in retail facilities are generally sold in "small volume packages, containers, and allotments."[467] OSHA pointed out that the preamble gives an example of a gasoline station as a type of facility that would fit within the definition of a retail facility and thus qualify for the exemption.[468] OSHA also mentioned in the Retail Exemption Memorandum that other federal agencies define the term similarly.[469] In particular, it states that the U.S. Department of Commerce, which develops NAICS codes, characterizes retail trade as follows (emphasis added):

> The Retail Trade sector comprises establishments engaged in retailing merchandise, generally without transformation, and rendering services incidental to the sale of merchandise. The retailing process is the final step in the distribution of merchandise; retailers are, therefore, organized to sell merchandise in ***small quantities*** to the general public. [470]

However, this is not how OSHA had always interpreted its PSM retail exemption.

After promulgation of the PSM standard, OSHA issued a series of letters of interpretation[471] and a PSM compliance directive[472] that interpreted the retail exemption more broadly than originally intended.[473] Under these interpretations, a facility was considered exempt from the PSM standard if it derived "more

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[463] *See*: http://www.csb.gov/assets/1/16/CSB_RFIcomments.pdf (accessed on December 28, 2015).
[464] *Ibid*.
[465] OSHA. "Process Safety Management of Highly Hazardous Chemicals and Application of the Retail Exemption (29 CFR 1910.119(a)(2)(i))." OSHA Memorandum, July 22, 2015.
[466] *Ibid*.
[467] 57 *Federal Register* 6356, 6369.
[468] *Ibid*.
[469] OSHA. "Process Safety Management of Highly Hazardous Chemicals and Application of the Retail Exemption (29 CFR 1910.119(a)(2)(i))." OSHA Memorandum, July 22, 2015.
[470] U.S. Department of Commerce. *NAICS Manual*, Sector 44–45: Retail Trade.
[471] OSHA letters of interpretation explain OSHA requirements, which are set by statute, standards, and regulations.
[472] OSHA. Compliance Directive (CPL) 02-03-045.
[473] OSHA. "Process Safety Management of Highly Hazardous Chemicals and Application of the Retail Exemption (29 CFR 1910.119(a)(2)(i))." OSHA Memorandum, July 22, 2015.

than 50 percent of its income from direct sales of highly hazardous chemicals to the end user" (the 50 percent test).[474] This rationale is how the WFC claimed the retail exemption for its storage of anhydrous ammonia. If FGAN had been covered under the PSM standard before the WFC incident, the retail exemption, as it had been interpreted, would have precluded PSM coverage at the WFC and similar facilities. In addition, this 50 percent test allowed employers that sold or distributed large bulk quantities of highly hazardous chemicals directly to end users to claim the exemption, even if the end users were themselves commercial establishments.[475] This reasoning led to confusion about the definition of the term "end user." In its Retail Exemption Memorandum, OSHA said that it did not intend either of these outcomes.

OSHA's Retail Exemption Memorandum rescinded all previous documents, letters of interpretation, and memoranda related to the retail exemption and the 50 percent test.[476] OSHA states that its interpretation of the exemption is now more consistent with the standard's original intent.[477] In reference to the NAICS Manual, OSHA states that:

> Only facilities, or the portions of facilities, engaged in retail trade as defined by the current and any future updates to sectors 44 and 45 of the NAICS Manual may be afforded the retail exemption at 29 CFR 1910.119(a)(2)(i).[478]

Facilities that fall within Sectors 44–45: Retail Trade, consist of a number of subsectors. These facilities are now (or are still) considered retail facilities eligible for the retail exemption. Notably, NAICS codes typically used for FGAN bulk storage and sales do not fit into one of these classifications. As such, facilities that store or sell bulk FGAN do not qualify for the retail exemption. If OSHA's new interpretation were in effect before the incident, the WFC could not have claimed the retail exemption for its storage of anhydrous ammonia. Furthermore, it could not have claimed the exemption for its storage of FGAN had FGAN been included on the PSM list pre-incident.

If this new interpretation had been in effect before the incident, the WFC might have recognized that its storage of anhydrous ammonia was covered by the PSM standard. Although compliance efforts would have focused on this potential hazard, the WFC might have learned about FGAN-related hazards as well. As previously discussed, if the WFC had conducted a facility siting analysis, it could have identified the close proximity of its FGAN storage warehouse to its anhydrous ammonia pressure tanks. This may have

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474 *Ibid*.
475 *Ibid*.
476 *Ibid*.
477 *Ibid*. According to a December 23, 2015, OSHA memorandum, through September 30, 2016, OSHA will not cite employers for violations of the PSM standard at facilities that it would not have cited applying the interpretation of the term "retail" that was in place prior to July 22, 2015.
478 OSHA. "Process Safety Management of Highly Hazardous Chemicals and Application of the Retail Exemption (29 CFR 1910.119(a)(2)(i))." OSHA Memorandum, July 22, 2015. Facilities that fall under Sectors 44–45: Retail Trade consist of a number of subsectors, including Motor Vehicle and Parts Dealers (NAICS 441), Building Material and Garden Equipment and Supplies Dealers (NAICS 444), Gasoline Stations (NAICS 447), and General Merchandise Store (NAICS 452).

led the WFC to explore the potential for FGAN to catch fire and detonate under certain conditions. It also may have caused the WFC to implement safeguards to prevent hazards associated with the two different chemicals.

OSHA's revised interpretation of the retail exemption would mean that facilities such as the WFC would be covered for their use of anhydrous ammonia. According to the fertilizer industry, more than 3,800 U.S. retail facilities previously exempted by the older interpretation of the retail exemption would be covered under the requirements of the PSM standard because of anhydrous ammonia storage.[479] WFC use of FGAN could also be regulated directly in the future, but only if FGAN were added to PSM's List of Highly Hazardous Chemicals, Toxics and Reactives. CSB recommends that OSHA consider including FGAN for coverage under the PSM standard.[480] CSB supports OSHA's revised interpretation of the retail exemption to guarantee that potential changes to the PSM standard will apply to facilities like the WFC that store anhydrous ammonia as well as FGAN, which would provide the basis for the CSB's proposed recommendation to add FGAN to the PSM list.

8.4.1.2 Guidance on Recognized and Generally Accepted Good Engineering Practices Under the PSM Standard

OSHA also recently addressed its reference to the common industry term, "recognized and generally accepted good engineering practices" (RAGAGEP), under its PSM standard. This term is often used in performance-based standards like PSM. Generally, standards can be either prescriptive or performance based. As its name suggests, a prescriptive standard sets rigid compliance specifications. A performance-based standard, on the other hand, simply delineates the expected performance outcome or end result, without specifying how the outcome or result is to be achieved. In other words, a prescriptive standard describes *how* something is to be achieved, but a performance-based standard only specifies *what* is to be accomplished. For example, OSHA's Explosives and Blasting Agents standard (Section 8.2) is a prescriptive standard that contains FGAN-specific provisions. That part of the standard is prescriptive because its provisions set out *how* to handle FGAN; the provisions are inflexible.

In contrast, OSHA's PSM standard is performance-based. It employs a broad approach to materials and applications and enables incorporation of current industry practices. As a performance-based standard, it allows employers to select the RAGAGEP that they choose to apply to their facilities.[481] These chosen RAGAGEP are the ones that employers must follow at their facilities so that they are deemed compliant. Although the PSM standard does not define RAGAGEP, OSHA's Petroleum Refinery PSM National

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[479] TFI/ARA Hearing Statement: "Examining the Use of Agency Regulatory Guidance." *See*: http://www.mo-ag.com/uploaded/Senate%20HSGAC%20RFAM%20Hearing%209-23-15.pdf (accessed December 1, 2015).

[480] OSHA has initiated a Small Business Regulatory Enforcement Fairness Act panel on its PSM standard, after issuing an RFI in November 2013 seeking public comment on ways to improve the standard. ATF/OSHA/EPA. "Actions to Improve Chemical Facility Safety and Security." ATF/OSHA/EPA Fact Sheet, June 2015.

[481] OSHA. "RAGAGEP in Process Safety Management Enforcement." OSHA Memorandum, June 8, 2015.

Emphasis Program references the definition established in the Center for Chemical Process Safety's *Guidelines for Mechanical Integrity Systems*:

> Recognized and Generally Accepted Good Engineering Practices (RAGAGEP) are engineering, operation, or maintenance activities based on established codes, standards, published technical reports or recommended practices or a similar document. RAGAGEP detail generally approved ways to perform specific engineering, inspection or mechanical integrity activities, such as fabricating a vessel, inspecting a storage tank, or servicing a relief valve.[482]

This is the definition OSHA references in addressing its use of the term under the PSM standard.

Following the WFC incident, OSHA provided guidance on its use of the term RAGAGEP under its PSM standard in a June 8, 2015, memorandum, "RAGAGEP in Process Safety Management Enforcement" (PSM RAGAGEP Memorandum). As noted by OSHA in its PSM RAGAGEP Memorandum, the PSM standard directly references or implies the use of RAGAGEP in three provisions:

1. 29 CFR 1910.119(d)(3)(ii): Employers must document that all equipment in PSM-covered processes complies with RAGAGEP.
2. 29 CFR 1910.119(j)(4)(ii): Inspections and tests are performed on process equipment subject to the standard's mechanical integrity requirements in accordance with RAGAGEP.
3. 29 CFR 1910.119(j)(4)(iii): Inspection and test frequency follows manufacturer's recommendations and good engineering practice, and more frequently if indicated by operating experience.[483]

Accordingly, RAGAGEP under the PSM standard apply to process equipment design, installation, operation, and maintenance; inspection and test practices; and inspection and test frequencies.[484]

The PSM RAGAGEP Memorandum notes the following primary sources of RAGAGEP: (1) published and widely adopted codes, (2) published consensus documents, and (3) published nonconsensus documents.[485] Published and widely adopted codes are those consensus standards that have been widely adopted by federal, state, or municipal jurisdictions.[486] Published consensus documents are identified as those published by certain organizations which must follow the American National Standards Institute (ANSI) "Essential Requirements: Due process requirements for American National Standards" (ANSI Essential Requirements).[487] Published nonconsensus documents include publications that do not conform to the ANSI Essential Requirements and peer-reviewed technical articles.[488] It is important to note that

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[482] OSHA. Compliance Directive (CPL) 03-00-010.
[483] OSHA. "RAGAGEP in Process Safety Management Enforcement." OSHA Memorandum, June 8, 2015.
[484] *Ibid*.
[485] *Ibid*.
[486] *Ibid*. Examples of published and widely adopted codes include NFPA 101 (*Life Safety Code*) and NFPA 70 (*National Electric Code*).
[487] *Ibid*. Examples of published consensus documents include the ASME B31.3, "Process Piping Code," and the International Institute of Ammonia Refrigeration (IIAR) ANSI/IIAR 2-2008, "Equipment, Design, and Installation of Closed-Circuit Ammonia Mechanical Refrigerating Systems."
[488] *Ibid*. Examples of published nonconsensus documents include the Chlorine Institute "pamphlets" focusing on chlorine and sodium hypochlorite safety and the Design Institute for Emergency Relief Systems guideline book addressing technology for reactive and multiphase relief systems design.

while OSHA generally accepts published and widely adopted codes and published consensus documents as RAGAGEP, published nonconsensus documents are not necessarily generally accepted. However, OSHA may choose to accept them if they are applicable and appropriate.[489]

The PSM RAGAGEP Memorandum also explains the difference between "shall" and "should" language. In particular, OSHA notes that positive and negative uses of "shall," "must," or similar language in published RAGAGEP reflect the developer's view that the practice is a mandatory minimum to control a hazard.[490] Thus, if an employer deviates from such RAGAGEP, OSHA will presume a violation.[491] Where "should" language applies in RAGAGEP, OSHA presumes that employer compliance with the recommended approach is acceptable.[492] If an employer chooses to deviate from the recommended approach, however, OSHA will evaluate whether the employer has determined and documented that its alternative approach is at least as protective as the recommended approach or whether the recommended approach does not apply to the employer's operation.[493] OSHA presumes a violation if employers act in a way that RAGAGEP deem they "should not."[494]

These enforcement considerations emphasize that RAGAGEP are more than optional recommendations. Many RAGAGEP are mandatory standards based on scientific data and previous incidents and it is crucial that employers comply with them. If FGAN is added to the PSM list, the use of RAGAGEP will allow facilities to select and comply with FGAN-specific standards, such as NFPA 400, that have been recently updated to address and help prevent the conditions that led to the WFC explosion.

8.4.2 EPA Risk Management Program Rule

The EPA Risk Management Program rule (40 CFR Part 68, Subparts A through H) is intended to prevent and minimize the consequences of accidental releases of toxic or flammable substances.[495] Enacted in 1996, the regulation required facilities to be compliant by 1999.[496] In general, covered facilities are those with a substance on one of the Risk Management Program rule's two lists, one for toxic substances and one for flammable substances, in a quantity that meets or exceeds the threshold quantity for the substance.[497] These facilities must perform a hazard assessment, consisting of worst case and alternative release scenarios as well as a five-year accident history; implement an accident prevention program (which is required for most facilities); establish an emergency response program; and develop an RMP

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489 *Ibid*.
490 *Ibid*.
491 *Ibid*.
492 *Ibid*.
493 *Ibid*.
494 *Ibid*.
495 EPA. "Accidental Release Prevention Requirements: Risk Management Program Under the Clean Air Act." RFI, July 31, 2014.
496 *See*: http://nepis.epa.gov/Exe/ZyPDF.cgi/100038BD.PDF?Dockey=100038BD.PDF (accessed on December 28, 2015).
497 *See*: http://www.epa.gov/rmp/risk-management-plan-rmp-rule-overview (accessed on December 28, 2015).

and submit it to EPA.[498] Facility management must revise and resubmit its RMP to EPA at least every five years.[499]

EPA has developed three program levels for process classification to ensure that individual processes are subject to requirements that appropriately match their size and risks they pose.[500] Program Level 1 applies to processes with lower risks that would not significantly affect the public in a worst case release scenario and that have had no accidents with specific offsite consequences in the last five years.[501] These facilities have limited and/or minimal accident prevention requirements.[502] Program Levels 2 and 3 cover higher-risk facilities that must meet more stringent accident prevention requirements.[503] A Program Level 3 facility is not eligible for classification under Program Level 1 and is either (1) subject to OSHA's PSM standard or (2) classified in one of 10 specified NAICS codes.[504] Program Level 3 requires implementation of an accident prevention program that is virtually equivalent to the one required under the PSM standard.[505] Program Level 2 applies to facilities that are not eligible for classification in Program Level 1 or Program Level 3.[506] Program Level 2 requires implementation of a streamlined accident prevention program.[507]

The WFC was a Program Level 2 facility under the Risk Management Program rule for its storage of anhydrous ammonia, a regulated substance, which the WFC kept in amounts that exceeded the substance's threshold quantity. Program Level 2 facilities must conduct hazard reviews.[508] For this requirement to be satisfied, facilities must conduct a review and identify the following:

- Hazards associated with the Program 2 process and regulated substances.
- Opportunities for equipment malfunction or human error that could cause a release.
- Safeguards that will control the hazards or prevent the malfunction or error.
- Steps to detect or monitor releases.[509]

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[498] *Ibid*.
[499] *Ibid*.
[500] *See*: http://www.epa.gov/sites/production/files/2013-10/documents/caa112_rmp_factsheet.pdf (accessed on December 28, 2015).
[501] *Ibid*.
[502] *Ibid*.
[503] *Ibid*.
[504] *Ibid*. These 10 manufacturing NAICS codes are (1) 32211 pulp mills; (2) 32411 petroleum refineries; (3) 32511 petrochemical manufacturing; (4) 325181 alkalis and chlorine manufacturing; (5) 325188 all other basic inorganic chemical manufacturing; (6) 325192 cyclic crude and intermediate manufacturing; (7) all other basic organic chemical manufacturing; (8) plastics material and resin manufacturing; (9) nitrogenous fertilizer manufacturing; and (10) pesticide and other agricultural chemical manufacturing. *See*: http://www2.epa.gov/sites/production/files/2013-11/documents/cd-chap-02.pdf (accessed on December 28, 2015).
[505] *See*: http://www.epa.gov/sites/production/files/2013-10/documents/caa112_rmp_factsheet.pdf (accessed on December 28, 2015).
[506] *Ibid*.
[507] *Ibid*.
[508] *See*: http://www.epa.gov/sites/production/files/2013-11/documents/chap-06-final.pdf (accessed on December 28, 2015).
[509] *Ibid*.

CSB discovered that the WFC implemented a prevention program that included a hazard review. In its most recent RMP from 2011, the WFC identified major hazards, which included toxic releases, equipment failure, and earthquakes, but did not include fire or explosion.[510] The facility also indicated that it did not use mitigation systems, such as sprinklers, for its storage of anhydrous ammonia.[511] Clearly, this hazard review did not provide the type of protection needed to address the fire and explosion that occurred on the day of the WFC incident. Because FGAN is not a regulated substance, the WFC was not required to conduct such a hazard review for its storage of FGAN. Accordingly, CSB recommends that FGAN be added to the Risk Management Program list.[512]

CSB contends that EPA should consider adding FGAN to the list of regulated substances, taking into account the more recent recognition of the unpredictable explosive hazards of FGAN, better awareness of the location of FGAN facilities across the United States, greater knowledge of the quantity of FGAN normally stored at these facilities, and continuance of FGAN-related incidents since the issuance of the final Risk Management Program list. As demonstrated in Appendix B, FGAN-related incidents continue to occur, domestically and abroad. Despite tremendous property damage and economic cost, the most devastating result of these incidents is the immeasurable loss of human life. CSB found that a likely cause of such loss of life is the alarming number of FGAN facilities located in communities—next to schools, hospitals, residences, and businesses (discussed in Section 9). Another cause, as determined by CSB, is the tendency of these facilities to store FGAN in large quantities. Coupling these factors with the more recent recognition that FGAN is susceptible to unstable detonation under certain conditions, CSB recommends that FGAN be listed under the Risk Management Program rule. Moreover, CSB reviewed original listing criteria and found that inclusion of FGAN on the Risk Management Program list is warranted.

8.4.2.1 Risk Management Program Rule Listing Criteria Background

Under CAA Section 112(r)(4), the factors to be considered in listing substances for Risk Management Program rule coverage are (1) the severity of acute adverse health effects associated with accidental releases of the substance, (2) the likelihood of accidental releases of the substance, and (3) the potential magnitude of human exposure to accidental releases of the substance.[513] When EPA first promulgated its Risk Management Program list of chemicals and threshold quantities in 1994, it reviewed 11 different lists, including three EPA lists.[514] The criteria used for development of these lists were reviewed to determine whether the criteria were related to the factors mandated by Congress for list development

[510] WFC 2011 RMP submission to EPA.
[511] *Ibid*.
[512] EPA has issued a RFI and worked on a Notice of Proposed Rulemaking for its Risk Management Program rule. ATF/OSHA/EPA. "Actions to Improve Chemical Facility Safety and Security." ATF/OSHA/EPA Fact Sheet, June 2015.
[513] 58 *Federal Register* 5102 (January 19, 1993).
[514] *Ibid*.

under CAA Section 112(r).[515] Acute toxicity was generally considered in developing these lists of chemicals, but some also used flammability and explosivity as criteria for regulating chemicals.[516]

As part of its review of the first factor to be considered for listing substances under the Risk Management Program rule, EPA reviewed chemicals that could cause severe acute adverse health effects. EPA found that the severity of acute adverse health effects can be related to the inherent hazards (i.e., hazardous material properties that cannot be changed) of the substances of interest, such as the toxicity of a substance resulting in lethal effects.[517] EPA noted that acute adverse health effects also could result from other inherent hazards, such as the flammability or high reactivity of the substance.[518] Importantly, it stated that the phenomena associated with these hazards could be, for example, radiant heat from a chemical fire or blast waves from an explosion of a chemical.[519]

In reviewing the second Risk Management Program listing criteria factor, EPA stated that the likelihood of an accidental release of a chemical can be related to typical usage and handling scenarios, such as equipment commonly used in typical facility operations.[520] EPA stated that ubiquitous substances, because of greater handling and use, might have a greater potential for an accidental release.[521] The agency observed that a history of a large number of accidents in the past, for example, might be an indicator of an existing hazard related to a particular substance and its potential to be involved in accidental releases in the future.[522] Notably, EPA stated that chemicals that are found in large volumes at many locations and chemicals that are particularly prevalent (e.g., commodity chemicals, like chlorine and ammonia) might be more likely to be involved in accidental releases than small-volume, less commonly used chemicals.[523]

With respect to the last factor to be considered for Risk Management Program listing, EPA found the magnitude of human exposure associated with accidental releases to be related to the severity of the health effects (hazards) and the likelihood of a release (the chance that a release will have an effect on the population of environment beyond the facility fenceline).[524] The agency noted that this definition was somewhat different from the traditional risk assessment definition of human exposure, which relates magnitude of exposure to the population and sensitive environments that might be affected by a release from a specific site.[525] It recognized that factors that might affect the magnitude of human exposure could be site specific or accident specific and could vary widely by location and incident.[526] Significantly, EPA

[515] *Ibid*.
[516] *Ibid*.
[517] *Ibid*.
[518] *Ibid*.
[519] *Ibid*.
[520] *Ibid*.
[521] *Ibid*.
[522] *Ibid*.
[523] *Ibid*.
[524] *Ibid*.
[525] *Ibid*.
[526] *Ibid*.

also contended that proximity to population centers, for example, might play a role in the magnitude of accidental releases.[527]

8.4.2.2 Risk Management Program Rule Listing Criteria and Coverage for FGAN

CSB reviewed the original listing criteria to determine their application to FGAN and found support for inclusion of FGAN on the Risk Management Program list. First, CSB found a high severity of acute adverse health effects related to accidental releases of FGAN because one of the phenomena associated with the hazards of FGAN as a reactive and as an explosive is blast waves from an FGAN explosion. Acute adverse health effects from blast waves can include not only major injuries (such as fractures and injuries to the head, ears, and eyes), but also death. All of these were reported after the WFC incident. As stated previously, EPA specifically deemed blast waves to be considered in assessing the severity of acute adverse health effects related to accidental releases of the substance.

CSB concluded that FGAN meets the second criteria for listing under the Risk Management Program rule because the likelihood of accidental releases of FGAN is high. Before assessing the merits of this listing factor, CSB sought to define such accidental releases and ultimately found that they can be described as emissions of blast waves and thermal energy from FGAN explosions. An accidental release is defined by the CAA Amendments of 1990 as "an unanticipated emission of a regulated substance or other extremely hazardous substance into the ambient air from a stationary source."[528] In general, this definition has been interpreted to apply only to gases and liquids, not to solids such as FGAN.[529] However, in its original Risk Management Program rule listing notice, EPA determined the proposed threshold quantity for high explosives[530] based on the quantity that could produce potentially lethal blast waves from an explosion at a distance of 100 meters.[531] This determination is significant because it supports the conclusion that EPA envisioned blast waves as qualifying as unanticipated emissions when it considered explosives for addition to the Risk Management Program list.

CSB also conducted its own research on explosions and emissions. An explosion involves a sudden release of large amounts of energy. This energy release can be dissipated as blast waves, propulsion of

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[527] *Ibid*.
[528] 40 CFR 68.3
[529] ARA. "Re: Accidental Release Prevention Requirements: Risk Management Programs under the Clean Air Act, Section 112(r)(7); Request for Information; Docket # EPA-HQ-OEM-2014-0328; FRL-9911-61-OSWER." October 29, 2014.
[530] High explosives represent the category of explosives that might most easily detonate. 59 *Federal Register* 4487 (January 31, 1994). They are likely to cause severe impacts in detonation scenarios. These explosives were subsequently deleted from coverage in 1998 due to settlement of litigation with the Institute for Manufacturers of Explosives. 63 *Federal Register* 640 (January 6, 1998). It is important to note, however, that this was not due to any potential misinterpretation of the term "accidental release" (as discussed in the *Explosive Substances* Section).
[531] 58 *Federal Register* 5102 (January 19, 1993).

debris, or the emission of thermal and ionizing radiation.[532] Furthermore, the term "emissions" is not strictly limited to the release of toxic or flammable liquids and vapors. It can refer to the generation of hot gases and overpressures that result from explosions. This interpretation aligns with EPA's reasoning that explosives can produce accidental releases, as demonstrated by EPA's original inclusion of high explosives on the Risk Management Program list and by its associated determination of the appropriate threshold quantity for such explosives. CSB supports EPA's original reasoning that blast waves are emissions for purposes of listing substances under the Risk Management Program rule. In particular, CSB supports that this reasoning should apply to FGAN.

CSB concluded that there is a reasonable likelihood of an accidental release of FGAN because FGAN is a ubiquitous commodity chemical that is stored in large volumes at many locations. CSB found that this was true not only at the WFC facility (where the WFC stored 80,000 to 120,000 pounds of FGAN), but also at domestic fertilizer facilities throughout the South and the Midwest where Alabama, Missouri, Tennessee and Texas make up more than 50 percent of FGAN consumption in the United States.[533] FGAN also has been involved in a large number of accidents in the past (described in Appendix B). It has been at the center of major disasters such as the Oppau, Germany, incident in 1921 and the Texas City, Texas, incident in 1947; each caused more than 500 fatalities. EPA considered these exact factors (i.e., ubiquity, commodity, volume, and past accident history) to be indicative of whether an accidental release of a substance is likely.

Finally, CSB determined the magnitude of human exposure associated with accidental FGAN releases is significant because FGAN storage is commonly located close to many population centers. This was clearly the case in West, Texas, where a playground, four public school buildings, a nursing home, and an apartment complex all surrounded the WFC facility. It is also the case throughout Texas, where many fertilizer facilities are in communities and downtown neighborhoods (noted in Section 5.4). Because of the WFC investigation and other CSB investigations that identified offsite consequences from chemical releases, land use planning and siting of chemical facilities remain important issues for CSB. As discussed previously, EPA considered the proximity of facilities to population centers as a significant determinant of potential impact. The WFC incident demonstrates the validity of this conclusion. After finding that all three listing criteria were satisfied, CSB concludes that FGAN warrants listing under the Risk Management Program rule.

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[532] Akhavan, *Chemistry of Explosives* (3rd Edition). London: Royal Society of Chemistry, 2011. *See*: http://app.knovel.com/hotlink/toc/id:kpCEE0001C/chemistry-explosives/chemistry-explosives (accessed on November 14, 2015).

[533] *See*: https://www.tfi.org/sites/default/files/documents/ammoniumnitrateinfographic.pdf (accessed November 17, 2015). Akhavan, *Chemistry of Explosives* (3rd Edition). London: Royal Society of Chemistry, 2011. *See*: http://app.knovel.com/hotlink/toc/id:kpCEE0001C/chemistry-explosives/chemistry-explosives (accessed on November 14, 2015).

[533] *See*: https://www.tfi.org/sites/default/files/documents/ammoniumnitrateinfographic.pdf (accessed November 17, 2015).

8.4.2.3 Additional Support for Risk Management Program Rule Coverage for FGAN

Besides considering the three listing criteria factors mandated under the CAA, EPA identified other substances based on similarities with the mandated substances and selection criteria.[534] EPA considered options that accounted for the inherent hazards of the substances to be listed and for the potential of these hazards to affect the community if an accidental release occurred.[535] In particular, EPA analyzed hazards such as toxicity, flammability, reactivity, explosivity, and radioactivity, stating that all of them can result in acute effects after short-term exposure.[536] EPA identified substances associated with each of these hazards, but also considered the potential impact that the identified substances would have on the community if a release took place.[537] It evaluated each hazard independently, as well as each hazard's potential to pose a threat to the community.[538] Ultimately, a group of toxic substances, a group of flammable substances, and a group of explosive substances were proposed in the January 19, 1993, rule for addition to the 16 mandated substances in the CAA.[539] Because they pertain to FGAN, CSB conducted further research on explosives and on reactive substances.

Explosive Substances

With respect to the group of explosive substances, EPA proposed to focus on physical hazards because of their ability to impact communities beyond the fenceline in the event of an accidental release.[540] EPA viewed commercial high explosives, which have the potential to detonate, as the explosive substances with the greatest potential to affect such communities and therefore proposed commercial high explosives as a category for listing.[541] In determining the threshold methodology, EPA indicated that a blast wave overpressure of 3.0 psi from a detonation could have potentially lethal effects in communities beyond the fenceline.[542] The agency noted that this overpressure level could cause serious structural damage to buildings, lead to serious wounds from flying glass, and potentially cause eardrum rupture.[543] The agency also considered reactive substances that have explosive properties, including oxidizers (e.g., pure AN), for listing.[544] In its final decision however, EPA deferred listing these types of substances for lack of an adequate technical basis upon which to evaluate offsite consequences from unstable and reactive substances.[545] Nonetheless, EPA concluded in its response that "this decision does not preclude the

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[534] 58 *Federal Register* 5102 (January 19, 1993).
[535] *Ibid*.
[536] *Ibid*.
[537] *Ibid*.
[538] *Ibid*.
[539] *Ibid*.
[540] *Ibid*.
[541] *Ibid*.
[542] *Ibid*.
[543] *Ibid*.
[544] *Ibid*.
[545] EPA. "Proposed List of Substances and Thresholds for Accidental Release Prevention: Summary and Response to Comments," January 14, 1994: 146.

Agency from revisiting this issue in the future, in response to a petition to list, or when the list is reviewed and the listing criteria modified."[546]

For several decades, a number of agencies and organizations have regulated materials with explosive potential. ATF regulates the manufacture, processing, use, distribution, and storage of explosive materials; ATF regulations include requirements for licensing, permitting, and recordkeeping and for storage of explosives.[547] DOT regulates the transportation of explosives, and other agencies, such as OSHA, Mine Safety and Health Administration (MSHA), Department of Defense (DOD), and International Maritime Organization, regulate certain aspects of the explosive industry.[548] In its 1993 *Federal Register* notice, however, EPA stated that although explosives are regulated by federal, state, and local governments, these regulations do not uniformly address the issue of using appropriate hazard assessment techniques to identify hazards, designing and maintaining a safe facility, and minimizing the consequences of accidental releases when they do occur.[549] EPA noted that all of these elements were to be addressed in the Risk Management Program regulations, which it described as "intended to help focus on accident prevention."[550] The agency therefore asserted that these substances should be considered for purposes of list development and accidental release prevention regulations, and for some time, high explosives (classified as Class 1, Division 1.1 on DOT's Hazardous Materials Table) were included on the final 1994 Risk Management Program list.[551] However, DOT Division 1.1 explosives were delisted four years later.[552]

After promulgation of the Risk Management Program list, the Institute of Makers of Explosives (IME) petitioned against EPA for judicial review, challenging the listing of high explosives.[553] IME objections included the contention that existing ATF, DOT, MSHA, and OSHA regulations already adequately controlled DOT Division 1.1 explosives.[554] EPA and IME ultimately settled, with EPA agreeing to delist the explosives in exchange for IME's promise to undertake specific measures to enhance local emergency response.[555] CSB found this information important with respect to its investigation because FGAN has explosive properties under certain conditions. Accordingly, CSB conducted research to determine whether FGAN was listed and then delisted along with these DOT Division 1.1 explosives.

CSB found that DOT Division 1.1 explosives include one less common form of AN (classified by the United Nations as UN0222) containing more than 0.2 percent carbonaceous material. However, this form of AN is not commercially used or manufactured. Importantly, CSB discovered that FGAN has never

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546 *Ibid*.
547 58 *Federal Register* 5201 (January 19, 1993).
548 *Ibid*.
549 *Ibid*.
550 *Ibid*.
551 *Ibid*.
552 79 *Federal Register* 44607 (July 31, 2014).
553 61 *Federal Register* 16598 (April 15, 1996).
554 *Ibid*.
555 *Ibid*. *See also*: 63 *Federal Register* 640 (January 6, 1998).

been explicitly regulated under the Risk Management Program rule because it is not a DOT Division 1.1 explosive. Furthermore, even if FGAN were a DOT Division 1.1 explosive, the DOT Division 1.1 explosives were never specifically identified by name on the Risk Management Program list. Therefore, AN has never explicitly been listed under the Risk Management Program rule. Nonetheless, CSB found it significant that EPA evaluated explosives, and the effects they can have upon communities in detonation scenarios, when determining the substances to include on the Risk Management Program list.[556] Because FGAN can detonate under certain conditions, CSB recommends that FGAN be included for coverage under the Risk Management Program rule. Further support for including FGAN on the Risk Management Program list can be found in EPA's original inquiry into reactive substances and in CSB's past work on reactives.

Reactive Substances

At the time of its 1993 *Federal Register* notice, EPA was attempting to evaluate the hazards of reactive and unstable chemicals and to develop an adequate technical basis for determining the potential effects on the community.[557] For example, EPA investigated computer models that estimate heats of reaction and also the possible use of heats of reaction to compare the effects of an explosion of an unstable substance to the effects of an explosion of TNT.[558] EPA stated that this method would only be appropriate for substances that detonate, an outcome that appeared to be unlikely for many unstable substances.[559] Ultimately, EPA contended that unstable and reactive substances would be considered for listing for accidental release prevention if the evaluation indicated potential community consequences.[560] On the basis of the WFC investigation and on the CSB's "Improving Reactive Hazard Management" study, CSB recommends that FGAN be added to the Risk Management Program list.

In the early 1990s, EPA considered listing reactive substances, such as AN, on the Risk Management Program list.[561] Specifically, EPA assessed whether to include chemicals whose reactive properties could cause impacts on nearby communities in the event of an accident.[562] In December 2002, CSB issued the study, "Improving Reactive Hazard Management," which examined reactive hazard management across the United States.[563] The study found regulatory coverage of reactive hazards to be a key issue.[564] As a result of the study, CSB issued several regulatory recommendations, including the following recommendation to EPA:

> Revise the Accidental Release Prevention Requirements, 40 CFR 68, to explicitly cover catastrophic reactive hazards that have the potential to seriously impact the public, including

[556] 58 *Federal Register* 5102 (January 19, 1993).
[557] *Ibid*.
[558] *Ibid*.
[559] *Ibid*.
[560] *Ibid*.
[561] *Ibid*.
[562] *Ibid*.
[563] CSB. "Hazard Investigation: Improving Reactive Hazard Management." December 2001.
[564] CSB. "Hazard Investigation: Improving Reactive Hazard Management." December 2001, 3.

those resulting from self-reactive chemicals and combinations of chemicals and process-specific conditions. Take into account the recommendations of this report to OSHA on reactive hazard coverage. Seek congressional authority if necessary to amend the regulation.[565]

Unfortunately, EPA has not initiated rulemaking consistent with CSB's recommendation more than 10 years since its issuance.[566] Therefore, CSB has categorized the status of this recommendation as "Open—Unacceptable Response."[567]

Since issuing its reactive hazard investigation study in 2002, CSB has investigated several industrial accidents involving reactive chemicals.[568] These are summarized in Table 12.

Table 12. CSB Investigations Involving Reactive Chemicals Since 2002

Incident	**Date**	**Location**	**Severity**
First Chemical Corp.: Reactive Chemical Explosion	October 13, 2002	Pascagoula, MS	• 3 injured
MFG Chemical Inc.: Toxic Gas Release	April 12, 2004	Dalton, GA	• 154 hospitalized
Synthron Chemical: Explosion	July 31, 2007	Morganton, NC	• 1 fatality • 12 injured
T2 Laboratories Inc.: Reactive Chemical Explosion	December 19, 2007	Jacksonville, FL	• 4 fatalities • 13 hospitalized
Bayer CropScience: Pesticide Waste Tank Explosion	August 28, 2008	Institute, WV	• 2 fatalities
West Fertilizer Company: Explosion and Fire	April 17, 2013	West, TX	• 15 fatalities • More than 260 injured

It is important to note, however, that Table 12 depicts only those incidents involving reactive chemicals *that CSB investigated* since 2002. That is, these incidents do not represent the universe of reactive chemical accidents, which is much larger.

[565] CSB. "Hazard Investigation: Improving Reactive Hazard Management." December 2001, 102.
[566] CSB. "Recommendations Status Change Summary." Improving Reactive Hazard Management, 2001-1-H-R3. March 11, 2014.
[567] *See*: http://www.csb.gov/recommendations/?F_RecipientId=8 (accessed on December 17, 2015). OSHA's associated recommendations are also categorized as "Open—Unacceptable Response." *See*: http://www.csb.gov/UserFiles/file/CSB-OSHACorrespondence.pdf (accessed on January 15, 2016).
[568] CSB. "Recommendations Status Change Summary." Improving Reactive Hazard Management, 2001-1-H-R3. March 11, 2014.

8.4.2.3.1.1 General Duty Clause

After the incident, CSB referenced its reactives study in "Preliminary Findings of the CSB from its Investigation of the West Fertilizer Explosion and Fire."[569] With respect to the EPA Risk Management Program rule, CSB specifically stated:

> In developing the RMP regulation, the EPA did not explicitly include explosives or reactive chemicals in the list of covered chemicals. In 2002, the CSB issued a study on reactive hazards, identifying 167 prior reactive incidents (including a 1994 explosion at an AN manufacturer). The Board recommended that . . . EPA expand [its] standard[] to include reactive chemicals and hazards. However, [EPA has not] yet acted upon the recommendation[].[570]

On June 6, 2014, after learning the Open—Unacceptable Response status of its recommendation, EPA raised, in a letter to CSB, its concern that CSB had mischaracterized in its reactives study the scope and history of EPA's use of the CAA Section 112(r)(1), General Duty Clause (GDC).[571] Because the GDC is a provision which CSB believes likely could have been used to cite the WFC facility, but was not, CSB conducted further research into the requirement.

The GDC is a statutory obligation that makes owners and operators of facilities that possess regulated and other extremely hazardous substances responsible for ensuring that their chemicals are managed safely.[572] In CAA Section 112(r)(1), the GDC states:

> The owners and operators of stationary sources producing, processing, handling or storing such substances [i.e., a chemical in 40 CFR Part 68 or any other extremely hazardous substance] have a general duty [in the same manner and to the same extent as the general duty clause in the Occupational Safety and Health Act] to identify hazards which may result from (such) releases using appropriate hazard assessment techniques, to design and maintain a safe facility taking such steps as are necessary to prevent releases, and to minimize the consequences of accidental releases which do occur.[573]

Accordingly, EPA has the authority to apply the GDC to facilities not only after incidents, but also before incidents to prevent them. The GDC is a broad provision with great potential to enhance safety measures at facilities that contain certain hazardous substances.

In addressing the hazards associated with reactive substances and application of the GDC, CSB has stated that "many substances are unlikely to be considered 'extremely hazardous' since they do not present an inherent catastrophic reactive hazard until combined with other chemicals or under process-specific conditions."[574] This circumstance should not preclude, and EPA affirms has not precluded, such

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[569] CSB. "Preliminary Findings of the U.S. Chemical Safety Board from its Investigation of the West Fertilizer Explosion and Fire," June 27, 2013.
[570] *Ibid*.
[571] EPA letter to CSB, June 6, 2014.
[572] *See*: http://www2.epa.gov/sites/production/files/2013-10/documents/gdc-fact.pdf (accessed on December 29, 2015).
[573] 42 U.S.C. § 7412(r)(1).
[574] CSB. "Recommendations Status Change Summary." Improving Reactive Hazard Management, 2001-1-H-R3. March 11, 2014.

substances from enforcement under the GDC. EPA referenced a 1989 Report of the Senate Environment and Public Works Committee, which stated that the presumption should be that a substance is extremely hazardous if it causes significant adverse impacts by acute toxic effect or "by blast, fire, corrosion or other reaction."[575] The report also states that "extremely hazardous substances" would "include other agents which may or may not be listed" that "as the result of short-term exposures associated with [accidental] releases to the air cause death, injury or property damage due to their toxicity, reactivity, flammability, volatility, or corrosivity."[576] According to this report, therefore, EPA could apply the GDC to reactive substances. However, EPA did not use the GDC to cite the WFC after the incident for its unsafe storage of FGAN.

Considering the totality of the EPA regulatory landscape, CSB determined that requirements for facilities to safely store and handle FGAN are insufficient. As discussed, the Risk Management Program rule does not regulate FGAN because FGAN is not on the list of regulated substances. Furthermore, while EPA could use the GDC to impose requirements on facilities to ensure the safe management of FGAN as a reactive substance, EPA does not contend that the GDC is as easy to apply as a regulation. EPA may have been able to apply the GDC against the WFC after the incident, but it did not. Therefore, without more from the GDC, it is the recommendation of CSB that FGAN be included on the Risk Management Program list, especially in light of the fatal incident in West, Texas.

8.4.2.4 Risk Management Program Rule and Coverage of Anhydrous Ammonia

As previously discussed, although the WFC was not covered under the Risk Management Program rule for its storage of FGAN, it was covered under Program Level 2[577] of the rule for its storage of more than 10,000 pounds, the threshold limit, of anhydrous ammonia. The facility submitted its RMP registration in 1999, 2006,[578] and 2011.[579] The WFC's 2006 RMP for anhydrous ammonia included important safety elements to prevent, control, and respond to an anhydrous ammonia release.[580] For example, the insurance company conducted a hazard review to identify major release scenarios and address actions that would prevent or mitigate a release.[581] Another important feature of the RMP was development of an emergency action plan with step-by-step procedures, detailing how employees should respond to an anhydrous ammonia release.[582] Other program elements included operating procedures, maintenance and

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[575] EPA letter to CSB, June 6, 2014.

[576] Senate Committee on Environment and Public Works, CAA Amendments of 1989, Senate Report No. 228, 101st Congress, 1st Session 211 (1989).

[577] The WFC fell under Program 2 requirements for its storage of anhydrous ammonia because it did not meet the requirements for Program Level 3 and was not eligible for Program Level 1 coverage.

[578] The WFC did not resubmit its RMP registration as it was supposed to in 2004 because of a change in ownership. EPA cited the company in 2006 for failing to refile its RMP in a timely manner. The WFC refiled it in 2006.

[579] WFC RMP submissions to EPA.

[580] *Ibid*.

[581] *Ibid*.

[582] *Ibid*.

inspection programs, training programs, incident investigations, offsite consequence analyses, and compliance audits.[583]

The Risk Management Program rule also required the WFC to comply with RAGAGEP for anhydrous ammonia, such as ANSI K61.1, "Safety Requirements for the Storage and Handling of Anhydrous Ammonia," and OSHA's Storage and Handling of Anhydrous Ammonia regulation (29 CFR 1910.111).[584] As previously mentioned, the Risk Management Program list does not include FGAN, so the WFC was not required to take related Risk Management Program safety measures for FGAN. Of course, FGAN coverage under the Risk Management Program rule likely would have increased awareness of the explosion hazards of FGAN, leading to better management of the substance through compliance with federal safety regulations and best industry practices. If EPA had included FGAN under the Risk Management Program rule, the WFC would have been required to apply it for its storage of FGAN and perhaps could have reduced the risk of catastrophic accidents like the one that occurred at the WFC.

8.5 Emergency Planning

The CSB investigation of the WFC incident identified the explosive potential of FGAN. CSB further found that no immediate evacuation at the first sign of fire occurred, in part because no in-place emergency plan addressed response specifically to an incident at the WFC warehouse. This situation left emergency responders and the West community unaware of the urgent need to evacuate. For FGAN facilities, there must be a well-exercised local emergency plan that emphasizes immediate notification to emergency responders and the community at the first sign of fire, as well as evacuation protocols. If there was an immediate evacuation once the fire was detected at the WFC, the number of fatalities and injuries likely would have been lower.

Emergency planning is part of emergency management, which includes four different stages: (1) mitigation, (2) planning, (3) response, and (4) recovery. The nation's emergency management system is intended to prepare communities for all types of hazards, including natural disasters, terrorism, and hazardous materials (HAZMAT) incidents. The responsibilities of emergency management personnel are shared among federal agencies that provide assistance through funding and training. For example, DHS primarily focuses its efforts on terrorism and natural hazards and also serves as the umbrella organization for other agencies that supply assistance to state and local authorities. Other federal agencies such as EPA and OSHA have emergency planning regulations for environmental and occupational accidents involving HAZMAT. The next sections discuss these regulations at the federal, state, and city levels and discuss their relevance to the WFC incident.

[583] *Ibid*.
[584] 40 CFR 68.48(b).

8.5.1 Federal Emergency Planning

In response to growing concerns about the safety and health of people and the environment after releases of hazardous substances in the U.S. in the 1970s and 1980s and the disaster in Bhopal, India, Congress passed new laws authorizing EPA and OSHA to regulate these risks. One was the Emergency Planning and Community Right-to-Know Act (EPCRA) of 1986, which was intended to address concerns about local preparedness for chemical emergencies and to ensure public access to information. EPCRA established a framework for states to organize resources to pre-plan for chemical accidents. EPCRA requirements include: (1) emergency planning (SARA Title III, Sections 301–303); and (2) emergency and hazardous chemical inventory reporting (SARA Title III, Sections 311 and 312).[585] Each section of EPCRA covers a subset of chemicals and the statute and EPA regulations specify quantities that trigger reporting requirements (Table 13).[586] Because they are pertinent to the WFC incident, requirements for emergency planning and hazardous chemical inventory reporting are discussed in greater detail.

Table 13. EPCRA Chemicals and Reporting Thresholds

	Section 302	**Sections 311 and 312**
Chemicals Covered	355 extremely hazardous substances (EHSs)	Approximately 500,000 hazardous chemicals
Thresholds	Threshold planning quantity (TPQ): 1 to 10,000 lbs. onsite at any one time	500 lbs. or TPQ, whichever is lower, for EHSs; 75,000 gallons for gasoline; 100,000 gallons for diesel; and 10,000 lbs. for all other hazardous chemicals

EPCRA emergency planning establishes, in part, requirements for sharing information among industry and state, tribal, and local governments. As shown in Table 13, under Section 302, a facility that has an extremely hazardous substance (EHS) at or above its specific threshold planning quantity (TPQ) must report the substance. Reporting of EHSs, as well as other hazardous chemicals under Sections 311 and 312, must be made to the State Emergency Response Commission (SERC), Local Emergency Planning Committee (LEPC), and local fire department.[587]

State governors designated the SERCs which then designated roughly 3,500 local emergency planning districts and LEPCs for each district.[588] At minimum, LEPCs must be composed of elected state and local officials; police, fire, civil defense, public health, transportation, and environmental professionals; representatives of facilities subject to EPCRA emergency planning requirements; community groups; and

[585] Regulations implementing EPCRA are codified at 40 CFR Parts 350–372.
[586] *See*: http://www2.epa.gov/sites/production/files/2013-08/documents/epcra_fact_sheet.pdf (accessed on December 29, 2015).
[587] The local fire department receives only inventory information under Sections 311 and 312.
[588] *See*: http://www2.epa.gov/sites/production/files/2013-08/documents/epcra_fact_sheet.pdf (accessed on December 29, 2015).

the media.[589] SERCs are supposed to supervise and coordinate the activities of LEPCs, establish procedures for receiving and processing public requests for information, and review local emergency response plans.[590] LEPCs are supposed to develop emergency response plans, review the plans annually, and provide information to the public.[591]

EPCRA emergency planning also requires LEPCs to develop and update emergency response plans. LEPCs are supposed to use information reported by facilities to develop these plans, which cover procedures that describe how emergency responders should respond to chemical releases.[592] The plans must (1) identify EHS facilities and transportation routes; (2) describe emergency response procedures, onsite and offsite; (3) designate a community coordinator and facility coordinators to implement the plan; (4) outline emergency notification procedures; (5) explain the means to determine the probable area and population affected by chemical releases; (6) describe local emergency equipment and facilities and the people responsible for them; (7) outline evacuation plans; (8) provide a training program for emergency responders (including schedules); and (9) detail methods and schedules for exercising emergency response plans.[593]

Importantly, EPCRA emergency planning requirements mandate the identification of facilities with EHSs only; identification of facilities without EHSs is not required. Thus, although facilities must *report* EHSs and certain non-EHSs (i.e., other hazardous chemicals under Sections 311 and 312), only facilities with EHSs trigger EPCRA emergency response *plan* requirements.[594] For purposes of the WFC investigation, CSB determined that while anhydrous ammonia is on the EHS list, FGAN is not. CSB found, however, that AN is on the list of hazardous chemicals under Sections 311 and 312 that triggers emergency and hazardous chemical inventory reporting requirements.

EPCRA emergency and hazardous chemical inventory reporting requires reporting of certain quantities of EHSs and hazardous chemicals. As shown in Table 13, under Sections 311 and 312, an EHS must be reported if it is held at the lower of 500 pounds or the substance's TPQ, gasoline must be reported at 75,000 gallons, diesel must be reported at 100,000 gallons, and all other hazardous chemicals must be reported at 10,000 pounds.[595] These reporting requirements are tied to OSHA's Hazard Communication Standard (29 CFR 1910.1200). This standard requires employers to maintain SDSs for all hazardous chemicals in the workplace.[596] SDSs contain crucial information, including chemical and hazard

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[589] *Ibid. See also*: 42 U.S.C. §11001(c).
[590] *Ibid*. *See also*: 42 U.S.C. §11001(a).
[591] *Ibid*. *See also*: 42 U.S.C. §11001(c).
[592] *See*: http://www2.epa.gov/sites/production/files/2013-08/documents/epcra_fact_sheet.pdf (accessed on December 29, 2015).
[593] *Ibid*. *See also*: 42 U.S.C. §11003(c).
[594] It should be noted that EPA has suggested, through guidance to SERCs and LEPCs (including the most recent fact sheet to these entities), that they include Sections 311 and 312 facilities in their planning process.
[595] *See*: http://www.epa.gov/sites/production/files/2013-08/documents/epcra_fact_sheet.pdf (accessed on December 29, 2015).
[596] *Ibid*.

identification; ingredient composition; first aid measures; firefighting measures; accidental release measures; handling and storage precautions; exposure controls and personal protection; physical and chemical properties; stability and reactivity properties; toxicological information; ecological concerns; disposal considerations; transport information; regulatory requirements; and other information.[597] Facilities must maintain SDSs onsite and submit copies of them (or a list of SDS-covered chemicals) to their SERCs, LEPCs, and local fire departments.[598]

Facilities covered by Section 311 must also submit Emergency and Hazardous Chemical Inventory forms to their SERCs, LEPCs, and local fire departments annually.[599] Facilities provide either a Tier I or Tier II inventory form.[600] Tier I inventory form include the following aggregate information for each applicable hazard category:

- An estimate (in ranges) of the maximum amount of hazardous chemicals for each category present at the facility at any time during the preceding calendar year.
- An estimate (in ranges) of the average daily amount of hazardous chemicals in each category.
- The general location of hazardous chemicals in each category.[601]

The Tier II inventory form contains basically the same information as the Tier I, but it must list the specific chemicals. Tier II inventory form provide the following for each chemical:

- The chemical name or the common name as indicated on the SDS.
- An estimate (in ranges) of the maximum amount of the chemical present at any time during the preceding calendar year and the average daily amount.
- A brief description of the manner of storage of the chemical.
- The location of the chemical at the facility.
- An indication of whether the owner elects to withhold location information from disclosure to the public.[602]

Information submitted under Sections 311 and 312 is available to the public from SERCs and LEPCs.[603]

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[597] *See*: https://www.osha.gov/Publications/HazComm_QuickCard_SafetyData.html (accessed on December 29, 2015). OSHA does not enforce the ecological information, disposal considerations, transport information, and regulatory information sections of SDSs because other agencies regulate this information.
[598] *See*: http://www2.epa.gov/sites/production/files/2013-08/documents/epcra_fact_sheet.pdf (accessed on December 29, 2015).
[599] *Ibid*.
[600] *Ibid*.
[601] *Ibid*.
[602] *Ibid*. It is important to note that under Section 312(f), upon request by the fire department with jurisdiction over the facility, owners/operators must provide *fire departments* with location information. They must also allow fire departments to conduct onsite inspections.
[603] *Ibid*.

8.5.2 State Emergency Planning in the State of Texas

Texas has suffered some of the worst disasters in U.S. history, both in kind and magnitude. One of the first was the devastating hurricane in Galveston in 1900, which almost destroyed the city and killed thousands. In 1937, in New London, a gas leak explosion destroyed a school and killed approximately 300 students and teachers. Ten years later, the FGAN explosion in Texas City inflicted an enormous loss of life and property that remains unknown to this day; it is ranked as one of the worst industrial accidents in U.S. history.[604]

As a result of these disasters, Texas enacted statutes to address all-hazard emergency management.[605] The Texas Disaster Act of 1975 requires local jurisdictions to designate an emergency management coordinator to develop an emergency operations plan composed of a basic plan with 22 annexes.[606] The basic plan and its annexes outline guidance for emergency management activities and assign roles and responsibilities to local agencies.[607] Although the basic plan offers general guidance, the annexes provide more detail.[608] For example, Annex Q, "Hazardous Materials and Oil Spill Response," identifies the HAZMAT incidents that could occur in a specific community and how such an incident would likely affect nearby populations.[609] Once a hazard is identified, appropriate response actions must be planned, including timely notification, identification of evacuation routes, and assignment of roles and responsibilities.[610] Training exercises and drills must also test response effectiveness.[611]

When Congress enacted EPCRA in 1986, its provisions were incorporated into Texas's existing emergency planning framework and into state codes.[612] The SERC is the Emergency Management Council of Texas and includes participation from multiple state agencies.[613] Within that group of agencies, 10 are considered to be SERC members with specific roles in emergency response and planning. For example, the TCEQ is responsible for receiving reports about accidental spills and releases;[614] the Texas Department of State Health Services is designated to receive the Tier I or Tier II Emergency and Hazardous Chemical Inventory forms submitted electronically by facilities;[615] and the Texas Department of Public Safety, Division of Emergency Management, is tasked with overseeing the

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[604] *Texas Emergency Management Executive Guide* (FY 2014 Edition).
[605] *Ibid.*
[606] Texas Administrative Code, Title 37, Part 1, Chapter 7. Texas Government Code, Chapter 418.
[607] *See*: *Texas Emergency Management Executive Guide* (FY 2014 Edition), 4.
[608] *Ibid.*
[609] *See*: McLennan County. Annex Q: Hazardous Materials & Oil Spill Response. Version 2.4, July 2009.
[610] *See*: *Texas Emergency Management Executive Guide* (FY 2014 Edition), 4.
[611] *Ibid.*
[612] Texas Health and Safety Code, Title 6, Subtitle D, "Hazardous Substances," Chapters 505 through 507. Texas Administrative Code, Title 37, Part 1, Chapter 7. Texas Government Code, Chapter 418.
[613] Texas Department of Public Safety. *See*: https://www.txdps.state.tx.us/dem/stateLocalOrganizations.htm#EMC (accessed on December 29, 2015).
[614] *See*: https://www.tceq.texas.gov/response/spills (accessed on December 29, 2015).
[615] This designation has changed since the date of the WFC incident. The Tier II Chemical Reporting Program has moved to the TCEQ. *See*: https://www.dshs.state.tx.us/tiertwo/ (accessed on December 29, 2015).

all-hazard emergency management program and providing guidance and funding for cities, counties, and state agencies so that they can develop their own programs.[616]

8.5.3 City Emergency Planning in the City of West

To fully understand the WFC incident, this section reviews emergency planning and management in West and at the WFC facility. West is located in McLennan County, which is West's local emergency management district and which formed an LEPC in 1992. The McLennan County LEPC meets four times per year.[617] Its members are nominated by the county judge and approved by the SERC.[618] The LEPC membership consists of city, industry, hospital, and emergency response officials.[619] CSB found that the WFC, however, was not listed on the attendance roster for any LEPC meeting for more than 21 years.

As required by both state and federal regulations, the McLennan County LEPC prepared an emergency response plan (ERP) in accordance with guidance from the Texas Department of Public Safety, Division of Emergency Management.[620] As discussed previously, this consisted of a basic plan with 22 annexes. It described in part McLennan County's approach toward emergency planning, response, and notification. McLennan County officials review the plan annually and officially revise or update it every 5 years, as required by Texas law.[621] Prior to the WFC incident, McLennan County last formally reviewed its ERP in 2010.[622]

The McLennan County ERP includes procedures on how to alert the public when natural or human-initiated disasters occur. ERP annexes describe actions to take in various scenarios, such as how to disseminate information quickly,[623] how to warn special facilities (e.g., hospitals and schools) and populations of a hazard,[624] and how to use alert systems to activate immediate evacuation.[625] A vital component of ERPs and ERP annexes is LEPC engagement and communication. Without these, community members might not have the necessary information to respond appropriately to a specific type of incident.

For example, on February 12, 2013, WIS was temporarily evacuated because of a controlled burn at the WFC facility. Before the evacuation, the school principal alerted 911 of the fire, but the 911 dispatcher did not acknowledge a coordinated burn. Students and staff were evacuated for approximately 30 minutes to WMS, using coordinated transportation. The WFC did not notify the WISD or WIS in advance that the

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[616] *See*: https://www.txdps.state.tx.us/internetforms/Forms/TDEM-10.pdf (accessed on December 29, 2015).
[617] McLennan County LEPC Bylaws, Article II, Section 5, "Meetings."
[618] McLennan County LEPC Bylaws, Article II, Section 1, "Membership."
[619] *Ibid.*
[620] State of Texas. *Local Emergency Planning Committee (LEPC): A Primer for Local Planning for Hazardous Materials*, July 2006.
[621] Texas Administrative Code, Title 37, Part 1, Chapter 7, Subchapter B, Rule 7.12.
[622] CSB reviewed the 2010 McLennan County ERP for this investigation report.
[623] McLennan County Basic Plan, Annex I.
[624] McLennan County Basic Plan, Annex E.
[625] *Ibid.*

facility was conducting a controlled burn of pallets and brush. After this incident, the WISD asked the emergency service providers and the WFC to provide advance notice of future burning activities. The WFC could have communicated its plans to the WISD or WIS through LEPC activities.

The McLennan County ERP specifically includes Annex Q, "Hazardous Material and Oil Spill Response," which requires identification of all regulated facilities within the county.[626] Such facilities are those that are regulated by EPCRA. In particular, a regulated facility is:

> A plant site where handling/transfer, processing, and/or storage of chemicals is performed. For the purposes of [Annex Q], regulated facilities (1) produce, use, or store EHSs in quantities which exceed threshold planning quantities or (2) hold one or more hazardous chemicals in a quantity greater than 10,000 pounds at any time.[627]

Because the WFC was regulated by EPCRA, it would follow that Annex Q might list the WFC. However, the WFC was not listed.

EPCRA covered the WFC for at least two reasons. First, the WFC stored anhydrous ammonia in quantities that exceeded the anhydrous ammonia TPQ of 500 pounds. Specifically, CSB found that the WFC reported holding 34,000 pounds of anhydrous ammonia at the time of the incident. Clearly, the WFC had onsite sufficient amounts of an EPCRA Section 302 EHS. This triggered not only reporting requirements, but also emergency response planning requirements.[628] Thus, the WFC should have been listed in Annex Q for its EPCRA-regulated storage of anhydrous ammonia.

Second, the WFC stored FGAN, a hazardous chemical under EPCRA Sections 311 and 312, in quantities that exceeded the AN threshold quantity of 10,000 pounds. In particular, CSB found that the WFC reported 80,000 to 120,000 pounds of FGAN onsite at the time of the incident. As such, the WFC was required to report its quantities of FGAN under EPCRA. CSB obtained WFC Tier II form documents, dated from 2000 to 2012, and found that the WFC annually reported its quantities of anhydrous ammonia to the WVFD, McLennan County LEPC, and Texas Department of State Health Services, but reported its FGAN only in its 2012 Tier II report. Ideally, under the best set of circumstances, the WFC should have been listed in Annex Q for its storage of FGAN. The WFC was not listed in Annex Q, however, due to a misunderstanding of EPCRA's agricultural use exemption.

EPCRA's agricultural use exemption is a statutory exemption to the definition of "hazardous chemical." It reads:

> Hazardous Chemical Defined. For purposes of this section, the term "hazardous chemical" has the meaning given such term by section 1910.1200(c) of title 29 of the Code of Federal

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[626] McLennan County Basic Plan, Annex Q.
[627] *Ibid*.
[628] The WFC was also expected to develop an emergency response plan for its storage of anhydrous ammonia, as required by the Risk Management Program rule. According to EPA, the EPCRA plan and the RMP must be coordinated. *See*: http://www2.epa.gov/sites/production/files/2013-11/documents/chap-08-final.pdf (accessed on December 29, 2015). However, no evidence indicated that the WFC RMP was shared with the LEPC or the WVFD.

> Regulations, except that such term does not include the following: . . . Any substance to the extent it is used in routine agricultural operations or is a fertilizer held for sale by a retailer to the ultimate customer.[629]

It is important to note that this exemption may apply only to Sections 311 and 312 reporting requirements; it does not apply to emergency planning requirements under Section 302. Furthermore, the agricultural use exemption applies directly to the hazardous chemical itself, not the specific individual or entity holding the chemical. That is, the exemption does not relieve an individual or entity of its responsibilities; rather, the individual or entity is exempt from EPCRA reporting requirements if the chemical in question is exempt. Where individuals or entities hold multiple chemicals, each chemical must be assessed individually to determine exemption status.

The agricultural use exemption impacts those who use substances in "routine agricultural operations" and retailers who hold substances as fertilizer for sale to the ultimate customer. With respect to those who use substances in routine agricultural operations, CSB referred to guidance on EPA's website that, in response to a question asking which hazardous chemicals are reportable for farmers under Sections 311 and 312, states:

> Under Section 311(e)(5), any substance when used in routine agricultural operations is exempt from reporting under Section 311 and 312. This exemption is designed to eliminate the reporting of fertilizers, pesticides, and other chemicals when stored, applied, or otherwise used at the farm facility as part of routine agricultural activities. . . . Thus, the storage and use of a pesticide or fertilizer on a farm would be considered the use of a chemical in routine agricultural operations and is, therefore, exempt under Sections 311 and 312.[630]

The belief is that minimal risk is involved when farmers use a substance in routine agricultural operations because farmers promptly apply those substances to their crops. Therefore, the exemption eliminates EPCRA reporting requirements under Sections 311 and 312 for at least certain farmers. However, for retailers who hold a substance as fertilizer for sale to the ultimate customer, CSB found that although EPA has published several hypothetical-based questions and answers on its website, it offers little *general* guidance.

CSB discovered that the McLennan County LEPC reported that the WFC's storage of anhydrous ammonia and FGAN appeared to qualify under EPCRA's agricultural use exemption, a conclusion which the county stated was also confirmed by the SERC. The WFC's anhydrous ammonia and FGAN were erroneously considered exempt from both emergency planning and hazardous chemical inventory reporting requirements because of the phrase "fertilizer held for sale by a retailer[631] to the ultimate customer" and because the main WFC customers who bought fertilizer were nearby farmers (ultimate

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[629] EPCRA, Section 311(e)(5). 40 CFR 370.66.

[630] *See*: https://emergencymanagement.zendesk.com/hc/en-us/articles/211416278-What-hazardous-chemicals-are-reportable-for-farmers-under-311-and-312- (accessed on December 29, 2015). It should be noted, however, that although farmers may be exempt under Section 311(e)(5) from reporting these fertilizers in their Sections 311 and 312 reports, they are still required to notify the SERC (or TERC), LEPC (or TEPC), and local fire department under Section 302 if they have an EHS at or above its TPQ.

[631] There is no definition of "retailer" under EPCRA.

customers / end users). This reason likely explains why the McLennan County LEPC ERP did not include the WFC for its storage of anhydrous ammonia, despite the fact that the exemption does not relieve reporting requirements for EHSs under Section 302.

Because the WFC facility not only sold pure fertilizer but also blended chemicals to make fertilizer (e.g., for custom orders), CSB also examined how the agricultural use exemption applies to blends. EPA states that chemicals "held for the purpose of producing fertilizer" are "starting materials used to make a fertilizer," not the fertilizer itself, so the retailer therefore should report them.[632] EPA recognizes, however, that if those chemicals are not blended but rather sold individually to the end customer, then those chemicals are exempt.[633] EPA confirmed this position in a September 3, 2010, letter to TFI, stating that the "mixing of fertilizers" must be reported and reiterating that "fertilizer held for sale by a retailer to the ultimate customer . . . is one that is merely held for sale, not one that is mixed or formulated."[634]

To bolster its reasoning, EPA further explained:

> Congress' intent was to focus Section 311/312 reporting on manufacturers and wholesalers—those are facilities that typically have large quantities of fertilizer, and that use and manufacture a wide range of chemical compounds. Congress appreciated that such manufacturers and wholesalers presented significant risks that needed to be addressed by emergency response authorities, but that mere retailers did not. Assuming arguendo that Congress' intent is ambiguous, the above interpretation is one that EPA adopts as being the most reasonable interpretation of the statute. Therefore, consistent with the Agency's prior Q&A guidance, the amount of chemicals intended for blending and the new product should be reported under Section 311 and 312 if the reporting thresholds are exceeded.[635]

On this basis, facilities that blend chemicals to make fertilizer such as the WFC should not apply the agricultural use exemption to those chemicals meant for blending. However, there is confusion about both who specifically qualifies for the exemption as well as the issue of blending because, although hypothetical-based Q&As are available, limited general EPA guidance exists. Therefore, EPA should develop a general guidance document pertaining to EPCRA's agricultural use exemption and make a widespread effort to communicate its contents to the fertilizer industry.

Since the incident, the Agricultural Retailers Association (ARA), a nonprofit trade association that represents the interests of agricultural retailers and distributors on legislative and regulatory issues, issued an alert to its members on May 14, 2013, warning agricultural retailers that blend (i.e., use nonchemical reactions to mix) dry fertilizers to report those fertilizers on their annual Tier I or Tier II inventory reports submitted to SERCs, LEPCs, and local fire departments. The alert also warned members that EPA has

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632 *See*: https://emergencymanagement.zendesk.com/hc/en-us/articles/212089537-Are-hazardous-chemicals-blended-for-fertilizer-exempted-under-agricultural-use-exemption- (accessed on December 29, 2015).
633 *Ibid*.
634 Dana S. Tulis, EPA Acting Director Office of Emergency Management. Letter to Chris S. Leason, counsel to TFI, September 3, 2010.
635 *Ibid*.

cited agricultural retailers for incomplete inventory forms.[636] TFI further noted in a verbal statement on November 15, 2013, at the Washington, DC, "Listening Session Regarding President Obama's Executive Order Improving Chemical Facility Safety and Security":

> As most of you know, there is a fertilizer retail exclusion for reporting under EPCRA. TFI supports removal of this exclusion. We feel everyone should report hazardous chemicals stored on site to the LEPC and SERC and work with local fire departments without exception.[637]

Despite these post-incident efforts, the ARA and TFI cover only some of the thousands of FGAN facilities in the United States. Consequently, EPA should take steps to ensure that fertilizer facilities fully comply with EPCRA and do not mistakenly apply the agricultural use exemption. In fact, EPA already hosted, from May to September 2014, 32 workshops for members of Local Emergency Planning Committees, which were held in Texas, Arkansas, Louisiana, Oklahoma, and New Mexico and attended by 1,340 representatives from local, state, and federal government as well as industry.[638] It also recently released an online training module of key requirements for SERCs and LEPCs and a factsheet, "How to Better Prepare Your Community for a Chemical Emergency: A Guide for State, Tribal, and Local Agencies."[639] While these efforts demonstrate progress, CSB believes the development of more general EPCRA guidance, as well as a guidance document on the agricultural use exemption, could help significantly improve emergency planning at all levels.

8.5.4 Other Emergency Planning Requirements

During the course of its investigation, CSB also found issues in emergency planning related to FGAN training and compliance with OSHA's Hazardous Waste Operations and Emergency Response (HAZWOPER) standard (29 CFR 1910.120). CSB determined that employees at the WFC had limited training on FGAN hazards. The agency learned through interviews that some WFC employees were unaware that the FGAN fertilizer stored onsite could explode. Many said the April 1995 Oklahoma City bombing was the only basis of their knowledge of this. Nonetheless, WFC employees generally understood FGAN security regulations so as to verify that customers buying FGAN were registered and were using it only for agricultural purposes. CSB found that the lack of formal training at the WFC was a central reason why employees were largely unaware of FGAN hazards.

Some WFC employees recalled having discussions about avoiding FGAN contact with heat, fire, and moisture. However, CSB concluded that FGAN safety training was inconsistent and that no formal training addressed FGAN hazards or required discussion of the FGAN SDS. WFC employees also lacked formal training on the facility's ERP for anhydrous ammonia. Employees informally shared information

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[636] Unfortunately, the alert, even if made before the date of the incident, would have had little impact on the WFC because the facility was not a member of the ARA.

[637] *See*: http://www.tfi.org/media-center/news-releases/tfis-verbal-statement-presented-nov-15-washington-dc-listening-session-re (accessed on December 29, 2015).

[638] *See*: https://www.osha.gov/chemicalexecutiveorder/EO13650FS-ImprovingChemicalFacilitySafety.pdf (accessed on December 29, 2015).

[639] *Ibid*.

so that they knew to evacuate as far as possible if such a release occurred. They also knew which emergency numbers to call. However, much of the WFC employee training was hands on and job specific. Thus, a lack of comprehensive emergency planning and response training played a role in how the incident unfolded.

In addition, CSB discovered issues with OSHA's HAZWOPER standard, which too is an integral element of emergency planning. Under the HAZWOPER standard, the WFC was required to develop an ERP for all "hazardous substances." As defined by the standard, hazardous substances include those covered by EPA or DOT.[640] FGAN meets this definition because it is listed in DOT's Hazardous Materials Table.[641] The WFC was therefore required to develop a HAZWOPER ERP, or would be considered exempt if it met another OSHA standard, Emergency Actions Plans (29 CFR 1910.38).[642]

The HAZWOPER ERP should have addressed pre-emergency planning and coordination with outside parties, personnel roles, lines of authority, training and communication, emergency recognition and prevention, safe distances and places of refuge, site security and control, evacuation routes and procedures, decontamination, and emergency medical treatment and first aid.[643] However, no evidence indicated that the WFC developed the HAZWOPER ERP or was considered exempt under the Emergency Action Plans standard for FGAN. Consequently, OSHA cited the WFC after the incident for not providing an FGAN-related HAZWOPER ERP.

8.6 Fire Protection Codes and Standards

Fire protection codes and standards generally refer to the most recently developed practices to protect people and property from fire and natural disasters. When adopted by states or local jurisdictions, codes (including building, electrical, plumbing, mechanical, and other codes) represent mandatory regulations. Standards, on the other hand, provide methods to achieve compliance with codes. Both codes and standards must be adopted through some process, usually state-level fire or building codes. The legislature must enact that adoption before a fire protection (or prevention) code or standard applies. Because fire and building codes may also include references to many standards, such standards are generally not adopted separately but instead are included once the fire or building code is adopted.

Fire codes specify practices that must be followed; that is, codes are mandatory only if adopted. In contrast, fire protection standards typically refer to practices that, despite their mandatory language, are voluntary unless adopted into law (e.g., as a state fire code). The nation's leading fire protection codes and standards are issued by the NFPA and the International Code Council (ICC). Both employ a public consensus process to produce model codes and standards that jurisdictions can adopt into law. The NFPA updated its current code for FGAN, NFPA 400 (*Hazardous Materials Code*) Chapter 11, after the WFC

[640] 29 CFR 1910(a)(3).
[641] 49 CFR 172.101.
[642] 29 CFR 1910.120(q)(1).
[643] 29 CFR 1910.120(q)(2).

incident to address the conditions that likely led to the FGAN detonation. The ICC's International Fire Code (IFC) also addresses storage and handling of oxidizing materials.

Texas does not have a state-wide fire code and as a result, most fire departments in the state have no authority to inspect facilities against, or compel them to follow the safe practices outline in these codes, unless a fire code is adopted at the county or city level. In July 2015, the Texas Department of Insurance did adopt NFPA 1 (*Fire Code*) for inspections by the Texas State Fire Marshal's office on the complaint of any person. However, even if fire protection standards are incorporated into state and local fire codes, catastrophic incidents can occur when such standards are deficient.

CSB reviewed the ICC IFC and NFPA 1 (*Fire Code*). The IFC is in use or adopted in 42 states,[644] and NFPA 1 is adopted statewide in 19 states. CSB also researched fire protection codes on the state, county, and city levels—specifically, in the state of Texas, in McLennan County, and in the city of West. The first part of this section describes the NFPA, with details on the NFPA standard for FGAN. The second part of this section describes the ICC, with details on how it addresses HAZMAT. The third and last part of this section describes fire code regimes on a more local level and analyzes codes in Texas, which can be improved to better protect emergency responders and the public from fire events.

8.6.1 National Fire Protection Association

The NFPA is an international nonprofit organization that develops and publishes industry consensus codes and standards, guides, and recommended practices associated with fire prevention and related hazards. Companies can voluntarily comply with NFPA codes and standards or can be required to follow a standard if it is adopted by reference in local, state, or federal laws (e.g., in a local or state fire code). Many of the NFPA codes and standards are also incorporated in OSHA regulations. The EPA Risk Management Program rule and OSHA PSM standard regulations require owners and operators of covered facilities to ensure that facility processes are designed to comply with RAGAGEP, which can include NFPA codes and standards. However, if these consensus codes and standards are deficient, they can lead to insufficient protections.

8.6.1.1 NFPA Code for FGAN

AN requirements were first covered by NFPA 490 (*Storage of Ammonium Nitrate*), which was adopted in 1965. In 2010, NFPA withdrew NFPA 490 when it was incorporated into NFPA 400 (*Hazardous Materials Code*). NFPA 400 establishes provisions for the storage, use, and handling of a number of hazardous substances, using four broad categories addressing building construction, storage requirements, fire protection systems, and general protections against fire. The 2013 edition had been published and was in effect at the time of the incident.

The code has a specific chapter on AN (Chapter 11, "Ammonium Nitrate Solids and Liquids"). This distinguishes AN from other chapters because other chapters of the code are organized by chemical

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[644] The IFC is also adopted in the District of Columbia, NYC, Guam and Puerto Rico.

properties (such as “oxidizers” or “unstable or water reactive materials”) that can each apply to several chemicals. The scope of Chapter 11 covers “the storage, use, and handling of solid or liquid AN” in quantities exceeding 1,000 pounds. The chapter does not include FGAN manufacturing operations or the composition of FGAN designated as DOT hazard Class 1 explosives. The NFPA 400 code includes provisions for indoor and outdoor storage, fire protection systems, and general use; annexes offer additional guidance. In addition, the maximum allowable quantity (MAQ) designation is used in building and fire codes when addressing the storage, handling, and use of HAZMAT. The MAQ is integral to the NFPA 400 approach. It includes provisions for classifying materials, determining their MAQs, and adding other protective features if the intention is to use greater quantities of material.

When evaluating the provisions in NFPA 400 (2013 Edition) against the factors that likely contributed to the WFC incident, CSB found code deficiencies concerning scope, building design, storage practices, and fire prevention and firefighting response for facilities that store bulk FGAN. However, it is important to note that the WFC would not have been required to comply with the code at the time of the incident unless the authority having jurisdiction enforced it retroactively. The WFC facility was constructed in 1962, so the requirements of NFPA 400 did not apply. Nonetheless, in response to some of the lessons learned from the WFC incident, CSB and other agencies and organizations participated in meetings with the NFPA Technical Committee on Hazardous Chemicals to provide input on the next revision of NFPA 400 (2016 Edition).

A significant effort of the NFPA Technical Committee focused on addressing the requirements for existing FGAN storage facilities covered under NFPA 400 because the previous editions had primarily covered requirements for new facilities.[645] As discussed, the wood construction of the WFC warehouse and bins that stored FGAN not only assisted in the rapid spread of the fire but also increased the sensitivity of the material that led to the detonation. In addition, the WFC warehouse had no installed fire detection or suppression systems, allowing the fire to spread through the building. If a building fire detection system had been operational, the early stages of the fire possibly could have been extinguished. Furthermore, sprinklers could have extinguished the fire before it could heat the FGAN pile sufficiently to produce a detonation.

Similar to the OSHA Explosives and Blasting Agents standard, NFPA 400 (2013 Edition) allowed wood and combustible construction materials for bulk storage bins for FGAN as long as the bins were “protected against impregnation by FGAN.” The code noted in an annex that sodium silicate, epoxy coatings, or polyvinyl chloride (PVC) coatings were acceptable means to achieve this protection. However, the method used to coat the wood to resist FGAN impregnation does not prevent a fire. The presence of combustibles during a fire can create explosive conditions within a building that stores bulk FGAN. NFPA 400 (2016 Edition) now prohibits the use of combustible materials for all construction and bins at new facilities, even when coatings are applied to protect against FGAN impregnation.

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[645] Pearce, Nancy. “Safer Storage.” NFPA Journal, May 1, 2015.

However, the 2016 revisions to NFPA 400 do not apply the same requirements to prohibit combustible construction at existing facilities. The NFPA was challenged to reasonably specify construction requirements for facilities with combustible construction, which comprise the majority of FGAN storage facilities.[646] To address existing facilities, NFPA 400 (2016 Edition) contains the new Section 11.1.5, "Protection of Existing Buildings." This includes requirements that apply retroactively, where adopted, for existing buildings with combustible content. Facilities are required to install automatic fire sprinkler and detection systems. Activation of the fire detection system must automatically initiate an audible and visual alarm at the facility as well as a public notification or alert system to warn individuals located within one mile of the facility that they need to evacuate.

Another shortcoming of NFPA 400 (2013 Edition) lies in Annex E, "Properties and Uses of Ammonium Nitrate and Fire-Fighting Procedures," which called for large volumes of water to be applied as quickly as possible unless the fire reached "massive and uncontrollable proportions," when responders were advised to evacuate and withdraw to a safe location. CSB found this guidance to be vague because the user had to determine when to categorize a fire as "massive and uncontrollable" and when to make the decision to evacuate rather than attempt to extinguish the fire. Because of FGAN's unpredictable nature, immediate evacuation should be the first action for responders, using a minimum evacuation distance calculated in advance based on the quantity of FGAN stored. The 2013 edition of NFPA 400 did not require pre-planning, but given the events that unfolded during the WFC response, firefighters should also have a pre-incident plan to facilitate quick and effective decision making when responding to an FGAN fire.

NFPA 400 (2016 Edition) now requires new and existing facilities to have emergency action plans that clearly state that "fire potentially affecting FGAN storage beyond the initial (incipient) stage shall not be approached by facility personnel."[647] The emergency plan must also specify whether the FGAN storage facility has a sprinkler system and whether it is constructed of combustible materials. For new facilities, the plan must establish a safe evacuation distance based on an approved[648] analysis of potential offsite consequences. If no analysis has been performed, a distance of one mile should be used. The revised Annex E of NFPA 400 (2016 Edition) offers additional guidance to firefighters, including information on the conditions that cause FGAN explosions. The guidance states that only incipient fires in FGAN storage areas (or in vehicles transporting FGAN) should be attacked by using manual fire extinguishing methods that require a human operator.[649] Firefighters should withdraw to a safe distance and allow the structural fire to burn to completion once it progresses beyond the incipient stage.[650]

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[646] *Ibid*.
[647] NFPA. *NFPA 400: Hazardous Materials Code*, 2016 Edition. Quincy, MA: NFPA, 2016.
[648] Plan approvals are performed by the authority having jurisdiction, such as the fire department or fire marshal.
[649] NFPA. *NFPA 400: Hazardous Materials Code*, Annex E, 2016 Edition. Quincy, MA: NFPA, 2016.
[650] NFPA 400 (2016 Edition) states that "responses to incipient releases of hazardous materials where the material can be absorbed, neutralized, or otherwise controlled at the time of release by employees in the immediate release area, or by maintenance personnel, shall not be considered emergency responses as defined within the scope of this code."

Following the WFC incident, the NFPA-sponsored Fire Protection Research Foundation[651] (the Foundation) conducted a study[652] to determine the adequacy of the separation distances prescribed for hazardous materials in NFPA 400, with a greater focus on FGAN. NFPA 400 specifies separation and clearance distances for newly constructed hazardous chemical storage from other on-site equipment and occupied buildings.

The Foundation's technical committee was made up of industry representatives, and research and engineering organizations that conducted literature reviews of existing methodologies to determine safe separation distances and testing to characterize the effect of AN detonations on personnel and processes near an explosive event. The study included reviews of various sources for risk-based and consequence-based methodologies for determining the safe distances as well as established distance tables. To study the adequacy of the existing separation distances in NFPA 400, the Foundation commissioned explosive testing to characterize the effects of nearby processes and personnel using a 3,000 pound ANFO donor charge to simulate an explosion.

As part of the analysis, blast consultants compared the blast pressures and data recorded at various distances from the donor charge and compared the effects to the recommended distances for Class 3 Oxidizers in detached unsprinklered storage prescribed in NFPA 400 Chapter 15 (*Oxidizer Solids and Liquids*). The study concluded that the process-to-process separation distances for solid AN may be inadequate to provide protection against blast effects, but the process-to-personnel separation distances may be acceptable if personnel are inside buildings located at prescribed distances. However, the study concluded that additional testing and analysis is necessary to validate the absolute safety of personnel based on variations in processes, design, and potential reactants.

The purpose of the project was to provide guidance to the NFPA technical committee for the development of technically-based separation distances for storage. Thus, the Foundation recommends a technical-based approach to establish safe separation distances that takes into account the risks associated with a known material and process, as well as the potential consequences of a catastrophic event involving that material.

8.6.2 International Code Council

Like the NFPA, the ICC is an international nonprofit organization that develops and publishes consensus codes and standards. In addition to publishing the IFC, the ICC also produces the International Building Code (IBC), which is in use or adopted in 50 states. Jurisdictions can adopt the model codes by reference. The ICC views its codes as "companion" documents that work across disciplines (e.g., building construction, fire protection, mechanical systems, plumbing, zoning). Thus, a regulation for HAZMAT storage will affect building code requirements for construction, mechanical code requirements for

[651] The Fire Protection Research Foundation is an affiliate of NFPA and plans, manages, and communicates research on fire safety issues in collaboration with academics, laboratories, and industry.

[652] *See*: http://www.nfpa.org/Assets/files/AboutTheCodes/59A/RFSeparationDistancesNFPACodesAndStandards.pdf (accessed on December 30, 2015).

ventilation, plumbing code requirements for drainage, and fire code requirements for operations and handling. The codes are cross-referenced for ease of use.

The ICC requirements for protecting AN from fire exposure and explosion are based on material properties, quantities stored, and storage and handling conditions. The ICC defines storage as "the keeping, retention or leaving of hazardous materials in closed containers, tanks, cylinders, or similar vessels; or vessels supplying operations through closed connections to the vessel."[653] Therefore, despite common references to the WFC FGAN as "in storage," the IFC would interpret this application as "handling," which it defines as "the deliberate transport by any means to a point of storage or use," or as "use," which it defines as "placing a material into action, including solids, liquids and gases."[654]

The IFC does not have a separate chapter for AN. The IFC refers to NFPA 400 when AN intended for explosive materials is stored, handled, or used. Otherwise, AN is treated as an oxidizing agent, subject to the general requirements for each oxidizer class in IFC Chapter 63 (*Oxidizers, Oxidizing Gases and Oxidizing Cryogenic Fluids*) and Chapter 50 (*Hazardous Materials*).

8.6.3 State Fire Codes

Without a comprehensive federal standard, states must rely on their own regulations to oversee HAZMAT storage. Most states have enacted fire codes or have adopted model fire codes. These codes typically include HAZMAT storage and emergency planning provisions. However, at the time of the incident, Texas had no state fire code, and the state still has no such code as of publication of this report.

The majority of states have adopted model fire codes through referencing them into law.[655] Two recognized model fire codes are the IFC and NFPA 1. Both establish minimum requirements for fire prevention and protection systems. Some states and municipalities have developed their own fire codes, using model codes as a guide. New York City updated its fire code in December 2007, marking its first major revision since 1913.[656] After investigating an industrial waste explosion and fire in 2001 in the Chelsea district of Manhattan, CSB issued a recommendation to the Mayor and City Council to better address HAZMAT.[657] The city developed its own code, borrowing heavily from the IFC (2003 Edition) but requiring some more stringent provisions.

States could potentially apply other IFC chapters for storing bulk FGAN. For example, IFC Chapter 63 (*Oxidizers, Oxidizing Gases and Oxidizing Cryogenic Fluids*) includes provisions for storage and use of oxidizing materials, such as FGAN. This chapter says that indoor storage of oxidizers should be located in a detached building with an automatic sprinkler system and smoke detection systems. Additional

[653] ICC. Chapter 50, Section 5002.1. *International Fire Code*, 2015 Edition. Washington, DC: ICC, 2015.
[654] *Ibid*.
[655] ICC. "International Code Adoption." *International Fire Code*. Washington, DC: ICC, 2014. *See*: http://www.iccsafe.org/gr/Pages/adoptions.aspx (accessed on November 6, 2014).
[656] Cassono, Salvatore. "A New Fire Code for New York City." *Building Safety Journal* (July–August 2008).
[657] CSB. "Chemical Waste-Mixing Incident: Kaltech Industries Group, Inc." CSB Investigation Report, April 25, 2002.

requirements for storage configuration, separation barriers, and explosion control depend on the class of oxidizer, of which the IFC names four. NFPA 1 includes similar requirements for oxidizers in Chapter 70 (*Oxidizer Solids and Liquids*). This chapter directs users to follow NFPA 400, which also incorporates similar building and fire protection requirements for indoor storage of oxidizers.

The WFC did not voluntarily implement any of the provisions from the oxidizer chapters of the IFC or NFPA 1, nor were they required to do so by the authority having jurisdiction. The WFC did not install an automatic sprinkler or smoke detection system in the fertilizer warehouse, nor did it store its FGAN in a separate building, away from combustibles. The location where the fire originated was adjacent to the FGAN bin, and no fire-rated wall separated the rooms. The WFC was not subject to code provisions because none of the relevant jurisdictions—not the state of Texas, McLennan County, or the city of West—had adopted a fire code.

Texas affords counties and municipalities the discretion to adopt or develop fire codes. However, state law limits which counties can adopt such codes. Only a county with a population of more than 250,000 (and counties adjacent to a county with a population of more than 250,000) may adopt a fire code. Moreover, even if such a county does adopt a fire code, that code applies only to the unincorporated areas of the county. Cities within the county can adopt the county fire code, not adopt a fire code, or develop their own fire codes. Adoption of a city fire code does not affect any unincorporated areas outside the city. Although many major Texas cities have adopted fire codes, the pattern is inconsistent.

As of September 2014, 43 facilities stored FGAN in 36 Texas counties. Only one of those 36 counties has a population of more than 250,000 people,[658] and only six of those counties are adjacent to counties with populations that equal or exceed 250,000. Consequently, 79 percent of the 43 FGAN storage facilities are located in Texas jurisdictions that, under state law, cannot adopt a fire code.

According to the 2010 census, the population of McLennan County was 241,281. Thus, the county fell below the population threshold. However, one of the seven adjacent counties had a population of more than 250,000. Accordingly, McLennan County had the authority to adopt a fire code, but this was not required. It is also important to note that the WFC facility was only partially within city limits. The fertilizer warehouse was located in an unincorporated area of West. If McLennan County had adopted a fire code, it would have applied to the WFC fertilizer warehouse only. Furthermore, if West had decided to adopt its own fire code, it would have applied to the entire WFC facility except for the warehouse.

Although efforts have been made to make a state fire code in Texas mandatory, such endeavors have not been successful. The Texas Legislature debated the issue of adopting a state fire code at least as far back as 1978. Legislative committee reports between 1978 and 1984 from the Texas House of Representatives and the Texas State Senate identified the severe fire problem, and one report contended that the losses from fires exceeded "loss of life and property" from "all natural disasters combined" in the state.[659] After

[658] U.S. Census Bureau. *2010 U.S. Census*. Washington, DC: U.S. Census Bureau, 2011.
[659] Texas House of Representatives Committee on Business and Industry. "Interim Report," October 13, 1978.

hearing multiple testimonies in public hearings across the state, a committee report concluded that Texas was "one of the leading states in property loss and lives lost because of fire."[660] This same committee report also found that such major losses occurred not in the most populated municipalities that had adopted fire and building codes, but in the unincorporated areas where fire codes did not apply.[661] It stated that unincorporated areas were particularly problematic when annexed into a municipality because the city assumed responsibility for fire-prone buildings that were not built to code specifications.[662] Because growth areas in counties are inevitable targets for municipal annexation, if counties are not granted proper regulatory authority, cities inevitably inherit the problems thus created.

The Texas legislative committee reports also identified that without a state fire code, the State Fire Marshal cannot fulfill the duty of minimizing fire risks. One report noted that the State Fire Marshal has no authority to adopt a fire code, despite holding responsibility for the inspection of state-owned and state-leased buildings. Without a code, the State Fire Marshal is unable to set criteria to assess a fire hazard and enforce corrective actions. Moreover, although the local fire marshals hold authority to inspect facilities in their jurisdictions, without a fire code, they cannot enforce safety measures that are not legally required.

The Texas Fire Protection Standard Committee, a special interim legislative committee, studied the fire problem and issued an interim report to the 69th session of the Texas Legislature in December 1984.[663] This committee confirmed many of the findings above.[664] In addition, the committee analyzed NFPA national fire data from 1978 to 1982.[665] These data indicated that the per capita number of fires, deaths, and injuries and the dollar loss resulting from fire were all lower in states with fire codes than in those without them.[666] The data also suggested that education alone to minimize human errors was insufficient to reduce fire loss because fire causation was mostly attributable to improper structural design and equipment malfunction.[667] This committee also received extensive testimony from around the state indicating that the loss of life in the volunteer firefighter service was primarily "because there were no codes."[668]

Over the years, proposed bills in the Texas Legislature for adoption of a fire code failed to gain support. In 1977, the Texas House of Representatives addressed a proposed bill to enforce a "fire prevention code" that would apply only to unincorporated areas and would be enforced by the state and county fire

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[660] Texas Senate Subcommittee on Consumer Affairs. "Final Staff Recommendations," December 1980.
[661] *Ibid*.
[662] *Ibid*.
[663] Texas Fire Protection Standards Committee. "Interim Report to the 69th Texas Legislature." December 1984.
[664] *Ibid*.
[665] *Ibid*.
[666] *Ibid*. It was noted in the report that the fire loss data had limitations because mandatory reporting requirements were not consistent throughout the nation. This limited statistical analysis nonetheless pointed out principal causes of fires.
[667] *Ibid*.
[668] *Ibid*.

marshals.[669] In 1997, 20 years later, another proposed Texas House bill sought adoption of a code that would apply to (1) buildings located in unincorporated areas that have not adopted a fire code, (2) municipalities that did not adopt a fire code, (3) public assembly buildings in municipalities that have not adopted either model code, and (4) state-owned buildings.[670] Neither bill progressed out of committee.

In 1989, the Texas Legislature granted limited authority to counties with a population of 250,000 or more to adopt and enforce a fire code.[671] This authority was later amended in 1997 to address growing populations and include counties adjacent to those with a population of at least 250,000.[672] The failure to mandate a statewide fire code left some counties such as McLennan County without minimum fire protection measures.

The absence of a state-wide fire code and the local population restrictions for code adoption remain an important issue for CSB. However, since the WFC incident, Texas has amended the administrative code to provide the State Fire Marshal with greater authority to enforce some NFPA codes at FGAN storage facilities, as well as to enter, upon complaint, and inspect facilities against the provisions of NFPA 1. Though the adoption did not create a state-wide fire code, it allows for the State Fire Marshal to inspect against a more comprehensive standard than NFPA 101 (*Life Safety Code*) that Texas previously adopted.[673] Additional changes to the Texas State Fire Marshal's authority to inspect FGAN facilities were enacted as part of House Bill 942 (described in Section 8.7.2). In addition, the Texas Agriculture Code was amended to impose additional requirements on FGAN retailers (described in Section 8.7.1).

8.7 Post-Incident State and Local Regulatory Developments

Since the 2013 WFC incident, state and local legislators in Texas have attempted to improve FGAN safety through regulatory change. These efforts represent important first steps in recognizing the potential catastrophic hazards of FGAN under certain conditions. However, they are not entirely adequate. For example, when Texas House Bill (HB) 942 became law, it simply codified existing state hazardous chemical reporting requirements. Also, although the revised Texas Commercial Fertilizer Rules establish requirements for FGAN to be separated by at least 30 feet from combustible and flammable materials,[674] this requirement is much less restrictive than the newly revised NFPA 400

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[669] 65th Texas Legislative Session. House Bill (HB) 325, "An act relating to the promulgation and enforcement of a state fire prevention code for unincorporated areas of the state by the State Board of Insurance."
[670] 75th Texas Legislative Session. HB 2922, "An act relating to a statewide building and fire code."
[671] 71st Texas Legislative Session. HB 2252, "An act relating to the authority of the commissioners courts of certain counties to adopt a fire code for certain buildings in unincorporated areas."
[672] 75th Texas Legislative Session. State Bill (SB) 10, "An act relating to the authority of certain counties to adopt and enforce a fire code."
[673] *See*: https://texreg.sos.state.tx.us/public/readtac$ext.TacPage?sl=R&app=9&p_dir=&p_rloc=&p_tloc=&p_ploc=&pg=1&p_tac=&ti=28&pt=1&ch=34&rl=303 (accessed on December 30, 2015).
[674] Texas Administrative Code, Title 4, Chapter 65, Section 65.6(d)(3). *See*: http://otscweb.tamu.edu/Laws/PDF/CommercialFertilizerRules.pdf (accessed on December 29, 2015).

standard and might not fully eliminate the risk of molten FGAN contamination during a fire. This section includes a discussion of the Texas Commercial Fertilizer Rules, a general analysis of HB 942 as well as a comparison of HB 942 to other legislation pending in committee as of this report's publication date, and a review of an Athens, Texas, ordinance that mandates a ban on the bulk storage of FGAN.

8.7.1 Texas Commercial Fertilizer Rules

The Office of the Texas State Chemist (OTSC) regulates the sale of FGAN and FGAN-containing materials. Enacted by 2007 amendments to the Texas Agricultural Code Section 65.6, the law places limits on FGAN sales. It establishes requirements for registration certificates issued by the Texas Feed and Fertilizer Control Service as a condition of selling (or offering to sell) FGAN.[675] To reduce theft or terrorism, the requirements focus on security measures for FGAN storage and on recordkeeping to identify people who purchase FGAN.

In June 2014, Texas revised the provisions of its Commercial Fertilizer Rules.[676] The revised rules require FGAN facilities to file Top-Screen information under the federal CFATS rule as well as EPCRA Tier II information with the Texas Department of State Health Services as a condition for receiving an annual certificate of registration to sell FGAN. The 2014 revisions also require OTSC to inspect FGAN storage areas. Such inspections are to confirm that combustible and flammable materials, such as potential sources of ignition—fuels, oils, hay, or other organic materials—are separated from FGAN by at least 30 feet. If facilities do not comply with these requirements, OTSC can deny, suspend, or revoke annual certificates to sell (or offer to sell) FGAN.

8.7.2 Texas House Bill 942

The summary of Texas HB 942 says that it is an "act relating to the storage of certain hazardous chemicals; transferring enforcement of certain reporting requirements, including the imposition of criminal, civil, and administrative penalties, from the Department of State Health Services to the Texas Commission on Environmental Quality." It became law on June16, 2015.[677] The law bars facilities from storing FGAN with any nonfertilizer materials, requires that FGAN be stored at least 30 feet away from combustible materials, moves FGAN regulation from the Department of State Health Services to the TCEQ, allows the State Fire Marshal to inspect FGAN facilities, gives fire departments access for pre-fire planning assessments, and requires correction of hazardous conditions within 10 days.[678]

Although this law is an effort by state legislators to better regulate FGAN, it is not entirely adequate. For example, the requirement that FGAN storage be at least 30 feet from combustible materials was already required by the Texas Commercial Fertilizer Rules, as amended in June 2014 (and discussed in Section

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[675] *See*: http://www.tlc.state.tx.us/pubssoe/80soe/80soe.pdf (accessed on December 29, 2015).
[676] *See*: http://otscweb.tamu.edu/Risk/AmNitrate/PDF/AN-Compliance-Guide.pdf (accessed on December 29, 2015).
[677] *Ibid*.
[678] *See*: http://kwbu.org/post/abbott-signs-bill-tackles-ammonium-nitrate-storage (accessed on December 29, 2015).

8.7.1), a year before HB 942 became law. During a May 2015 meeting of the Texas Senate Committee on Natural Resources and Economic Development, Senator Brian Birdwell, who sponsored the bill, affirmed this fact. He said, "To be clear this is not a new regulatory scheme. HB 942 simply codifies existing regulations regarding reporting of hazardous chemicals. These are existing regulations which 100 percent of FGAN storage facilities in this state [must currently comply with]."[679]

A related bill, HB 417, would impose penalties for improper FGAN storage and would create rulemaking authority over FGAN facilities.[680] The bill states, "The commissioner of insurance, after consultation with the state fire marshal, by rule shall adopt fire protection standards for FGAN storage facilities, including standards for the storage of FGAN at those facilities."[681] State Representative Joe Pickett, the author of HB 417, told the Texas House Committee on Environmental Regulation in April 2015 that "the rulemaking authority is a way to make changes without the Legislature being in session," explaining that the Commissioner of Insurance would work with state agencies.[682] This regulatory authority distinguishes HB 417 from HB 942. Although HB 417 does not necessarily establish new regulations, it gives the Commissioner of Insurance an opportunity to do so. As of December 2015, however, this bill remains pending in committee.[683]

8.7.3 Athens City Ordinance

After the May 29, 2014, FGAN-related fire at the East Texas Ag Supply facility in Athens, Texas (discussed in Section 7.4), the city of Athens initiated efforts to prevent similar events. On May 29, 2015, Athens passed an ordinance that banned bulk storage of FGAN and anhydrous ammonia.[684] The ordinance (No. O-24-14) states in simple terms, "Commercial Fertilizer Storage or Manufacturing Facilities used to produce, transfer, store, or offer for sale Bulk FGAN, Bulk FGAN Material and/or Anhydrous Ammonia shall not be allowed in any zoning district in the City." A "commercial fertilizer storage or manufacturing facility" is defined as one that "stores, mixes, or manufactures 10,000 or more pounds of FGAN and/or anhydrous ammonia and/or is required to register with the Texas Feed and Fertilizer Control Service." The ordinance also streamlines chemical reporting and allows volunteer fire departments to inspect facilities.[685] However, this ordinance does not apply retroactively to the facilities that existed when the ordinance was enacted.

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[679] *Ibid*.
[680] *See*: http://www.texastribune.org/2015/04/07/proposed-bill-aims-prevent-another-fertilizer-blas/ (accessed on December 29, 2015).
[681] Texas HB 417, "An act relating to information regarding the storage of certain hazardous chemicals; providing penalties."
[682] *See*: http://www.texastribune.org/2015/04/07/proposed-bill-aims-prevent-another-fertilizer-blas/ (accessed on December 29, 2015).
[683] *See*: http://txlege.texastribune.org/84/bills/HB417/ (accessed on December 29, 2015).
[684] *See*: http://www.kltv.com/story/29192400/one-year-after-fire-city-of-athens-state-make-changes-in-ammonium-nitrate-storage (accessed on December 29, 2015).
[685] *Ibid*.

8.8 **Industry Standards**

Since the WFC incident, the fertilizer industry has implemented initiatives to prevent such an incident from reoccurring. In February 2014, TFI and the ARA, two primary agricultural trade associations, developed and issued *Safety and Security Guidelines for the Storage and Transportation of Fertilizer Grade Ammonium Nitrate at Fertilizer Retail Facilities* (or Safety and Security Guidelines).[686] This public document explains the OSHA Explosives and Blasting Agents standard, but also provides more specific guidance. In March 2014, TFI and the ARA initiated an FGAN stewardship program. Participation involves a voluntary assessment every three years of facility safety and security, focusing on FGAN and anhydrous ammonia.

8.8.1 The Fertilizer Institute (TFI)

TFI is a major trade association for the fertilizer industry.[687] TFI members include BP Energy Company, Dow AgroSciences, DuPont Sulfur Products, JP Morgan, Mitsubishi International Corporation, Shell Sulphur Solutions, and Union Pacific Railroad.[688] TFI lists security, energy, the environment, and worker health and safety as concerns to its members.[689] It also lists product safety stewardship as one of its key issues.[690] TFI offers tools to enhance the safety and security of products and equipment (discussed in Appendix E) across the supply chain.[691] Post-WFC incident tools include the Compliance Assessment Tool, the Safety and Security Guidelines, and the ResponsibleAg program. Each of these is discussed in the next sections.

8.8.1.1 Compliance Assessment Tool

The Asmark Institute, a private not-for-profit educational organization that is a resource center for the agricultural retail industry, developed the web-based Compliance Assessment Tool.[692] With regulatory compliance consistently cited during the last 18 years as one of the top 10 threats to the long-term viability of agricultural retail facilities, the Compliance Assessment Tool is meant to assist the agricultural retail industry.[693] This tool helps personnel at facilities, terminals, warehouses, and farm equipment dealers in identifying the regulations that apply to their specific sites.[694] The Compliance Assessment Tool evaluates onsite compliance efforts.[695] Through accessing the website, entering facility

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[686] ARA, TFI. "Safety and Security Guidelines for the Storage and Transportation of Fertilizer Grade Ammonium Nitrate at Fertilizer Retail Facilities," February 2014.
[687] *See*: http://www.tfi.org/about (accessed on December 29, 2015).
[688] *See*: http://www.tfi.org/about/membership-list (accessed on December 29, 2015).
[689] *See*: http://www.tfi.org/about (accessed on December 29, 2015).
[690] *See*: https://www.tfi.org/advocacy/stewardship (accessed on December 29, 2015).
[691] *See*: http://www.tfi.org/safety-and-security-tools (accessed on December 29, 2015).
[692] *See*: http://www.tfi.org/compliance-assessment-tool (accessed on December 29, 2015).
[693] *See*: https://www.asmark.org/Compass/ComplianceAssessmentTool/ (accessed on December 29, 2015).
[694] *Ibid*.
[695] *Ibid*.

information, and describing scope of operations, the user can download a specific compliance assessment document and then complete a worksheet.[696] Periodic use of the tool is encouraged to help control risk and to support compliance efforts.[697]

8.8.1.2 Safety and Security Guidelines for the Storage and Transportation of FGAN at Fertilizer Retail Facilities

TFI and the ARA created the Safety and Security Guidelines.[698] TFI's website notes that "the document was created to fill the void in emergency response guidelines specific to FGAN fertilizer at retail fertilizer facilities."[699] The guidelines outline best practices for safe and secure storage and transport of FGAN.[700] They also summarize storage and handling regulations for FGAN facilities as well as recommendations for first responders.[701] Moreover, they provide rules for transporting FGAN via truck, highway, rail, and barge.[702]

8.8.1.3 ResponsibleAg

Created by TFI and the ARA in 2014, ResponsibleAg is a third-party auditing program for fertilizer retailers.[703] Although any business that stores or handles fertilizer product is eligible to participate in the ResponsibleAg Certification Program, the first three years of the program focus on companies that store and handle AN and/or anhydrous ammonia fertilizer.[704] Using federal requirements for the storage and handling of fertilizer products, ResponsibleAg has compiled a checklist of more than 320 questions for auditing each participating facility.[705] The participating facility determines the audit scope; however, all participants must have a "base audit."[706] A participating facility may become ResponsibleAg certified only if it passes the initial audit or if it takes all necessary steps to correct the issues identified during the audit and documented in the facility's corrective action plan.[707]

ResponsibleAg also allows its participating suppliers to access the list of participating facilities that have successfully completed the assessment and earned certification.[708] This is important because it allows suppliers to determine whether prospective buyers have successfully completed the ResponsibleAg assessment, which thereby promoted federal regulatory compliance. This approach enables

[696] *Ibid*.
[697] *Ibid*.
[698] *See*: http://www.tfi.org/ammonium_nitrate_guidelines (accessed on December 29, 2015).
[699] *Ibid*.
[700] *Ibid*.
[701] *Ibid*.
[702] *Ibid*.
[703] *Ibid*.
[704] *See*: http://www.responsibleag.org/About.cgi (accessed on December 29, 2015).
[705] *Ibid*.
[706] *Ibid*.
[707] These corrective actions must be certified by ResponsibleAg, usually during a verification audit.
[708] *See*: https://www.responsibleag.org/FAQ.cgi#Link02 (accessed on December 29, 2015).

ResponsibleAg members to engage in some elements of product stewardship (as discussed in Section 8.8.3). Notably, CF Industries and EDC, the only AN fertilizer manufacturers in the United States, are listed as ResponsibleAg participants.[709] Appendix F includes additional information on the ResponsibleAg program process.

8.8.2 Agricultural Retailers Association (ARA)

The ARA is also a major trade association for the fertilizer industry.[710] It represents agricultural retailers and distributors across the United States on legislative and regulatory issues.[711] ARA members represent the majority of agribusinesses in the United States.[712] The ARA works with Congress to create legislation, and updates federal agencies and legislators on important issues affecting the industry.[713] The ARA offers programs and services to keep its members informed of important industry issues.[714]

8.8.3 Product Stewardship

As of this report's publication, only two companies in the United States, CF Industries and EDC, manufacture FGAN.[715] Fertilizer manufacturers can promote the safe storage and handling of FGAN by distributors and retailers by implementing product stewardship programs. According to the Center for Chemical Process Safety, product stewardship encourages safety and health in the design, manufacture, marketing, distribution, handling, use, and disposal of chemical products.[716] Responsibility for safely managing the product is shared throughout the supply chain and the product life cycle. Because it is a self-regulated program, product stewardship can only be as effective as industry intends and allows.

CSB determined that components of an effective product stewardship program should generally include the following elements for each product:

- Identifying and communicating all product hazards among manufacturers, distributors, and retailers.
- Providing supplemental technical information on safe handling practices for the product (furnished by manufacturers and/or distributors) to other distributors and/or retailers.
- Establishing accountability for distributors and retailers to promote safe handling of a product throughout the chain of customers.
- Performing monitoring and auditing, such as onsite visits to the locations where the product will be stored or used.

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709 *See*: https://www.responsibleag.org/ParticipantList.cgi (accessed on December 29, 2015).
710 *See*: http://www.aradc.org/ARADC/About/About/ (accessed on December 29, 2015).
711 *See*: http://www.aradc.org/becomeamember/ (accessed on December 29, 2015).
712 *Ibid*.
713 *Ibid*.
714 *See*: http://www.aradc.org/about/about (accessed on December 29, 2015).
715 The WFC also reported receiving imported AN from foreign manufacturers between 2006 and 2013.
716 Center for Chemical Process Safety. *Guidelines for Safe Handling of Powders and Bulk Solids*. New York: Center for Chemical Process Safety/AIChE, 2005: 521.

- Developing mechanisms for outreach to communities near the facilities where the products are stored or used.

Information sharing is an important component of product stewardship. When information about product hazards or details about the storage practices of a certain facility are known, people and companies dealing with the product or with the facility have the opportunity to effectively manage the risks associated with that product. The same logic applies to the management of FGAN. The WFC incident highlighted the need for greater awareness of the unpredictable nature of AN and the conditions under which it can detonate. Two industry programs, Responsible Care and ResponsibleAg, both advocate information sharing. Accordingly, the programs have serious product stewardship potential.

As described in Section 8.8.1.3, the joint TFI-ARA ResponsibleAg program currently addresses some aspects of product stewardship. In particular, fertilizer sellers (i.e., manufacturers and/or distributors) may elect to access the list of ResponsibleAg-participating facilities to determine assessment completion and certification of prospective buyers (i.e., distributors and/or retailers). By doing so, the seller verifies that the buyer safely stores fertilizer (or at least has a record of safely storing fertilizer). Similarly, the American Chemistry Council's (ACC) Responsible Care initiative includes information sharing in its product stewardship program. Participation in Responsible Care is a condition of membership for ACC members.[717] The program specifies 11 management practices and focuses on leadership commitment, accountability and management, prioritization of products, product information, risk characterization, management of new information, product safety management, product design and improvement, value chain communication, cooperation and outreach, information sharing, and performance assessment and continual improvement.[718]

Serious participation in product stewardship programs such as ResponsibleAg and Responsible Care can promote the safe handling and storage of domestically manufactured FGAN. This is especially true for FGAN because there are only two companies, CF Industries and EDC, that manufacture FGAN in the United States. As such, domestically manufactured FGAN product can be linked to one of these two companies. CF Industries and EDC are already members of ResponsibleAg. Product stewardship programs such as ResponsibleAg can ensure that FGAN management practices, starting with FGAN manufacturers CF Industries and EDC, are subject to greater scrutiny. However, it is also important to make sure that distributors and retailers handle and store the product safely.

Because responsibility for a chemical product does not always end after it is manufactured, it is important that manufacturing companies know how the product is handled and stored once it leaves the production site. In other words, a manufacturer cannot simply confirm that its direct buyer safely stores and handles the manufacturer's product because that buyer may in turn sell to another buyer that does not store or handle the product safely. The same reasoning applies to communicating product hazards. Of course, requiring the manufacturer to communicate the hazards of its product to its buyer is surely a step in the

[717] *See*: http://responsiblecare.americanchemistry.com/ (accessed on November 30, 2015).
[718] *See*: http://responsiblecare.americanchemistry.com/Responsible-Care-Program-Elements/Product-Safety-Code/Responsible-Care-Product-Safety-Code-PDF.pdf (accessed on November 30, 2015).

right direction, but the buyer must also communicate the same hazards to its buyers, if any. Otherwise, catastrophic incidents can occur. Importantly, therefore, these distribution chains must not break; effective communication must endure from top to bottom.

To ensure continuity of communication throughout the supply chain, industry should voluntarily take an active role. Because government agencies cannot reasonably be expected to routinely inspect every FGAN facility, industry's product stewardship programs must play a significant role in making sure that this top-to-bottom approach is implemented. Product stewardship offers an important opportunity for industry to further manage risk, beyond providing SDSs to retailers. Although CF Industries and EDC use different business models, both have executed initiatives that ascribe to product stewardship elements post-incident.

8.8.4 Efforts to Address FGAN Hazards Post-Incident

Since the WFC incident, both CF Industries and EDC have made additional efforts to make sure that their FGAN product is stored and handled safely as it moves out of their manufacturing facilities. CF Industries has implemented a certification process for its customers (purchasing organizations as well as facilities that receive FGAN deliveries) to confirm that customers communicate both the hazards and safe storage and handling practices of FGAN. As of December 31, 2014, CF Industries requires existing facilities to certify through a signed certification letter that they are in compliance with applicable guidelines and regulations before they can receive FGAN product. All new purchasing organizations and sites must also return the signed certification letter before receiving FGAN from CF Industries. Specifically, the letter requires senior responsible officials at both the purchasing organization and the delivery facility to certify that they are either in compliance with, or legally exempt from, 17 items. These items include, for example, attestations that:

- The purchasing organization provided the FGAN SDS developed by CF Industries to all of its sites.
- The purchasing organization and site provided copies of the CF Industries FGAN SDS to all employees.
- The site complies with OSHA requirements for FGAN storage.
- The site filed EPCRA and SARA Tier II Chemical Inventory Reports with appropriate emergency response organizations.
- The site maintains and follows an emergency response plan and written procedures for the safe handling of AN.

By signing the certification statement, officials at the purchasing organization certify that all relevant personnel at the site are aware of FGAN safety handling requirements and that adequate procedures are in place to comply with all 17 listed items. The certification packet also includes an up-to-date FGAN SDS developed by CF Industries and the TFI-ARA guidance for FGAN. CSB determined that this process could provide a reasonable degree of assurance that FGAN product hazards are being communicated as the product is delivered to new and existing customers and, most important, that those customers comply with applicable regulations and practices in order to receive product. If CF Industries does not receive a completed and signed certification statement, it will not sell FGAN product.

Although not in the form of a certification statement program, EDC also took steps to enhance the safety of its FGAN product post-incident. EDC updated its SDS for FGAN to include more information regarding firefighter precautions and added a reference to NFPA 400.[719] Moreover, EDC developed a product information bulletin to accompany its SDS to emphasize FGAN hazards and safety measures.[720] To better communicate FGAN hazards in response to the WFC incident, EDC conducted mass mailings to all of its customers. The mailings included the following:

- EDC's revised SDS (September 2013 and November 2014 versions).
- TFI-ARA Safety and Security Guidelines for Ammonium Nitrate.
- OSHA Guidance on Ammonium Nitrate Storage Requirements in 29 CFR 1910.109(i).

In addition, EDC repaired and replaced wooden bins at its own owned-and-operated retail site locations to ensure compliance with OSHA requirements regarding the protection of bins against AN impregnation.

In gathering information regarding these post-incident safety initiatives, CSB found that CF Industries and EDC operate under different business models, despite their status as the only two manufacturers of FGAN in the United States. CF Industries does not directly sell to retailers, but may deliver directly to retailers at the instruction of a direct customer. It delivers FGAN only to independently owned and operated distributors or their retail customers. CF Industries does not own any of the distribution facilities to which it ships product, and it does not sell directly to retailers, although it might deliver directly to retailers at the instruction of a direct customer.

Unlike CF Industries, EDC delivers some FGAN product to its own owned-and-operated distribution sites. In this regard, the business models of CF Industries and EDC differ. EDC produces FGAN in El Dorado, Arkansas, which is shipped by rail or truck to either (1) its own distribution sites, which operate under the name EDC Ag Products Company, LLC (EDC Ag Products),[721] or (2) its larger customers. Approximately 40 percent of the FGAN produced at the EDC Arkansas manufacturing facility is shipped to its 11 EDC Ag Products distributor locations (most in Texas), and approximately 60 percent is sold directly to customers. From the EDC Ag Products distributor locations, FGAN may be sold to other distributors or to retailers or farmers. All of the FGAN sold directly from the EDC manufacturing facility in Arkansas is delivered mainly to dealers, with a small quantity to brokers.

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[719] *See*: http://eldoradochemical.com/MSDS_Sheets/EDC/EDC_Products/EDCC_AN_Prill_SDS_Information_Bulletin_Nov_2014.pdf (accessed December 29, 2015).
[720] *Ibid*.
[721] At the time of the incident, the distribution sites operated under the name El Dorado Chemical. El Dorado Chemical Company and EDC Ag Products Company, LLC are subsidiaries of LSB Industries, a manufacturing and marketing company.

At the time of the WFC incident and as long ago as 2004, EDC sold products to International Chemical Company (Inter-Chem), which acted as a trader or supplier of FGAN, among other fertilizer products. Through its Domestic Plant Foods Group, Inter-Chem is a distributor of phosphate, nitrogen, and potash products in the United States.[722] Essentially, Inter-Chem served as a broker and consignee of finished fertilizer products to the WFC. Although Inter-Chem did not produce or manufacture the fertilizer product that was sold to the WFC, its role as a broker was significant. Importantly, Inter-Chem functioned as another link in the chain of commerce as the FGAN traveled from manufacturer to retailer through the broker. To better understand the chain of hazard communication involved in this investigation, CSB started at the top with the manufacturers and analyzed the pre-incident SDSs and hazard communication practices of both EDC and CF Industries.

Before the WFC incident, EDC provided a copy of its SDS to its customers and to Inter-Chem. The EDC SDS in use at the time of the 2013 WFC incident was last revised in 2011. CSB reviewed the SDS and found that it lacked certain safety information, specifically related to firefighting measures. The 2011 EDC SDS included warnings about the hazards of AN, such as its capability to support combustion and become explosive in the presence of contaminants or when under confinement. Under the firefighting measures section, the SDS instructed firefighters to “flood with water” but did not address the proper way to handle massive and uncontrollable fires, the need to extinguish such fires from a distance, or the possible need for evacuation. In addition, the SDS lacked references to applicable AN safety standards, such as the OSHA Explosives and Blasting Agents standard and NFPA 400 (2010 Edition). On the other hand, the CF Industries pre-incident SDS included a comprehensive list of AN hazards and firefighting measures. Nonetheless, both CF Industries and EDC made changes to enhance the safe handling of their products after the WFC incident.

As previously discussed, both U.S. FGAN manufacturers have improved communications with their customers about FGAN hazards and safe storage practices since the WFC incident. CF Industries implemented a program to certify compliance with applicable standards and guidelines as a condition of sale. In contrast, EDC conducted hazard communication in the form of mass mailings, replaced and repaired its own wooden bins at EDC Ag Products facilities, and continues to audit and inspect its retail sites (which it can readily do because EDC owns and operates these retail divisions) to make sure that about 40 percent of its manufactured FGAN is stored in compliance with applicable standards. These efforts represent a step in the right direction. However, because both EDC and CF Industries sell significant quantities of FGAN through brokers or through independent warehouses or distributors, whose direct customers may be unknown to EDC and CF Industries, it might not be possible in certain situations for the manufacturers to always ensure that their product is handled and stored in accordance with safety guidelines as the product moves downstream. At the very least, however, the certification statement program implemented by CF Industries attempts to ensure compliance with applicable regulations by causing its customers to attest to having knowledge of them.

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[722] *See*: http://www.ictulsa.com/domestic_fert.html (accessed on December 29, 2015).

As previously discussed, the CF Industries certification program strives to certify compliance by requiring purchasing organizations to affirm that their customers are in compliance with the CF Industries certification program elements. CSB found no evidence of such a program at EDC. Because EDC also sells product through wholesalers and distributors, a similar certification program, if implemented properly in conjunction with other components of product stewardship, will ensure that EDC product is handled safely throughout by its chain of customers. In concert with CF Industries' efforts, this can effectively promote the safety of all domestically manufactured FGAN.

9.0 Land Use

The West Fertilizer Company (WFC) incident led many observers to ask a seemingly simple question: Why would a community be located so close to a facility storing a potentially dangerous chemical? Although the question might be simple, the answer is not. In fact, the city of West, Texas, was so near the WFC facility primarily because of the following factors:

- The city "came to" the WFC facility over the years.
- There was a lack of zoning regulations.

These factors are interrelated. The growth of the community near the WFC facility made it difficult for the city to later enact zoning regulations to require risk mitigating actions such as a buffer zone between the facility and the community.

This is not to say that West is an anomaly. Many communities in Texas and nationwide are located too close to facilities resembling the WFC plant.[723] This reality highlights the need to explore why communities live with these hazards so that authorities can better mitigate the offsite consequences from incidents such as the fire and explosion at the WFC plant in West.

In this section, CSB seeks to explain the previously mentioned factors, providing insights into the proximity of the WFC facility to the West community. Following that discussion, other CSB investigations involving offsite consequences are highlighted to emphasize the scope of the problem. International land use perspectives also are provided to compare various approaches to the issue. In addition, efforts to address land use planning after the WFC incident are discussed.

9.1 Land Use Planning: An Introduction

Land use planning is a complex and controversial topic. It provides a framework for limiting private land use when necessary for the public benefit. However, economic, social, safety, and environmental interests must be effectively balanced to achieve this benefit. Such competing interests generate highly emotional and contentious debates. Ultimately, however, the decision is political in nature. The community must decide on the best use of land for its development and growth. Urban sprawl,

[723] As of December 6, 2013, Texas had 104 facilities storing 10,000 pounds or more of FGAN.

environmental concerns, and hazardous conditions are just some of the issues that land use planning addresses.

The United States takes a decentralized approach to land use planning; that is, states are largely vested with the authority to regulate and enforce the private use of land. In turn, the states delegate this authority to local governments. This approach generally results in municipalities establishing land use regulations for various areas within their respective jurisdictions. The federal or state government has asserted authority in some areas of land use planning, but the majority of land use planning authority in the United States lies with local governments. The benefits of such an approach stem from the regulatory flexibility to address issues of land use. The judiciary resolves any potential conflicts.

Land use planning cannot be said to solve all developmental issues that a community encounters. Land use regulation does give the community a control mechanism to reduce the consequences of an incident but does not eliminate the need for preventive controls. Rather, the mitigative control of land use planning must be combined with preventive controls employed by a variety of different stakeholders. Land use planning is a critical control to foster community development, but it must be integrated with other complementary approaches.

At its heart, land use planning offers the means for dealing with development and growth. However, many interests must be taken into account when attempting to effectively ensure a safe and satisfying community. Land use planning considerations can offer insights into the issues evident in the WFC incident. The location of the city of West near the WFC facility produced numerous benefits for the community; however, as the WFC fire and explosion revealed, such siting also had deadly consequences.

9.2 The City That "Came to" the WFC Over the Years

The WFC facilities were constructed and began operations in 1962.[724] At the time, the facilities were largely surrounded by open fields, raising little concern about any potential offsite consequences. Furthermore, no zoning regulations existed when the WFC began business.[725] Over the years, however, the city of West began to slowly develop around the WFC property. As the WFC was grandfathered into West ordinances and the city was subsequently zoned residential, little attention was paid to the city's slow but steady encroachment toward the WFC facility.

[724] Crain, Zac. "Love and Loss in a Small Texas Town." *D Magazine* (July 2013). *See*: http://www.dmagazine.com/Home/D_Magazine/2013/July/West_Texas_Love_and_Loss_in_a_Small_Town.aspx?page=1 (accessed on November 25, 2014).

[725] According to the West Code of Ordinances, the earliest zoning regulation was adopted on March 21, 1967. City of West. Chapter 14, Section 14.01.001. *Code of Ordinances*. *See*: http://z2codes.franklinlegal.net/franklin/Z2Browser2.html?showset=westset (accessed on November 25, 2014).

West was officially incorporated as a city in 1892, and with the help of a railroad track and fertile land for farming, it thrived.[726] Before construction of the WFC plant, the area north of the city was largely open fields used for agriculture and ranching. At the time that the WFC began operations, the area maintained the same character except for a residence located approximately 250 feet north of the WFC property line.[727] The location was ideal for such a business—just outside of the city, next to a railroad track, and within a convenient distance for local farmers. West lacked zoning regulations when the WFC completed its construction, and there appeared to be little need for such regulations as the WFC facilities were far removed from the city. Furthermore, the portion of the WFC property where fertilizers and pesticides were stored was outside of the West city limits and thus outside of its jurisdiction.[728]

Within this framework, the city of West began to expand and grow around the WFC facility. As shown in Figure 74, the city began developing further north over the years. This growth continued until the community was adjacent to the WFC property. Parks, subdivisions, nursing homes, schools, and an apartment complex sat within a 600-foot radius of the facilities. Furthermore, as the city continued to build its infrastructure near the WFC facility, the area became an even more attractive target for development. The community hardly noticed the WFC facility. It was only aware of the risk of accidental releases of anhydrous ammonia but viewed such events with little concern. Figure 75 shows the WFC facility before and after the incident.

[726] City of West. "City of West, Our History." *See*: http://www.cityofwest.com/our-history (accessed on November 25, 2014).
[727] Determined by using the December 14, 1964, aerial photograph of West, Texas, and employing Google Earth.
[728] McLennan CAD. "Property Search Results: Property ID 2013357, Adair Grain, Inc. for Year 2013." *See*: https://propaccess.trueautomation.com/Map/View/Map/20/201357/2013 (accessed on December 28, 2015).

1954

1970

1982

1988

1996

2010

Figure 74. Progressive Development of West (Source: GeoSearch)

Figure 75. Aerial Photographs of the WFC Facility Before (left) and After (right) the Incident (Source: NBC News)

This lack of proper foresight played a significant role in explaining why West came to be located so close to the WFC plant. Unfortunately, as the WFC was grandfathered into the city's Code of Ordinances,[729] the city was not required to address the risks involved in this encroachment. Not that West is a peculiar case; in many instances across the country, similar problems exist.[730]

9.3 Lack of Zoning Regulations

Both the federal government and Texas have failed to issue regulations relating to siting facilities that store and distribute FGAN near communities such as West. If a regulation had addressed issues such as buffer zones, barricades, or other techniques to mitigate consequences, the severity of the casualties and damage experienced in West could have been significantly reduced. Moreover, although regulation cannot solve all problems, it serves as a mechanism to compel all industries to adopt and implement safer operations. Ultimately, the failure to mitigate the consequences of incidents such as the WFC fire and explosion in West exists at all levels of government.

U.S. law largely assigns the authority to regulate private land use to the individual states.[731] In turn, the states generally assign this authority to individual municipalities. It is important to note, however, that

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[729] City of West. Chapter 14. *Code of Ordinances*. *See*: http://z2codes.franklinlegal.net/franklin/Z2Browser2.html?showset=westset (accessed on November 25, 2014).

[730] For example, CSB reports on NDK, DPC, Concept Sciences, and the Caribbean Petroleum Refining tank explosion and fire.

[731] Because the Federal government is only vested with the powers delegated to it through the Constitution—such as the power to regulate interstate commerce, coin money, and so forth—it is limited in its capability to regulate issues

the state's authority can be preempted by the federal government in certain instances, and two of the main instances are matters concerning interstate commerce[732] and international treaties.[733] This dual sovereignty can allow for greater flexibility in resolving land use issues that affect the public. Over time, the federal government has assumed an increasing role in the regulation of land use issues, including those relating to storing chemicals such as FGAN. ATF, the U.S. Department of Housing and Urban Development (HUD), the Pipeline and Hazardous Materials Safety Administration (PHMSA), OSHA, and EPA have all promulgated regulations or recommendations relating to the siting of explosives, reactives, oxidizers such as FGAN, and flammable cryogenics such as liquefied natural gas (LNG) near populated areas. Table 14 briefly lists the relevant regulations issued by these agencies.

Table 14. Relevant Siting Regulations

Agency	Regulation	CFR
ATF	Commerce in Explosives	27 CFR Part 555
DOT	Liquefied Natural Gas Facilities: Federal Safety Standards	49 CFR Part 193
HUD	Environmental Criteria and Standards	24 CFR Part 51
OSHA	Occupational Safety and Health Standards	29 CFR Part 1910
EPA	Chemical Accident Prevention Provisions	40 CFR Part 68
	Standards for Owners and Operators of Hazardous Waste Treatment, Storage, and Disposal Facilities	40 CFR Part 264

ATF holds the authority to require setting off stored explosive materials and low-explosive materials from inhabited buildings, public highways, public railways, and magazines.[734] Although explosive grades of FGAN are currently listed as explosive materials, the FGAN stored at the WFC facility is not categorized as an explosive material or a low-explosive[735] material.[736] Therefore, WFC storage of FGAN was not

related to land use. *See*: 10th Amendment, U.S. Constitution. However, state zoning regulations are subject to Federal preemption in areas where the use of land affects interstate commerce, international treaties, and Federal government spending powers.

[732] U.S. Constitution, Article I, Section 8.

[733] U.S. Constitution, Article VI.

[734] 27 CFR 555.218–219: "Explosive materials" are defined as explosives, blasting agents, water gels, and detonators. 27 CFR 555.11: "Explosives" are defined as any chemical compound, mixture, or device, the primary or common purpose of which is to function by explosion.

[735] Low explosives are defined as "explosive materials which can be caused to deflagrate when confined. *See*: http://www.gpo.gov/fdsys/pkg/FR-2012-09-20/pdf/2012-23241.pdf (accessed on December 29, 2015).

[736] *See*: http://www.gpo.gov/fdsys/pkg/FR-2012-09-20/pdf/2012-23241.pdf (accessed on December 28, 2015). *See also*: 27 CFR 555.220 Note (1), which states: "FGAN, by itself, is not considered to be a [explosive or blasting

subject to ATF set-off distances.[737] However, ATF has the authority to require a minimum separation distance between the FGAN stored at the WFC facility and certain blasting agents.[738]

DOT received Congressional authorization to "prescribe minimum safety standards for deciding on the location of a new liquefied natural gas [LNG] pipeline facility," which it oversees through PHMSA.[739] In turn, PHMSA has promulgated a series of recommendations concerning siting requirements for LNG facilities.[740] The regulations are based on NFPA 59A concerning the production, storage, and handling of LNG.[741] The siting requirements address issues such as thermal radiation protection, flammable vapor-gas dispersion protection, and wind forces. PHMSA applies the regulations to LNG facilities "designed, constructed, replaced, relocated or significantly altered after March 31, 2000," thereby grandfathering LNG facilities that existed before the March 31 date.[742] However, PHMSA has no regulations concerning the siting of AN facilities.

HUD requires projects receiving its assistance to be separated by an acceptable distance from specific stationary hazardous operations that store, handle, or process hazardous substances.[743] Hazardous substances are defined as "petroleum products (petrochemicals)" and other hazardous chemicals identified by HUD that can produce blast overpressure or thermal radiation levels in excess of HUD standards.[744] FGAN is not identified as a hazardous substance for the purposes of this standard.[745] In addition, the city of West would not qualify for HUD assistance as it does not meet HUD eligibility requirements.[746]

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agent]." *See also*: 72 *Federal Register* 18792, 18796, which states: "[A]lthough FGAN is a component of certain explosives such as ANFO, by itself, it is not an explosive. Therefore, it is not regulated by these ATF regulations."

737 The purpose behind regulating the siting of ANFO was "to protect interstate and foreign commerce against interference and interruption by reducing the hazard to persons and property arising from misuse and unsafe or insecure storage of explosive materials." Section 1101, Public Law 91-452, reprinted in: *U.S. Code Congressional and Administrative News* 1109 (1970).

738 27 CFR 555.220.

739 49 U.S.C. § 60103 (2014).

740 49 CFR 193 Subpart B (2014).

741 65 CFR 10950 (2000) and 69 *Federal Register* 11330 (2004).

742 49 CFR § 193.2051(2014).

743 24 CFR Subpart C; specifically 24 CFR 51.204 and 24 CFR 51.205. *See*: http://portal.hud.gov/hudportal/HUD?src=/program_offices/comm_planning/environment/training/guidebooks/hazfacilities (accessed on December 28, 2015). The intent in creating these regulations was "to encourage improvements in housing standards and conditions." "The National Housing Act." *See*: http://portal.hud.gov/hudportal/documents/huddoc?id=HUD-Guidebook.pdf (accessed on December 28, 2015): 3–4.

744 24 CFR 51.201, 203.

745 24 CFR Part 51, Appendix I to Subpart C. Anhydrous ammonia is also not listed as a hazardous substance; however, under special circumstances, the Secretary may require the application of a substance not listed in Appendix I to Subpart C. *See*: 24 CFR 51.207 (2014).

746 *See*: http://portal.hud.gov/hudportal/HUD?src=/program_offices/comm_planning/communitydevelopment/programs/entitlement (accessed on December 28, 2015). Eligible HUD grantees include (1) principal cities of metropolitan statistical areas, (2) other metropolitan cities with populations of at least 50,000, and (3) qualified urban counties with populations of at least 200,000 (excluding the population of entitled cities).

OSHA requires facilities handling highly hazardous chemicals to address facility siting issues; however, the requirement only deals with onsite consequences, not the issue of siting communities near highly hazardous chemical facilities.[747] This requirement is part of the Process Safety Management (PSM) regulation, which seeks to prevent or minimize the consequences of catastrophic releases of "highly hazardous chemicals."[748] However, the PSM regulation does not include FGAN as a highly hazardous chemical.[749] In addition, OSHA has the authority to require separation distances between FGAN and blasting agents,[750] in the same manner as ATF.[751]

The federal agency concerned with offsite consequences, EPA, addresses the siting of hazardous facilities near population centers by issuing various regulations and guidance.[752] For example, EPA regulates facility siting through its Risk Management Program rule, which calls on operators to address "stationary source siting" in its Program Level 3 process hazard analysis.[753] However, EPA offers little to no guidance to operators on how to satisfy the "stationary source siting" requirement.[754] The Risk Management Program rule also requires operators to conduct an offsite consequence analysis to provide government officials and the public with information about the potential consequences of an accidental release.[755] However, as FGAN is not classified as a hazardous regulated substance under the Risk Management Program rule, the WFC was not required to conduct such an analysis for its stored FGAN. In addition, EPA is currently considering the inclusion of "facility and equipment siting factors" in the Risk Management Program rule.[756]

Furthermore, EPA addresses facility siting through regulation and guidance concerning the siting of hazardous waste management facilities near communities and sensitive environments.[757] EPA also has issued guidelines relating to siting schools near potential environmental hazards, which could have proven

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747 29 CFR 1910.119(e)(3)(vii).
748 29 CFR 1910.119.
749 29 CFR 1910.119, Appendix A.
750 29 CFR 1910.109, Table H-22.
751 27 CFR 555.220.
752 *See*: http://www.epa.gov/statelocalclimate/local/topics/land.html (accessed on December 28, 2015).
753 40 CFR 68.67(c)(5) (2014).
754 The only real guidance on these terms is found in API RP 752, "Permanent Building Siting"; API RP 753, "Portable Building Siting"; and API RP 756, Tent Siting (to be issued in 2014). However, these guidance documents have been developed without any regulatory guidance. Furthermore, the identified standards have nothing to do with the relationship of the facility to its surrounding community. *See*: http://www.absconsulting.com/webinars/facility-siting.cfm (accessed on December 28, 2015).
755 40 CFR 68.150–68.195 (2014). The analysis consists of two elements, a worst case release scenario and alternative release scenarios.
756 *See*: https://www.osha.gov/chemicalexecutiveorder/final_chemical_eo_status_report.pdf (accessed on December 28, 2015): 36.
757 *See*: http://www.epa.gov/osw/hazard/tsd/permit/site/sites.htm (accessed on December 28, 2015); 42 U.S.C. § 6924 (2014); 40 CFR 264.18 (2014); 40 CFR 265.18 (2014); 40 CFR 270.14(b)(11) (2014); and 40 CFR 270.32(b)(2) (2014). *See also*: http://homer.ornl.gov/sesa/environment/guidance/rcra/locate.pdf (accessed on December 28, 2015).

helpful to West and similarly situated communities.[758] Moreover, EPA has recommended using information related to the Emergency Planning and Community Right-to-Know Act to inform a community's decisions concerning zoning and land use planning.[759]

Thus, federal regulations and guidance on land use do exist and do give communities valuable information regarding various chemical hazards. However, because FGAN is not defined as an explosive or hazardous material, it is excluded from federal zoning regulations. Unfortunately, this situation allows fertilizer facilities to store FGAN onsite without any federal oversight to confirm that the associated risks of locating communities nearby are mitigated to sufficient levels.

At the state level, Texas does little to oversee land use issues.[760] Instead, Texas grants the most land use oversight authority to its municipalities.[761] Texas has no regulation relating to siting hazardous facilities near communities.[762] Moreover, no state administrative agency oversees hazardous facility siting.[763] At the county level, regulatory authority is limited to zoning specific areas (such as Padre Island, Lake Tawakoni, and Falcon Lake), which results in a failure to approach county zoning from a general perspective.[764] This observation does not indicate that a one-size-fits-all approach to zoning is always desired.[765] In fact, in many instances, land use oversight needs to be tailored to specific political, social, economic, and environmental needs of the community.[766]

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758 *See*: http://www.epa.gov/schools/siting/basic.html (accessed on December 28, 2015).
759 *See*: http://www.epa.gov/osweroe1/docs/chem/notice.pdf (accessed on January 6, 2016): 7; *see also*: http://www.nicsinfo.org/docs/LEPCStudyFinalReport.pdf (accessed on December 28, 2015): 7.
760 *See*: http://stateimpact.npr.org/texas/2013/04/22/after-west-fertilizer-explosion-concerns-over-safety-regulation-and-zoning/ (accessed on December 28, 2015).
761 Texas Statute, Local Government Code, Title 7, "Regulation of Land Use, Structures, Businesses, and Related Activities." *See*: http://www.statutes.legis.state.tx.us/ (accessed on January 6, 2016). For instance, municipalities must adopt a zoning ordinance in accordance with a comprehensive plan; county zoning ordinances deal with specific areas such as military zones, Padre Island, and Amistad Recreation Area. *See*: http://www.statutes.legis.state.tx.us/Docs/LG/htm/LG.231.htm (accessed on December 28, 2015).
762 The Texas Administrative Code fails to address such siting issues. The Texas Department of Public Safety, Division of Emergency Management, holds responsibility for preparing the state emergency management plan, which may include "recommendations for zoning, building restrictions, and other land-use controls . . . to eliminate or reduce disasters or their impact . . . ." Texas Government Code, Title 4, Subtitle B, Chapter 418, Section 418.042. However, the state has not issued any such recommendations. *See*: https://www.txdps.state.tx.us/dem/downloadableforms.htm#stateplan (accessed on December 28, 2015).
763 *See*: http://texreg.sos.state.tx.us/public/readtac$ext.ViewTAC (accessed on December 29, 2015).
764 *See*: http://www.statutes.legis.state.tx.us/Docs/LG/htm/LG.231.htm (accessed on December 28, 2015). Texas House of Representatives, Committee on County Affairs. "Interim Report to the 80th Texas Legislature," December 2006: 7. *See also*: http://www.lrl.state.tx.us/scanned/interim/79/C832.pdf (accessed on December 8, 2014).
765 APA discussion on Growing Smart project with Stuart Meck. *See*: http://www.planning.org/growingsmart/background.htm (accessed on January 6, 2016).
766 *See*: http://www.planning.org/growingsmart/background.htm (accessed on December 28, 2015).

At the local level, Texas municipalities are granted the authority to regulate private land, including the location of hazardous facilities.[767] Among other requirements, the zoning regulations must be designed to ensure public safety from fires and other dangers.[768] However, the municipality is not given the authority to remove the hazardous condition on the property that exists at the time the governing body implements zoning authority and that is used in a public service business.[769] The municipality is allowed to impose zoning regulations relevant to the storage and use of hazardous substances.[770]

In the case of West, Texas, this arrangement led to the city being vested with the most authority in regulating public use. West exercised this authority through its Code of Ordinances.[771] West had zoned all property within the city limits for residential purposes only. However, all real property that had been used for commercial purposes before 1987 could remain commercial in nature. Any future development with commercial intent required a rezoning procedure.[772] This provision is consistent with West's comprehensive plan to zone all property within the city limits as residential property.

In essence, regulatory authority has been delegated to municipalities to oversee the siting of facilities storing and distributing FGAN near cities such as West. Neither the federal government nor the state of Texas takes any part in oversight. In many instances, however, municipalities are unable to adequately address this complex issue through regulatory mechanisms. For instance, facilities such as the WFC plant existed before promulgation of the city's Code of Ordinances, posing an issue of grandfathered facilities. Many different economic, safety, environmental, and agricultural interests must also be balanced. Furthermore, municipalities already face a shortage of resources for other essential governmental functions. However, safety issues can be addressed through reasoned regulation, using a number of methods. For example, a regulation requiring separation distances between public receptors and facilities handling FGAN could help mitigate offsite consequences in cities such as West. At root, however, locating these facilities near communities represents a national concern; therefore, all levels of government should give consideration to developing land use regulations to counter this problem.

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[767] Texas Statute, Local Government Code, Title 7, Subtitle A, Chapter 211, Section 211.003. *See*: http://www.statutes.legis.state.tx.us/Docs/LG/pdf/LG.211.pdf (accessed on December 28, 2015).
[768] Texas Statute, Local Government Code, Title 7, Subtitle A, Chapter 211, Section 211.004. *See*: http://www.statutes.legis.state.tx.us/Docs/LG/pdf/LG.211.pdf (accessed on December 28, 2015).
[769] Texas Statute, Local Government Code, Title 7, Subtitle A, Chapter 211, Section 211.013. *See*: http://www.statutes.legis.state.tx.us/Docs/LG/pdf/LG.211.pdf (accessed on December 28, 2015).
[770] Texas Statute, Local Government Code, Title 7, Subtitle A, Chapter 211, Section 211.017. *See*: http://www.statutes.legis.state.tx.us/Docs/LG/pdf/LG.211.pdf (accessed on December 28, 2015). The term "hazardous substances" is not defined in the chapter.
[771] *See*: http://z2codes.franklinlegal.net/franklin/Z2Browser2.html?showset=westset (accessed on December 28, 2015).
[772] Section 14.01.002. *See*: http://z2codes.franklinlegal.net/franklin/Z2Browser2.html?showset=westset (accessed on December 28, 2015).

9.3.1 Importance of Land Use Planning in Siting Communities Near Facilities Storing FGAN and Other Hazardous Chemicals

The issue of siting hazardous facilities storing FGAN near cities such as West is not an anomaly; it is a nationwide problem. In addition, although not directly associated with FGAN storage facilities, land use issues have been at the forefront of multiple CSB investigations. Furthermore, CSB has identified—multiple times—the risks of locating a hazardous chemical facility near public receptors. Table 15 lists CSB investigations that involved land use issues.

Table 15. Investigations Involving Land Use Issues

Investigation	Public Receptors	Chemical Involved	Offsite Consequences
NDK Crystal, Inc.	Interstate commerce, businesses	Synthetic quartz crystal (silica and NaOH)	1 fatality
DPC (Festus, MO)	Highways, railroads, residences, businesses, farms	Chlorine	63 residents who sought medical treatment
Concept Sciences	Businesses, residences	Hydroxylamine	5 fatalities, 14 injuries, significant damage to buildings and shattered windows at residences
CAI/Arnel	Businesses, residences	Heptane, isopropyl alcohol, n-propyl alcohol	10 injuries, 24 houses and 6 businesses significantly destroyed
DPC (Glendale, AZ)	Residences	Chlorine	14 injuries
Freedom Industries	Residences, businesses, drinking water supply	MCHM, PPH	369 residents who sought medical treatment for exposure
Millard Refrigerated Services	Businesses, environment	Anhydrous ammonia	150 people who sought medical treatment for ammonia exposure
T-2 Laboratories Inc.	Businesses, residences, railroads	Methylcyclopentadienyl manganese tri-carbonyl	28 injuries, significant property damage to nearby businesses
Silver Eagle Refinery	Residences	Hydrocarbons	Damage to residences
Kaltech	Residences, businesses, public streets	Chemical waste	At least 36 injured people, damage to residences and businesses
Chevron Refinery	Residences, businesses, public streets	Hydrocarbons	Approximately 15,000 people who sought medical treatment

Investigation	Public Receptors	Chemical Involved	Offsite Consequences
Caribbean Petroleum	Residences, businesses, public streets	Hydrocarbons	Shutdown of major highways, evacuation of local residents
Bayer CropScience	Residences, college, businesses, interstate commerce, waterways	Methomyl, methyl isobutyl ketone	Property damage, community shelter-in-place activated

In light of this information, the WFC incident in West serves as yet another unnecessary and deadly reminder that little has been done to address the risks of locating communities near facilities handling hazardous chemicals such as FGAN. Furthermore, if the incident had occurred during school hours, many more adults and children could have been injured. This incident represents a microcosm of the potential harms that many communities across the nations could endure.[773]

9.3.2 International Perspectives

Other countries have confronted problems similar to those in West, Texas, and have taken a variety of approaches to address them. The European and Australian strategies merit consideration given their sophistication relative to the current U.S. approach. The discussion in this section explores the approaches taken by the European Union (EU), the United Kingdom (U.K.), and Australia.

9.3.2.1 European Union

Through its Seveso III Directive, the EU requires member countries to take land use planning policies "into account" as part of major accident prevention.[774] The policy behind the requirement is designed to mitigate the consequences of major chemical accidents experienced by public receptors. The EU developed this requirement in the aftermath of major industrial incidents, including the FGAN explosion in Toulouse.[775] In fact, the Seveso III Directive lists AN as a "dangerous substance," classifying the chemical into four different categories, depending on whether it is FGAN, technical grade ammonium

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[773] *See*: http://news.yahoo.com/devastated-texas-town-ponders-schools-140711695.html (accessed on December 29, 2015).
Jaeah Lee. "Map: Is There a Risky Chemical Plant Near You?" *Mother Jones* (April 17, 2014). *See*: http://www.motherjones.com/environment/2014/04/west-texas-hazardous-chemical-map (accessed on July 8, 2014).
[774] Seveso III Directive, Article 13, "Land-use planning." *See*: http://eur-lex.europa.eu/legal-content/EN/TXT/?uri=CELEX:32012L0018 (accessed on November, 2, 2015).
[775] G. Vierendeels, et al. "Modeling the major accident prevention legislation change process within Europe." *Safety Science.* 516 (2010).

nitrate (TGAN), off-specification ammonium nitrate (AN), or AN capable of self-sustaining decomposition.[776]

Under the Seveso III requirements, member countries are to ensure that their policies address "appropriate distances" between covered facilities and residential areas. Furthermore, the countries must "set up appropriate consultation procedures" with competent authorities to "facilitate the implementation" of the land use planning policies. The Seveso III Directive applies to new facilities, facilities undergoing modifications, and new developments. Existing facilities must determine whether additional technical measures are required to avoid an increase in risk to the nearby community.[777]

The Seveso III Directive does not prescribe best practice guidance for its technical requirements (such as separation distances), consistent with its respect for each country's political, cultural, technical, and economic differences. However, various entities such as the Institute for Systems and Informatics and Safety provide best practice guidance, which refers to the use of technical approaches and procedural issues.[778] Although such guidance offers helpful insights to member countries, the appropriate response for a specific site is still recognized as a matter of interpretation for each country.

Given the immense differences among the approaches to land use planning of the member countries, it is difficult to compare EU country land use policies. However, the establishment of groups such as the European Commission and the Committee of the Competent Authorities under the Seveso III Directive emphasizes the important role that land use planning issues play in the European community.[779] Although issues still remain relating to each country's practices and methodologies, the emphasis on siting of facilities storing hazardous materials near public receptors highlights the importance that the European community places on land use planning in major accident prevention.

9.3.2.2 United Kingdom

The U.K. vests a hazardous substances authority with the power to administer and enforce land use planning as it relates to storing or using hazardous substances. The hazardous substances authority is generally an entity charged with dealing with land use planning and zoning issues, known as the local

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[776] Seveso III Directive, Notes Section, "AN compounds with more that 28% by weight and AN based fertilizers." 2012/18/EU. *See*: http://eur-lex.europa.eu/legal-content/EN/TXT/?uri=CELEX:32012L0018 (accessed on November 2, 2015).

[777] Seveso III Directive, Article 13, "Land-use planning." 2012/18/EU. *See*: http://eur-lex.europa.eu/legal-content/EN/TXT/?uri=CELEX:32012L0018 (accessed on November 2, 2015).

[778] Christou, M.D., and S. Porter. "Guidance on Land Use Planning as Required by Council Directive 96/82/EC (Seveso II)." Institute for Systems Informatics and Safety, 1999. *See*: http://ipsc.jrc.ec.europa.eu/fileadmin/repository/sta/mahb/docs/LandUsePlanning/EUR18695EN_LandUsePlanningGuidance.pdf (accessed on December 28, 2015).

[779] Major Accident Hazards Bureau. "Land Use Planning." *See*: http://ipsc.jrc.ec.europa.eu/index.php/Land-use-planning/694/0/ (accessed on December 28, 2015).

planning authority.[780] Consequently, the U.K. takes an approach similar to that of the United States in decentralizing land use planning to allow a local authority to promulgate and enforce land use requirements.[781] For the WFC incident in West, Texas, the West City Council would be the analogue to the U.K. hazardous substances authority.

The U.K., however, requires land use policies to account for major accidents caused by hazardous substances.[782] This responsibility is executed through a collaborative effort among the hazardous substances authority, U.K. Health and Safety Executive (HSE),[783] U.K. Environment Agency,[784] and other interested stakeholders. Essentially, organizers of a proposed development must seek a hazardous substances consent from the hazardous substances authority to establish a facility that will store or use hazardous substances[785] within its jurisdiction.[786]

When the hazardous substances authority receives an application for consent, it must consult with the HSE and the U.K. Environment Agency for advice on whether consent to the proposed development is warranted. Other interested stakeholders are also consulted or given the opportunity to publicly comment on the proposed development.[787] Using all of the relevant information provided, the hazardous substances authority weighs all competing interests and decides whether to grant a hazardous substances consent to the proposed development.[788]

The U.K. attempts to balance each local community's interest in deciding the risks that it will tolerate, drawing on the expertise and resources of national governmental bodies. Such an approach makes it more likely that all relevant issues and concerns about locating a development that stores or uses hazardous substances near the public will be presented to the hazardous substances authority before a

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780 *See*: https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/16628/hazardoussubstancesguide.pdf (accessed on December 28, 2015).

781 The U.K. has experienced similar catastrophic incidents that had effects on the population, including the Flixborough (Nypro UK) Explosion in 1974 and the Buncefield incident in 2005. *See*: http://www.hse.gov.uk/comah/sragtech/caseflixboroug74.htm and http://www.buncefieldinvestigation.gov.uk/, respectively (accessed on December 28, 2015).

782 Seveso Directive II, Article 12, "Land Use Planning." *See*: http://eur-lex.europa.eu/LexUriServ/LexUriServ.do?uri=CONSLEG:1996L0082:20031231:EN:PDF (accessed on December 28, 2015).

783 The U.K. HSE is a governmental body responsible for enforcing health and safety at workplaces. *See*: http://www.hse.gov.uk/contact/authority.htm (accessed on December 28, 2015).

784 The U.K. Environment Agency is a governmental body responsible for protecting and improving the environment and for promoting sustainable development. *See*: http://www.environment-agency.gov.uk/aboutus/default.aspx (accessed on December 28, 2015).

785 FGAN is included within the definition of a "hazardous substance." *See*: http://www.legislation.gov.uk/uksi/1999/981/schedule/1/made (accessed on December 28, 2015).

786 *See*: http://www.hse.gov.uk/landuseplanning/what.htm (accessed on December 28, 2015).

787 Other stakeholders include the local parish council, fire and civil defense authorities, and the governmental agency English Nature.

788 *See*: http://www.environment-agency.gov.uk/aboutus/default.aspx (accessed on December 28, 2015).

decision is rendered. The U.K. thus believes that major offsite risks can be effectively managed before permitting a hazardous substance to be stored near a population in its vicinity.[789]

9.3.2.3 Western Australia

Australia's land use planning methods regarding hazardous substances vary across jurisdictions.[790] Although each Australian state and territory applies varying regulations regarding land use planning of FGAN storage facilities, the Government of Western Australia employs an insightful and sophisticated approach to the issue. In essence, Western Australia uses a risk-based method that subjects FGAN storage facility siting to government approval.[791]

Western Australia legislatively addresses land use issues concerning FGAN through its Dangerous Goods Safety Act 2004 (the Dangerous Goods Act). This act places a duty on all people involved with dangerous goods to minimize risk associated with those goods.[792] To minimize risk, the Dangerous Goods Act requires that "all reasonably practicable measures" be used. In determining whether a measure is "reasonably practicable," consideration is given to issues such as the severity of the harm, severity of the risk to people, and suitability of the means in question.[793] FGAN is treated as a dangerous good under the Dangerous Goods Safety (Storage and Handling Non-Explosives) Regulations 2007 and the Dangerous Goods Safety (Major Hazard Facilities) Regulations 2007, which both support the Dangerous Goods Act.[794]

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[789] *See*: https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/16628/hazardoussubstancesguide.pdf (accessed on December 28, 2015).

[790] See: http://www.chemicalspolicy.org/downloads/chemicals-plastics-regulation.pdf (accessed on December 29, 2015).

[791] Dangerous Goods Safety Act 2004. *See*: http://www.slp.wa.gov.au/legislation/statutes.nsf/main_mrtitle_242_homepage.html (accessed on December 28, 2015). Dangerous Goods Safety (Storage and Handling Non-Explosives) Regulations 2007. *See*: http://www.slp.wa.gov.au/legislation/statutes.nsf/main_mrtitle_12972_homepage.html (accessed on December 28, 2015). Dangerous Goods Safety (Major Hazard Facilities) Regulations 2007. *See*: http://www.slp.wa.gov.au/legislation/statutes.nsf/main_mrtitle_12983_homepage.html (accessed on December 28, 2015). Department of Consumer and Employment Protection Government of Western Australia. *Safe Storage of Solid FGAN: Code of Practice*: iii. *See*: https://miningandblasting.files.wordpress.com/2009/09/safe-storage-of-solid-ammonium-nitrate-code-of-practice.pdf (accessed on December 28, 2015).

[792] Dangerous Goods Safety Act 2004, Part 2. *See*: http://www.slp.wa.gov.au/legislation/statutes.nsf/main_mrtitle_242_homepage.html (accessed on December 28, 2015).

[793] *Ibid*.

[794] Dangerous Goods Safety (Storage and Handling Non-Explosives) Regulations 2007. *See*: http://www.slp.wa.gov.au/legislation/statutes.nsf/main_mrtitle_12972_homepage.html (accessed on December 28, 2015). Dangerous Goods Safety (Major Hazard Facilities) Regulations 2007. *See*: http://www.slp.wa.gov.au/legislation/statutes.nsf/main_mrtitle_12983_homepage.html (accessed on December 28, 2015). Department of Consumer and Employment Protection Government of Western Australia. *Safe Storage of Solid FGAN: Code of Practice*: iii. *See*: https://miningandblasting.files.wordpress.com/2009/09/safe-storage-of-solid-ammonium-nitrate-code-of-practice.pdf (accessed on December 28, 2015).

Land use planning as related to siting facilities storing FGAN near public receptors is implemented by applying separation distances. These distances are subject to acceptance by Resource Safety, a department of the Government of Western Australia.[795] If it is determined that an FGAN facility is not satisfying the separation distance requirement, Resource Safety may limit the quantity of FGAN within the facility or require that other safety conditions be met.[796]

The New South Wales Department developed the required separation distances with the intent of reducing the risk of offsite consequences insofar as reasonably practicable.[797] The distances were not designed to completely eliminate the risks associated with offsite consequences, nor were they intended to replace preventive controls.[798] The separation distances are categorized by a threshold quantity (i.e., whether FGAN is stored in quantities greater than or less than 10 metric tons). For instance, if FGAN exceeding 10 tons is stored at a facility, it must be separated by at least 300 meters (985 feet) from critical infrastructure, 240 meters (790 feet) from residential buildings, and 140 meters (460 feet) from commercial buildings.[799]

Western Australia seeks to address land use planning through a risk-based scheme that requires government permission to site FGAN facilities near public receptors. Depending on the quantity of FGAN stored, each facility must be sited at a minimum distance from such public receptors. Furthermore, if the facility is not sited at the required minimum distance, it might have to limit the maximum quantity of FGAN that it can store. A study of the risk associated with a particular facility might be required to reach agreement between the government and the facility on appropriate separation

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[795] Department of Consumer and Employment Protection Government of Western Australia. *Safe Storage of Solid FGAN: Code of Practice*: 8–10. *See*: https://miningandblasting.files.wordpress.com/2009/09/safe-storage-of-solid-ammonium-nitrate-code-of-practice.pdf (accessed on December 28, 2015).
See also: http://www.dmp.wa.gov.au/6611.aspx (accessed on December 28, 2015).

[796] Department of Consumer and Employment Protection Government of Western Australia. *Safe Storage of Solid FGAN: Code of Practice*: 8–10. *See*: https://miningandblasting.files.wordpress.com/2009/09/safe-storage-of-solid-ammonium-nitrate-code-of-practice.pdf (accessed on December 28, 2015).

[797] Department of Consumer and Employment Protection Government of Western Australia. *Safe Storage of Solid FGAN: Code of Practice*: 8–10. *See*: https://miningandblasting.files.wordpress.com/2009/09/safe-storage-of-solid-ammonium-nitrate-code-of-practice.pdf.
Government of Western Australia. *Code of Practice: Safe Storage of solid FGAN*, 3rd Edition: 6-7. *See*: http://www.dmp.wa.gov.au/Documents/Dangerous-Goods/DGS_COP_StorageSolidAmmoniumNitrate.pdf (accessed on December 29, 2015). *Hazardous Industry Planning Advisory Paper No. 4—Risk criteria for land use safety planning*. HIPAP4. *See*: http://www.planning.nsw.gov.au/Policy-and-Legislation/~/media/0D39F08E7889409BBA1FA88D5FB859FD.ashx (accessed on January 7, 2014).

[798] Department of Consumer and Employment Protection Government of Western Australia. *Safe Storage of Solid Ammonium Nitrate: Code of Practice*: 8–10. *See*: https://miningandblasting.files.wordpress.com/2009/09/safe-storage-of-solid-ammonium-nitrate-code-of-practice.pdf (accessed on January 6, 2016). Government of Western Australia. *Code of Practice: Safe Storage of solid ammonium nitrate*, 3rd Edition: 6–7. *See*: http://www.dmp.wa.gov.au/Documents/Dangerous-Goods/DGS_COP_StorageSolidAmmoniumNitrate.pdf (accessed on December 29, 2015).

[799] Government of Western Australia. *Code of Practice: Safe Storage of solid ammonium nitrate*, 3rd Edition: 6–7. *See*: http://www.dmp.wa.gov.au/Documents/Dangerous-Goods/DGS_COP_StorageSolidAmmoniumNitrate.pdf (accessed on December 29, 2015).

distances. This approach gives Western Australia the capability to balance the risk associated with storing FGAN against the need for land development.

9.4 Efforts to Address Land Use Planning After the West Incident

In the weeks, months, and years following the West incident, few inroads have been made to resolve land use issues. The federal government has developed a working group that is tasked with developing recommendations related to chemical facility safety and security; however, the timeline for delivery has been extended.[800] At the state level, general opposition remains to any type of change in the Texas approach to land use planning.[801] In fact, strong opposition has contested any regulation of FGAN facilities in Texas.[802] The city of West is currently awaiting recommendations from state and federal officials; however, it does plan on siting any new fertilizer facilities away from the community.[803]

The Texas State Fire Marshal's Office (SFMO) has taken a proactive approach by providing all counties with software demonstrations that estimate blast zones from facilities storing FGAN.[804] In addition to assisting first responders, the software gives community leaders the opportunity to assess community impacts relating to the siting of a new FGAN facility. In addition, the SFMO will assist each county in reviewing best practices for dealing with the storage and handling of FGAN.

At the county level, the McLennan County Local Emergency Planning Committee (LEPC) has emphasized the importance of land use issues in agreeing to focus on "upfront planning" when siting community buildings such as schools or hospitals near chemical facilities.[805] The LEPC has agreed to continue to meet quarterly. The city of West has also committed to advising other communities about identifying the potential hazards that they might face in locating chemical facilities near their towns and citizens.[806]

Applied Research Associates, Inc. (Applied Research) has engaged in an effort to understand and validate the separation distances prescribed in NFPA 400. After completing a literature review, Applied Research selected a consequence-based case study and developed a test plan. The firm then carried out the case

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[800] *See*: https://www.osha.gov/chemicalexecutiveorder/index.html (accessed on December 28, 2015).
[801] *See*: http://www.nytimes.com/2013/05/10/us/after-plant-explosion-texas-remains-wary-of-regulation.html?_r=0 (accessed on December 28, 2015).
[802] Henry, Terrence, NPR. "Proposals to Prevent Another Fertilizer Explosion Immediately Meet Resistance," July 2, 2014. *See*: http://stateimpact.npr.org/texas/2014/07/02/proposals-to-prevent-another-fertilizer-explosion-immediately-meet-resistance/ (accessed on December 8, 2014). The Associated Press. "New bill on West blast would delay new rules." *CBS DFW* (August 5, 2014). *See*: http://dfw.cbslocal.com/2014/08/05/new-bill-on-west-blast-would-delay-new-rules/ (accessed on December 29, 2015).
[803] *See*: http://res.dallasnews.com/interactives/2013_December/westretrospective/1215_westretrospective.html (accessed on December 28, 2015).
[804] *See*: http://res.dallasnews.com/interactives/2013_December/westretrospective/1215_assessment.html (accessed on December 28, 2015).
[805] *Ibid.*
[806] *Ibid.*

study test plan to assess the adequacy of the separation distance for safe storage of AN and the safe separation distance for personnel in a process building in the event of an explosion. Applied Research then developed a series of recommendations regarding separation distances in NFPA 400, including possible approaches for improving those distances, to guide NFPA and its affiliated Fire Protection Research Foundation project panel in future research efforts.[807]

The city of West is currently rebuilding. The blast substantially damaged more than 350 homes, completely destroying 150 of them, and caused approximately $100 million in damages.[808] The West High School has been razed, and a new school will be constructed on the same site.[809] The site of the accident will likely become an industrial park.[810]

10.0 Key Findings

Technical Findings

1. The presence of combustible materials used for construction of the facility and the fertilizer grade ammonium nitrate (FGAN) storage bins, in addition to the West Fertilizer Company (WFC) practice of storing combustibles near the FGAN pile, contributed to the progression and intensity of the fire and likely resulted in the detonation.

2. The WFC facility did not have a fire detection system to alert emergency responders or an automatic sprinkler system to extinguish the fire at an earlier stage of the incident.

3. On the basis of interviews with eyewitnesses and supporting photographic evidence, the first observed fire and smoke originated in and above the seed room and progressed throughout the northern half of the WFC facility. The radiant heat from the fire, fueled by the structure, flammable building contents, and the asphalt roof shingles, likely heated the surface of the FGAN pile. Contamination from soot, molten asphalt, and molten polyvinyl chloride (PVC) from an overhead conveyer produced a detonable mixture of combustibles and FGAN oxidizers. Increased ventilation generated a brighter and hotter flame, heating the FGAN-fuel mixture on the surface of the pile.

Regulatory Findings

4. Occupational Safety and Health Administration (OSHA) efforts to oversee facilities that store and handle FGAN fell short at the time of the incident.

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807 Fire Protection Research Foundation. "Separation Distances in NFPA Codes and Standards, 2014." *See*: http://www.nfpa.org/Assets/files/AboutTheCodes/59A/RFSeparationDistancesNFPACodesAndStandards.pdf (accessed on September 25, 2015).

808 *See*: http://www.hazmatmag.com/news/in-harms-way/1002482923/ (accessed on January 6, 2016) and http://res.dallasnews.com/interactives/2013_December/westretrospective/1215_whatwelearned.html (accessed on December 28, 2015).

809 CBS. "DFW, West Getting New Schools After Explosion," October 30, 2014. *See*: http://dfw.cbslocal.com/2014/10/30/west-getting-new-schools-after-explosion/ (accessed on December 6, 2014).

810 *See*: http://res.dallasnews.com/interactives/2013_December/westretrospective/1215_westretrospective.html (accessed on December 28, 2015).

a. Section (i) of the OSHA Explosives and Blasting Agents standard, 29 CFR 1910.109(i), was not very well known among those in the fertilizer industry, likely due in part to the fact that (1) application of the section was unclear; and (2) the section had rarely been used previously to cite fertilizer facilities.

b. OSHA inadvertently omitted ammonium nitrate (AN) from the List of Highly Hazardous Chemicals, Toxics and Reactives in its Process Safety Management (PSM) standard, 29 CFR 1910.119, even though AN possesses reactive characteristics that would have triggered its inclusion.

5. Because the WFC facility was covered under the U.S. Environmental Protection Agency (EPA) Risk Management Program rule for its anhydrous ammonia tanks (but not for its FGAN), WFC employees and emergency responders demonstrated a greater awareness of the hazards associated with onsite storage of anhydrous ammonia than those associated with FGAN. AN is not on the EPA Risk Management Program list of chemicals, so the WFC was not required to take safety measures for FGAN similar to those for ammonia.

Insurance Findings

6. WFC's previous property and liability insurer, which provided insurance to WFC from 2006 through 2009, did not focus on FGAN hazards in its annual insurance inspections because it was not required to do so. However, the insurer did not renew WFC's commercial property policy in 2010 because WFC repeatedly failed to comply with the insurer's safety-related recommendations (e.g., to replace corroded electrical wiring), which were identified in loss control surveys. The CSB found little evidence of onsite activity or inspections by WFC's subsequent insurer, U.S. Fire, which insured the facility at the time of the incident.

Emergency Response Findings

7. The West Volunteer Fire Department (WVFD) did not conduct pre-incident planning or response training at the WFC facility to address FGAN-related incidents because was no such regulatory requirement. Thus, the firefighters who responded to the WFC fire did not have sufficient information to make an informed decision on how best to respond to the fire at the fertilizer facility.

8. Federal and state of Texas curriculum manuals used for hazardous materials (HAZMAT) training and certification of firefighters placed little emphasis on emergency response to storage sites containing FGAN. On the other hand, HAZMAT shipping and transportation were covered frequently in the courses. Many federal and state grants support the resource needs of firefighters and fire departments; however, these grants are used more often for resources such as personal protection equipment or firefighting equipment rather than for training.

9. Lessons learned from previous FGAN-related fires and explosions were not shared with volunteer fire departments, including the WVFD. If previous lessons learned had been applied in West, the firefighters and emergency personnel who responded to the incident might have better understood the risks associated with FGAN-related fire.

Emergency Planning Findings

10. Despite WFC documentation of its FGAN in a 2012 Tier II report, the WVFD did not conduct drills and exercises at the WFC facility before the 2013 fire and explosion.

11. The agricultural use exemption under the Emergency Planning and Community Right-to-Know Act (EPCRA) is not clear about which facilities are covered under the exemption. Before the WFC fire and explosion, the state of Texas determined that the WFC was exempt under the EPCRA agricultural use exemption.

Land Use Planning Findings

12. At the time of its construction, the WFC facility was surrounded by open fields, and no zoning regulations existed when it began operations.

13. As the city of West developed over the years, it expanded toward the WFC facility.

14. The proximity of the city of West to the WFC facility magnified the offsite consequence impacts.

15. Other FGAN facilities throughout Texas are located in close proximity to schools, residences, and care facilities. Of the 40 FGAN facilities in Texas as of October 2015, 48 percent are within 0.5 miles of a school, nursing home, or hospital while 83 percent are within 0.25 miles of a residence.

11.0 Recommendations

U.S. Environmental Protection Agency (EPA)

2013-02-I-TX R1

Develop a guidance document on Emergency Planning and Community Right-to-Know Act (EPCRA) requirements that is issued annually to State Emergency Response Commissions (SERCs) and Local Emergency Planning Committees (LEPCs) and ensure that the guidance focuses on the following:

a. Explains which chemicals are exempt and which must be reported.
b. Describes how emergency responders should use Tier I and Tier II inventory reports and Safety Data Sheets, such as in safety training, practice drills, and for emergency planning.
c. Includes comprehensive LEPC planning requirements, with an emphasis on annual training exercises and drills for local emergency response agencies.

2013-02-I-TX R2

Develop a general guidance document on the agricultural exemption under EPCRA Section 311(e)(5) and its associated regulation, 40 CFR 370.13(c)(3), to clarify that fertilizer facilities that store or blend fertilizer are covered under EPCRA. Communicate to the fertilizer industry publication of this guidance document as well as the intention of Section 311(e)(5).

2013-02-I-TX R3

Revise the Risk Management Program rule to include fertilizer grade ammonium nitrate (FGAN) at an appropriate threshold quantity on the List of Regulated Substances.

a. Ensure that the calculation for the offsite consequence analysis considers the unique explosive characteristics of FGAN explosions to determine the endpoint for explosive effects and overpressure levels. Examples of such analyses include that adopted by the 2014 Fire Protection Research Foundation report, "Separation Distances in NFPA Codes and Standards," Great Britain's Health and Safety Executive, and other technical guidance.
b. Develop Risk Management Program rule guidance document(s) for regulated FGAN facilities.

U.S. Occupational Safety and Health Administration (OSHA)

2013-02-I-TX R4

Develop and issue a Regional Emphasis Program for Section (i) of the Explosives and Blasting Agent standard, 29 CFR 1910.109(i), in appropriate regions (such as Regions IV, VI, and VII) where fertilizer grade ammonium nitrate (FGAN) facilities similar to the West Fertilizer Company facility are prevalent. Establish a minimum number of emphasis program inspections per region for each fiscal year. Work with regional offices to communicate information about the emphasis program to potential inspection recipients.

2013-02-I-TX R5

Implement one of the following two regulatory changes, either option (a) or (b) below, to address FGAN hazards:

a. Add FGAN to the OSHA Process Safety Management (PSM) standard List of Highly Hazardous Chemicals, Toxics and Reactives in 29 CFR 1910.119**,** Appendix A, and establish an appropriate threshold quantity. Identify National Fire Protection Association (NFPA) 400 as a source of Recognized and Generally Accepted Good Engineering Practices (RAGAGEP) for PSM-covered FGAN equipment and processes.
b. Revise the OSHA Explosives and Blasting Agents standard, 29 CFR 1910.109, to ensure that the title, scope, or both make(s) clear that the standard applies to facilities that store bulk quantities of FGAN. Revise 1910.109(i), "Storage of Ammonium Nitrate," to include requirements similar to those in NFPA 400, *Hazardous Materials Code* (2016 Edition), Chapter 11. Ensure the following elements are considered:
    i. For new construction, prohibit combustible materials of construction for FGAN facilities and FGAN bins. For existing facilities, establish a phase-in requirement for the replacement of wooden bins with bins made of noncombustible materials of construction within a reasonable time period (e.g., 3 to 5 years from the date standard revisions are enacted), based on feedback from the fertilizer industry.
    ii. Require automatic fire sprinkler systems and fire detection systems for indoor FGAN storage areas.

iii. Define adequate ventilation for FGAN for indoor storage areas.
iv. Require all FGAN storage areas to be isolated from the storage of combustible, flammable, and other contaminating materials.
v. Establish separation distances between FGAN storage areas and other hazardous chemicals, processes, and facility boundaries.

International Code Council (ICC)

2013-02-I-TX R6

In a subsequent edition of the International Fire Code, develop a chapter or a separate section under Chapter 50 (“Hazardous Materials”) or Chapter 63 (“Oxidizers, Oxidizing Gases and Oxidizing Cryogenic Fluids”) that includes the following requirements for the storage and handling of ammonium nitrate (AN):

a. Require automatic fire detection and suppression systems in existing buildings constructed of combustible materials
b. Provide ventilation requirements in accordance with the International Mechanical Code to prevent the accumulation of off-gases produced during AN decomposition
c. Provide smoke and heat vents to remove heat from AN during fire situations
d. Establish minimum safe separation distances between AN and combustible materials to avoid contamination in the event of fire.
e. Prohibit the use of combustible materials of construction.

Department of Homeland Security, Federal Emergency Management Agency (FEMA)

2013-02-I-TX R7

Through a new or existing program and in conjunction with training partners, create and implement a competitive funding mechanism to provide training to regional, state, and local career and volunteer fire departments on how to respond to fire and explosion incidents at facilities that store fertilizer grade ammonium nitrate (FGAN). Continue to use available funding to ensure training effectiveness.

2013-02-I-TX R8

During the proposal review process for the program, ensure that the FGAN training includes multiple delivery methods to enable a broad reach. Training should allow for instructor-led, web-based, and train-the-trainer courses; initial orientation; and refresher training. Training also should accommodate both resident and mobile capabilities to facilitate flexible delivery.

Objectives of the selected training course should address the following:

a. Previous FGAN fire and explosion incidents, incorporating lessons learned
b. Hazards posed by other materials and chemicals stored near FGAN, including FGAN incompatibility with those materials and chemicals

c. Pre-incident planning for fires involving FGAN
d. On-scene emergency response and decision-making requirements for FGAN fires, including risk assessment, scene size-up, and situational awareness
e. National Incident Management System and Incident Command System.

2013-02-I-TX R9

Assist training partners to develop and provide continual oversight for an FGAN training program. In addition, evaluate the training curriculum to confirm that it adequately meets course objectives as well as the details of recommendation 2013-02-I-TX R8.

2013-02-I-TX R10

Develop an outreach program that notifies regional, state, and local fire departments about available FGAN training opportunities. The program should include the following:

a. Guidance for fire departments on how to identify FGAN hazards within their communities by engaging State Emergency Response Commissions and Local Emergency Planning Committees
b. Details on how to obtain FGAN training by submitting a proposal in response to the funding opportunity
c. Information on training partners and programs that provide FGAN training.

Texas Commission on Fire Protection (TCFP)

2013-02-I-TX R11

Develop minimum standards for course curricula to include hazard awareness of fertilizer grade ammonium nitrate (FGAN) for those fire departments that either have FGAN facilities in their jurisdictions or respond as mutual aid to other jurisdictions with FGAN facilities. In addition, develop a training program specific to FGAN.

Objectives of the program's training course should address the following:

a. Previous FGAN fire and explosion incidents, incorporating lessons learned
b. Hazards posed by other materials and chemicals stored near FGAN, including FGAN incompatibility with those materials and chemicals
c. Pre-incident planning for fires involving FGAN
d. On-scene emergency response and decision-making requirements for FGAN fires, including risk assessment, scene size-up, and situational awareness
e. National Incident Management System and Incident Command System.

2013-02-I-TX R12

Implement outreach to regional, state, and local fire departments that either have FGAN facilities in their jurisdictions or respond as mutual aid to jurisdictions with FGAN facilities, informing them about the new FGAN training certification requirements and opportunities to receive training. Include the following in the outreach:

a. Guidance for fire departments on how to identify FGAN hazards within their communities by engaging State Emergency Response Commissions and Local Emergency Planning Committees
b. Encouragement for fire departments in jurisdictions with FGAN facilities to become certified in FGAN training.

State Firefighters' and Fire Marshals' Association of Texas (SFFMA)

2013-02-I-TX R13

Develop a fertilizer grade ammonium nitrate (FGAN) training certification program for fire departments that either have FGAN facilities in their jurisdictions or respond as mutual aid to other jurisdictions with FGAN facilities. The certification program should include multiple delivery methods to enable a broad reach. The certification program should allow for instructor-led, web-based, and train-the-trainer courses; initial orientation; and refresher training. The training also should accommodate both resident and mobile capabilities to facilitate flexibility in delivery.

The criteria for the certification program should address the following:

a. Previous FGAN fire and explosion incidents, incorporating lessons learned
b. Hazards posed by other materials and chemicals stored near FGAN, including FGAN incompatibility with those materials and chemicals
c. Pre-incident planning for fires involving FGAN
d. On-scene emergency response and decision-making requirements for FGAN fires, including risk assessment, scene size-up, and situational awareness
e. National Incident Management System and Incident Command System.

2013-02-I-TX R14

Develop an outreach component for the training certification program that notifies regional, state, and local fire departments with FGAN facilities in their jurisdictions about the training certification opportunities available for FGAN. Ensure that the following items are included in the development of this program:

a. Guidance for fire departments on how to identify FGAN hazards within their communities by engaging State Emergency Response Commissions and Local Emergency Planning Committees
b. Encouragement for members in jurisdictions with FGAN facilities to become certified in FGAN training
c. Information on training partners and programs that provide FGAN training.

Texas A&M Engineering Extension Services (TEEX)

2013-02-I-TX R15

Develop and administer a hazardous materials training module for career and volunteer fire departments that addresses fertilizer grade ammonium nitrate (FGAN) and other hazardous materials or chemicals that could pose new specialized hazards. Ensure that the training includes multiple delivery methods to enable a broad reach. The training should allow for instructor-led, web-based, and train-the-trainer courses; initial orientation; and refresher training. The training also should accommodate both resident and mobile capabilities to facilitate flexibility in delivery.

Objectives of the training course should address the following:

a. How to respond to industrial fires involving FGAN and other hazardous materials or chemicals that could pose new specialized hazards to responding firefighters
b. Previous FGAN fire and explosion incidents, incorporating lessons learned
c. Hazards posed by other materials and chemicals stored near the FGAN, including FGAN incompatibility with those materials and chemicals
d. Pre-incident planning for fires involving FGAN and other hazardous materials or chemicals that could pose new specialized hazards to responding firefighters
e. On-scene emergency response and decision-making requirements for FGAN fires, including risk assessment, scene size-up, and situational awareness
f. National Incident Management System and Incident Command System.

2013-02-I-TX R16

Develop an outreach program that notifies state, regional, and local fire departments about available FGAN training opportunities. The program should include the following elements:

a. Guidance for fire departments on how to identify FGAN and other recognized hazards associated with other hazardous materials or chemicals within their communities by engaging with State Emergency Response Commissions and Local Emergency Planning Committees
b. Promotion of use of the hazardous materials training module with TEEX training partners.

Texas Department of Insurance (TDI)

2013-02-I-TX R17

For companies that provide insurance to agricultural facilities storing bulk fertilizer grade ammonium nitrate (FGAN) in Texas, including surplus lines insurers and Texas-registered risk retention groups, develop and issue guidance to assist in underwriting risk and conducting annual loss control surveys. Guidance should include the following:

a. Combustible materials of construction for facilities and bins storing FGAN
b. Storage of combustible materials near FGAN piles
c. Adequate ventilation for indoor FGAN storage areas
d. Automatic sprinklers and smoke detection systems for indoor FGAN storage areas
e. Separation distances between FGAN and other hazardous materials onsite

f. Potential for offsite consequences from a fire or explosion, including the proximity of FGAN facilities to nearby residences, schools, hospitals, and other community structures.

Provide references in the guidance document to existing materials from the following sources or to other equivalent guidance:

a. National Fire Protection Association (NFPA), *NFPA 400, Hazardous Materials Code*, 2016 Edition, Chapter 11, "Ammonium Nitrate"
b. FM Global, "Property Loss Prevention Data Sheet 7-89"
c. U.S. Environmental Protection Agency, Occupational Safety and Health Administration, and Bureau of Alcohol, Tobacco, Firearms and Explosives; "Chemical Advisory: Safe Storage, Handling, and Management of Solid Ammonium Nitrate Prills"
d. TDI, "Best Practices for the Storage of Ammonium Nitrate"
e. National Fire Protection Research Foundation, "Separation Distances and NFPA Codes and Standards."

West Volunteer Fire Department (WVFD)

2013-02-I-TX R18

Develop standard operating procedures for pre-incident planning for facilities that store or handle hazardous materials such as fertilizer grade ammonium nitrate (FGAN).

El Dorado Chemical Company (EDC)

2013-02-I-TX R19

For all distributors and bulk retail sites (i.e., customers) that receive fertilizer grade ammonium nitrate (FGAN) manufactured by El Dorado Chemical Company (EDC) for storage, shipment, and sale:

a. Encourage customers to conduct internal monitoring and auditing (in accordance with recent industry standards and guidelines) in locations where FGAN will be stored or used. Communicate that such internal monitoring and auditing may be conducted through established product safety programs, including ResponsibleAg.
b. Develop a process to establish mutual product stewardship expectations for the downstream chain of customers. Communicate expectations to existing customers, and to new customers before their first shipment of FGAN. Include the following components:
    i. For all FGAN sold to distributors, encourage distributors to provide Safety Data Sheets and FGAN safety guidance to their customers and bulk retail sites to which FGAN is sold or shipped
    ii. For all EDC bulk retailers and non-EDC bulk retailers that store and sell FGAN, encourage bulk retailers to address, such as through certification checklists, the following:
        - Written procedures for the safe handling of FGAN, including employee training

- Emergency response plans to be sent to Local Emergency Planning Committees and local fire departments
- Tier II Chemical Inventory Report submissions.

This signature block is placed immediately after the last recommendation.

By the
U.S. Chemical Safety and Hazard Investigation Board

Vanessa Allen Sutherland
Chair

Kristen Kulinowski
Member

Manuel Ehrlich
Member

Richard Engler
Member

Date of Board Approval

12.0 Appendix A: Rebuilding of the West Independent School District

The West Independent School District (WISD) ultimately decided to demolish the West Intermediate School (WIS),[1] West High School (WHS), and approximately half of West Middle School (WMS) based on the level of damage to these buildings. The WISD is rebuilding by constructing a combined middle school and high school consisting of a common entryway, cafeteria, and auditorium but separate offices and gymnasiums for each school. The left side of the structure will accommodate the middle school students (grades 6 through 8), and the right side will serve high school students (grades 9 through 12). Table 16 shows the distribution of grade levels within the old facilities and the new facilities. Groundbreaking took place on October 30, 2014, and construction began shortly thereafter; the WISD expects the school to open in September 2016. The new West Middle School/West High School will be located on the same site as the previous WHS campus. The site will house the WISD baseball field, softball field, eight-lane running track and facilities for field events, two practice fields, four tennis courts, and supporting concession and restroom facilities.[2] Although the city demolished the WIS campus, the existing site paving remained in place so that it could serve as temporary parking for the WISD transportation department. The former WIS site currently houses a donated metal building used for agriculture shop for WHS students[3] but could potentially become the final location of the WISD transportation, maintenance, and receiving facility.

[1] WIS will not be rebuilt.
[2] *See*: http://www.restorewestisd.com/assets/sd_west-hs-ms-final-web.pdf (accessed on December 30, 2015).
[3] The donated metal building is approximately a block and a half from the temporary high school; however, it would take up too much instructional time for students to walk there, so buses take each class to the shop on days when students participate in agriculture class.

Table 16. Distribution of Grade Levels at the Old and New WISD Schools

School	Old Facilities (Grades)	New Facilities (Grades)
West Intermediate School	4 and 5	Not rebuilt
West Middle School	6 and 7	6 through 8
West High School	7 through 12	9 through 12
West Elementary School	K through 3	K through **5**

During the rebuild, the WISD created a temporary campus for middle and high school students, ultimately locating it on the existing middle school site. Students in grades pre-K through 5 attended school at West Elementary School, which sustained minimal damage in the explosion. Students in grades 6 through 12 were housed in temporary facilities at the existing WMS site.[4] The sixth graders from WMS initially transferred to portable structures behind the elementary school until the end of the school year before moving to the middle school site for the 2013–2014 school year. The students in grades 7 through 12 moved to empty buildings owned by the Connally Independent School District,[5] which is about 9 miles south of West, from April 17, 2013, until the end of the school year. Although the physical location of classes changed, WISD teachers still taught these students, who were still enrolled in the WISD. In August 2013, all of the students in grades 7 through 12 returned to West for classes in modular and portable buildings, and they eventually will transfer to the new school once the rebuild is complete. The temporary middle school and high school site consisted of 17 temporary portable facilities, 10 portable facilities donated by surrounding school districts that were leased by the WISD, and a temporary structure to cover the existing foundation and floor system saved from the original practice gymnasium.[6]

FEMA provided the WISD with a grant totaling nearly $20.8 million to assist in providing secure temporary classrooms and administrative buildings to replace those that were destroyed.[7] The FEMA grant will pay the federal share, or 75 percent, of the eligible costs for the rebuild, and the WISD will

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[4] *See*: http://www.restorewestisd.com/plans.html (accessed on December 30, 2015).
[5] Connally Independent School District is a Texas public school district located in central McLennan County, serving the cities of Lacy, Lakeview, and Waco as well as the communities of Elm Mott, Chalk Bluff, and Gholson.
[6] *See*: http://www.restorewestisd.com/plans.html (accessed on December 30, 2015).
[7] *See*: http://www.fema.gov/news-release/2013/08/01/fema-obligates-nearly-28-million-west-texas-independent-school-district (accessed on December 30, 2015). *See*: http://www.wfaa.com/story/local/2015/07/06/14167886/ (accessed on December 30, 2015).

cover the remaining 25 percent of the cost. The remaining cost to rebuild will be funded by the Texas Education Agency, which is providing the WISD with almost $10.3 million in Foundation School Program funds.

At the time of the incident, the WISD was insured for $58 million. The school district received $30 million from the Argonaut Insurance Company, the WISD's insurance carrier at the time of the explosion; however, WISD assessments indicate that the damage to its four schools far exceeded $30 million. Currently, the WISD is in litigation with Argonaut Insurance Company,[8] Trident Insurance Services LLC,[9]and the Texas Association of Public Educators.[10] Based on a district assessment and planning presentation to the WISD Board of Trustees on April 29, 2013, the proposed cost for rebuilding temporary facilities and renovating the facilities damaged by the explosion would amount to $16,562,706.[11] This Phase One cost estimate for temporary facilities and renovations includes the following:

- Existing administrative and office building renovations.
- High school football stadium renovations.
- Existing middle school site (1967 gymnasium repair, 1923 and 1957 building weatherization, maintenance and transportation building replacement).
- Existing elementary school cafeteria additions and building renovations.
- WISD-wide demolition and temporary classrooms.
- Loose equipment moving and temporary storage.
- WISD-wide technology connectivity.
- Contingency funds.

The initial proposed estimated cost for Phase Two rebuilding—including a new high school, new intermediate and middle school, new track and field facility, new maintenance and transportation permanent replacement building and contingency, and program financial audit—was $100,791,719.[12]

13.0 Appendix B: FGAN Incidents Tables

Appendix B provides two tables, both depicting incidents involving FGAN. CSB listed only those incidents that it could confirm. As such, these lists are not meant to be comprehensive. The first table

[8] Argonaut Insurance provides specialty property and casualty insurance and is a subsidiary of Argo Group International Holdings, Ltd.

[9] Trident Insurance Services is a specialty commercial insurance provider for small- to middle-market public sector entities; it served as the administrator and adjustor for the insurance policy sold by Argonaut Insurance Company.

[10] The Texas Association of Public Educators is a nonprofit organization managed by Argonaut Insurance Company to assist in the procurement of insurance and the administration of claims for school districts.

[11] *See*: http://www.restorewestisd.com/assets/west-isd-presentation_final-sm.pdf (accessed on December 30, 2015).

[12] *See*: http://www.restorewestisd.com/assets/west-isd-presentation_final-sm.pdf (accessed on December 30, 2015).

(Table 17) provides only those FGAN incidents that occurred at stationary sites. The second table (Table 18) shows all other FGAN incidents, many of which are transportation-related.

The incidents are listed chronologically. Date, location, and a brief description of each incident are provided. For transportation incidents, the location given is the location where the incident occurred. An indication of whether the incident involved fire and/or explosion is also included. Quantity, or mass, of FGAN involved in each incident is provided as well. This information may or may not reflect the quantity of FGAN that actually caught fire and/or detonated. Where available, a description of casualties and property damage is given. Where information could not be found or determined, entries appear blank.

Of the 32 total confirmed FGAN incidents researched by CSB, 22 occurred at stationary sites. At least 654 fatalities resulted from these stationary-site incidents. Thousands were injured and/or evacuated. Of the 10 FGAN incidents that occurred at non-stationary sites, at least 823 were fatally injured. Again, thousands were injured and/or evacuated.

Table 17. FGAN Incidents at Stationary Sites

Date	Location	Description	Fire	Explosion	Quantity (lbs)	Casualties	Property Damage	References
14-Jan-1916	Gibbstown NJ, USA	Explosion occurred in evaporating pan		x	4K	• One fatality • 12 injured	Plant property heavily damaged	1
21-May-1921	Oppau, Germany	Detonation involved FGAN and ammonium sulfate mixture or hidden explosives		x	900K	• 561 fatalities • 2,000 injured	Buildings flattened	2
1-Mar-1924	New Brunswick (Nixon), NJ	Explosion occurred at fertilizer building	x	x		• At least 20 fatalities • A dozen missing		3
5-Aug-1940	Miramas, France	Explosion of freight car launched explosive shell into burning mixture of FGAN and toluene at storage building	x	x	480K			4
26-Aug-1947	Presque Isle, ME	Fire involving fertilizers occurred	x	--				5

[1] NFPA. *Quarterly of the NFPA*, Vol. 16, No. 1. July 1922. *See*: https://books.google.com/books?id=-MAdAQAAIAAJ&printsec=frontcover&source=gbs_ge_summary_r&cad=0#v=onepage&q&f=false (accessed on December 30, 2015).
[2] Oxley, J.C. et al. "AN: thermal stability and explosivity modifiers." *Thermochimica Acta* 384 (2002): 23–45.
[3] *See*: http://query.nytimes.com/gst/abstract.html?res=9E05EEDD1E3CE733A25751C0A9659C946595D6CF (accessed on December 31, 2015).
[4] *See*: http://www.societechimiquedefrance.fr/extras/Guiochon%20VO/exinvolontaireVO.htm (accessed on December 31, 2015).
[5] Oxley, J.C. et al. "AN: thermal stability and explosivity modifiers." *Thermochimica Acta* 384 (2002): 23–45.

Date	Location	Description	Fire	Explosion	Quantity (lbs)	Casualties	Property Damage	References
1-Sep-1947	St. Stephens, Canada	Fire occurred in warehouse containing bagged FGAN	x	--	800K			6
14-Oct-1949	Independence, KS	Fire occurred in warehouse next to storage building containing FGAN piled in paper bags	x	--	2.8– 5.4 million			7
9-Nov-1966	Mt. Vernon, MO	Explosion involving bagged FGAN occurred	x	x	100K			8
c. 1967	USA	Screw conveyor shaft for FGAN burst after welding operation	x	x				9
c. 1973	Cherokee, OK	Severe storage fire occurred in wooden FGAN storage area	x	x	28 million	None injured		10
c. 1978	Rocky Mountain, NC	Fire occurred at storage facility containing FGAN	x	--	1 million		Storage facility destroyed by fire	11

[6] *Ibid*.
[7] *Ibid*.
[8] *Ibid*.
[9] ABS Consulting. "West Fertilizer Incident Support Services Final Report." August 28, 2015.
[10] Marlair, G., and M.A. Kordek. "Safety and security issues relating to low capacity storage of AN-based fertilizers." *Journal of Hazardous Materials* 123(1–3) (2005): 13–28.
[11] Oxley, J.C. et al. "AN: thermal stability and explosivity modifiers." *Thermochimica Acta* 384 (2002): 23–45.

Date	Location	Description	Fire	Explosion	Quantity (lbs)	Casualties	Property Damage	References
c. 1979	Moreland, ID	Fire involved wood framework and belting of overhead conveyor system in fertilizer plant while being used to unload railroad car of FGAN	x	--	400K		Fire spread to roof	[12]
c. 1982	United Kingdom	Fire in warehouse where wooden furniture stored near FGAN resulted in deflagration	x	x	6 million	750–1,000 evacuated		[13]
13-Dec-1994	Port Neal, IA	Two explosions occurred at the Terra Industries AN plant		x		• Four fatalities • 18 injured	• Anhydrous ammonia released • Ground water under plant contaminated	[14]
6-Jan-1998	Xingping, Shaanxi, China	Explosions occurred at fertilizer company		x		• 24 fatalities • 56 injured		

[12] Boggs, Thomas L. et al. "Realistic Safe-Separation Distance Determination for Mass Fire Hazards." Naval Air Warfare Center Weapons Division. March 2013.
[13] Nygaard, Erik C. et al. "Safety of Ammonium Nitrate." International Society of Explosives Engineers. Vol. 2, 2006. *See*: https://miningandblasting.files.wordpress.com/2009/09/safety-of-ammonium-nitrate.pdf (accessed on January 4, 2016).
[14] Boggs, Thomas L. et al. "Realistic Safe-Separation Distance Determination for Mass Fire Hazards." Naval Air Warfare Center Weapons Division. March 2013.

Date	Location	Description	Fire	Explosion	Quantity (lbs)	Casualties	Property Damage	References
21-Sep-2001	Toulouse, France	Explosion occurred in warehouse containing FGAN and TGAN		x	400 – 600 K (TGAN+FGAN)	• 29 fatalities • Nearly 2,500 injured, 30 of which severe	Severe damage to plant and surrounding community	15
Jan-2003	Cartagena, Murcia, Spain	Fertilizer storage facility held self-sustained detonation fire	x	x				16
Oct-2003	Saint-Romain-en-Jarez, France	Fire occurred in end user storage facility containing FGAN in bags	x	x	10K	Three heavily injured		17
30-Jul-2009	Bryan, TX	Fertilizer plant caught fire	x			Over 80,000 evacuated		18

[15] Nygaard, Erik C. et al. "Safety of Ammonium Nitrate." International Society of Explosives Engineers. Vol. 2, 2006. *See*: https://miningandblasting.files.wordpress.com/2009/09/safety-of-ammonium-nitrate.pdf (accessed on January 4, 2016).

[16] Boggs, Thomas L. et al. "Realistic Safe-Separation Distance Determination for Mass Fire Hazards." Naval Air Warfare Center Weapons Division. March 2013.

[17] Marlair, G., and M.A. Kordek. "Safety and security issues relating to low capacity storage of AN-based fertilizers." *Journal of Hazardous Materials* 123(1–3) (2005): 13–28.

[18] Boggs, Thomas L. et al. "Realistic Safe-Separation Distance Determination for Mass Fire Hazards." Naval Air Warfare Center Weapons Division. March 2013.

Date	Location	Description	Fire	Explosion	Quantity (lbs)	Casualties	Property Damage	References
17-Apr-2013	West, TX	Fire and explosion occurred at fertilizer plant	x	x	80 – 100 K	• 15 fatalities • Over 236 injured	• Facility destroyed • Widespread damage to over 150 offsite buildings, including high school, middle school, intermediate school, apartment complex, and nursing home • Early estimates placed property damage at over $100 million	
29-May-2014	Athens, TX	Fertilizer warehouse containing FGAN caught fire and burned	x					19
12-Aug-2015	Tianjin, China	Hazardous materials storage warehouse containing AN* caught fire and exploded	x	x		Over 100 fatalities		20

[19] Babrauskas, Vytenis. "Explosions of ammonium nitrate fertilizer in storage or transportation are preventable accidents." *Journal of Hazardous Materials* (2015).
[20] See: http://www.theguardian.com/world/2015/aug/18/tianjin-blasts-warehouse-handled-toxic-chemicals-without-licence-reports (accessed on January 19, 2016)

Table 18. Non-Stationary FGAN Incidents

Date	Location	Description	Fire	Explosion	Quantity (lbs)	Casualties	Property Damage	References
16-Apr-1947	Texas City, TX	Fire occurred in hold of ship and detonated	x	x	4–11 million	• Approximately 500 fatalities • Approximately 3,000 injured • 2,000 left homeless	• Commercial and residential buildings damaged or destroyed • Ships destroyed • Two planes knocked out of sky • Barge lifted out of water • Early property damage total estimated at approximately $40 million	21
23-Jan-1953	Red Sea, Israel	Spontaneous ignition of paper bags containing FGAN on ship	x	x	8–16 K		Ship destroyed	22
17-Dec-1960	Traskwood, AR	Explosion occurred in cars containing FGAN, petroleum, and paper	x	x	80—100 K			23

[21] NFPA. "The Texas City Disaster." The Quarterly. July 1947.
[22] Oxley, J.C. et al. "AN: thermal stability and explosivity modifiers." *Thermochimica Acta* 384 (2002): 23–45.
[23] *Ibid*.

Date	Location	Description	Fire	Explosion	Quantity (lbs)	Casualties	Property Damage	References
1972	Taroon, Australia	Transport of low density bagged AN prills involved in fire and explosion	x	x		Three fatalities		24
c. 1997	Brazil	Delayed explosion occurred involving truck loaded with FGAN that caught fire due to nearby petrol tanker	x	x				25
c. 2000	FL	Collision occurred between AN truck and gasoline tanker	x	--				26
18-Feb-2004	Neyshabur, Khorasan, Iran	Fire and explosion resulted from derailment of train containing bagged FGAN	x	x	840K	300 fatalities		27
Feb-2004	Barracas, Spain	Accident occurred during road transport of FGAN	x	x	50K	• Two fatalities • Three injured		28

[24] Marlair, G., and M.A. Kordek. "Safety and security issues relating to low capacity storage of AN-based fertilizers." *Journal of Hazardous Materials* 123(1–3) (2005): 13–28.
[25] *Ibid*.
[26] *Ibid*.
[27] Nygaard, Erik C. et al. "Safety of Ammonium Nitrate." International Society of Explosives Engineers. Vol. 2, 2006. *See*: https://miningandblasting.files.wordpress.com/2009/09/safety-of-ammonium-nitrate.pdf (accessed on January 4, 2016).
[28] Marlair, G., and M.A. Kordek. "Safety and security issues relating to low capacity storage of AN-based fertilizers." *Journal of Hazardous Materials* 123(1–3) (2005): 13–28.

Date	Location	Description	Fire	Explosion	Quantity (lbs)	Casualties	Property Damage	References
May-2004	Near Bucharest, Romania	Truck accident occurred during road transport of bagged FGAN	x	x	50K	At least 18 fatalities		29
17-Feb-2007	Estaca de Bares, Spain	Self-sustained decomposition fire of nitrogen, phosphorous, potassium (NPK) fertilizer occurred in cargo of ship	x		12.024 million (NPK)			30

[29] *Ibid*.
[30] Boggs, Thomas L. et al. "Realistic Safe-Separation Distance Determination for Mass Fire Hazards." Naval Air Warfare Center Weapons Division. March 2013.

14.0 Appendix C: TFI Safety and Security Tools

The Fertilizer Institute (TFI) offers a wide variety of tools designed to support the fertilizer industry. Most of these tools are information based and readily accessible online; some of the tools, however, are also interactive, allowing for personalization and customization. These tools include the following:

- Access to a new online Compliance Assessment Tool.
- General fertilizer retail industry information resources, such as industry fact sheets, fertilizer product fact sheets, and infographics.
- New fertilizer grade ammonium nitrate (FGAN) guidelines, "Safety and Security Guidelines for the Storage and Transportation of Fertilizer Grade Ammonium Nitrate at Retail Facilities."
- An educational brochure, "America's Security Begins with You," designed to alert the agriculture community of the dangers associated with ammonium nitrate (AN) if it ends up in the wrong hands.
- A brochure, "Health Effects of Ammonia," discussing the sources and uses of ammonia as well as how the body processes it.
- Newly updated liquid fertilizer guidelines, "Aboveground Storage Tanks Containing Liquid Fertilizer–Recommended Mechanical Integrity Practices," which provides recommended uniform industry inspection and maintenance procedures for aboveground storage tanks of liquid fertilizer.[1]
- An anhydrous ammonia brochure, "Recommended Practices for Loading/Unloading Anhydrous Ammonia Rail Tank Cars in North America–Reduce and Eliminate Non-Accidental Release," accompanied by an associated DVD.
- Access to a new nonprofit organization, ResponsibleAg, an industry-led stewardship[2] initiative founded to promote the public welfare by helping agribusinesses comply with safety and security rules regarding the handling and storage of fertilizer products.[3]
- Access to a multimedia safety training program, the "Anhydrous Ammonia Training Tour," developed through TFI sponsorship of the Transportation Community Awareness and Emergency Response and focused on the provision of pertinent information regarding the properties of ammonia, steps that should be taken to ensure safe transport of ammonia, appropriate emergency response measures in case of an ammonia release, and hands-on training.[4]
- Access to free web-based anhydrous ammonia safety training, composed of subject-based training modules on (1) properties of ammonia, (2) personal protective equipment, (3) transportation of ammonia to and from the field, (4) safe hook-up of ammonia tanks in the field, and (5) emergency response and first aid procedures.[5]

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[1] *See*: http://www.tfi.org/safety-and-security-tools/recommended-mechanical-integrity-guidelines-aboveground-storage-tanks-liqu (accessed on December 30, 2015).
[2] Merriam-Webster defines a stewardship as "the activity or job of protecting and being responsible for something."
[3] *See*: http://www.responsibleag.org/FAQ.cgi (accessed on December 30, 2015).
[4] *See*: http://www.tfi.org/safety-and-security-tools/transcaer%C2%AE-anhydrous-ammonia-safety-training (accessed on December 30, 2015).
[5] *See*: http://www.tfi.org/safety-and-security-tools/web-based-anhydrous-ammonia-safety-training (accessed on December 30, 2015).

- Access to a web-based compliance tool, myRMP Suite of Guidance Materials, a revised version of the Retail Guidance Document for Agricultural Retailers supported by the U.S. Environmental Protection Agency.[6]
- A new suite of second-generation web-based tools, mySPCC Suite of Guidance Materials Version 2.0, developed exclusively to assist agricultural retailers in implementing their Spill Prevention, Control, and Countermeasures (SPCC) plans, which enables the personalization of such plans to specific facilities and incorporates base information from the SPCC rule with accumulated knowledge gained by industry over the last 20 years.[7]

[6] *See*: http://www.tfi.org/safety-and-security-tools/myrmp (accessed on December 30, 2015).
[7] *See*: https://www.asmark.org/mySPCC/ (accessed on December 30, 2015).

15.0 Appendix D: ResponsibleAg

As part of the ResponsibleAg program, participating facilities undergo an audit once every 3 years, and as many as 17 areas of a facility (e.g., dry fertilizer, liquid fertilizer, anhydrous ammonia, shop, office, and grounds) are assessed.[1] Within 24 hours after completing the audit, the auditor enters findings into a secure portal on the ResponsibleAg website.[2] Once the information is processed, the participating facility receives a corrective action plan if applicable, detailing any issues detected during the audit.[3] This plan not only lists the issues discovered but also provides information on how to correct the issues and a recommended time frame for doing so.[4] At the end of the recommended period of time, the auditor visits the facility again for a verification audit. The participating facility obtains certification only after all outstanding issues are addressed.[5] To ensure a high level of reliability, a statistically valid sample of all participating facilities receives random verification from an independent auditor, approved by ResponsibleAg, every year.[6] An annual accountability report includes the number of registered facilities, credentialed auditors, completed assessments, and random verifications.

[1] *See*: http://www.responsibleag.org/About.cgi (accessed on December 30, 2015).
[2] *Ibid*.
[3] *Ibid*.
[4] *Ibid*.
[5] *Ibid*.
[6] *See*: http://www.tfi.org/node/736 (accessed on January 6, 2016). *See also*: https://www.responsibleag.org/documents/RAHandout.pdf (accessed on December 30, 2015).

U.S. CHEMICAL SAFETY AND HAZARD INVESTIGATION BOARD

INVESTIGATION REPORT

XCEL ENERGY HYDROELECTRIC PLANT PENSTOCK FIRE

(Five Dead, Three Injured)

CABIN CREEK

GEORGETOWN,

COLORADO

OCTOBER 2, 2007

KEY ISSUES:

- SAFE LIMITS FOR WORKING IN CONFINED SPACE FLAMMABLE ATMOSPHERES
- PRE-JOB SAFETY PLANNING OF HAZARDOUS MAINTENANCE WORK
- CONTRACTOR SELECTION AND OVERSIGHT
- EMERGENCY RESPONSE AND RESCUE

REPORT NO. 2008-01-I-CO

AUGUST 2010

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Acronyms and Abbreviations

AIHA	American Industrial Hygiene Association
ANSI	American National Standards Institute
API	American Petroleum Institute
APPA	American Public Power Association
ASTM	American Society for Testing and Materials
ATSDR	Agency for Toxic Substances and Disease Registry
ATV	all-terrain vehicle
BLS	Bureau of Labor Statistics
CBI	Colorado Bureau of Investigation
CCC	Certified Coatings Company
CCFA	Clear Creek County Fire Authority
CDFS	Colorado Division of Fire Safety
CFOI	Census of Fatal Occupational Injuries
CSB	U.S. Chemical Safety and Hazard Investigation Board
CURT	Construction Users Roundtable
EMR	experience modification rate
EPA	Enviornmental Protection Agency
EPRI	Electric Power Research Institute
ESD	Emergency Services District
FACE	Fatality Assessment and Control Evaluation
FERC	Federal Energy Regulatory Commission
FSA	Formal Settlement Agreement
HSEES	Hazardous Substances Emergency Events Surveillance
IChemE	Institution of Chemical Engineers
IDLH	Immediately Dangerous to Life and Health
IIPP	Injury and Illness Prevention Program
IMIS	Integrated Management Information System
LEL	Lower Explosivity Limit
LFL	Lower Flammability Limit
MEK	methyl ethyl ketone
MSDS	Material Safety Data Sheet
MW	megawatt

NACE	National Association of Corrosion Engineers
NFPA	National Fire Protection Association
NIOSH	National Institute of Occupational Safety and Health
OIICS	Occupational Injury and Illness Classification
OSHA	Occupational Safety and Health Administration
PHA	Process Hazard Analysis
PPE	Personal Protective Equipment
ppm	parts per million
PSCo	Public Service Company of Colorado
psig	pounds per square inch gauge
PSCo	Public Service Company of Colorado
PSM	Process Safety Management
PUC	Colorado Public Utilities Commission
QP 1	Qualification Procedure No. 1
RFP	Request for Proposal
SCBA	Self Contained Breathing Apparatus
SCPDI	Southern California Painting and Drywall Industries
SSPC	Society of Protective Coatings (formally Steel Structures Painting Council)
TRB	Transportation Research Board of the National Academies

1.0 Executive Summary

1.1 Incident Synopsis

On October 2, 2007, a chemical fire inside a permit-required confined space[1] at Xcel Energy's hydroelectric plant in a remote mountain location 45 miles (72 kilometers) west of Denver, Colorado, killed five and injured three workers. Industrial painting contractors were in the initial stages of recoating the 1,530-foot (466-meter) steel portion of a 4,300-foot (1,311-meter) enclosed penstock[2] tunnel with an epoxy coating product when a flash fire occurred. Flammable solvent being used to clean the epoxy application equipment in the open penstock atmosphere ignited, likely from a static spark. The initial fire quickly grew as it ignited additional buckets of solvent and substantial amounts of combustible epoxy material, trapping and preventing five of the 11 workers from exiting the single point of egress within the penstock. Fourteen community emergency response teams responded to the incident. The five trapped workers communicated using handheld radios with co-workers and emergency responders for approximately 45 minutes before succumbing to smoke inhalation.

1.2 Scope of the Investigation

Catastrophic workplace accidents typically are not the result of a single error or one piece of faulty equipment; rather, higher-level safety system deficiencies are often found at facilities where such accidents occur. It has also been established that accident prevention is most effective when these

[1] The US Occupational Safety and Health Administration (OSHA) defines, in its general industry rule, a confined space as having three attributes: (1) large enough to enter and perform work; (2) limited access and egress; and (3) not designed for continuous occupancy. OSHA states that a permit-required confined space has one or more of the following characteristics: "(1) contains or has the potential to contain a hazardous atmosphere; (2) contains material that has the potential for engulfing an entrant; (3) has an internal configuration such that an entrant could be trapped or asphyxiated by inwardly converging walls or by a floor that slopes downward and tapers to a smaller cross section; or (4) contains any other recognized serious safety or health hazard. OSHA has identified one type of hazardous atmosphere as '[f]lammable gas, vapor or mist in excess of 10% of its lower flammable limit (LFL)' [29 CFR 1910.146(b)].

[2] A penstock in hydroelectric service is typically an enclosed conduit such as a tunnel or pipe that delivers a flow of water to a turbine that generates electric power

systemic causes are understood and learned.[3] As such, the U.S. Chemical Safety Board (CSB) examined both the technical and organizational causes of the fire at Xcel Energy's Cabin Creek penstock.

The investigation found that a number of safety issues contributed to the accident, including a lack of planning for hazardous work, inadequate contractor selection and oversight, and insufficient regulatory standards pertaining to the use of flammables within confined spaces. The investigation also examined the technical aspects of recoating a penstock, the work conditions of the unique confined space, and the training the contractors received prior to starting work. Finally, the CSB evaluated aspects of emergency response, including planning for timely and qualified rescue and the need for certified confined space rescue responders in the state of Colorado.

1.3 Incident Description

On October 2, 2007, a work crew of industrial painters employed by RPI Coating, Inc. (RPI) began applying a new epoxy coating to the steel interior section of the penstock[4] at the Cabin Creek hydroelectric plant operated by Xcel Energy, Inc. (Xcel), located south of Georgetown, Colorado.

Shortly after the epoxy application commenced, the work crew experienced problems with the spraying process, resulting in poor coating quality. Spraying was terminated and the crew began cleaning the sprayer system equipment with a flammable solvent, methyl ethyl ketone (MEK),[5] to remove epoxy residue before taking the equipment out of the penstock. During this cleaning operation, MEK vapors

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[3] The Center for Chemical Process Safety (CCPS) states that identifying the underlying or root causes of an incident has a greater preventative impact by addressing safety system deficiencies and averting the occurrence of numerous other similar incidents, while addressing the immediate cause only prevents the identical accident from recurring (1992).

[4] The Cabin Creek penstock is a tunnel with a diameter that varies between 12 and 14 feet that runs between two reservoirs; water flows from the upper reservoir to the lower reservoir through the penstock, passing over turbines which produce electricity (see Section 2.1.1.1).

[5] Methyl ethyl ketone (MEK) is an organic chemical compound often used as a solvent in painting activities listed by the National Institute for Safety and Health (NIOSH) as "highly flammable." *NIOSH MEK International Chemical Safety Cards*, 1998. MEK is a Class IB flammable liquid, with a flash point below 73°F (23°C) and boiling point at or above 100°F (38°C). *NIOSH Pocket Guide to Chemical Hazards, 2005*

inside one of the two epoxy hoppers ignited and flashed. The resulting fire grew quickly, consuming several other open containers of MEK and numerous buckets of epoxy material positioned around the sprayer.

Four RPI crew members positioned on the side of the fire nearest the exit evacuated the penstock, although three were later treated for injuries: one received minor burns, one fractured his arm, and another suffered breathing difficulties. Five additional crew members trapped opposite the exit were unable to evacuate due to the fire and narrow configuration of the penstock. The five workers later succumbed to smoke inhalation inside the penstock and died.

1.4 Increasing Need for Penstock Recoating

Many hydroelectric plants have steel penstocks that have not been relined or recoated for many years. In North America, estimates suggest that 3 million feet (1 million meters) of in-service penstocks exist. Interior coatings and linings are required to maintain the structural integrity and serviceability of penstocks to prevent corrosion and provide water tightness. When periodic internal inspections uncover linings that have deteriorated to the extent that rehabilitation is no longer possible, repair projects are initiated to remove the old penstock linings and replace them with newer epoxy coatings that typically have a 20- to 30-year service life (EPRI, 2000, ch. 1-3). Removing the old linings and applying new interior coatings in penstocks present special hazards to workers, including potential flammable and/or toxic atmospheres and limited access and egress within these confined spaces.

Because of the serious nature of this incident and the unique hazards associated with penstock coating work, the CSB launched an investigation to determine root and contributing causes and to make recommendations to help prevent similar incidents.

1.5 Key Findings

1. On the day of the incident, approximately 16 gallons (61 liters) of highly flammable methyl ethyl ketone (MEK) solvent stored in plastic buckets was used in the penstock to clean the epoxy

sprayer and associated equipment. The cleaning involved pouring MEK into the sprayer's two hoppers and circulating it through the sprayer in the open penstock atmosphere. A number of ignition sources present or created by the work activity were not eliminated or controlled. The circulation of MEK through non-conductive hose likely led to static discharge, igniting the MEK in the sprayer hopper and resulting in a flash fire.

2. Xcel and RPI managers were aware of the plan to operate the epoxy sprayer inside the penstock and the need to use solvent to clean the sprayer and associated equipment in the open penstock atmosphere during the epoxy application portion of the project. However, they did not perform a hazard evaluation of the epoxy recoating work; as a result, they failed to identify serious safety hazards involving use of flammable liquids within the confined space. Effective controls were not evaluated or implemented during their pre-job safety planning, such as substituting MEK with a non-flammable solvent.

3. During the recoating project, neither Xcel nor RPI treated the Cabin Creek penstock as a permit-required confined space, nor did they re-evaluate hazards in the space caused by changing work activities. Such activities included the introduction of flammables into the penstock, hot work within the confined space, and the switch from abrasive blasting to recoating of the penstock interior.

4. Neither Xcel's nor RPI's corporate confined space programs adequately addressed the special precautions necessary to safely manage the hazard of potential flammable atmospheres. Their policies and procedures did not address the need for a confined space monitoring plan or the need for continuous monitoring in the work area where flammables were being used. Neither of their permit-required confined space policies or permit forms required or established a maximum

permissible percentage of the lower explosive limit (LEL)[6] for safe entry and occupancy inside a permit space.

5. On the day of the incident, RPI monitored the atmosphere of the penstock, a permit-required confined space, for flammable atmospheres only at is entrance, 1,450 feet (442 meters) from the work activities, rather than where flammables were being used.

6. The majority of RPI employees working at Cabin Creek had not received comprehensive formal safety training; effective training on company policies; or site-specific instruction addressing confined space safety, the safe handling of flammable liquids, the hazard of static discharge, emergency response and rescue, and fire prevention. The Joint Apprenticeship Training Committee and Center, established by the parties to the Painters and Allied Trades District Council 36 Master Labor Agreement (including RPI), provide comprehensive safety training on these topics as part of its apprenticeship program, but most of the painters hired by RPI had not taken these courses nor had they otherwise received documented equivalent safety training.

7. The U.S. Occupational Safety and Health Administration's (OSHA) Permit-Required Confined Spaces Rule for general industry establishes no maximum permissible percentage of the LEL for safe entry and occupancy inside a permit space. OSHA has interpreted its rule to allow working in a permit-required space where the atmosphere is above 10 percent of the LEL.[7] However, the rule defines a flammable concentration above 10 percent of the LEL as a hazardous atmosphere "that may expose employees to the risk of death, incapacitation, impairment of ability to self-

[6] LEL is defined as "that concentration of combustible material in air below which ignition will not occur" in Recommended Practice for Handling Releases of Flammable and Combustible Liquids and Gases, NFPA 329 (2005). The terms LEL and lower flammability limit (LFL) have different definitions but are commonly used interchangeably. This report uses LEL except where citing other sources that use LFL in their standard or regulation. The OSHA Permit-Required Confined Space Standard 29 CFR 1910.146 uses the term LFL in its provisions.

7 Letter to Macon Jones, Blasting Cleaning Products LTD, from John B. Miles Jr., Director, dated September 4, 1996, concerning entry into a confined space when the LFL is greater than 10 percent.

rescue…injury, or acute illness" [29CFR 1910.146(b)]. Other OSHA regulations addressing confined and enclosed spaces in the maritime industry and other sectors prohibit entry and work activities above a specific percentage of the LEL (such as 10 percent). The recent trend of consensus safety guidance and regulatory requirements from other jurisdictions has been to establish safe work limits for confined space flammable atmospheres substantially below the LEL.

8. The CSB identified identified 53 serious flammable atmosphere confined space incidents involving fires and explosions from 1993 to April 2010; 57 percent involved a fatality. These incidents caused 54 injuries and 45 fatalities, a majority of which occurred since 2003. These flammable atmosphere incidents include two the CSB investigated in 2009 where confined space explosions resulted in four fatalities.

9. The penstock had only one egress point. Published safety guidance for penstocks discusses the importance of alternative escape routes in the event of an emergency (ASCE, 1998, pp. 2-8). Xcel Energy had identified the sole egress point as a major concern in the penstock planning as had RPI personnel; however, no remedial action was taken. When the flash fire occurred, five RPI workers who were on the side of the sprayer opposite the exit became trapped by the growing fire and restricted egress.

10. The planned use of flammable solvent in the open atmosphere inside the penstock created the potential for an immediately dangerous to life or health (IDLH)[8] flammable atmosphere. Xcel's and RPI's emergency response plan for rescue services for the penstock reline project was to call

[8] IDLH, or Immediately Dangerous to Life or Health, is a personal exposure limit for a chemical substance set forth by the National Institute of Occupational Safety and Health (NIOSH); it is typically expressed in parts per million (ppm). OSHA's Permit-Required Confined Spaces rule for general industry states that IDLH "means any condition that poses an immediate or delayed threat to life or that would cause irreversible adverse health effects or that would interfere with an individuals ability to escape unaided from a permit space" [29 CFR 1910.146(b)].

9-1-1 emergency dispatch. No emergency responders with confined space technical rescue certification were at the hydroelectric plant and immediately available for rescue on the day of the incident, and the approximate response time of the closest identified certified community rescue service was approximately 1 hour and 15 minutes. The trapped workers died from smoke inhalation approximately 1 hour before this response service arrived on site.

11. While the Colorado Division of Fire Safety (CDFS) does not track technical rescue certification in the state, available evidence indicates a limited number of Colorado emergency response organizations with personnel certified individually by an accredited program in technical rescue. The CDFS has a voluntary accredited certification program for firefighters and hazardous materials responders but does not offer certification for technical rescue, including confined space rescue.

12. Xcel's prequalification process[9] for determining which potential contractors were allowed to participate in the Cabin Creek bid process considered only the contractors' financial capacity and did not disqualify bidders based on unacceptable past safety performance.

13. Once prequalified, Xcel reviewed and ranked the contractors' proposals, considering factors such as past performance, quality, and safety records in addition to price. RPI received the lowest score, "zero," in the safety category, which, according to Xcel's evaluation form, meant that the proposal should have been automatically rejected. However, RPI was still allowed to compete for the contract. While another contractor's proposal was judged the best from a technical and quality perspective, RPI's proposal received the highest ranking in the evaluation process, based primarily on low price.

[9] When contractors are selected, an initial prequalification process is often used during which each potential contractor must meet basic qualifications. In this case, Xcel's prequalification process considered only the financial capacity of the potential contractor.

14. Due to concerns about RPI's record of injuries and fatalities in past projects, Xcel added a safety addendum to the penstock recoating contract affirming that Xcel would "closely observe" RPI's safety performance during the recoating project. During the initial penstock project activities prior to the incident, Xcel managers became aware of several significant safety problems attributable to RPI, including a recordable injury where an RPI worker was sent to the hospital; the evacuation of the penstock due to high readings of carbon monoxide, a toxic gas; and electrical problems that resulted in the destruction of penstock equipment. These problems did not result in Xcel increasing its scrutiny of RPI's safety performance or taking corrective action.

15. Prior to the incident, Xcel corporate officials had not conducted safety audits examining company adherence to its corporate policies on contractor selection and oversight at each of its power-generating facilities.

1.6 Recommendations

As a result of this investigation, the CSB makes recommendations to the following recipients:

- U.S. Occupational Safety and Health Administration (OSHA)
- Governor of Colorado
- Colorado Public Utilities Commission
- Director of the Colorado Division of Fire Safety
- Director of the Colorado Division of Emergency Management
- Xcel Energy
- RPI Coating
- American Public Power Association
- Society for Protective Coatings

- Southern California Painting and Drywall Industries Joint Apprenticeship and Training Committee

Section 13.0 of this report provides the detailed recommendations.

1.7 Conduct of the Investigation

The CSB investigation team arrived at the incident scene on October 3, 2007, the day after the incident. They joined the Incident Command structure and began on-scene investigation activities. That same day, Incident Command demobilized, and emergency responders disbanded after the five deceased RPI crew members were removed from the penstock. Investigative teams from the Colorado Bureau of Investigation (CBI), OSHA, and the CSB remained onsite and worked with Xcel management to protect and preserve evidence at the Cabin Creek site within the penstock, as well as those areas of the Cabin Creek site relevant to the case, including the upper reservoir.

After careful and extensive pre-entry safety planning with all involved parties, the CSB entered the penstock on two separate occasions (November 6 and 11, 2007) to examine the incident scene, and was present onsite when evidence was removed from the penstock on December 19, 2007. Investigators video-and photo-documented evidence, took numerous size and distance measurements, and physically examined all items within the penstock. Through joint agreements with all involved parties, the equipment and associated evidence within the penstock were removed to a secure site; the evidence was more thoroughly examined on two separate occasions: December 12, 2007, and January 7, 2009.

The team conducted more than 54 interviews throughout the course of its investigation, collecting the testimony of employees from the various companies involved in the penstock project, emergency responders, officials from the sprayer system manufacturer, supervisors from other contractors involved in penstock recoating work, Colorado state officials, and union training center representatives. The CSB examined a variety of company documents, including those pertaining to contractor selection and management, safety policies and practices, and employee training, as well as the contractual agreements between Xcel and the various contractors involved in the penstock project. Samples of material taken from burned buckets and the sprayer hoppers were also tested in a laboratory for identification and composition analysis. This investigative work activity was coordinated with OSHA, the CBI, and the various companies involved in the penstock coating project.

The CSB encountered a number of obstacles and lack of cooperation in regard to the involved parties of the investigation, including Xcel and RPI. Xcel failed to fully respond to a number of CSB requests for both records and interrogatories. The CSB required the assistance of the U.S. Attorney's Office for the District of Colorado, Civil Division, to attempt to obtain information relevant to its investigation from Xcel. RPI did not respond to numerous interrogatory requests and a number of RPI managers asserted their constitutional right against self incrimination.

Near the end of the CSB's investigation in the spring of 2010, Xcel and RPI who faced criminal charges arising from the Cabin Creek fatalities took the unprecedented step of going to federal court to block the publication of the CSB report.[10] Ultimately, the presiding judge squarely rejected Xcel's effort to prohibit publication of the CSB's findings and recommendations:

> Based on the evidence presented at the June 24, 2010 hearing, the arguments, and the applicable law, I find Defendants' arguments to be without merit. Moreover, the Defendants cite no authority in support of their request that I bar the issuance of the CSB's final Cabin Creek report. First, I find the CSB acted as an independent federal agency in conducting its investigation and drafting its report as required by 42 U.S.C. §7412(r)(6)(A)-(S). There is no evidence whatsoever that the CSB acted in concert with the prosecution in investigating this accident or intentionally delayed the issuance of its report.[11]

While CSB's position was supported by a federal district judge, Xcel and RPI's legal action delayed completion of the CSB report for several months, and diverted CSB resources from other ongoing

[10] *United States v. Xcel Energy, Inc., et al.*, No. 09-cr-00389-WYD (District of Colorado).

[11] Id. Order of June 30, 2010 (docket #178).

investigations. Despite the clear findings to the contrary in the judge's ruling, Xcel representatives *continued* to make unsupported claims that the CSB had delayed release of its report to prejudice Xcel in the federal criminal prosecution in which the company is a defendant.

Finally, in early August 2010, an Xcel attorney provided an incomplete *draft* of the CSB report to the media on the eve of the Board's completion of its work. This last Xcel effort caused yet further delays in the process, and has created a risk that Xcel's Directors and shareholders will draw incorrect conclusions about the accident at Cabin Creek. Accordingly, the Board included in this report a formal recommendation that Xcel shareholders be directly notified by management of the significant findings and recommendations of this report, and of the actions Xcel management intends to take to implement needed safety improvements.

2.0 Xcel Energy

Xcel Energy (Xcel) is a Minneapolis, Minnesota-based holding company founded in 1909 with four wholly owned regulated utility subsidiaries that serve electric and natural gas customers in eight western and Midwestern states: Colorado, Michigan, Minnesota, New Mexico, North Dakota, South Dakota, Texas, and Wisconsin. The company employs nearly 12,000; serves 3.3 million electricity and 1.8 million natural gas customers; and exceeds $9 billion in revenues annually (2008).

2.1 Cabin Creek Hydroelectric Plant

The Public Service Company of Colorado[12] (PSCo) Cabin Creek hydroelectric plant, which began operating in 1967, is located off Guanella Pass, a partially paved road that winds through a remote area in the Rocky Mountains [10,018-foot (3053 meters) elevation] approximately 6 miles (10 kilometers) south of the Georgetown, Colorado and 45 miles (72 kilometers) west of Denver. PSCo is a subsidiary of Xcel; this report will refer to PSCo and Xcel Energy collectively as Xcel.

Cabin Creek is a pumped storage plant, with upper and lower water reservoirs totaling 1,977 acre-feet (2439 megaliters), used to generate electricity primarily during peak demand periods. Electricity is generated by releasing water from the upper reservoir where it flows into an intake structure, which is connected to a penstock; the water passes through turbines before being deposited in the lower reservoir (Figure 1). The flowing water rotates the turbines, which turn shafts that power the generators, producing electricity. When electricity use is low, the water is pumped back into the upper reservoir through the penstock to be used again. The plant has two generators capable of producing 150 megawatts (MW) of electricity for 4 hours.

[12] The Public Service Company of Colorado, a Denver-based company founded in 1869, is a regulated utility company in Colorado that operates seven coal, six hydroelectric, and two natural gas plants, and one wind turbine field, to provide electricity and natural gas utility services to 1.3 million customers located in Denver, other Colorado cities, and some rural areas.

Figure 1. Location of hydroelectric plant, reservoirs, and penstock pathway

2.1.1 Penstock

The penstock is 4,163 feet (1,269 meters) long from the upper reservoir's intake to the point at which the penstock splits into two pipes to feed the turbines in the powerhouse. Of this space, 3,123 feet (952 meters) can be traveled by foot. RPI was hired by Xcel to recoat roughly one-half of this relatively horizontal space (1,560 feet, or 475 meters, at a 2 degree incline). This section of the penstock is 12 feet (3.7 meters) in diameter, welded and steel-lined. The remaining portions of the penstock going up into the mountain vary in length and degree of gradient, with the 55 degree section too steep to traverse (Figure 2). The last 1,040 feet (317 meters) of the penstock requires climbing aids, ropes, or ladder structures to be traversed.

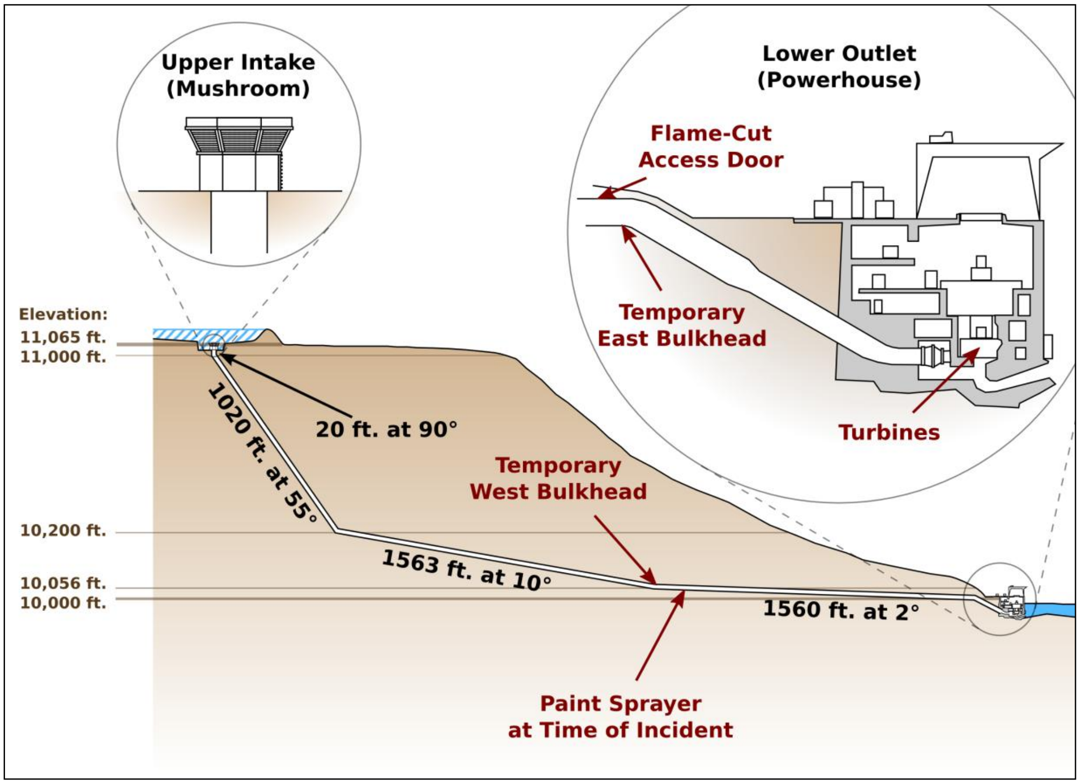

Figure 2. Penstock configuration

At the highest elevation point of the penstock in the upper reservoir is the intake structure known as the "mushroom." The mushroom is a 40-foot (12 meter) tall, cylindrical concrete and steel tower with screened openings near the top that open to the penstock. The mushroom has an access hatch approximately 20 feet (6.1 meters) above grade at a reverse incline position that requires climbing skill and significant physical strength to enter (Figure 3).

Figure 3. Upper reservoir mushroom access hatch

While the penstock runs underground for most of its length, as it exits the mountain rock face near the lower reservoir, a 15-foot (4.6 meter) section is accessible from the powerhouse yard. In this portion of the penstock, a 4 by 6 foot (1.2 by 1.8 meter) opening was flame-cut into the steel penstock pipe to provide access for the recoating project workers and equipment.

2.1.2 Deteriorated Penstock Interior Lining Requires Replacement

During the fall 2000 plant outage,[13] a Federal Energy Regulatory Commission[14] (FERC)-mandated internal inspection of the penstock found numerous indications of deterioration of the epoxy coating (flaking, blistering, and checking) in the interior of the steel-lined pipe section, which resulted in areas of

[13] An outage is a period when a plant, such as this one, is not in normal operation because of maintenance work and/or inspections.

[14] FERC is a self-funded, independent regulatory agency within the U.S. Department of Energy with jurisdiction over electricity sales, wholesale electric rates, hydroelectric licensing, natural gas pricing, and oil pipeline rates. FERC also reviews and authorizes liquefied natural gas (LNG) terminals, interstate natural gas pipelines, and approximately 1,600 non-federal hydropower projects in the U.S.

rusting and pitting corrosion to the steel pipe. Although the structural integrity of the pipe had not been compromised, the inspection report recommended repairs to the coating before more damage resulted. After obtaining an extension for repairs from FERC for several years, a project to remove the lining and replace it with a new epoxy lining was scheduled for the fall 2007 outage.

3.0 Contractors

3.1 RPI Coating, Inc.

Xcel selected RPI Coating, Inc. (RPI), a commercial painting and coating company headquartered in Santa Fe Springs, California, to remove the old liner from the steel portions of the Cabin Creek penstock and apply the new epoxy (for additional information on the selection process, see Sections 4.1.2 and 8.0). RPI, which operated as Robison-Prezioso, Inc. until 2007, was ranked the nation's seventh-largest specialty paint company based on revenues in 2005, according to the *Engineering News-Record* (2005). At the time of the incident, RPI had approximately 275 employees and more than 13.5 million in annual sales.

Prior to this incident, when RPI was still Robison-Prezioso, federal and state OSHA had inspected the company 46 times since 1972. Of these inspections, 31 had been initiated due to a complaint, referral, or accident; 90 violations were issued with fines totaling $135,569. Some violations were issued after accidents that had resulted in serious injuries and/or fatalities to employees (Appendix B).

3.2 KTA-Tator, Inc.

Xcel hired KTA-Tator, Inc. (KTA), a 250-employee consulting/engineering firm, for several work tasks associated with the penstock project. These tasks included writing the technical specifications for the application of the new epoxy coating in the penstock, assisting in the selection of the coatings contractor by reviewing and evaluating submitted bids, helping resolve technical issues arising from application of the coating, and performing periodic quality control checks to ensure proper old coating removal and new coating application.[15]

[15] The first three tasks were completed by a KTA chemical engineer specializing in coatings applications in the water and power industries; the fourth was performed by a KTA coatings inspector certified by the National Association of Corrosion Engineers (NACE).

4.0 Incident Description

The penstock fire occurred on October 2, 2007, but the recoating project had been initiated months earlier.

4.1 Pre-Incident Events

4.1.1 Initial Evaluations of the Penstock Project Hazards

Almost a year before the October 2, 2007, incident, Xcel conducted a hazard assessment of the penstock project, which was later provided to potential contractors during the bidding process. However, this "Safety and Health Hazard Assessment Survey" focused only on the abrasive blasting portion of the recoat project work and did not examine the risks of epoxy recoating associated with the penstock, the use of flammables inside the confined space, or the limited access and egress of the penstock. This was the only hazard assessment Xcel conducted for the entire penstock recoating project.

Later in the penstock project development process, during the spring of 2007, a civil engineer employed by Xcel highlighted a number of difficulties specific to the unique and challenging penstock work that would affect the success of the project in his document, "Cabin Creek Penstock Major Items of Concern."

Within the document, the civil engineer identified the need for an additional point of access, as the penstock's single entryway – a 20-inch (51 centimeters) man hole – was the only existing penstock opening at the start of the project. The civil engineer also discussed the challenges of trying to achieve the necessary temperature conditions within the penstock for successful epoxy application and the significant difficulties of completing the project in the 10 weeks allotted, suggesting that the harsh weather conditions typical of October and November in the Colorado mountains would hinder timely completion. These concerns were given to the Xcel Cabin Creek principal engineer, who later became responsible for preparing for the project with RPI, and a number of other Xcel employees, prior to the start of the recoating work. Yet neither Xcel's submission to the potential bidders for the recoat project, nor RPI's bid response, discussed methods for minimizing or rectifying the concerns raised by the civil engineer.

4.1.2 Contractor Selection

Xcel issued a Request for Proposal (RFP) for a competitive bidding process to several contractors in July 2007. The contractor selected to perform the work was to be chosen based upon the "best value/best overall evaluated offer," which was supposed to consider factors such as schedule, price, qualifications, and safety performance (TRB, 2006, p.S-3). The Xcel process also included an initial prequalification step that examined the contractors' financial capacity to carry out the work but did not consider safety performance.

Due to key safety criteria deficits in RPI's safety record, Xcel rated the company as "zero" in that category, which should have meant its automatic disqualification from the bidding process; however. RPI's bid was not rejected, and it was eventually awarded the contract despite its poor safety record (Section 8.0).

4.1.3 Planning and Preparing for Penstock Recoating Project

While RPI employees prepped the job site, Xcel held a preconstruction meeting for the penstock recoating project on September 5, 2007, attended by an RPI vice president, the RPI Safety and Quality Control representative, and two RPI project foremen. During this meeting, the Xcel project manager indicated that this was a "high profile project with [the] attention of FERC" and that a high standard toward quality control needed to be maintained. On September 10, at the request of RPI's safety director, an instructor with the Southern California Painting and Drywall Industries (SCPDI) District 36 Training Center conducted a six-hour safety refresher training session at the Xcel Cabin Creek site for some RPI industrial painters to address gaps that the Xcel safety director had identified in RPI's contract bid submissions. Only nine of the 14 RPI crew members were on site to attend this general safety training, and no make-up session was offered to those not in attendance (Section 9.0).

4.1.4 Work Preparation Prior to Recoating

Before the old liner could be removed from the steel sections and the new epoxy applied, the plant was shut down and water drained from the penstock. This occurred during the first week of September 2007, as a number of RPI personnel began arriving at the Cabin Creek site to set up for the job.

After the water was drained from the penstock, a 4-foot wide by 6-foot (1.2 by 1.8 meters) tall access opening was flame-cut[16] into the side of the steel penstock pipe for personnel and equipment access. Wooden stairs and a ladder at the access door provided means for personnel to enter and exit the penstock (Figure 4).

Xcel and RPI personnel then entered the penstock to remove standing water, dead fish, mud, and debris. Eyewitnesses reported that the penstock was extremely slippery due to moss buildup, and that personnel often slipped during initial entries. One RPI employee dislocated his shoulder when he slipped and fell.

[16] The access opening was cut by a specialty welding contractor.

Figure 4. Access door cut into penstock for recoating work

To contain the sandblasting debris and control ventilation, RPI built a wooden bulkhead west of the penstock area to be recoated (“west bulkhead”), with a 2 by 2 foot (0.7 by 0.7 meter) access hatch near the bottom, and sealed it against the walls of the penstock with foam. RPI built a second sealed wooden bulkhead about 20 feet east of the penstock’s access door (“east bulkhead”). Two 20-inch (51 centimeters) diameter flexible ventilation ducts, connected to dehumidification, heating, and dust collection equipment located outside the penstock, were brought into the penstock to dry and dehumidify the air and collect dust. The air supply duct was routed along the penstock wall and terminated near the west bulkhead at the steel/concrete transition where the air was discharged; the air return duct terminated near the penstock access door.

Compressed air and 120/240-volt electrical service were brought into the penstock to power equipment and provide lighting. Power cables for the electrical service were connected to a portable transformer located outside the penstock. A 240-volt heavy gauge power cable (6 AWG[17]) ran along the penstock floor from the access door and terminated at power distribution centers (commonly called "spider boxes"), one of which was located about 100 feet (30.5 meters) from the west bulkhead to provide power to the work area; this cable had non-watertight twist lock connector fittings joining sections of cable. The spider box contained 240- and 120-volt GFCI-protected electrical power supply outlets. On the day of the incident, the electric heaters on the sprayer, halogen work lights positioned on top of the sprayer, and explosion-proof lighting mounted on a scaffold immediately adjacent to the bulkhead were plugged into this spider box.

On September 16, 2007, another contractor performing inspection work inside the penstock complained to Xcel about being delayed entry into the penstock for 2 hours due to high carbon monoxide (CO) levels; he also noted a problem with RPI's electrical service inside the penstock when some of the contractor's testing equipment was damaged after it was plugged into an RPI spider box. An RPI foreman later rewired this electrical box, which was located near the sprayer on the day of the incident.

4.1.5 Removal of Old Epoxy Liner

Beginning on September 20, 2007, RPI sandblasted and removed the old liner from the the steel section immediately east of the west bulkhead; sandblasting continued until September 28, when the first 500-foot section was completed. On September 22, the Xcel project manager for the penstock recoating work observed RPI conducting abrasive blasting inside the penstock, noting that "[w]ork conditions inside the penstock are highly hazardous on many levels. In the best of conditions, the coating removal is dirty, nasty work." Beginning September 28 and continuing for 4 days, leaks were patched, and the abrasive

[17] AWG (American Wire Gauge) is a U.S. standard set of non-ferrous wire conductor sizes.

blasting medium was vacuumed up and removed from the penstock. An Xcel worker entered the penstock during this period on two occasions to weld weep holes to stop leaks.[18]

4.1.6 Additional Evaluations and Inspections of the Penstock Work Space

On September 22, KTA conducted its own initial pre-job hazard assessment of the penstock. In this assessment, the KTA inspector noted that the Material Safety Data Sheets (MSDSs) for all coatings and solvents to be used in the project were available and would be reviewed relative to personal protective equipment (PPE) and respiratory protection needs, and that the contractor and Xcel project manager were told about this review. In the assessment, the use of solvents was once again identified when the need for eye protection was pinpointed due to the use of "solvents, paints, abrasives, etc." According to the assessment document, the project manager was to be advised on the use of solvent.

In this same inspection, the KTA inspector also indicated that the project would require workers to enter a work area classified as a permit-required confined space. By delineating the space as such, several requirements were outlined to be followed, including review entry procedures and entry permit, verify that air monitoring is performed prior to and during entry, verify that an attendant is present and rescue equipment is onsite, and use respiratory protection in accordance with controlling employer's entry procedures. Despite these requirements, entry procedures were not developed and the required daily permits were incomplete and lacking detail pertaining to the hazards of the day's work activities. Air monitoring was performed almost exclusively at the entrance, about 1,450 feet (442 meters) away from the actual work area within the penstock. Finally, rescue equipment was not available and ready for use onsite throughout the project or on the day of the incident.

Two days later, on September 26, the KTA inspector conducted an inspection of the penstock interior, indicating in his documentation that thinner would be used as part of the coating materials' mixing and

[18] Neither Xcel Energy nor RPI could provide copies of hot work permits for this welding work to the CSB.

pre-application process. Thinner/solvent was required to be run through the sprayer system equipment (including hoses, nozzles, and the sprayer itself) prior to the introduction of the epoxy components. This step ensured that the machine was completely free of all residue or contaminants prior to usage for actual spraying.[19]

On October 1, an Xcel safety consultant inspected RPI employees working in the penstock, but noted no unsatisfactory conditions.

Sandblasting activities, including hand-sanding and grinding of the walls, were completed on the morning of October 2, and 13 RPI crew members[20] began preparing the penstock interior for the new coating. No reevaluation of the safety hazards was held that morning to specifically assess new risks that could be associated with the change in planned work activities from sandblasting to epoxy coating application, nor were special precautions taken within the work environment beyond those put in place prior to the start of the sandblasting operation.

4.1.7 Staging Equipment and Coating Materials

The sprayer, a plural component (two-part) epoxy spraying system manufactured by Graco, is typically used in industrial epoxy application projects (Figure 5).

[19] In the September 26, 2007, KTA Inspection Report, "Task Summary: Coating Observation Hold Points," the inspector indicates that thinner would not be used in any ratio with the paint during either the first or second coat of paint. More traditional types of paint require a thinner or solvent to adjust the viscosity of the paint for proper application. However, the Duromar HPL-2510 two-part epoxy selected as the paint for the penstock interior did not require thinner to be added, as the two parts of the epoxy themselves are mixed according to a specific ratio of hardener to base. While a thinner or solvent was unnecessary for the actual paint mixture to be applied to the penstock interior, the solvent was needed to flush the sprayer system and clean equipment prior to and throughout the spraying process to keep the machine running smoothly for proper application of the two-part epoxy.

[20] One of the 14 contractors left the site prior to October 2nd for personal reasons.

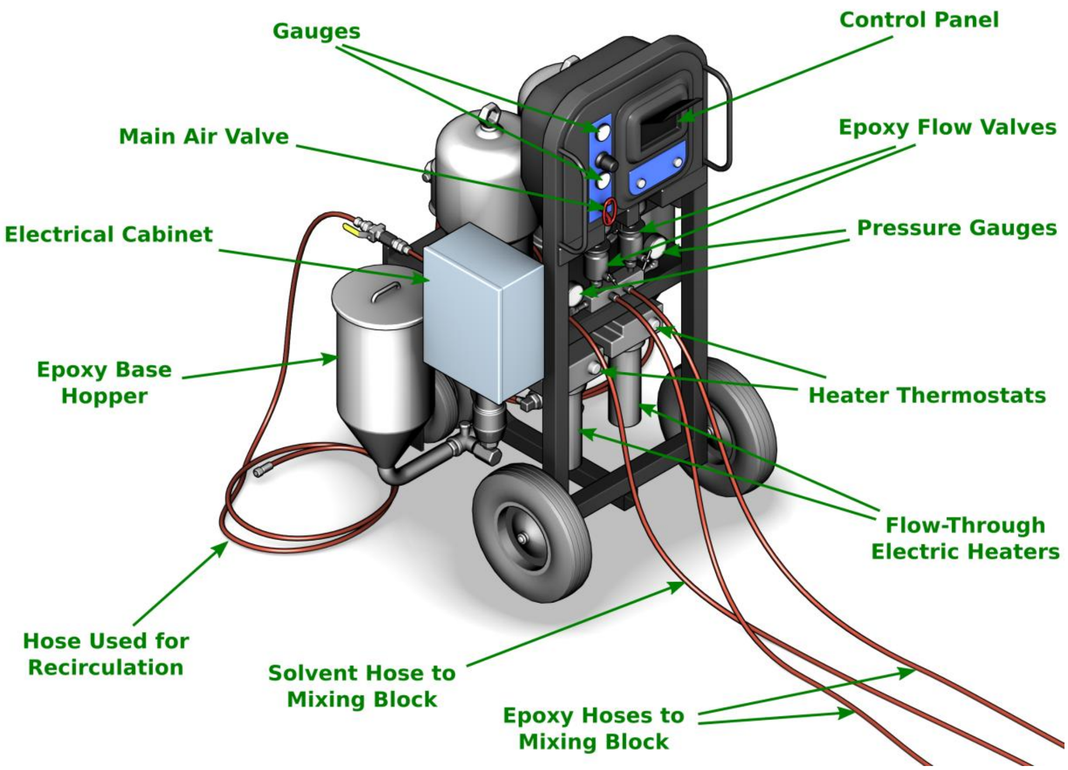

Figure 5. The epoxy sprayer system used within the penstock

Each epoxy component – a base and a hardener – is poured into its respective hopper, and each flows through a heater to achieve the proper application viscosity. Pumps for each component force the heated material through separate hoses to a mixing block, where the hardener and base are homogeneously blended. This separation of heating prior to mixing is necessary because once the two components blend, they begin to "set," forming an epoxy bond that hardens rapidly. The combined epoxy product is then carried through a hose from the mixing block to the spray wand for surface application. Workers stated that the epoxy components used in the Cabin Creek project, once mixed, had a short "pot life"—a period of approximately 20 minutes before they began to permanently harden together.[21]

[21] The epoxy product data sheet gives the "pot life" as 45 minutes at 70 ºF, but the workers described the period before the mixed epoxy began to set up as much shorter in actual working conditions.

Solvent, such as MEK, is needed if problems arise when applying the epoxy mixture. If the combined epoxy product was to set, it would harden within the hoses and spray wands, destroying the equipment. Solvent would be used to flush out the mixing block and hoses to the spray wands to ensure that the epoxy mixture was fully removed from the equipment and would not permanently render it unusable. Solvent would be introduced into these portions of the spray system using a third smaller pump on the back of the machine that would take in solvent from an open bucket placed on the ground at the back of the sprayer (Figure 6). A hose ran directly from this pump to the mixing block.

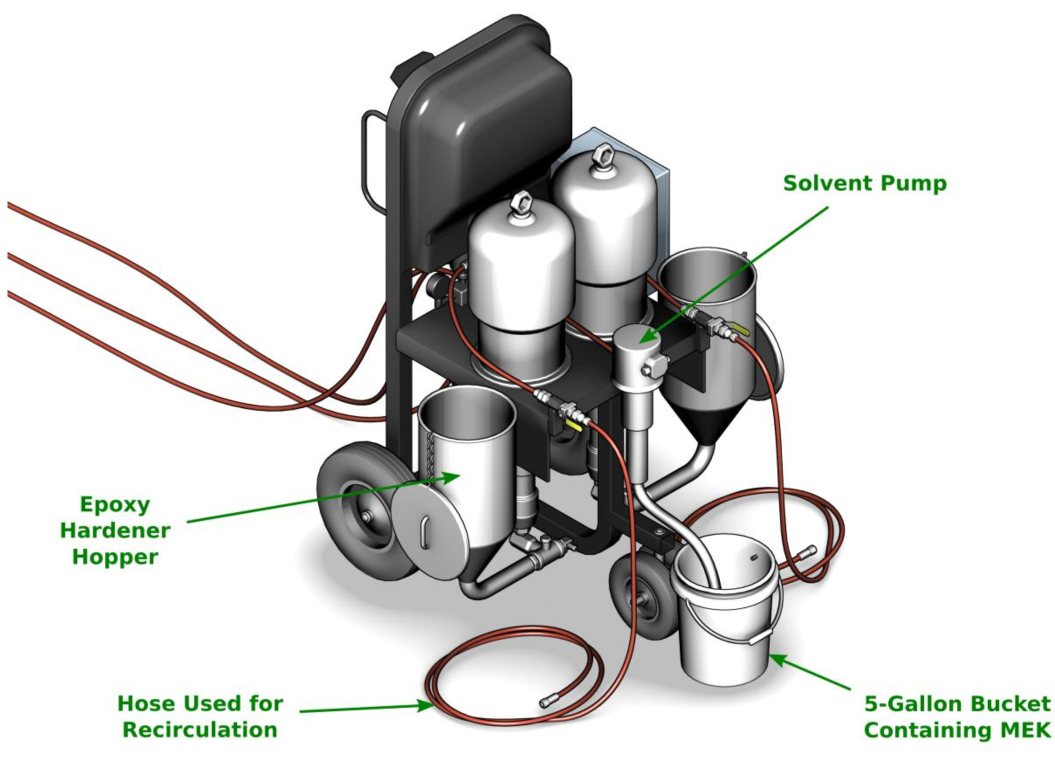

Figure 6. The solvent pump on the back side of the epoxy sprayer

The sprayer was positioned in the penstock on wheeled scaffolding, which the RPI crew called the "stage," about 1,450 feet (442 meters) from the access door and approximately 90 feet from the west bulkhead (Figure 7). The controls for the sprayer faced the west bulkhead, so that when a contractor was in position to manipulate the controls, he was looking in the direction of the access door, with the sprayer between him and that single point of egress.

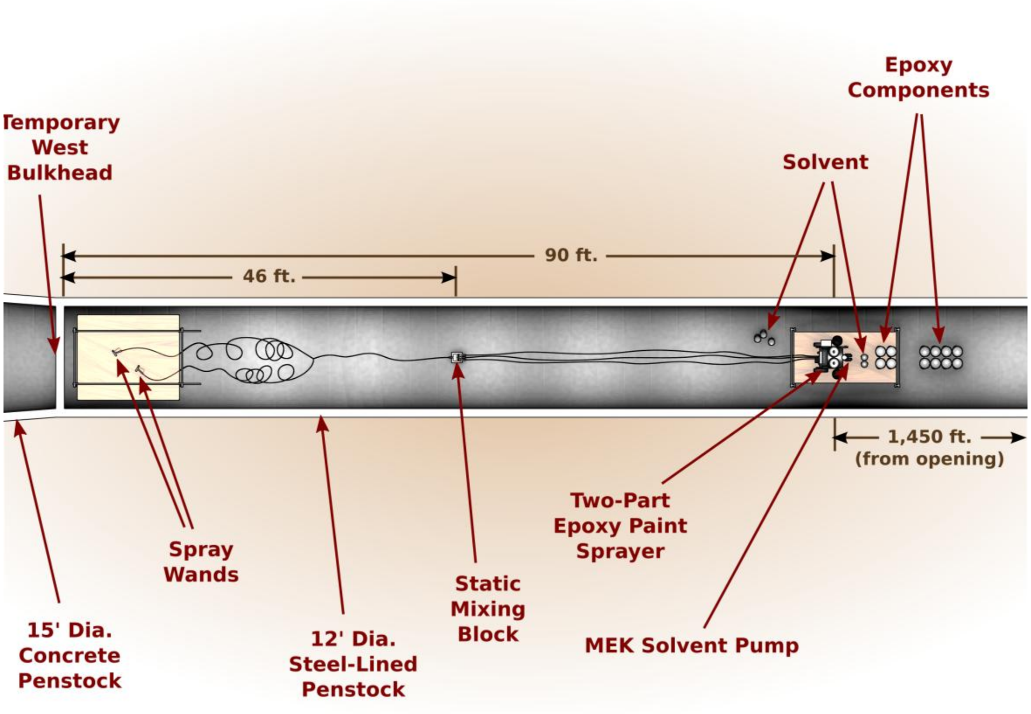

Figure 7. Aerial view of equipment arrangement in work area of the penstock

In the hour leading up to the incident, five of the 13 contractors were working around the sprayer system (Figure 8). Three of these individuals – two of whom were foremen – worked the controls of the sprayer, while two others were stationed on the sides, each responsible for manning a hopper. Four additional contractors were runners, bringing epoxy, solvent, and other equipment to and from the work area to assist the five at the sprayer, and one person was stationed as the "hole watch" attendant at the access door 1,450 feet (442 meters) away.[22]

[22] Among other responsibilities, the assigned "hole watch" is responsible for tracking who enters the confined space and the duration of time each spends within the space.

Figure 8. Depiction of contractors working with the sprayer immediately prior to the flash fire

The last two of the 13 contractors – besides the general foreman – were at the far end of the work area near the temporary west bulkhead, preparing to begin recoating the penstock interior using a wheeled scaffold that had been built for the crew as they used spray wands to recoat the penstock interior (Figure 9).

Figure 9. Depiction of contractors recoating the penstock interior near the temporary west bulkhead

4.1.8 Preparation for Coating Application

In preparation for applying the epoxy, approximately 10 gallons of MEK was brought into the penstock in 5-gallon plastic buckets to flush out the entire sprayer system prior to applying the epoxy. This flushing cleans out the mixing block and combined epoxy product hose lines to the spray wands and involves pouring MEK into each of the hoppers and re-circulating the solvent through the sprayer from the hopper to the discharge of the pump.[23] This full flushing process ensures that all foreign matter, debris, and leftover epoxy products are completely removed from the equipment before new epoxy products are introduced.

MEK is highly flammable and can produce hazardous atmospheres with air and be ignited under almost all ambient temperature conditions (NIOSH, 1998; NFPA 2007b, Table 6.2) (Section 6.5.1 details the hazards of MEK).

On October 2, after this flushing process was completed, the open buckets of used MEK were kept within the sprayer area for future use. Immediately prior to the incident, at least eight buckets of epoxy and three buckets [about 11-12 gallons (42-45 liters)] of MEK were on the stage. One of these buckets was a 5-gallon (19 liters) pail that sat open underneath the solvent pump on the back side of the sprayer. A halogen lamp sat on top of the pumps, projecting light onto the hoppers. In addition, more than 95 plastic buckets of base and hardener epoxy products were distributed throughout the penstock (Appendix C provides an inventory of epoxy and solvent within the penstock at the time of the incident).

The KTA inspector and RPI general foreman examined the penstock work area and determined that the contractors could begin applying epoxy. The inspector and general foreman then left the site for lunch at about 1:10 pm, while the other 12 RPI workers remained at the site, 11 of whom continued working within the penstock.[24]

4.1.9 Epoxy Coating Application Problems

The application process did not go smoothly, and solvent (MEK) had to be used several times to flush out the equipment. Eyewitnesses reported that the sprayer was not flowing accurate hardener-to-base ratios

[23] This preparatory cleaning of the equipment is discussed in the Duromar epoxy application guide and the Graco sprayer manual as normal practice during general commercial or industrial painting prior to introducing epoxy into the sprayer system.

[24] The twelfth contractor was the attendant stationed at the access door.

and that its electronic display continually gave error readings, which automatically shut down the sprayer. Because of "fingering," or uneven application of the epoxy to the surface, the contractors were able to spray only about a 10-foot (3-meter) area of the penstock wall interior. [25]

Each time the sprayer shut down, the contractors ran MEK from the sprayer's solvent pump to the mixing block, through the two hoses of combined epoxy product to the spray wands, where the solvent flushed the epoxy out of the hoses into plastic buckets.

This flushing between attempts of epoxy application occurred approximately four times before one of the RPI foremen decided that the contractors would be unable to apply the epoxy evenly. He instructed the contractors to flush the entire sprayer system by circulating MEK through all the equipment in preparation for removing the sprayer from the penstock.

After flushing the mixing block and the spray wands, the two contractors at the west bulkhead who had been operating the spray wands took the buckets containing a mixture of MEK and epoxy waste to the sprayer area. Other members of the crew began cleaning out the sprayer by removing the epoxy products within each hopper.

Another contractor brought in about 6 more gallons (23 liters) of MEK in several trips using 2-gallon (7.6 liters) plastic buckets that had originally contained the hardener. As a result, about 11-12 gallons (42-45 liters) of pure MEK and another 12 gallons (45 liters) of epoxy/MEK waste product [of which about 5 gallons (19 liters) were MEK] were in close proximity to the sprayer.

At this time, two of the contractors retrieved some of the nearby buckets of MEK to flush out the sprayer system, while two others began walking toward the access door to retrieve even more buckets of the solvent. MEK was poured into the hardener side and circulated through the sprayer system. The

[25] "Fingering" is painting jargon for uneven paint application: when a thick residue of paint is left in long vertical lines, like fingers, up and down a surface.

contractors then poured MEK in the base hopper for circulation. This circulation through the base side of the sprayer was ongoing when the initial flash fire occurred.

4.2 The Incident

At approximately 1:55 p.m., on Tuesday, October 2, 2007, a flash fire ignited at the sprayer in the immediate vicinity of the base hopper while the contractors were flushing the system with MEK. An RPI contractor was circulating the MEK from the base hopper through the pump, discharging the solvent back into the hopper through a nylon hose. At the time of the ignition, the contractor was holding the end of the hose equipped with a metal fitting inside the base hopper; he reported witnessing the initial flash arising from the interior of the hopper. The burning solvent forcefully erupted from the hopper and sprayed onto the contractor and the surrounding area. The flash fire caught the contractor’s sleeve on fire and quickly engulfed the buckets of MEK. Another contractor, who left the work area to retrieve portable fans to help dissipate the strong MEK odor, was about 40-50 feet (12-15 meters) from the sprayer when the fire ignited. Two others, on their way out of the penstock to retrieve more MEK, heard a loud rumble; they turned in the direction of the noise and saw a flash of fire that seemed to roll toward them. These eyewitnesses reported that the fire appeared to come from the base hopper.

This rapidly growing fire separated the contractors who were standing on either side of the equipment. The five contractors who were on the far side of the sprayer found their exit blocked by the fire and were unable to escape. The trapped men shouted for fire extinguishers.

4.3 Emergency Response

4.3.1 Fire Extinguishers

No fire extinguishers were staged near the sprayer where the initial fire started. After the initial flash, the fire died down enough for those trapped behind the sprayer to communicate with the survivors on the other side. Those trapped instructed the others to retrieve extinguishers. The contractors on the side of sprayer with access to the entrance ran about 1,450 feet (442 meters) down the penstock to retrieve the fire extinguishers, which were located outside of the penstock.

While they ran for the access door, several flash fires ignited and loud booms reverberated down the penstock as the initial fire ignited the solvent and caused the epoxy buckets surrounding the sprayer to burst. The fire increased in size and intensity and spread to additional epoxy buckets in the vicinity of the sprayer. The trapped men retreated uphill, away from the sprayer and farther up into the penstock.

With extinguishers in hand, two of the crew ran back inside toward the fire and sprayer with the intention of putting out the fire. The thick black smoke reduced their visibility to almost zero and made breathing difficult; as a result, they could not get near enough to the sprayer and burning epoxy products to effectively extinguish the fire. This initial attempt, and all additional re-entries the work crew made to extinguish the fire, failed.

4.3.2 Initial 9-1-1 Call

One of the crew members who retrieved the first two fire extinguishers from outside the penstock handed the extinguishers to his coworkers before running to the nearest phone, located at the Cabin Creek powerhouse entrance east of the penstock. He called the Cabin Creek power house control board, notifying them of the penstock fire and need for 9-1-1 assistance.

Clear Creek County Emergency Dispatch received the first 9-1-1 call from an Xcel control room operator at 2:03 p.m. The caller told the 9-1-1 operator that there was a fire in the penstock, but did not explain that the penstock was a confined space or that specialized rescue personnel and equipment would be required to fight the fire and rescue trapped workers.[26] The 9-1-1 operator immediately broadcast a request to Clear

[26] The caller told the 9-1-1 operator that there was "a fire in our penstock…in our tunnel…outside on our surface deck, outside of the plant…on the surface."

Creek County Emergency Services[27] to respond to the Cabin Creek site, indicating that there was a fire on the "surface deck."

The RPI worker also called the company corporate office to notify management of the emergency. He then went back to the access door of the penstock and found that the RPI general foreman and KTA inspector had arrived.

During this time the trapped workers used a radio to remain in communication with the crew that escaped.[28]

4.3.3 Emergency Responders Arrive

Upon arriving at the Cabin Creek site, emergency responders established an Incident Command structure. At 2:11 p.m., the first Clear Creek County Sheriff's officers arrived on the scene, followed shortly by a volunteer paramedic and firefighter from the Clear Creek County Fire Authority (CCFA). These responders saw no signs of a surface fire when they arrived. Xcel and RPI employees quickly informed them that the fire was inside the penstock and that several workers were trapped. At 2:20 p.m., the 9-1-1 center broadcast an update indicating that the fire was 1,000 feet (305 meters) inside the penstock tunnel and below ground. The message also informed responders that they would need 1,000 feet (305 meters) of hose and the equipment necessary to fight an underground fire.

The CCFA responders lacked the necessary equipment and resources to safely enter the penstock; they were also concerned that they lacked the appropriate training to perform rescue within the confined space.

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[27] Clear Creek Fire Authority (CCFA) is a consolidated fire protection and emergency service agency serving the municipalities of Empire, Georgetown, Idaho Springs, and Silver Plume, and the unincorporated lands of Clear Creek County previously represented by the Clear Creek Emergency Services District (ESD). CCFA's territory includes I-70 (Colorado's primary east-west transportation corridor); Clear Creek (a rafting river); four 14,000-foot (4,300 meters) peaks; two ski areas; several hundred abandoned mines; and residential and business districts. (Colorado Division of Emergency Management, http://dola.colorado.gov/dem/operations/operations.htm, accessed July 30, 2010).

[28] The CSB determined this timeline by correlating events discussed in interviews with security video footage of the area outside the penstock.

4.3.4 Call for Mutual Aid

CCFA personnel en route to the site, based on information broadcast over their radios (i.e., that the fire was located deep inside the penstock and that workers were trapped), contacted Denver's West Metro Fire Protection District (West Metro) to request firefighting and rescue assistance.[29] West Metro Emergency Response personnel are located on the west side of Denver, approximately 1 hour and 15 minutes travel time (about 45 miles or 72 kilometers) from Cabin Creek.

At one point, firefighters requested and received the MSDSs from RPI.

At 2:30 p.m. the Incident Commander contacted Climax Molybdenum Company's (Henderson Mine) mine rescue team to request support in rescuing the stranded workers.

4.3.5 Attempted Entry by Early Rescuers

Approximately 45 minutes after the initial fire, but before West Metro or Henderson Mine emergency personnel arrived, four Clear Creek firefighters entered the penstock to assess the fire and the prospect of rescuing the five trapped RPI employees. Wearing protective fire-fighting clothing and self-contained breathing apparatuses (SCBAs), they used a small gasoline-powered all-terrain vehicle (ATV)[30] to explore the penstock. Because of the smoke and lack of visibility, they were able to move only about 200 feet (61 meters) into the penstock before they stopped and returned to the entrance, concluding that they were unable to extinguish the fire and/or rescue the trapped workers. CCFA did not attempt further entry into the penstock until after Henderson Mine rescue personnel cleared the penstock.

[29] West Metro and CCFA have a Mutual Aid agreement for technical firefighting and confined-space rescue.

[30] The ATV was placed in the penstock at the beginning of the project to transport personnel and supplies throughout the steel portion to be recoated.

4.3.6 Stranded Workers Still Communicating 45 Minutes into Incident

Radio communications between the trapped contractors and those outside the penstock continued for about 45 minutes after the initial flash fire. The trapped workers were instructed to move to the upper end of the penstock, away from the burning sprayer, epoxy, and solvent.

4.3.7 Emergency Responders Evaluate Further Entry into the Penstock

West Metro arrived at the Cabin Creek site around 3:40 p.m., but because they did not know about the conditions inside the penstock—whether explosive hazards existed—they did not enter to fight the fire or attempt rescue. Instead, they joined CCFA and another rescue group, Alpine Rescue, at the top of the penstock (the mushroom). Upon arrival at the mushroom, West Metro was told that breathing air bottles and respirators, a light, and a radio were lowered down into the vertical portion of the penstock in the hopes of reaching the trapped contractors. This activity posed its own difficulties due to the winding pot-holed road leading to the mushroom and the challenges of using the mushroom's access hatch.

4.3.8 Emergency Responders Enter the Penstock

The first of two Henderson Mine rescue teams arrived shortly after 4:00 p.m. and prepared to enter the penstock at the access door.

Sometime between 4:45 p.m.and 5:30 p.m., Xcel operations personnel reversed the penstock ventilation fans to try and reverse the penstock airflow and draw the smoke away from the stranded workers.

Henderson Mine responders entered the penstock at 5:45 p.m. After verifying that the fire had burned out, they continued up the penstock to determine if any of the workers had survived. They found the first body approximately 100 feet (30.5 meters) uphill of the fire. The four remaining were located even further uphill, near the point at which the penstock's incline abruptly steepens. Post incident, it was determined at all five died of asphyxiation shortly after radio communications ceased, at approximately 2:45 p.m.

5.0 Incident Analysis

The CSB found that numerous safety issues collectively contributed to the October 2, 2007, incident.

5.1 Pre-Incident Events

Insufficient ventilation, improper equipment for fire prevention, and a tight schedule created an unsafe work environment even before the epoxy application activities began.

5.1.1 Insufficient Ventilation

Adequate ventilation was an important safety issue of the penstock work environment. The work area being sandblasted and coated was sandwiched between two wooden bulkheads built to confine the sandblasting medium and epoxy coating materials, and to isolate the work area space of the penstock. Ventilation and the control of nuisance dust was to be accomplished using two desiccant-style dehumidifiers that would force air into the space at a rate of approximately 13,000 cubic feet per minute (CFM).[31] Additionally, a 12,000 CFM dust extractor was to be used that would pull air out of the penstock and remove dust particles before discharging the air outside. This ventilation setup, if operating optimally, equated to approximately 4.4 air changes per hour (ACH)[32] in the work area between the two bulkheads.[33] In constrast, the Flammable and Combustible Liquids OSHA standard requires a room that simply stores flammable and combustible liquids be ventilated at a rate of six air changes per hour in order to prevent explosive vapors from accumulating [29 CFR 1910.106(d)(4)(iv)]. None of the

[31] The inlet air was delivered into the work area via a 20-inch (52-centimeter) diameter flexible plastic supply duct magnetically attached near the floor of the metal-walled penstock. The return duct located near the access door directed the air from the penstock through the dust collector before it was discharged to the outside atmosphere. During sandblasting, additional portable blowers and fans moved the dust-laden air down the penstock toward the east bulkhead near the access door. The additional portable blowers or fans were not used while the epoxy coating was being applied.

[32] The number of times air is replaced in an hour.

[33] Volume of Air: 13,000 CFM x 60 min = 780,000 CFH; Volume of Space: $(6\text{ ft})^2 \times 1560\text{ ft} \times \pi = 176{,}432\text{ ft}^3$; Air Changes: 780,000 CFH/176,432ft3 = 4.4 air changes per hour

ventilation design documents obtained by the CSB indicated any analysis of the adequacy of 4.4 air changes per hour in relation to the dissipation of flammable vapors in the work space. The penstock's ventilation setup was designed soley for the purpose of ensuring the penstock ambient conditions were optimal for the sandblasting and epoxy application activities.

After using MEK to clean the spray wands on the scaffold near the west bulkhead, one of the contractors left the work area to get a fan to dissipate the buildup of solvent "fumes" that he smelled through his respirator. He told the CSB that, as he squeezed past the scaffold holding the sprayer, there was "no air movement at all" in the vicinity of the sprayer. Post-incident, OSHA cited RPI for not ensuring ventilation equipment provided acceptable confined space entry conditions [OSHA 21 Mar 2008, inspection 310470034, citation 2(8)]. While adequate ventilation is a necessary component for managing the hazards of confined space work, the CSB has concluded that ventilation alone was insufficient to safely control the risks of using flammables in the open atmosphere of the penstock.

5.1.2 Improper Equipment Choices for Fire Prevention

Penstock recoating equipment choices made by RPI personnel, including management officials, increased the likelihood of a fire.

5.1.2.1 Decision not to Use Heated Hose Lines

The CSB determined that the primary reasons for the epoxy application difficulties were due to the inability to achieve and maintain the necessary temperatures of the epoxy components for application, which likely would have been avoided had heated hose lines been used. Heated hoses are often used in specialized industrial painting projects to overcome the negative impact of temperature, which can affect the viscosity of the epoxy and thus the quality of the coating application. However, a decision was made to use regular spray hoses instead, despite the penstock ambient and surface temperatures being below recommended levels for proper epoxy application.

The product data sheets for the epoxy base and hardener, RPI provided to Xcel as a part of its bid submission package, state that the minimum surface temperature during application must be no colder than 60 ºF (16 ºC). However, in the week leading up the incident, ambient temperatures averaged 58 ºF (14 ºC), and on October 2, the KTA inspector recorded the interior surface temperature of the penstock as 54 ºF (12 ºC). The General Application Guidelines for the epoxy, also included in the bid package, indicate that the base and hardener components be stored in "a warm area where the temperature remains between 60-90 ºF (16-32 ºC). Cold products are very viscous and will be very difficult to mix and apply." While the epoxy components were initially stored in a heated trailer, more than 95 buckets of epoxy were brought into the penstock and staged in groups along 1,450 feet (442 meters) of the penstock's cold steel floor.

The RPI work crew reported that the sprayer was having trouble heating the cold material, particularly the base, due to its thickness and initial cold temperature. When mixing the two epoxy components together, the combined product should have been between 70-80 ºF (21-27 ºC). A RPI contractor taking temperature readings of the unmixed products within the hoppers with a laser gauge immediately prior to application stated that the temperature readings of the base that day reached no greater than "45 º, 47 º."

Furthermore, the sprayer had difficulties maintaining the required epoxy temperature for an extended period. When workers circulated the two epoxy components several times through each side of the sprayer and the attached heaters, the limited quantity of each component within the sprayer system was able to achieve the requisite temperature.[34] However, after the heated components were sent to the mixing block for blending, additional (cold) epoxy had to be added to each hopper to keep the flow of combined product out of the spray wands consistent. But additional time was needed for the cold epoxy to circulate through the heaters to warm up to the appropriate application temperature. The CSB concluded that the 44 feet (13 meters) of hose from the sprayer to the mixing block and the additional 40-60 feet (12-18 meters) of hose from the mixing block to the spray wands was too great a distance to maintain the requiste

[34] Testimony from an RPI crew member stated that the crew had to circulate the material multiple times to get the paint to the requisite temperature.

temperature as cold epoxy was added to the sprayer and then passed through hose that ran along the cold penstock floor to the area being recoated.[35]

The RPI vice president discussed the plan to use in-line heated hose as late as five days prior to the incident, yet they were not incorporated into the equipment setup within the space. The lack of heated hose, in combination with the extensive length of hose required to complete the application work, contributed to the crew's inability to keep the epoxy at the appropriate temperature for proper epoxy application. As a result, the sprayer would not function effectively and the crew was forced to repeatedly flush the hoses from the mixing block to the spray wands with MEK between each failed attempt, which contributed to the buildup of MEK in the atmosphere.

5.1.2.2 Electrical Safety Precautions not Met

Equipment used to handle flammable material must be properly bonded and grounded, and hoses must be electrically conductive. These electrical safety precautions were not met on the day of the incident; specifically, the CSB determined that some of the hose chosen for the penstock job was likely non-conductive.

Non-conductive flexible hoses are not recommended for use with flammable liquids due to their static-accumulation capabilities unless, at a minimum, all conductive couplings (e.g., end fittings or connectors) are bonded and grounded (NFPA 77, 2007a, Section 8.4.3.2).

While most of the hoses around the sprayer were destroyed in the fire, an examination of the equipment post-fire uncovered the remains of the hose used to circulate solvent through the hardener hopper and its associated equipment still attached to the sprayer, including a hose connector (metal swivel) and the inner woven metal sheath. The hose used to circulate solvent through the base side of the sprayer was destroyed

[35] An RPI crew member with experience working with this product recommended that the paint come out of the spray wands at a temperature of 110 ºF for correct application.

in the fire and the inner woven metal sheath was not observed to be attached to the sprayer was not found in the surrounding debris. Due to the lack of an inner metal sheath, the CSB concluded that the base side solvent hose was likely non-conductive and did not establish appropriate bonding to allow for the dissipation of static electricity on the metal hose connector. (Appendix D.1). A static charge likely built up as solvent travelled through this hose; eventually an electrical spark between the hose connector and the metal base-side hopper of the sprayer likely resulted in the initial flash fire (Section 5.2.2 and Appendix D discuss this ignition scenario in detail). To prevent static charge buildup, conductive, rather than non-conductive, hose should have been used with the sprayer.

5.1.2.3 Use of Unsafe Lighting

Unsafe lighting was also used within the penstock when flammables were present. RPI's "Spraying Equipment and Operations" policy within its IIPP states: "Explosion proof [sic] portable lamps must be used to illuminate the spray areas." However, the penstock spray area, including where the sprayer system was setup, was illuminated with a variety of lighting, not all of which was explosion-proof. Specifically, several halogen lamps were placed around the sprayer, with one resting on top of the sprayer pumps at the time of the incident (Figure 10).

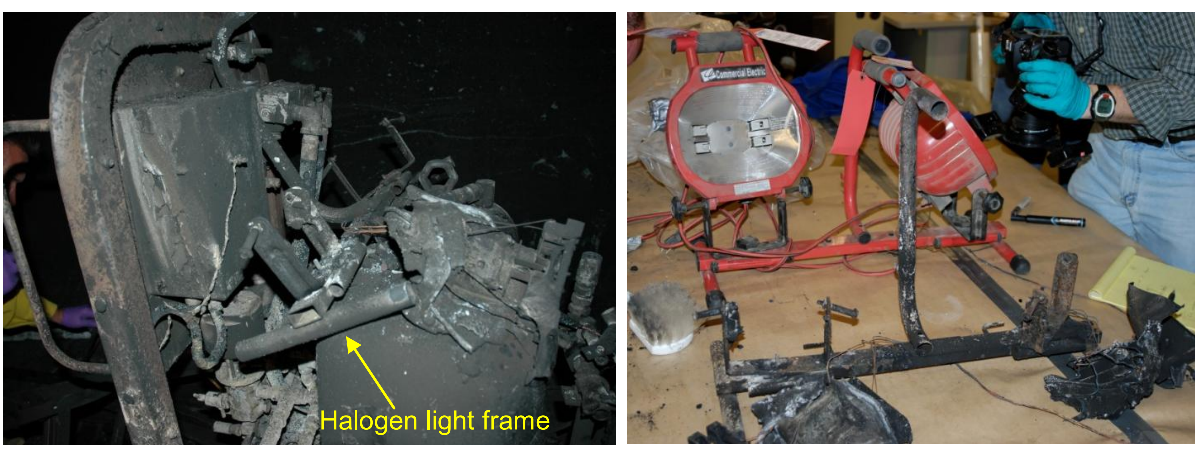

Figure 10. Remains of the halogen light sitting atop the sprayer inside the penstock (left); the same remains being compared to an exemplar halogen light (right).

Equipment and supplies needed for the penstock project were planned by the onsite foremen, the RPI shop manager, and RPI upper level management in advance of the work crew's activities inside the penstock. While the ignition of MEK vapor from the heat of a halogen light was determined to be a less likely ignition scenario (Appendix D), the CSB concluded that this unsafe lighting choice was a serious safety risk when used in conjunction with the introduction of flammables within a confined space.

5.1.2.4 No Fire Extinguishers Within the Work Area

Fire extinguishers were not immediately available to the contractors after the initial flash fire because they were not situated by the sprayer and within the work area. Contractors had to go approximately 1,450 feet (442 meters) – a length of over four football fields – to the exit of the penstock and retrieve extinguishers after the initial fire. RPI's "Fire Protection and Prevention" policy, within the IIPP, states that fire extinguishers "must be in close proximity to all painting operations." While "close proximity" is not defined, it is reasonable to conclude that 1,450 feet (442 meters) does not meet the definition. Additionally, NFPA 851, Recommended Practice for Fire Protection for Hydroelectric Generating Plants (2005), states that fire suppression equipment should be "provided where risk of fire exists" and "located for easy access" (NFPA 851, section 8.8.1). It goes on to state "Portable fire extinguishers of suitable capacity should be provided where…flammable liquids are stored or handled" (NFPA 851, section 8.8.2).[36] Had extinguishers been present at the location of the sprayer work activities, the solvent flash fire likely could have been suppressed or extinguished at the time of initial ignition prior to the combustion of the larger quantities of the epoxy products.

[36] Section 1.3.2 of NFPA 851 states that the recommendations within the Recommended Practice are intended for new installations, but notes that "the recommendations contained in this document represent good industry practice and should be considered for existing installations."

5.1.3 Scheduling and Production Pressures

A tight 10-week project completion schedule, severe weather concerns, several unplanned work delays, and perceived production requirements placed RPI employees under intense pressure to complete the recoating work. These stressors contributed to a rushed work pace on the day of the incident, which likely affected the crew's ability to focus on safety. Decisions made in haste and under stress can often have deleterious side effects, including inadvertent step deletion or heavy focus on one issue while minimizing the significance of others (Dismukes, Berman, & Loukopoulos, 2007, p.261). Evidence indicates that the RPI workers experienced a rushed work pace the morning of the incident, and safety was likely negatively impacted as a result.

For a power plant like the Xcel Cabin Creek site, the downtime of the penstock would be costly. An RPI foreman involved in the initial planning of the recoating project confirmed that the project was set on a "short schedule," where work would be conducted on a 24-hour/7-days-a-week schedule until completed in order to be able to accomplish the recoating project in shortest time period possible. In addition, the vice president of RPI noted the very tight schedule in emails during the planning phase of the project, questioning if only one coat of epoxy, rather than two, could be applied to the floor of the penstock to accelerate the work pace and decrease curing time of the epoxy.

The project's timing was also one of five items emphasized as problematic in the Xcel "Major Items of Concern" penstock project planning document (Section 4.1.1), written by an Xcel civil engineer who noted that the time it would take to drain the penstock, coat the interior lining, allow the epoxy to cure, and refill the penstock for hydroelectric power would be difficult to accomplish, even in the best conditions, within the allotted 10-week schedule. He added that the weather during the time of year the penstock would be recoated – September through November – would "not lend itself to the best of conditions."

As the project began, several delays in the initial work tasks constrained the already tight schedule significantly from the initial timeline RPI submitted to Xcel with its bid submission documentation. A compressor was blown out during the sandblasting portion of the work. The RPI crew experienced electrical problems, blowing out a few of the electrical "spider" boxes and lighting, which required repair and replacement; and the contractors had to spend extra time sandblasting to remove the necessary amount of old liner prior to recoating. Specifically, the submitted schedule stated that the first quarter of the 1,560 feet (475 meters) of the penstock being recoated would be sandblasted and coated by the first of October; but the crew was just making its initial application attempts on October 2, over one week behind schedule.

In interviews with the CSB, the RPI employees confirmed that they were behind schedule before they even began the epoxy application process. Penstock crew personnel stated that they heard the general foreman report to RPI headquarters that a number of work tasks were completed before they actually were. The day of the incident, eyewitnesses stated that the general foreman was anxious about the crew's progress and was pushing to get the recoating portion of the project underway. A number of the employees stated that with past projects they typically had regular safety meetings to review work tasks and safety concerns, but that the penstock job was different in that such safety discussions were not held as often, nor were they as focused on safety, as in previous jobs. According to the workers, any discussions held the morning of the incident focused on preparing equipment within the penstock for the recoating work, not on any safety risks inherent with the work, such as with using a flammable within a confined space, nor on any steps taken to mitigate those risks, such as ensuring fire extinguishers are located within close proximity to the sprayer system. Instead, the employees reported that the focus that day was solely on getting the epoxy on the walls.

In addition to the work delays and schedule pressures, RPI employees reported that the company used unofficial financial incentive programs – both in the past and in this recoating project – to ensure that work was completed in a timely manner. A number of the survivors asserted that if the crew finished the project on time or earlier than scheduled, the general foreman would receive a financial bonus. Some contractors stated that the general foreman would share the bonus with the hardest working members of the crew. Employees testified that this incentive was based purely on the timeliness of work completion. Incentive programs like these are common in many workplaces; however, attention must be given to ensure that such rewards do not have unintended negative consequences, such as a decline in work quality or safety in order to ensure on-time work progress (Hopkins, 2005, p.51 – 60; Hopkins, 1999, p.13 and 94).

5.2 Incident Events

The use of solvent within the confined space of the penstock to clean the sprayer created a flammable atmosphere. A static spark most likely ignited the flammable atmosphere within the sprayer hopper, resulting in a flash fire that quickly intensified as additional solvent and the combustible epoxy surrounding the sprayer ignited. The rapid spread of fire and toxic smoke from burning epoxy prevented the workers uphill of the sprayer from exiting through the penstock's only egress point, resulting in their deaths.

5.2.1 Unsafe Sprayer Flushing Method Contributed to a Flammable Atmosphere

On October 2, the contractors flushed the entire sprayer system with MEK while it was still within the penstock's confined space, creating a flammable atmosphere within the work area. Flushing the sprayer system with solvent outside the penstock could have avoided creating this flammable atmosphere, as none of the equipment, with the exception of the mixing block itself and the hoses going to the spray wands, required immediate flushing with a solvent. It is only when the hardener and base epoxy components are combined that they react with each other and solidify (Section 4.1.7). The potential for a flammable atmosphere to develop would have been greatly reduced, had the solvent only been used to flush the mixed epoxy material from the hoses extending from the mixing block to the spray wands.

5.2.2 Most Probable Ignition Source

The CSB concluded that the fire inside the penstock was most likely ignited by a static spark that originated from the electrically isolated (ungrounded) metal swivel connector attached to one end of the non-conductive hose being handheld inside the base hopper of the sprayer as MEK was being flushed through (Appendix D.1). The CSB calculated that the MEK concentration in the vapor surrounding the metal swivel connector was between 7.6 and 9.1 volume percent, which is well within the flammable limits of 1.8 and 11 volume percent, based on the MEK vapor-liquid equilibrium concentration adjusted for penstock environmental conditions (Appendix E). The CSB determined that the MEK circulation flow through the sprayer was likely capable of developing a charging current, accumulating stored energy on the electrically isolated metal swivel connector and producing incendiary sparks of sufficient magnitude to ignite the flammable MEK vapor (Appendix F).

While the CSB determined that a static spark was the most probable ignition source, two other potential ignition sources could not be completely ruled out:

- An electrical arc produced inside the base hopper by a stray current inside the sprayer system (Appendix D.2), or
- Autoignition of flammable MEK vapor by the hot bulb of the portable halogen lights positioned above the sprayer (Appendix D.3)

Fire damage to the sprayer and associated equipment precluded the CSB from completely dismissing a stray current arc as the ignition source. The two electrical discharge ignition scenarios (static spark and stray current arc) are similar with respect to the location of the spark (metal swivel connector attached at the end of the hose) and vapor composition constraints limited to the base hopper. However, since a static spark requires a non-conductive hose and a stray current arc requires a conductive hose, these two electrical discharge mechanisms are mutually exclusive. Available evidence indicates that the base hardener hose was constructed from a non-conductive (nylon) material and the end connector was attached without any internal electrical bonding.

Conflicting testimony and fire damage to the sprayer's heaters and control panel also meant that the CSB could not conclusively verify whether the MEK was being heated as it circulated through the sprayer at the time the fire occurred. Thus, the CSB could not totally eliminate the possibility that the MEK temperature was hot enough to develop a flammable atmosphere above the sprayer, where the hot bulb surface from the portable halogen lights could have caused autoignition of the flammable MEK vapor. However, witnesses stated that the fire originated inside the base hopper and the CSB considered it unlikely for the fire to have been ignited at the halogen lights with a flame front traveling back to the hopper without being observed.

Three additional ignition scenarios were evaluated and eliminated as probable ignition sources: hot surface ignition by the sprayer heater(s) (Appendix D.4); compression ignition inside one of the sprayer piston pumps (Appendix D.5); or electrical spark from the heater control box (Appendix D.6). In summary, although either autoignition by the halogen bulb or a stray current arc were both possible ignition sources, evidence suggests that the most likely ignition source was a static spark between the metallic end connector on the non-conductive hose and the wall of the hopper.

To reduce the risk of fire or explosion, fire safety measures should employ protections aimed at eliminating at least two legs of the fire triangle [37]: oxygen, fuel, and ignition source (Scarbrough, 1984, pp.521-552). Potential ignition sources are often difficult to identify and control in situations where flammable liquids are being used. Because oxygen is normally present and difficult to remove, especially when people need to employ or interact with equipment that uses flammable liquid, fire safety measures stress the need to keep concentrations of flammable vapors well below the LEL[38] to prevent flash fires and explosions. This is especially important in a confined space where the number of air changes can be

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[37] The fire triangle is a concept used to explain the three conditions – heat, fuel, and oxygen – that must be present for combustion.

[38] LEL is defined as "that concentration of combustible material in air below which ignition will not occur." "Recommended Practice for Handling Releases of Flammable and Combustible Liquids and Gases, NFPA 329 (2005). The terms lower explosive limit (LEL) and lower flammability limit (LFL) have different definitions but are commonly used interchangeably. This report will use LEL except where citing other sources that use LFL in their standard or regulation. The OSHA Permit-Required Confined Space Standard 29 CFR 1910.146 uses the term LFL in its provisions.

limited, causing flammable vapors to quickly concentrate. In this incident, a lack of fire safety measures to control or eliminate the concentrations of flammable vapors being generated during the flushing operation resulted in the penstock fire igniting when a suitably energetic ignition source appeared.

5.2.3 Flash Fire Becomes Sustained Toxic Fire, Trapping Workers

Approximately 16 gallons (61 liters) of MEK and at least 30 of the 95 buckets of epoxy[39] were destroyed in the fire. The initial flash fire involved only the solvent being used directly within the hopper; however, the large amount of solvent surrounding the sprayer, as well as numerous buckets of epoxy hardener and base, caused the flash fire to grow into a sustained, intense toxic fire.

Neither the MEK nor the epoxy components needed to be in the penstock in such large quantities. The amount of solvent required to flush the lines from the mixing block to the spray wands was significantly less than what was needed to clean out the entire sprayer system.

Had the decision been made to remove the sprayer from the penstock prior to flushing – a decision that should have been made by management prior to any onsite activities related to the penstock recoating project – the creation of a flammable atmosphere likely would have been avoided. And, had there not been additional MEK in buckets surrounding the sprayer, the initial flash fire likely would not have intensified. Finally, the subsequent ignition of the combustible epoxy components turned the growing fire into a toxic one.[40] This sustained fire prevented the trapped contractors from climbing around the sprayer. They had no choice but to run up the penstock, away from the burning products and their only exit.

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[39] Because the fire burned many of the plastic buckets, leaving only the metal handles, it was impossible to discern if these melted buckets were 2-gallon hardener or 5-gallon base buckets. Therefore, a more precise quantity (in gallons) of epoxy burned in the fire could not be determined.

[40] The MSDS for the epoxy hardener states that "heat and fire can generate toxic or irritating decomposition products that may cause a health hazard. Sudden reaction wand [sic] fire may result if product is mixed with an oxidizing agent" (Duromar HPL-2510 Hardener, 7/2/2007). The MSDS for the epoxy base states that "heat from fire can generate flammable vapor and decomposition products that may cause a health hazard." The base is also noted as a "known human carcinogen" (Duromar HPL-2510 Base, 3/21/2007).

6.0 Confined Space

The penstock recoating project was hazardous in that introducing and using flammable and toxic chemicals within a confined space presents numerous safety risks. The unique features of the penstock, including its extensive size and lack of a secondary point of egress, amplified the danger. Extensive and detailed pre-job safety planning was needed to evaluate and address the hazards inherent in this maintenance work.

The CSB concluded that Xcel, RPI, and KTA initially recognized the Cabin Creek penstock as a permit-required confined space, but did not treat it as such during the penstock project. As a result, the companies did not effectively coordinate and plan to control the hazards inherent in the recoating work. Nor did RPI re-evaluate the hazards when working conditions changed inside the penstock, such as the introduction of flammable MEK into the work area. Xcel's and RPI's lack of sufficient planning and coordination for the hazardous recoating work within the confined space was causal to the incident.

6.1 Penstock is a Permit-Required Confined Space

The Cabin Creek penstock is a permit-required confined space, as defined by OSHA: it is large enough and so configured that an employee can bodily enter and perform assigned work, it has limited or restricted means for entry or exit, and it is not designed for continuous human occupancy [29 CRF 1910.146(b)]. The penstock's 12-foot (4-meter) diameter space is large enough for workers to enter and work inside; entry and exit are feasible only through the temporary 4 by 4-foot (1.2 by 1.2-meter) opening cut at the lower end and, when generating hydroelectric power, the penstock is full of flowing water. The penstock also meets an additional criterion: it "contains or has the potential to contain a hazardous atmosphere," making it not just a confined space, but a *permit-required* confined space [29 CRF 1910.146(b)]. A hazardous atmosphere, as defined by the OSHA Permit-Required Confined Spaces

Rule,[41] is one that may expose employees to the risk of death; incapacitation; impairment of ability to self-rescue; injury; or acute illness from flammable gas, vapor, or mist in excess of 10 percent of its lower flammability limit (LFL).[42] OSHA requires employers to evaluate their workplace to determine if any confined spaces meet the criteria for a permit-required confined space [29 CFR 1910.146(c)(1)]. Despite initial recognition that the penstock was a permit-required confined space, neither Xcel nor RPI treated the penstock as a permit-required confined space while the recoating work was being conducted.

6.1.1 Initial Evaluation of the Confined Space Indicated a Permit-Required Program was Necessary

In early 2007, an Xcel safety consultant, at the request of the penstock recoating team, prepared the "Safety and Health Hazard Assessment Survey" for abrasive blasting inside the penstock, which lists confined space entry as one of the potential health hazards associated with the recoating work, in conjunction with applying epoxy or other surface coatings. The survey states that "a confined space air monitor is required," which is a key safety requisite in a permit-required confined space program. While this document was made part of the bid package and sent to potential contractors, Xcel did not implement a permit-required confined space program or issue permits for its personnel who entered the penstock on numerous occasions for inspection and maintenance.

In addition, a KTA inspector completed a separate "Initial Pre-Job Hazard Assessment," which it submitted to Xcel on September 24, 2007, for abrasive blasting inside the penstock, explicitly indicating that the penstock was a permit-required confined space.

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[41] In addition, the OSHA Permit-Required Confined Space rule states that these risks follow from one or more of the following causes: (1) flammable gas, vapor, or mist in excess of 10 percent of its LFL; (2) airborne combustible dust in a concentration that meets or exceeds its LFL; (3) atmospheric oxygen concentration below 19.5 percent or above 23.5 percent; and/or (4) atmospheric concentration that could result in employee exposure in excess of its dose or permissible exposure limit.

[42] The terms LEL and lower flammability limit (LFL) have different definitions but are commonly used interchangeably. This report uses LEL except where citing other sources that use LFL in their standard or regulation. The OSHA Permit-Required Confined Space Standard 29 CFR 1910.146 uses the term LFL in its provisions.

RPI wrote a number of partially completed confined space permits with air monitoring logs between September 11 and October 2, 2007, where the crew indicated that continuous air monitoring was required inside the penstock—another element of a permit-required confined space program.[43,44]

Although Xcel, RPI, and KTA acknowledged that elements of a permit-required space were necessary for the penstock work, the companies did not take the steps necessary – and required by OSHA – to manage the risks inherent in the space.

6.1.2 The Known Work Activities in the Penstock Necessitated a Permit-Required Confined Space Program

The potential atmospheric hazards related to future work activities in the penstock known to Xcel and RPI during the early stages of the penstock recoating project should have triggered the application of a permit-required confined space program. These potential atmospheric hazards in the confined space included

- High carbon monoxide (CO) levels that caused air monitors to alarm and required the penstock to be briefly evacuated;
- Fumes created from welding conducted inside the penstock by an Xcel employee on two occasions;
- Irritating dust and breathing hazards created by abrasive blasting; and
- Flammable vapors generated while using MEK to flush and clean the sprayer.

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[43] The logs typically listed only the gas detector readings for oxygen written on a page taken from RPI's multipage confined space permit form. No other pages of the permit form were completed

[44] Even number of the unsuccessful bidders for the penstock recoating project identified the penstock as a permit-required confined space in their submissions to Xcel. A proposal from a prospective bidder on the recoating project stated that the penstock would be considered a permit-required confined space when certain activities were undertaken, such as abrasive blasting, abrasive cleanup, and epoxy application.

6.1.3 Permit-Required Confined Space Inadequately Declassified

Once work began at Cabin Creek, Xcel, RPI, and KTA treated the penstock as a *non*-permit-required space; however, the companies did not take the OSHA-required steps to formally declassify the penstock to a non-permit confined space. Indeed, had they taken the requisite steps to attempt to declassify the penstock, they would have determined that the penstock space could not have been safely declassified.

OSHA's Permit-Required Confined Spaces Rule states that if an employer wishes to reclassify a permit-required confined space as a non-permit confined space, the employer must develop monitoring and inspection data demonstrating that the space poses no actual or potential atmospheric hazards, and this data must be documented by the employer [29 CFR 1910.146(c)(7), 1910.146(c)(7)(i), 1910.146(c)(5)(i)(F)]. Additionally, the employer is required to "document the basis for determining that all hazards in a permit space have been eliminated, through a certification that contains the date, the location of the space, and the signature of the person making the determination" [29 CFR 1910.146(c)(7)(iii)]. Neither RPI nor Xcel provided the CSB with a documented basis for declassifying the penstock space as non-permit required.

More important, the penstock's unique size – more than 4,000 feet (1200 meters) long – makes it an exception in the Permit-Required Confined Spaces Rule for declassifying a space. The rule states that "if isolation of the space is infeasible because the space is large or part of a continuous system (such as a sewer), pre-entry testing shall be performed to the extent feasible before entry is authorized and, if entry is authorized, entry conditions shall be continuously monitored in the areas where authorized entrants are working" [29 CFR 1910.146(d)(5)(i)]. The American Public Power Association (APPA), an industry organization for public utilities – of which Xcel is not – instructs its member organizations as follows: "If a hazard increasing work activity is to take place in a confined space (i.e., welding, painting, working with solvents and epoxy), the air in the space shall be continuously tested for the presence of flammable or toxic gases and vapors or insufficient oxygen" (APPA, 2007).[45]

The expansive size of the penstock required continuous monitoring at the location of the work, which at the time of the incident was 1,450 feet (442 meters) from the access door; this continuous monitoring within the penstock was not being performed by the RPI crew, the KTA inspector, or any Xcel personnel. The penstock's large size and the companies' lack of documented basis for declassifying the space require it to be treated as a permit-required confined space.

6.2 Lack of Pre-Job Safety Planning for Hazards

Despite a lengthy period of over one year devoted to pre-job safety planning for the recoating project of the Cabin Creek penstock, the CSB noted that serious hazards identified by the Xcel recoating project team and RPI management were not addressed before work began (Section 4.1).

In early 2007, Xcel completed the "Safety and Health Hazard Assessment Survey" for the recoating project; however, this assessment was incomplete, as it considered only the high pressure abrasive blasting work, not the recoating of the penstock interior (Section 4.1.1). As a result, the fire potential due to the use of solvents within the confined space of the penstock was not evaluated.

As an experienced contractor and the seventh-largest specialty paint company in 2005, RPI would be reasonably expected to understand the need for safety during relining operations in confined spaces (Engineering News-Record, 2005). Indeed, documents from the RPI bid and safety program reveal that the company was aware of the potential hazards posed by the penstock itself and those created when performing spraying operations inside it. The RPI bid contained several references to prior projects where similar safety issues to that of the penstock were encountered, including limited access in confined spaces

[45] Although APPA is an industry association for public utilities, which Xcel is not, the good practice guidance APPA publishes is useful to both public and private utility groups.

that created "inherent risks." RPI stated in its bid submission to Xcel that it handled these risks by providing training; confined space watch personnel; and emergency equipment, such as breathing apparatus and extraction devices. Whether these safety actions were actually implemented in the prior projects is unclear; however, that RPI listed them as precautionary steps taken in previous projects speaks to the company's familiarity with managing the hazards. Yet, training was less than adequate (Section 9.0), and no emergency breathing apparatuses were provided to the work crew at the penstock.

A KTA project engineer sent a review of RPI submittals[46] for the penstock recoating project to the Xcel Reline Project Team Leader. The RPI coating application plan clearly states that the sprayer would be brought inside the penstock. The product-specific application procedures for the epoxy describe the short working time after the base and hardener are mixed and the need to flush the sprayer with a solvent before introducing the epoxy into the system and to clear any blockages as necessary in the spraying equipment during use. Based on his review, the KTA project engineer recommended including eight additions and clarifications to the contract between Xcel and RPI, three of which had safety implications.[47] Yet the project engineer made no recommendations to Xcel concerning safeguards that would need to be employed if flammable solvents were used to flush the sprayer inside the penstock (such as ventilation and explosion-proof lights), nor did he provide recommendations for use of safer (e.g., nonflammable) solvents for flushing the sprayer. Xcel also had its own employees review the RPI bid submission documentation, but no actions were taken to manage the hazards associated with using flammables within a confined space.

[46] KTA reviewed a number of RPI's bid documents, including a surface preparation and coating application plan, a project schedule, product-specific application procedures, and product data sheets for the two-part epoxy material.

[47] The three additions that had potential safety implications were the need (1) for adequate heating inside the penstock, (2) to ensure the bulkheads were fitted with manways, and (3) to install strung lighting supplemented with spotlights.

In the September 5, 2007, preconstruction meeting, Xcel and RPI management and safety personnel discussed the need for additional safety precautions for the recoating project. Handwritten notes on an agenda in the files of the Xcel safety director indicate that both a safety addendum to the contract (Section 8.2.1) and the need to enforce Xcel's "Stop Work Authority" policy during the recoating project were discussed. Additionally, the Xcel safety director's handwritten notes indicate his recognition of the need for an external rescue team during the penstock work.

Months prior to the incident, the Xcel penstock recoat project leader emailed a power plant engineer and the Xcel plant manager stating that the contractors involved in the penstock work were requesting information concerning the site's confined space entry procedures, whether the air was being monitored, and who was responsible for the monitoring. The project leader received a reply email from the Xcel plant manager that this information would be covered in contractor orientation. This brief orientation – consisting of a 30-60-minute checklist review of potential hazards – was held on three separate occasions, led by different Xcel personnel and attended by various members of the crew. During one of the sessions, the Xcel employee leading the orientation did learn that RPI would be using a "ketone" solvent to clean the sprayer inside the penstock, but even after the incident he stated he was unaware if Xcel had received a copy of the solvent MSDS before epoxy application began.

6.3 No Monitoring Plan Established

Neither Xcel nor RPI had a monitoring plan established for safe entry and work inside the penstock. The OSHA Permit-Required Confined Spaces Rule discusses appropriate procedures for atmospheric testing to include evaluating the atmospheric hazards of the permit space that may exist or arise so that both entry procedures and safe entry conditions are clearly stipulated in advance of conducting work [29 CFR 1910.146] (Appendix B). Recommended practices for monitoring potential flammable atmospheres suggest that any company performing atmospheric monitoring should implement a "written, established protocol that describes the sampling procedures, sampling locations, and required sample collection time" (Levine, 2004, pp.35). Because hazardous gases or vapors may be stratified within the atmosphere, the location of air monitoring can significantly impact a worker's ability to determine if a flammable atmosphere exists. Additionally, the sampling procedures should address if continuous atmospheric testing is necessary. Criteria for determining this need includes work spaces with the potential for changes in work activities that "may affect the composition, concentration, flow rate or volume, pressure and/or temperature of flammable liquids, vapors or gases" or changes in "ambient conditions such as temperature, wind direction and wind speed" (Levine, 2004, p.36). Both of these factors were present in the penstock recoating work environment the day of the incident.

However, interviews with surviving RPI employees revealed that the atmosphere was not monitored continuously in the work area inside the penstock. Instead, readings were taken only two to three times per day at the penstock entrance by the RPI attendant, which did not meet the OSHA Permit-Required Confined Spaces Rule requirement for continuous monitoring of entry conditions in the areas where authorized entrants are working if the permit space is large, or part of a continuous system, and where isolating the space is infeasible [29 CFR 1910.146(d)(5)(i)]. While this monitoring requirement is related to the size of the space and not to the specific hazard of using a flammable solvent in the confined space, RPI was nonetheless required to continuously monitor the work area in the penstock.[48]

6.4 No Evaluation of Hazards When Conditions Changed

When work conditions inside the penstock changed from blasting to recoating, Xcel or RPI should have re-examined the space for new hazards, as per the OSHA Permit-Required Confined Spaces Rule.[49] As listed in 6.1.2, the CSB noted that RPI workers experienced a number of potential hazardous atmospheric

[48] Post-incident, OSHA issued a willful violation to RPI Coating ($63,000 proposed penalty) [OSHA, March 21, 2008, inspection 310470034, citation 2(9)] and serious violations to both Xcel and KTA ($4,500 proposed penalties, each) [OSHA, March 21, 2008, inspection 310470059, citation 1(9) and inspection 310470083, citation 1(6), respectively] for not continuously monitoring the air during the penstock recoating project.

[49] The Rule states: "When there are changes in the use or configuration of a non-permit confined space that might increase the hazards to entrants, the employer shall reevaluate that space and, if necessary, reclassify it as a permit-required confined space" [29 CFR 1910.146(c)(6)] and certify it through the required documentation [29 CFR 1910.146(c)(7)(iii)].

conditions within the penstock, including dust from abrasive blasting, flammable atmospheres from the use of solvents, welding fumes from hot work, and accumulation of toxic carbon monoxide from the use of an ATV with an internal combustion engine. Each time one of these hazards was introduced or encountered in the confined space, the permit should have been updated to accurately reflect the hazard(s) and the appropriate safeguards to protect the entrants and ensure that acceptable entry conditions were maintained. But neither RPI nor Xcel reassessed the hazards as conditions changed, thus these hazards were unmanaged.[50]

6.5 Safer Solvent Not Chosen

As the application procedures supplied to both Xcel and RPI made clear, the use of the sprayer inside the confined space required the use of a solvent to flush and clean the sprayer, which would occur in the open atmosphere of the penstock at least daily, given the project work schedule. Flammable MEK was chosen as the solvent for the penstock recoating project.

Bringing a flammable into a confined space to use in the open atmosphere increases the likelihood of a potential fire because it adds the second of the three conditions required for combustion: fuel, oxygen, and an ignition source – oxygen was already present in the penstock. Fire risk is significantly heightened because ignition sources can be difficult to identify and control where flammable liquids are being used. These hazards were not adequately assessed when MEK was chosen as the penstock recoating project solvent.

6.5.1 The Hazards of MEK

MEK is an organic chemical compound often used as a solvent in painting and industrial recoating activities. MEK is listed by the National Institute for Safety and Health (NIOSH) as “highly flammable”

[50] The CSB also noted that none of the forms were filled out completely and only portions of forms were retained for some dates.

(NIOSH, 1998). MEK is a Class IB Flammable Liquid, with a flash point below 73 °F (23 °C) and boiling point at or above 100 °F (38 °C) (NFPA 704, 2007b, Table 6.2; NIOSH, 1998).

As a highly flammable liquid, MEK poses significant hazards if used in a work area and the safety risk potential increases dramatically when the location of work is within a confined space. The epoxy application procedure specifically highlights the flammability risk involved with the use of MEK,[51] as do the MSDSs Xcel and RPI provided to the CSB.[52,53]

As part of its investigation, the CSB conducted a brief review of available MSDSs on MEK and found a number of MSDSs with warnings that the product should not be used in confined spaces.[54] The MEK MSDSs – including the MSDS Xcel provided to the CSB[55] – warn that MEK vapors may cause a flash fire or ignite explosively, and that the solvent's vapors may travel considerable distance to a source of ignition and flash back.[56] The MSDSs instruct the user to "prevent buildup of vapors or gases to explosive concentrations."[57] The various MSDSs also warn that MEK is sensitive to static discharge, so containers of the solvent should be bonded and grounded for transfer to avoid static spark.[58]

[51] The procedures states in capital bold letters that MSDSs should be consulted and "proper fire and ventilation procedures should be followed.

[52] The MSDS provided by Xcel states, "DANGER! EXTREMELY FLAMMABLE LIQUID AND VAPOR. VAPOR MAY CAUSE FLASH FIRE" (emphasis in original), and the MSDS RPI provided to the CSB also states that MEK is "EXTREMELY FLAMMABLE…vapors will accumulate readily and may ignite explosively" (emphasis in original).

[53] According to RPI, this MSDS was sent via fax to the Cabin Creek site by the company post-incident; it was provided to the CSB upon subpoena request in July 2008.

[54] Carboclor MSDS on MEK, June 2008; Sunnyside Corporation MSDS on MEK, 1/12/06; RAW Chemical Distribution Limited MSDS on MEK, 11/11/02; Linchem, Ltd. MSDS on MEK, 9/10/02.

[55] Mallinckrodt Baker, Inc. MSDS on MEK, 8/17/05 (retrieved online by Xcel Energy on 10/12/07 from www.jtbaker.com/msds/englishhtml/M4628.htm).

[56] Sunnyside Corp. MSDS on MEK, 1/12/06; RAW Chemical Distribution Limited MSDS on MEK, 11/11/02; Linchem, Ltd. MSDS on MEK, 9/10/02.

[57] Sunnyside Corp. MSDS on MEK, 1/12/06; RAW Chemical Distribution Limited MSDS on MEK, 11/11/02.

[58] Mallinckrodt Baker, Inc. MSDS on MEK, 8/17/05; Sherwin-Williams Co. MSDS on MEK, 10/2/07; Sunnyside Corporation MSDS on MEK, 1/12/06.

Despite the warnings within the MSDSs about MEK's extreme flammability and RPI's own safety policies that require flammable liquids to be stored and handled in safety cans,[59] 2- and 5-gallon (7.6 and 19 liters) plastic buckets were used to transport and store MEK solvent in the penstock. One open 5-gallon (19 liter) plastic bucket of MEK was placed under the solvent pump of the sprayer to supply solvent to the mixing block. After using MEK to clean out the spray wands, the 5-gallon (19 liters) plastic buckets of used solvent were left opened adjacent to the sprayer system instead of removed from the work area. Approximately 6 additional gallons (23 liters) of MEK were brought into the penstock in 2-gallon (7.6 liter) plastic buckets specifically to flush and clean the sprayer system immediately prior to the incident. Additionally, the MEK solvent was transferred from a 55-gallon (208 liter) drum in the storage trailer, hand-carried into the penstock, and stored in plastic buckets around the work area; these buckets were reportedly not covered when inside the penstock prior to and during the solvent cleaning process.

6.5.1.1 Evidence that Xcel and RPI Knew that MEK would be Used

While Xcel has disputed its knowledge of the use of MEK in the penstock recoating project, from the totality of evidence – including the fact that the Xcel project scheduler stated he was made aware that RPI would be using a "ketone" during the recoating work – the CSB has concluded that Xcel was aware of the use of flammable solvent in the penstock, and that both companies were aware that MEK solvent would be used during the epoxy application process.

Xcel sent all potential bidders for the penstock recoating project the document "Surface Preparation and Repainting of Interior of the Cabin Creek Penstock" prepared by KTA and reviewed by a number of Xcel employees involved in the penstock project planning, which states that a solvent would be used within the

[59] RPI's "Fire Protection and Prevention" policywithin its IIPP, as well as several others requires all flammable liquids to be stored and handled in safety cans. A safety can, as defined in the IIPP, is an approved container of not more than 5 gallons capacity, having a flash arresting screen, spring closing lid and spout cover.

penstock for initial cleaning of the surface, and instructs the bidders on appropriate storage methods for solvents and thinners during the project.

As part of its bid submission package to Xcel, RPI provided the three-page “Surface Preparation and Application Guide” from the manufacturer of the two-part epoxy product, that also referenced the need for a solvent for cleaning purposes. During the bid evaluation and selection process, this contractual documentation was reviewed by numerous management and safety personnel from both companies.

In August 2007, RPI’s vice president provided the Xcel Cabin Creek project manager with the more detailed epoxy “Specification and Application Procedures,” which discusses the use of solvents in the recoating process several times.[60]

Once RPI was onsite, evidence of the planned use of MEK within the penstock was witnessed by workers and supervisors from both companies. On September 12, 2007, 110 gallons (416 liters) of MEK [two 55-gallon (208 liters) drums] was delivered to the Cabin Creek site and signed for by an RPI crew member. According to testimony of the crew, the Xcel principle engineer and project scheduler witnessed the delivery of the MEK and confirmed with the crew that it was the solvent being delivered.

That same day, RPI conducted a test spray with the epoxy products and solvent on the Xcel Cabin Creek site. Five gallons of MEK were purchased for the test spray and used afterward to clean the equipment. The Xcel principle engineer was present during these activities and signed off on the invoice for the solvent and epoxy.

[60] The procedure document instructs that, upon initial setup, “solvent should be flushed through the line to check for any foreign matter, leakages, or blockages.” These procedures state that if blockages or other stoppages occur, “immediately shut off the heater, and place a clean bucket of solvent underneath the pump and flush the lines.” It goes on to state that merely spraying the material will build pressure and cause the epoxy product to begin to set; as a result, the user is instructed to “flush solvent through the system” and “re-circulate solvent until the pump and lines are clear.” Finally, the procedures provide guidance about cleanup: “Any mixing and application tools should be immediately wiped or scraped clean. Any residue can be removed with a solvent, such as 1,1,1-trichloroethane, MEK or an appropriate blend.”

6.5.2 Safer Alternatives

None of the companies considered safer alternatives to the flammable MEK, nor did they identify work tasks involving the solvent that could have been performed outside the penstock.

One significantly less hazardous option is a citrus-based solvent, a variety of which are available for industrial purposes and are often biodegradable, non-toxic, and have significantly higher flash-points than flammable solvents like MEK.[61] ANSI Z117.1, "Safety Requirements for Confined Spaces" recommends that the hierarchy of controls be followed to address confined space hazards [ANSI Z117, 2009, p.17]. Using this method of hazard control, primary consideration is given to eliminating the hazard or using engineering controls such as substitution; for instance, using less hazardous, non-flammable substitute solvents for the highly flammable MEK.

Another more effective safety approach within the hierarchy of controls would have been to conduct the work outside the confined space.[62] In the Cabin Creek penstock incident, while the hoses from the mixing block to the spray wands required immediate flushing due to the mixing the two-part epoxy, the sprayer itself did not need to be cleaned inside the confined space.

6.6 Xcel's and RPI's Confined Space Policies

Xcel's and RPI's corporate confined space policies in effect prior to the incident did not effectively establish safe limits for flammable atmospheres that would prohibit entry or occupancy when the limits were exceeded. Xcel's corporate confined space policies did not effectively establish acceptable entry conditions for flammable atmospheres as a specific percentage of the LEL, nor did they provide explicit

[61] A less flammable, but still hazardous, option is 1,1,1-trichloroethane. This organic compound has a history of use as a solvent within the industrial painting industry; however, its use has lessened due to its toxicity. The manufacturer of the two-part epoxy used in the penstock recoating project has communicated that several non-flammable solvents would be effective for cleanup activities, including n-Propyl Bromide and citrus-based products.

[62] The United Kingdom Confined Spaces Regulation [Statutory Instrument 1997, No. 1713] imposes the duty of first avoiding entry into the confined space by conducting the work outside the space, unless entry is unavoidable.

warnings to prohibit entry or occupancy based upon a specified flammable atmosphere limit. Xcel's confined space permit form allowed entry even when "atmospheric and/or serious hazards in the space that cannot be controlled or eliminated" were present, if certain unspecified precautions were being implemented. The confined space entry policy in effect at the time of the incident of Northern States Power Company, a subsidiary of Xcel, however, provides effective specific entry and occupancy limits for flammable atmospheres. The policy establishes 10 percent of the LEL as an alarm point and states: "If the air monitor alarms all entrants shall immediately evacuate the space." After the Cabin Creek incident, Xcel revised its confined space policy with improvements that designated greater than 10 percent of the LEL as an "alarm limit." However, the new policy does not explicitly prohibit entry or occupancy based upon the alarm limit, unlike the Northern States' policy.

RPI's confined space entry policy and permit provided to Xcel as part of the contractor selection process did not provide for safe entry and occupancy limits or effectively prohibit entry when those limits were exceeded. Neither the policy nor the permit defined a hazardous atmosphere or provided for acceptable confined space entry conditions.

The failure of Xcel's and RPI's confined space policies to establish safe flammable limits undermines the importance of monitoring in permit-required confined spaces; the need for periodic or continuous monitoring will not be effectively communicated to managers and workers if no limits are specified. This safety gap can also lead to a failure to address the serious hazards of flammable atmospheres, as was the case in the Cabin Creek penstock.

7.0 Emergency Response and Rescue

The CSB determined that the flash fire inside the penstock occurred at approximately 1:55 p.m. and the 9-1-1 call was placed at 2:03 p.m.. While the initial emergency responders arrived at the Cabin Creek site in less than 10 minutes from the dispatch notification, the first community emergency responder capable of performing a confined space rescue operation, West Metro Fire Rescue, did not enter the property for more than an hour and a half after the fire started due to their distant location. The trapped workers likely succumbed to smoke inhalation about one hour prior to West Metro's arrival. An immediately available qualified confined space technical rescue provider likely would have been able to effectively control the fire and prevent the worker fatalities. However, no such rescuers were immediately available outside the penstock on the day of the incident.

The lack of competent technical rescue services at Cabin Creek was the result of:

- Xcel's and RPI's lack of a competency evaluation of available confined spaces rescue services, as required by the OSHA Permit-Required Confined Spaces Rule;
- The failure of Xcel and RPI to identify the life-threatening hazards of using flammable solvents in the penstock and arrange for immediately available emergency response services onsite prior to the start of the epoxy application.

As a result of not evaluating the competency of available emergency service providers to perform permit-required confined space rescue, nor arranging for emergency response support to be onsite prior to the start of the penstock work activities, neither Xcel nor RPI were prepared to handle a confined spaces emergency such as they experienced on October 2, 2007. And because the first responders to the incident were voluntary firefighters without the training or qualifications to peform permit-required confined space rescue, no one was immediately available and capable to successfully enter the penstock to rescue the trapped workers. The CSB also notes that alternative egress and/or safety chambers were not provided in the penstock and the State of Colorado lacked a training and certification program for technical rescuers including confined space technical rescue.

7.1 Lack of Preparation by Xcel and RPI to Ensure Availability of Qualified Rescue Personnel

The OSHA Permit-Required Confined Spaces Rule [29 CFR 1910.146(k)] requires the employer to either arrange for a competent outside rescue and emergency services provider, or ensure that its employees can perform rescue and emergency services competently when they are working within a permit-required confined space. However, RPI and Xcel did neither.

The emergency response and rescue preparation conducted by Xcel and RPI ineffectively consisted of instructing RPI personnel that, in the event of an emergency inside the penstock, 9-1-1 would be called by Xcel personnel. On October 2, 2007, this was the emergency response step taken. Unfortunately, the first and closest emergency responders arriving at the Cabin Creek site were not prepared for entry into the penstock's confined space. Approximately less than 10 minutes after the 9-1-1 call, the first community emergency responder to arrive onsite was the Clear Creek County Sheriff's office, who established the Incident Command. Several volunteer Clear Creek County Fire Authority (CCFA) emergency medical and firefighters arrived next, but none of these responders had the necessary equipment or training to extinguish the fire in the penstock or initiate a rescue of the trapped RPI personnel.[63] Additionally, the fire service organizations had no pre-knowledge of the hazards of the chemicals onsite, their quantities, or locations. The site was not pre-equiped with appropriate firefighting equipment specific to the unique hazards of the penstock. Such planning and communication should have been implemented with designated emergency responders in advance of any recoating work being conducted withtin the penstock.

[63] This was noted by the Xcel control room operator, who added the following entry in the control room logbook: "14:20 Emergency services w/out confined space fire training – they have summoned a Denver team."

When an employer chooses to rely on an outside rescue and emergency service, the OSHA Confined Spaces Rule requires the employer to evaluate the service's ability, in terms of proficiency with rescue-related tasks and equipment, to function appropriately while rescuing entrants from the particular permit space or types of permit spaces identified [29 CFR 1910.146(k)(1)(ii)]. However, neither Xcel nor RPI evaluated CCFA's or other nearby responders technical capabilities.

Had Xcel and RPI arranged for a competent outside rescue and emergency services provider prior to beginning work inside the penstock and supplied the provider with pertinent information about the chemicals being used within the confined space, the first responders to the incident would likely have been prepared for entry, firefighting, and rescue activities.

7.2 Failure by Xcel and RPI to Arrange for Timely Rescue

Local fire service officials told the CSB that any attempted rescue of the trapped RPI workers could have been successful only with sufficient numbers of responders and the appropriate equipment immediately available onsite to fight a fire that was more than 1,450 feet (442 meters) inside the penstock.

The OSHA Permit-Required Confined Spaces Rule requires that emergency response be timely, based on the specific hazards involved in the entry. According to a December 9, 2003, settlement agreement between OSHA and the American Petroleum Institute (API), a "timely" response to a confined space emergency depends on the hazards the entrants may face. If entrants encounter hazards that are deemed potentially Immediately Dangerous to Life and Health (IDLH), [64] a rescue team must be stationed outside the confined space and ready for immediate entry. The use of MEK inside the penstock created the

[64] IDLH or Immediately Dangerous to Life or Health, is a personal exposure limit for a chemical substance set forth by the National Institute of Occupational Safety and Health (NIOSH); it is typically expressed in parts per million (ppm). OSHA's Permit-Required Confined Spaces rule for general industry states that IDLH "means any condition that poses an immediate or delayed threat to life or that would cause irreversible adverse health effects or that would interfere with an individuals ability to escape unaided from a permit space" [29 CFR 1910.146(b)].

potential for a flammable atmosphere and life-threatening conditions in the event of an ignition, especially when coupled with a single exit for evacuation.

An immediately available rescue and response team is especially important for a worksite like Cabin Creek, which is situated in a remote mountainous location where timely response would be extremely difficult.

Depending on the road conditions, vehicle type, and speed, driving the 5.5 miles (8.9 kilometers) from the Georgetown fire station – the closest community emergency response facility – to the Cabin Creek hydroelectric plant takes between 10 and 30 minutes. At the time of the incident, the only improved road to the site, Guanella Pass, was steep, narrow, and winding (Figure 11). This road had no guardrails, was partially unpaved with loose gravel and potholes, and has many hairpin turns that made it hazardous to drive at speeds above 20 miles an hour (32 kilometers per hour).[65]

[65] CCFA personnel told the CSB investigators that the turns were so tight that one of their fire support vehicles had to completely stop and back up several times to navigate through the turns.

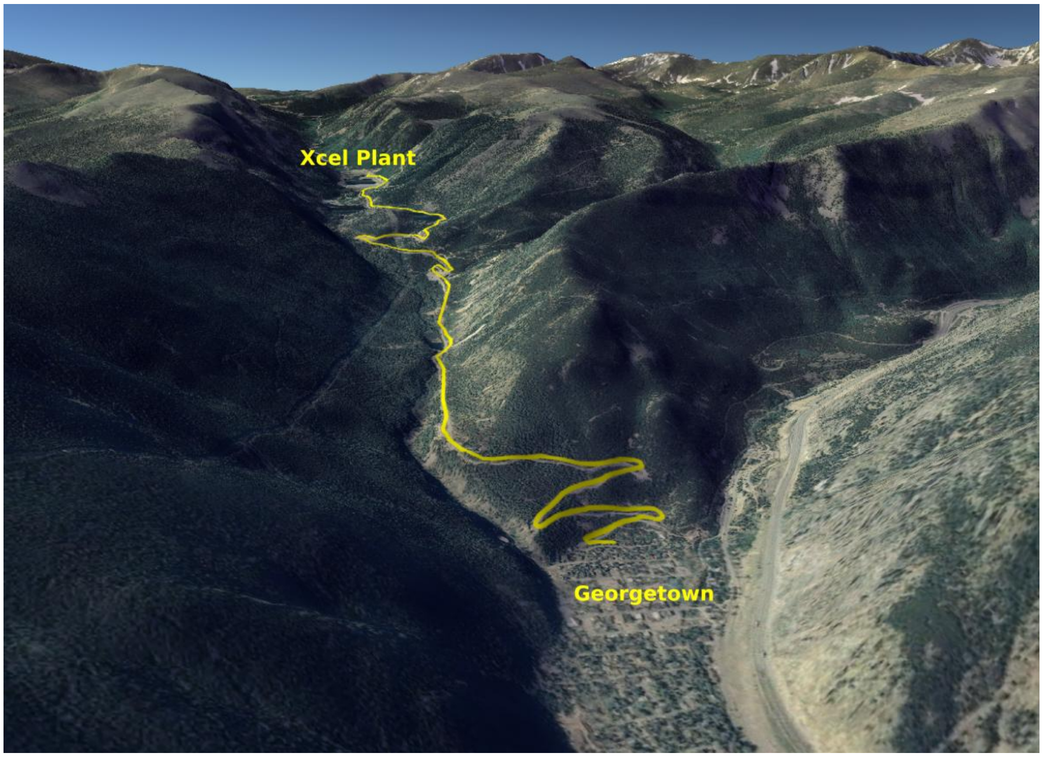

Figure 11. The winding, steep and narrow road from Georgetown to the Xcel hydroelectric plant

7.2.1 Requirements and Recommendations for Alternate Escape Routes or Safety Chambers

While the need for immediately available qualified technical rescue services was critical given the hazards in the penstock, another safety precaution that should have been taken by Xcel and RPI was to plan for an alternative escape route out of the penstock or a safety chamber within it. However, there was no plan for an alternate escape route out of the penstock if the primary route were to be blocked in an emergency.[66]

The penstock is a 4,163-foot (1269-meter) long sloping, underground confined space that required an access door in the side of the penstock to be cut for the recoating work crew to enter; this access opening

[66] Bid documents indicate that one of the unsuccessful bidders contemplated building a stairway to an egress opening in the mushroom.

was effectively the only way in or out of the penstock for RPI workers. Once the penstock starts its 55 degree incline, it is physically impossible to traverse the penstock without climbing paraphernalia setup in advance from the mushroom[67] and individual skill and qualifications in rigging and rope climbing, which none of the contractors were prepared or trained to do from inside the penstock. All of the deceased RPI workers were found beyond the west bulkhead with most near the start of the 55 degree incline.

The need for secondary escape routes from penstocks is identified in the American Society of Civil Engineering (ASCE) Task Committee's "Guidelines for Inspection and Monitoring of In-Service Penstocks" (ASCE, 1998, Section 2.3.6.1).

Alternatively, a safety/rescue chamber[68] inside the penstock could have housed fresh air, water, and reliable communication equipment for the trapped workers. The CSB notes that a useful guidance document was published in 2009 by the National Institute for Occupational Safety and Health (NIOSH) addressing instructional materials on refuge chamber setup, use, and maintenance (2009). At a minimum, self-contained breathing apparatuses could have been placed west of the west bulkhead, so that potentially trapped workers would have access to fresh air until rescue could be performed.[69]

Addressing the lack of secondary egress hazard by creating an alternative/emergency exit or installing a rescue chamber,[70] and staging qualified emergency rescuers near the penstock entrance would have likely have prevented the fatalities in this incident.

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[67] In September 2007, Xcel employees used climbing equipment to enter the penstock from the mushroom's vertical shaft entrance to inspect the interior for potential wear and damage of the concrete portion of the penstock.

[68] A safety/rescue chamber is an airtight chamber stocked with food, water, and oxygen, and typically used in underground mines. Such a chamber recently saved 72 miners who were trapped underground for 30 hours at the Mosaic Potash Mine in Saskatchewan, Canada.

[69] Three people survived a Bunker, Missouri, mine fire in January 2010 although their escape route was blocked by burning equipment; the mine had a rescue chamber with compressed air supplies that kept them alive until rescue teams were able to save them six-and-a-half hours later.

[70] This list also is not intended to be all inclusive, as other solutions could include actions such as increasing the ventilation and installing fire suppression.

7.3 Lack of a Technical/Confined Space Rescue Certification Progarm for Volunteer Firefighters

The first responders to the Cabin Creek penstock fire were local voluntary firefighters from the CCFA; none of these individuals held technical rescue qualifications or had received up-to-date workplace confined space training. The significant hazards inherent with confined spaces require specialized training and certification.

The Colorado Department of Public Safety, Division of Fire Safety, administers the firefighter voluntary certification program [8 CCR 1507] in the state. The purpose of this program is to measure the level of knowledge, skills, and abilities of firefighters and to attest that they meet nationally recognized standards. At the time of the incident, the state had certifications for various levels of firefighters and fire officials, fire inspectors, fire instructors, hazardous materials responders, fire apparatus drivers, and emergency medical first responders, but no certification program for technical and/or confined space rescue.

Interviews with Division of Fire Safety personnel revealed that the state does not track how many firefighters in the state are trained or certified in technical rescue because there is no certification program for this specialty. Interviews with various state fire officials revealed that several fire service and response organizations have achieved the operational capacity to conduct technical rescue, including confined space rescue[71]; however, only a small number of Colorado firefighters have been individually certified to perform technical rescue.[72]

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[71] NFPA 1670: Standard on Operations and Training for Technical Search and Rescue Incidents (2009) issued by the National Fire Protection Association (NFPA), establishes levels of functional capability for conducting technical rescue operations. Several Colorado fire service and responder organizations have been deemed to have established functional capability under this standard, including organizations affiliated with the Colorado Urban Rescue Task Force. NFPA 1670 does not, however, address individual technical rescuer qualifications.

[72] NFPA 1006: Technical Rescuer Professional Qualification (2008) establishes job performance requirements for rescue technicians.

At the time of the penstock incident, only two entities in the region were identified to have the organizational experience and training to handle the technical rescue issues this incident presented: West Metro Fire Rescue,[73] located in Denver (45 miles or 72 kilometers, approximately 1 hour 15 minutes travel time); and the Henderson Mine,[74] located near Empire, Colorado (21 miles or 34 kilometers, approximately 35 minutes travel time). The CCFA contacted and requested both to support the incident; due to the time each required to assemble a rescue team and travel to the Cabin Creek site, neither arrived at the penstock until approximately an hour after the trapped workers succumbed to smoke inhalation.

State fire officials informed the CSB that the availability of state voluntary certification for technical rescue, including confined space rescue, would improve the capabilities and capacity of Colorado fire service personnel to respond to events similar to the Cabin Creek incident.

[73] Members of the West Metro Fire Rescue have been trained in technical rescue in confined spaces as part of their duties as members of a regional FEMA Urban Search and Rescue Team, but were unfamiliar with the configuration of the Cabin Creek penstock

[74] Although the rescue team at the Henderson Mine is not trained in confined space rescue, the team has specialized training in underground mine rescue. As the penstock was bored through solid granite, it has many of the same characteristics and hazards as an underground mine. This rescue team is a private entity and not a public emergency response organization.

8.0 Contractor Selection and Oversight

Having both a strong contractor selection methodology and contractor oversight policy ensures that the owner receives both quality work from its contractors and worker safety is maintained for its own employees and those of the contractor. However, neither the methodology nor the oversight Xcel employed for the Cabin Creek penstock project adequately ensured that the recoating work would be conducted safely.

8.1 Contractor Selection

Xcel's contractor selection methodology did not disqualify contractors with substandard safety records from bidding on the penstock project.

8.1.1 Contractor Selection Process for the Penstock Project Request for Proposal

In April 2007, Xcel initiated the competitive bidding process to select a coating contractor for the Cabin Creek penstock recoating project. The company issued an RFP [75] to several contractors who were to be selected based upon the "best value/best overall evaluated offer"[76] rather than price alone. The Xcel RFP stated that the contractor would be evaluated, scored, and chosen using weighted rating factors, such as pricing (15%), safety experience modification rate (EMR)[77] (5%), historical quality of services and equipment (10%), operating history (10%), completeness of proposal (5%), and key personnel experience

[75] Xcel used the RFP procurement method for selecting suppliers of goods and services in more substantial acquisitions or projects.

[76] The "best value" procurement method considers a variety of factors in selecting contractors in addition to price, such as experience with similar projects, on-time completion, employee training, and safety record (TRB, 2006, p.S-3).

[77] EMR is used by the U.S. insurance industry "to determine premiums for workers' compensation insurance. An EMR less than 1 indicates above-average injury and illness performance, and an EMR greater than 1 indicates below-average performance. An owner can get some indication of a contractor's past safety performance by reviewing the contractor's EMR. A comparison of the EMRs of contractors bidding on a project may improve the selection process" (API RP 2220, 2005a, p.13). The RFP called for reporting the interstate EMR.

and continued availability (5%).[78] The RFP also established minimum qualifications and experience, including the need for at least five years of successful similar recoating experience and a QP 1 certification from the Society for Protective Coatings (SSPC), an industrial protective coatings trade association. [79] The Xcel contractor selection process for larger projects, such as the Cabin Creek penstock recoat, also included a prequalification[80] step that examined the contractor's financial capacity to successfully perform the work; however, the prequalification step did not consider safety performance.

Xcel's first attempt to select a contractor was unsuccessful. Of the three bidders submitting proposals, only one bid, from Certified Coatings Company (CCC), was evaluated as technically and commercially complete; however, its proposal was $450,000 above the budgetary allotment. Rather than increase the capital budget, Xcel re-bid the penstock project to find additional interested contractors. In late July 2007, an Xcel team that included the Cabin Creek plant manager and the penstock recoat project manager evaluated and scored the second group of proposals from four bidders.

[78] Other rating factors were exceptions to terms and conditions (10%), compliance with performance guarantees (15%), technical exceptions (5%), creative proposal options (10%), and QP 1 Certification/Experience (10%).

[79] SSPC certifies coating contractors based on demonstrated competence in areas such as technical capabilities, safety and environmental compliance, quality control, and management procedures. The certification process requires an evaluation of submittals to SSPC and an onsite audit of an active job site to verify that the stated programs are implemented. SSPC has established a QP 1 disciplinary action system with criterion for issuing warnings and placing contractors on probation or suspension based upon the severity of critical faults or violations in the areas of competence. (SSPC, http://www.sspc.org/certification/PCCP/QP1main.html , http://www.sspc.org/certification/PCCP/DAC.html, accessed March 8, 2009.)

[80] Contractor selection processes often have an initial prequalification during which each potential contractor must meet basic qualifications, including safety. A prequalification process is typically pass/fail; owners evaluate contractors and craft workers to determine if they meet the identified criteria and only firms that meet or exceed those requirements are allowed to bid in the final selection process. In this case, Xcel's prequalification process considered only the financial capacity of the potential contractor.

8.1.2 RPI Safety Record "Not Acceptable," but Allowed to Bid

The top two evaluated proposals from the second round of bidding were from CCC and RPI.[81] Xcel's project manager summarized the results of the proposal evaluations stating "from a technical and quality perspective, Certified Coatings (CCC) is the best evaluated proposal. They are at least $500 k over budget. The second best evaluated proposal is Robinson-Prezioso (RPI). Their safety EMR is high[,] although their OSHA incident rate does not reflect a safety problem. Their proposal is very close to budgetary requirements." The KTA consultant assisting Xcel stated that RPI's high EMR may have been the result of fatalities from their work on the "recent Golden Gate bridge project."[82] The RPI EMR was trending upward from 1.03 in 2005 to 1.28 in 2006; the contractor evaluation team was aware that under Xcel's policies, an EMR rate of 1.0 or above was unacceptable. In fact, the Xcel team gave RPI's proposal a safety rating of "zero" in the evaluation process. The RFP evaluation form the team used states that the rating of zero signifies that the bidder's proposal for that rating criterion "does not meet minimum requirements [and means] automatic rejection."[83]

RPI's penstock recoating proposal, however, was not rejected. The Cabin Creek plant manager concurred with the project manager: "I agree with you that RPI be the one selected due to cost and the fact that they are qualified." He recommended that the Xcel Colorado safety supervisor evaluate RPI's safety record and contact the contractor to discuss its EMR number. The project team asked the safety supervisor to investigate "whether a pattern of negligence is evident for this company [RPI]." When the Xcel safety

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[81] RPI's total score of the weighted rating elements was 4.3 with a technical ranking of 2.9; CCC's total score was 4.25 with a technical ranking of 2.95. RPI's bid was slightly over $1.3 million and CCC's was $1.7 million, a difference of less than $400,000.

[82] RPI had two fatality incidents during the Golden Gate retrofitting project. In September 2001, a passing motorist was killed by a falling scaffold. Then, in January 2002, an employee was crushed and four co-workers were injured when a platform buckled as it was being lowered onto a truck (Bjelland, S., et al., 11 Oct 2007).

[83] The Cabin Creek recoating proposals were rated with a scoring system that ranged from 0-5, with "0" representing the lowest score and defined on the scoring sheet as "does not meet minimum requirements, automatic rejection." The rating score of "5" was defined as "exceeds all requirements."

supervisor inquired, the RPI safety director stated that the company's EMR was high due to the Golden Gate Bridge job and that the company's EMR was trending down in 2007.[84]

8.1.3 Contractor Selection and Safety: Historical Background

An influential Business Roundtable report published in 1982, "Improving Construction Safety Performance," found that construction was one of the "most hazardous occupations" in the U.S. with a 54 percent higher injury and fatality rate based upon data from that period.[85] The report determined that contractors with a history of positive safety performance are more likely to perform safely in the future than those with a poor safety record. The report recommends that safety be considered when selecting construction contractors and that factors such as past safety performance and present safety capabilities be evaluated. The report includes a model safety prequalification form for use in selecting contractors.

A 2008 comprehensive report on contractor safety prequalification, "Contractor Safety Prequalification," (Phillips and Waitzman, 2008) refers to a 1991 John Gray Institute report, "Managing Workplace Safety and Health: the Case of Contract Labor in the U.S. Petrochemical Industry," as a "bellwether" for subsequent industry interventions addressing contractor safety, including the issue of contractor safety

[84] This information is not completely accurate. OSHA's "300 Log of Work-Related Injuries and Illnesses for 2006," the year that RPI experienced an EMR of 1.28, listed no injuries or illnesses that occurred in the area of the Golden Gate Bridge or the Bay Bridge in California. Robison-Prezioso, Inc. was cited by OSHA for a fatality incident on a Bay Bridge on January 4, 2002, and another fatality incident on the Bay Bridge on September 25, 2001, where a motorist was killed. Both of these cases are still listed as "open" on the OSHA website. The reference to the "Golden Gate Bridge" and RPI's high EMR rate was made by the Colorado Safety Supervisor in the Safety Addendum to the penstock contract signed by both parties. http://www.osha.gov/pls/imis/establishment.inspection_detail?id=300890555 , http://www.osha.gov/pls/imis/establishment.inspection_detail?id=300890100 , accessed June 4, 2009.

[85] The Business Roundtable represents the CEOs of some of the largest corporations in the U.S. The association develops policy and advocates positions on diverse issues such as workforce development, sustainable growth, and corporate leadership. CURT is an independent offshoot of the Construction Committee of the Business Roundtable and represents the viewpoints of member construction owners seeking to improve construction industry practices including safety performance [CURT, 1990].

prequalification.[86] The report found an association between rigorous screening in the selection of contractors and positive safety performance (Phillips and Waitzman, 2008, pp.49-50).[87]

8.1.4 Contractor Selection and Safety: Current Industry Guidelines

Recent studies note a modern trend of alternative procurement methodologies that use factors other than low price to select construction contractors, such as quality, past performance, and safety[88] (TRB, 2006, pp.40). Several organizations and industry associations, including the Construction Users Roundtable (CURT),[89] the American National Standards Institute (ANSI), the American Industrial Hygene Association (AIHA), and FM Global, have developed guidelines and recommended practices addressing the use of safety criteria for selecting contractors. One common method is prequalification, typically a pass/fail system that ensures that only contractors who meet specific requirements, including safety, are allowed to compete (CURT, 2004, pp. 1, 5). Another common alternative construction procurement

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[86] While the John Gray Institute report addresses contractor safety issues in the petrochemical industry, recent reports note the applicability of the conclusions from the 1991 report to general industry construction safety (Phillips and Waitzman,2008, pp.49-50). A case study examining the protection of contract workers at the Department of Energy's facilities found the John Gray Institute report to be the "most comprehensive study of safety related to contract labor" (Gochfeld and Mohr, 2007, pp.1607-1613).

[87] In 1989, an explosion and fire at the Phillips Chemical Complex in Pasadena, Texas, killed 23 and injured 232 workers. In the wake of the Phillips' incident, OSHA released a report to the President of the United States that identified multiple safety system failures that led to the incident including contractor safety issues (1990, pp.25-26). As a result, OSHA commissioned a major study to examine the health and safety issues related to the use of contractors in the U.S. petrochemical industry. OSHA specifically directed that the study examine the "the role of safety and health in the selection of contractors" (1990, p.64). Consequently, the John Gray Institute report used industry national surveys and case studies to understand the extent to which safety performance was considered in the selection of contractors (2006, pp.85-91). Partly in response to the John Gray report, OSHA's contractor safety requirements in the Process Safety Management Standard, C.F.R. 1910.119, include a requirement that employers when selecting a contractor "shall obtain and evaluate information regarding the contract employer's safety performance and programs," 1910.119(h)(2)(ii).

[88] The TRB (Transportation Research Board) report addresses highway procurement; however, the discussion of procurement methodologies more generally references industry or public sector procurement trends.

[89] CURT is an industry organization that promotes advocacy by users of construction services on national issues that includes "developing industry standards and owner expectations with respect to safety, training and worker qualifications" http://www.curt.org/2_0_about_curt.html, accessed 10/27/09. CURT is composed of 66 member companies, organizations, and government entities that represent some of the largest industrial corporations and users of construction services in the U.S. including DuPont, ExxonMobil, Dow Chemical, Intel, Proctor & Gamble, Duke Energy, General Motors, Shell, the U.S. General Services Administrations, and the U.S. Army Corp of Engineers.

method is referred to as "best value" contracting where, in addition to price, other key factors such as safety can be considered in evaluating the bid package—this method typically involves a rating system where bidders are scored and the highest evaluated bidder is selected (TRB, 2006, pp. S-2 – S-8). A third common procurement method combines prequalification and best value practices: only prequalified bidders are allowed to compete in the final selection process and the evaluation and rating of the bidders is based on best value parameters (CURT, 2005, pp.6-9; TRB, 2006, p.1). Xcel used both prequalification and best value components in its selection of the Cabin Creek penstock recoating contractor.

Industry guidelines addressing contractor selection support using a prequalification process that includes safety criteria. CURT has developed user practices addressing safety and contractor selection that are intended to educate CURT members and industry. The CURT User Practice, "Construction Safety: The Owner's Role," states that "[c]ontractors must be prequalified by the owner to participate in the final contractor selection process. Demonstrated safety performance is a critical criterion used in the prequalification process" (CURT, 2004b, p.6). CURT guidance lists a variety of typical criteria for safety prequalification: staff qualifications, accident history, EMR, a contractor's safety program, and an owner's previous experience.[90] Safety guidelines published by the AIHA, "Health and Safety Requirements in Construction Contract Documents" identify a number of specific prequalification criteria including EMR, OSHA injury and illness logs, OSHA citations, and training certifications. ANSI Standard Z-10, "Occupational Health and Safety Management Systems" also recommends that the

[90] The CSB noted in its BP Texas City investigation report (2007) that particular attention must be given by companies in developing effective safety performance metrics, which should include leading and lagging indicators (pp.184-185). Additionally, performance metrics that are commonly utilized may be inappropriate in some circumstances. For example, one contractor safety standard noted that the use of EMRs may not always be effective (API Standard 2220, 2005a, p.13).

contractor prequalification process include consideration of safety criteria for successful contractor safety performance management[91] (ANSI/AIHA Z-10, 2005, p.20).

8.1.5 Xcel Corporate Policies on Contractor Selection

Xcel had corporate policies in place prior to the incident that addressed contractor safety and the role of safety in selecting contractors. However, while these policies allowed a prequalification process to be used, and a rating and ranking RFP competitive bid process that awarded the contract to the "lowest evaluated bidder," using a prequalification process was not mandatory and the minimum specified requirements were left to the procurement representative. Thus, the use of safety criteria in the prequalification process was not required, nor was it considered in the prequalification step at the Cabin Creek project.

In addition to the score of zero that RPI received, the Xcel evaluation team was also aware of RPI's accident history that involved fatalities. Had Xcel examined RPI's OSHA inspection database and other sources publically available, they would have discovered a lengthy history of serious OSHA citations, including a number of violations specifically involving the unsafe handling of flammable liquids (Appendix B). Although the terms of the RFP relied on contractors to self-report accident histories, RPI did not provide Xcel with records related to several other serious relevant regulatory actions. [92, 93]

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[91] API Recommended Practice (RP) 2221, "Contractor and Owner Safety Program Implementation" also recommends contractor prequalification using a variety of safety criteria. The recommended practice states that "[t]he selection of a qualified contractor is the first step toward obtaining safe contractor performance" (API RP 2221, 2005b). API's RP 2221 provides a comprehensive prequalification form that includes 48 questions and data requests. While the API publication addresses refining and petrochemical industry facility owners, it is persuasive guidance for general industry to improve contractor safety performance, particularly in performing hazardous repair, maintenance, and construction as in the Xcel penstock recoating project.

[92] In 2006 RPI agreed to pay a penalty of $145,000 to a division of the California Environmental Protection Agency to settle violations that included illegally disposing of hazardous waste and making false statements to government officials.

[93] Xcel's "Contractor Safety, Health and Environmental Questionnaire," attached to the Cabin Creek penstock recoating RFP, required submission of any citations received from a regulatory agency during the past three years. RPI did not disclose to OSHA a 2005 serious OSHA violation in Arizona that occurred within the 3-year time period.

Moreover, Xcel's policies addressing contractor selection do not require that the records be verified and, in fact, Xcel confirmed to the CSB that it had not verified RPI's submissions or researched its background.

Xcel's "Contractor Safety" corporate policy provided for a health and safety evaluation of the contractor bids and recommended a review of the contractor's EMR. The policy stated that an EMR above 1 "would normally be considered unacceptable for the construction industry," but did not explicitly require a rejection of a bid proposal based upon the EMR. Xcel's policies allowed a contractor with "unacceptable" safety performance to further compete in the contractor selection process. CURT guidance on contractor selection prequalification illustrates an approach that more effectively ensures safety:

> Any contractors that do not meet base criteria fail and are not included on the potential list. An example of this type of pass/fail criteria might be: only contractors with an Experience Modification Rate less than 1.0 are acceptable (CURT, 2004a, p.5).

A prequalification policy consistent with industry guidelines would have disqualified RPI and prevented the firm from being considered in the final selection process.

8.2 Contractor Oversight

Xcel did not provide sufficient oversight to ensure that safe practices were upheld during the hazardous recoating work within the penstock.

8.2.1 Safety Addendum Added to Contract

In response to negative information about RPI's safety record, the Xcel safety supervisor proposed additional safety requirements for the penstock project. The agreement between Xcel and RPI included a safety addendum that required a number of additional safety measures. It reads as follows:

1. RPI will be extra diligent toward safety, ensuring [that] they are carefully following their safety policies and procedures.[94]
2. RPI will respond to safety questions and concerns from Xcel Supply in a timely manner.
3. Xcel Supply will observe closely the work and report any concerns immediately to RPI's on site supervision (daily by on site personnel and randomly by Energy Safety).
4. Xcel Supply will provide our Stop Work Policy to RPI and that all understand that any Xcel Supply employee can stop a job. This is routine and covered in our contractor orientation at the start of all jobs.

Xcel concluded that if it kept a "close watch" on RPI, the penstock recoating project would be safe and successful.

8.2.2 Xcel Cabin Creek Site Contractor Oversight Activities and RPI Safety Performance

Xcel did not increase its oversight of RPI nor did it implement corrective actions even though, during the penstock recoating project site activities prior to the incident, Xcel managers had identified serious safety hazards associated with the work and were aware of several significant safety problems attributable to RPI:

- An RPI worker slipped and fell inside the penstock due to the wet, slippery interior surface conditions. The worker suffered a dislocated shoulder and was treated at the hospital.
- The penstock was evacuated on several occasions prior to the incident due to high readings of CO, a toxic gas.

[94] RPI provided its entire "Injury and Illness Prevention Program" safety manual to Xcel as part of its bid package submission; therefore, Xcel was aware of RPI's safety policies and procedures and could ensure that they were followed.

- Electrical problems that destroyed of penstock lighting, electrical junction boxes, and other equipment.
- Xcel welded a "weep hole" inside the penstock on the day of the incident without issuing a hot work permit. Xcel's entry into the confined space lacked a confined space permit; that welding fumes could create a potential hazardous atmosphere was not analyzed.
- The Xcel penstock project manager identified serious hazards in the penstock work, stating in an email that "work conditions inside the penstock are highly hazardous on many levels."

Despite Xcel's knowledge of these serious safety problems, Xcel managers conducted safety observations of RPI's penstock activities on only two documented occasions: September 20, 2007 and October 1, 2007. The project manger completed an inspection checklist, noting the "extremely slick surfaces" inside the penstock. The penstock inspection form also stated "environment continuously monitored," but employee interviews and documentation indicate that the penstock was only periodically monitored at the access door entrance for hazardous atmospheres.[95] An Xcel safety representative visited the penstock for a safety observation the day before the incident, during sandblasting operations. The completed safety observation form listed a number of worker protection categories that were marked off as satisfactory, unsatisfactory, or not applicable. The safety representative had marked the worker protection category of "confined space entry permit" as "satisfactory." The comments section noted that an RPI worker was at the penstock entrance accounting for the personnel inside. However, as discussed, RPI and Xcel had not effectively implemented important elements of a permit-required confined space program. For example, the confined space permits were only partially completed and RPI had not established acceptable entry

[95] A few witnesses stated that the RPI supervisor also occasionally monitored the air farther inside the penstock, but not on the day of the accident. There is, however, no documentation of these readings.

conditions for the penstock. The form the project manager completed during the September 20 safety inspection similarly checked “OK” under the category of confined space safety practices.

8.2.3 Xcel Corporate Policies and Other Requirements Addressing Contractor Oversight

While Xcel’s corporate policies and contracting documentation place primary responsibility for safety on the contractor for work under its control, Xcel policies also contain specific contractor safety oversight requirements. In the wake of the Cabin Creek incident, Xcel spokespersons stated that safety was RPI’s responsibility and the contractors are “experts in the field and that’s why we hired them” (Lipsher, Mitchell, and McPhee, 2007). However, Xcel’s “Construction and Contractor Management” policy states: “[c]ontractor oversight or project control shall be established by both parties for all contracts with regard to health and safety standards.” Xcel’s “Contractor Safety” policy provides several contractor oversight requirements including the establishment of effective daily communication addressing safety issues between Xcel and the contractor, periodic jobsite visits by Xcel personnel to verify safety performance, and prompt notification and correction of deficiencies where violations of health and safety standards or regulations are discovered. Xcel’s corporate policy is consistent with industry safety guidelines for owner oversight of contractor safety. CURT user practices recognize that “[t]he owner must monitor contractor behavior to ensure effective implementation,” which includes auditing, measuring, and analyzing safety results, participating in incident investigation, and participating in contractor safety training (CURT, 2004b, pp.7-9).

However, Xcel ineffectively implemented its program for contractor safety oversight in a number of key areas identified by its contractor safety policy:

- Xcel and RPI managers did not establish effective daily communication concerning the hazards associated with the penstock recoating project. Xcel did not effectively plan and coordinate with RPI to identify and control serious hazards in the recoating project, including the use of a flammable solvent within the penstock confined space.

- The Xcel project manager or safety staff made documented safety observations only on two occasions at the penstock; these safety observations were ineffectively performed and failed to identify the serious confined space hazards.

- Violations of Xcel safety standards and OSHA regulations were not promptly communicated and corrected. The serious safety issues that were known to Xcel during the penstock work did not lead to increased scrutiny of RPI or effective corrective action.

Xcel acknowledged to the CSB that it had not audited the performance of its corporate contractor selection and safety oversight program prior to the incident. Periodic corporate audits play an important role in ensuring that safety policies and procedures are applied and effectively implemented so that safety hazards can be controlled or eliminated (ANSI/AIHA Z-10, 2005, p.25).

Xcel did not follow an effective contractor selection methodology that would ensure that contractors with a known unacceptable safety record would be disqualified from the bidding process. The company also failed to provide sufficient oversight to ensure that its contractors maintained a safe work environment while performing hazardous maintenance work at its Cabin Creek site.

9.0 EMPLOYEE SAFETY TRAINING

Employee safety training is integral to the success of a company's safety and health program. First and foremost, the company is responsible for ensuring that its employees are trained and capable of conducting work safely.[96]

Three broad types of training were available to RPI employees: 1) company-specific training provided by RPI; 2) general continuing education training provided through a union and the company partnership committee's Training Center; and 3) work-site specific training provided by RPI and Xcel. However, all of these modes of training were deficient in providing appropriate safety information to the penstock work crew, either by the administration of the training or the content of the material.

Specifically, the RPI employees were ill-prepared to safely conduct work inside the penstock because

- RPI did not provide adequate training to its employees on its safety policies and procedures
- RPI relied primarily on the partnership committee's Training Center to provide training to its employees, but the Training Center is not responsible for providing company- or site-specific training to its members;
- Only individuals hired as an apprentice or those specifically referred to the Training Center for enrollment in the apprenticeship program's semester-long courses receive the comprehensive and in-depth safety training the Training Center provides; consequently, just

[96] The American National Standard, "Occupational Health and Safety Management Systems (OHSMS), ANSI/AIHA Z10-2005," provides good practice guidance on training and competency. It states that the employer will "establish processes to ensure through appropriate education, training or other methods that employees and contractors are aware of applicable OHSMS requirements and are competent to carry out their responsibilities as defined in the OHSMS" (ANSI/AIHA, 2005).

two of the 14 contractors[97] on the penstock project who had gone through portions of the program received some of this in-depth training.

- Employees referred to the Training Center for evaluation are assessed only on their technical painting skills, not their safety knowledge.[98] And because the two RPI employees referred by RPI to the Training Center had skill levels at or above a mid-level apprentice, they were not required to take the basic painting level courses that included much of the in-depth safety training.

- Only nine of the 14 RPI employees received onsite training at Cabin Creek prior to the start of the recoating project, and that training was both abbreviated and did not effectively address the hazards inherent to the penstock recoating work.

As a result, the RPI work crew received inadequate training on the specific and unique hazards of the penstock, including the safe handling of flammables, proper and safe use of spray equipment in a confined space, fire prevention and mitigation, and emergency response and rescue awareness. Had the existing apprenticeship safety training been provided to all journeyman painters, the RPI work crew would likely have been better prepared to manage the unique hazards of the penstock.

9.1 Company-Specific Safety Training

Employers are responsible for providing appropriate and effective safety training to its employees. RPI's IIPP manual describes safe work practices and procedures on a wide array of safety issues, and while many are deficient (Section 6.6), a number address specific hazards that were associated with the penstock project, including the safe handling of flammables, proper confined space entry, and fire

[97] RPI had 14 employees working at the Cabin Creek site for the penstock recoating project; however, one left prior to the day of the incident for personal reasons. Twelve contractors and a general foreman remained on site.

[98] The only safety issue individuals are evaluated on is their knowledge of proper PPE

prevention. Training on the safety information within the IIPP manual likely would have mitigated some of the risks inherent with the recoating work.

Unfortunately, the company's method to ensure that newly hired individuals understood the IIPP information was simply to have them sign off on a Certificate of Compliance, which states that the employee received the *IIPP Manual* and the *Employee Safety Handbook* and agrees to comply with the rules and practices of these documents. At the time of the incident, RPI did not test or otherwise verify comprehension of the IIPP and its contents on an ongoing basis throughout an employee's career with the company. In fact, a 2006 audit of RPI by the SSPC found that RPI had "[n]o documentation of craft-worker assessment." In response to this finding, RPI stated that it was "currently implementing a training and documentation plan that will meet the requirements…" outlined in the audit. RPI went on to state that "[o]ur training[,] which will now be more stringently documented, will consist of; [sic] Ongoing Safety Training, Specialized Material Application Training, New Equipment Training, Site Specific Training…etc…)." Available evidence indicates that this training did not occur.

9.2 Training Center Safety Training

A Master Labor Agreement between the Painters and Allied Trades Union, District Council 36, and several participating multi-employer associations created the Southern California Painting and Drywall Industries (SCPDI) Joint Apprenticeship Training Committee and Center.[99] The SCPDI Training Center is charged with providing an apprenticeship training program for beginners in the industrial painting trade. Integrated within this apprenticeship training program are a number of critical safety components. Those who fully complete the program have the opportunity to build a solid foundation of technical painting skill and safety awareness.

[99] This Committee, and its Training Center, is maintained through a Master Labor Agreement between the Painters and Allied Trades Union (District Council 36) and several contractor associations, of which RPI is a member.

However, the number of individuals who benefit from the apprenticeship program training courses is limited, in that the SCPDI Training Center is responsible for providing in-depth safety training only to individuals who are either just entering the industrial/commercial painting field or those referred to the Training Center by their employer for a skills evaluation and are subsequently found to be lacking in painting skills and abilities. None of the 14 RPI employees working on the penstock project were graduates of the apprenticeship program; only two were referred to the Training Center by RPI for skills evaluation. And because the two RPI employees referred to the Training Center had skill levels at or above a mid-level apprentice, they were not required to take the basic painting level courses that included much of the in-depth safety training.

Additionally, those referred to the Training Center are evaluated solely on technical painting skill and expertise; safety knowledge is not assessed as part of the evaluation process. An individual could qualify at the fourth stage within the seven-stage Apprenticeship Program based on his/her demonstrated knowledge of proper painting techniques and abilities, without having to demonstrate that he/she has the *safety* knowledge necessary to perform work at that painting skills level within the program. Indeed, the evaluation procedure utilized by the Training Center does not include an assessment of safety knowledge. Individuals that enter midway into the Apprenticeship Program miss out on multiple opportunities for in-depth safety training, and those hired by the company and deemed sufficiently skilled in the trade are not sent to attend the semester-long Apprenticeship courses, and consequently are not exposed to the in-depth safety training.

These training gaps are compounded because the Training Center does not, and is not expected or required to, provide instruction on company-specific policies or site-specific hazards.

The SCPDI Training Center does offer general OSHA-required continuing education training opportunities[100] to its union members; however, this training is not worksite-specific.

9.3 Generic Onsite Training Provided at Cabin Creek

The RPI work crew did not receive comprehensive safety training specifically pertaining to the penstock work environment from either their employer (RPI) or the host company (Xcel).

An Xcel safety supervisor, after reviewing RPI's penstock project bid submittal, noted that a number of the RPI employees lacked several training courses pertinent to the penstock work, including confined space entry and electrical safety. He communicated this lapse in training to the RPI safety manager, who asserted that all RPI employees involved in the project would receive onsite training to cover these and other safety topics prior to starting work. The RPI safety manger asked a trainer at the SCDPI Training Center to come to the Cabin Creek site to provide basic OSHA-required continuing education/refresher training to the work crew.

Only nine of the 14 RPI employees on the penstock project received this onsite training on September 10, 2007. This training consisted of 6 hours of refresher-level safety review on six topics (each lasting about an hour). The contractors watched a safety video on each topic and were tested through multiple-choice exams. Those who had not arrived onsite until after September 10 were not provided an opportunity to take a make-up session.

In testimony to the CSB, the trainer stated that the review of safety topics was kept "pretty brief" because the contractors had attended the refresher courses multiple times. While repetition may seem burdensome, the real challenge in preparing for safe work is to ask: What about this job and these planned activities are

[100] CPR, Respirator Use and Fit Test, and Lead Worker Refresher is required annually; First Aid is required every three years; and the following courses are reviewed at least once per year in the Apprenticeship program but journeymen are required to take the training only once: Fall Protection, Scaffold/Swing Stage, Confined Space Awareness, Hazard Communication, Hearing Protection, Asbestos Awareness, Aerial Mobile Power Lifts, Forklift & Drywall.

different from what we've done before? What are the hazards of those different activities? How can that risk be eliminated or controlled?[101] Approaching hazards this way focuses attention on the risks that may not be readily apparent when reviewing generic training materials before the start of work.

The onsite training for the RPI employees was brief and generic and included only a basic review of confined space awareness. It included an overview of the definition of a confined space, but not how to evaluate a confined space for potential hazards, how to properly complete confined space entry forms, or how to prepare and arrange methods for evacuation. The onsite training also included a basic review of electrical safety, the material provided focused on the importance of using grounded equipment and following lockout/tagout procedures, but not on the need to use conductive hoses to prevent static discharge, nor did it explicitly instruct the crew about how to wire and ground equipment properly for safe use.

The hazardous communication training on September 10 did not include a site-specific discussion of safe use of flammable solvents in confined spaces, despite plans by both companies to use a solvent within the penstock during the recoating process[102] (Section 6.5). Nor were flammable and explosive atmospheres, fire prevention, and fire extinguisher use within the penstock incorporated in any onsite training for the contractors; also excluded was a discussion of procedures for emergency evacuation of the penstock. Neither Xcel nor RPI discussed the lack of a secondary egress with the work crew during the onsite training, and specific emergency response and rescue training did not extend beyond the instruction to the crew to call the Xcel control room for 9-1-1 services if an emergency should arise.[103]

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[101] A U.S. aircraft commander, who is also a human performance specialist, often prepares his crews by asking, "What is dumb, different, and dangerous about this specific mission?" to provoke their collective thinking about the specific and potentially unique risks of a given mission.

[102] The hazardous communication training on September 10 consisted of an employee's right to know the chemicals onsite, how to read an MSDS, and proper PPE.

[103] One likely reason for the lack of pertinent training on the issues inherent with the penstock project work was the trainer's lack of penstock experience. The trainer relied on a more experienced contractor within the RPI crew to

The RPI employees also received a brief onsite safety overview from Xcel as they arrived at Cabin Creek and began preparing for work inside the penstock.[104] This brief orientation – consisting of a checklist review of potential hazards – was held on three separate occasions, led by different Xcel personnel and attended by various crew members.[105] The orientation provider addressed confined space by asking the RPI crew if they had been trained on the safety topic, but the provider did not verify this training, nor were MSDSs of chemicals to be used within the penstock discussed or requested. The orientation did not cover a number of safety issues related to the penstock work, including emergency response and evacuation plans or safeguards for minimizing fire hazards within the confined space.

9.4 Safety Training Needs Specific to the Penstock

The unique characteristics of the penstock and the recoating work require knowledge and skill on a number of safety topics, including the safe handling and use of flammables, confined space entry and monitoring, fire prevention, and emergency preparedness. Many of these safety topics are covered effectively in the SCPDI apprenticeship program; others are covered within the safety policies of the host and contractor companies. Through interview testimony and training records, the CSB found that the necessary safety information pertaining to the penstock project was not, in most cases, effectively administered to the RPI workforce, nor did either company uphold and reinforce safe work practices at the work site. This section identifies where safety training and information existed but was not incorporated into the work activities at Cabin Creek.

inform the others of the penstock's hazards; however, according to witness testimony, the experienced contractor focused on slip, trip and fall hazards, not on the major confined space hazards of the penstock or the risks of working in flammable atmospheres.

[104] This orientation was meant to focus on Xcel policies and procedures; topics covered included lockout/tagout, forklift use, slipping hazards, and waste removal from the site.

[105] Each member attended the orientation once.

9.4.1 Substituting Non-flammables for Flammable Solvents

The use of potentially safer alternatives to MEK is discussed in the SCPDI apprenticeship program's training course, "Solvent and Hazardous Materials." The training materials state: "Whenever possible, organic solvents should be replaced with either water-based solvents or another less harmful organic solvent." The importance of exploring opportunities to exchange flammable solvents for non-flammable substitutes is reiterated throughout the training materials, which provide a substitution example dealing explicitly with MEK: "a citrus based [sic] cleaner could be used in place of MEK for tool clean up." Only one RPI crew member attended the "Solvent and Hazardous Materials" course (as part of his training through the Apprenticeship program). The use of a non-flammable solvent would have prevented the Cabin Creek fire.

9.4.2 Safe Handling and Use of Flammables

Training on the safe handling and use of flammables is offered only to employees who are going through the apprenticeship program or when specifically requested by a company. The IIPP safety policies concerning the safe handling and use of flammables were not provided to employees through in-house company-provided training, nor were employees' comprehension of these polices assessed.[106] As a result, RPI employees were not sufficiently trained on the safe use of flammables.

The proper and safe handling of flammables is covered in the "Basics of Solvents and Thinners" and "Solvent and Hazardous Materials" training courses the SCPDI Training Center offers. However, records going back five years prior to the incident show that none of the RPI employees working inside the penstock took the "Basics of Solvents and Thinners" course and, as stated, only one of the crew took the "Solvent and Hazardous Materials" training course.

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[106] When subpoenaed for all training materials, RPI did not provide any documentation that employees were tested on the IIPP safety information.

The "Basics of Solvents and Thinners" course materials provide many warnings about the risks of using flammables, and the "Solvents and Hazardous Materials" course goes further, stating: "NEVER leave solvent products open when not in use" (emphasis in original) and "Place solvent soaked rags or materials in all-metal containers with tight sealing tops" to prevent dangerous vapor accumulation in the work area. The training materials also warn: "Transport and store solvents ONLY in approved, properly labeled and marked containers" (emphasis in original). By following these safety rules, the training material asserts, the chance for a fire or explosion is reduced.

Some RPI employees stated they knew how to safely transfer flammables, but as metal safety cans for MEK transfer were not made available for use at Cabin Creek, adhering to this safety policy was impossible.

9.4.3 Flammable Atmospheres and Confined Space Entry

SCPDI Training Center training materials for "Confined Space Entry" state: "If the atmosphere contains flammable gas, vapor or mist in excess of 10 percent of its lower flammable limit (LFL), that atmosphere is not acceptable for entry." Yet on October 2, 2007, the Cabin Creek confined space work did not prohibit entry or occupancy of the penstock where the LFL was in excess of 10 percent, nor did Xcel or RPI's policies require this safeguard. The attendant was conducting atmospheric monitoring at the access door, more than 1,450 feet (442 meters) away from the crew using the solvent to flush the hoses, wands, and sprayer system with MEK, which was too far away to get an accurate measurement. MEK vapor produced with the flushing activities resulted in the accumulation of solvent vapors to levels above the maximum allowable for entry around the equipment and work crew.

9.4.4 Fire Prevention and Mitigation

Both the SCPDI fire prevention training course material and RPI's IIPP section, "Fire Protection and Prevention," stress the importance of both clear access to emergency response equipment and its placement close to the actual painting operation. Yet RPI provided only six of the 14 contractors with a general course on proper fire extinguisher placement within the worksite; this training occurred approximately two months prior to the incident.

The SCPDI fire prevention training also included instructions that there should be more than one exit in the area of work and that all workers keep their backs to an exit in case a fire necessitated escape. Despite these fire safety recommendations, the arrangement of spray equipment within the narrow confines of the penstock kept contractors separated from the work area's only exit. No remedial action was taken to address the lack of a secondary exit, although a number of RPI employees expressed concern about having only one egress point. The positive affects of training are significantly diminished when the good practices promoted in the training cannot be adhered to. Interestingly, a penstock project contract addendum, which both Xcel and RPI agreed to, empowered Xcel employees with "stop work authority" during the project, allowing Xcel employees to order RPI to cease work within the penstock if they observed unsafe work practices. This stop work authority was given specifically to Xcel employees, not the RPI work crew.

9.4.5 Proper and Safe Use of the Sprayer and Associated Equipment

RPI employees were not trained on the proper and safe use of the Graco epoxy sprayer system. The SCPDI Training Center does not train on Graco spray equipment exclusively, but a plural component (two-part) spray system is a topic within the apprentice spray painting course curriculum. However, only two of the 14 contractors went through the apprenticeship semester course that covers this information. This training, which was provided by a third party in agreement with RPI, had taken place two years prior to the penstock project. Working with unfamiliar equipment likely contributed to the operational problems the crew was experiencing during their application attempts.

The RPI crew working inside the penstock lacked the in-depth safety training and knowledge necessary to work safely within this unique and challenging confined space environment. RPI did not provide adequate training addressing the safety risks of the penstock recoating work to its employees. The Training Center

Apprenticeship Program does provide comprehensive safety training; however, few RPI employees received this in-depth safety training.

10.0 Regulatory and Industry Standards Analysis

RPI's and Xcel's policies and permits failed to established safe limits that prohibit entry or occupancy of a confined space with a hazardous flammable atmosphere. However, existing federal regulations for general industry do not require that employers establish such safety limits. Specifically, the current OSHA Permit-Required Confined Spaces Rule does not prohibit entry or occupancy in a confined space above a maximum permissible percentage of the LFL nor does it require continuous monitoring throughout the duration of the work[107] to ensure the concentration of flammable gases does not exceed that percentage.

The CSB determined that, even if combustible gas monitoring had been performed on the day of the incident in the area where flammable solvent was being used, this monitoring would likely not have been enough to prevent the initial flash fire in the penstock; with no set limit for flammable atmospheres, the RPI crew had no evaluation and action level in which to use to determine when it was safe to work and when cessation and/or evacuation was necessary.

10.1 Hazards of Confined Space Work in Potentially Flammable Atmospheres Inadequately Covered in Existing Standards

OSHA's Permit-Required Confined Spaces Rule for general industry states that a confined space must be permit-required when the space has a potential to contain a hazardous atmosphere, which is defined for flammables as an atmosphere that exceeds 10 percent of the LFL [29 CFR 1910.146(b)] (Section 6.1). A permit-required confined space program mandates that employers specify acceptable entry conditions and take actions such as purging or ventilating the space to eliminate or control atmospheric hazards such as a flammable atmosphere [29 CFR 1910.146(d)(3)(i), (iv)]. However, the rule does not define acceptable

[107] In this incident, the penstock space was "large or…part of a continuous system," which would require continuous monitoring (See Sections 6.1.3 and 11.2.2.2, which discuss 29 CFR 1910.146 (d)(5)(i)). However, the fact alone that a flammable was being used within a confined space would not have triggered the requirement for continuous monitoring.

entry conditions or specify what additional precautions must be taken for working in a permit-required confined space with a potential flammable atmosphere, nor does it limit entry based upon measureable critieria such as a specific maximum percentage of the LFL, even though OSHA defines an atmosphere as hazardous when it exceeds 10 percent of the LFL. Appendix C of the rule gives examples of permit-required programs, including a scenario where interior coatings/linings are applied in portable tanks. This scenario describes an approach to control the hazards by establishing forced air ventilation to keep the potentially flammable atmosphere below 10 percent of the LFL [29 CFR 1910.146 Appendix C, Example 3]. However, Appendix C provides only examples of permit-required programs; it does not establish enforceable requirements.

In 1996, OSHA issued a letter of interpretation that allows work to be performed in atmospheres in excess of 10 percent of the LFL, stating that when the atmosphere is above 10 percent, “all of the requirements of the rule must be met”; however, it provides no specific safety guidance (OSHA, 1996). The letter concludes that because the Permit-Required Confined Spaces Rule for general industry is a performance standard, “it does not specify procedures for conditions where the permit-required space has a hazardous flammable atmosphere” (OSHA, 1996). Rather, the employer must implement control measures based upon a hazard analysis of the “the means, procedures, and practices necessary for safe permit space entry operations” [29 CFR 1910.146(d)(3)]. In fact, the letter does not suggest any limits on entry based on measurements of the flammable atmosphere or even that safe entry conditions need be defined in terms of the LFL, which directly contradicts the more recent OSHA shipyard standards and recent NFPA guidance, as discussed below.

The Permit-Required Confined Spaces Rule requires “purging, inerting, flushing or ventilating the permit space as necessary to eliminate or control atmospheric hazards” [29 CFR 1910.146(d)(3)(iv)]. Under the rule, a hazardous atmosphere is one “that may expose employees to the risk of death, incapacitation, impairment of ability to self-rescue…injury, or acute illness” [29 CFR 1910.146(b)]. The logic of the provisions would appear to demand that for safe entry, the confined space flammable atmosphere would need to be reduced to 10 percent or less of the LFL or inerted to prevent the formation of a flammable mixture inside the permit space and the possibility of death or injury; however, the Rule has no such explicit requirement.

The following support the need for effective requirements or limits for working in flammable atmospheres in terms of confined space entry and occupancy:

1. Establishing safe flammable limits as a percentage of the LFL, with the effective use of appropriate monitoring devices (e.g., combustible gas detectors), is an accurate method for obtaining quantitative data to evaluate the potential degree of hazard and protect personnel (McManus, 1999, p.748).

2. Safe flammable atmosphere limits are needed because no adequate PPE is available that can protect workers from an explosion within a confined space (NFPA 1006, 2008).

3. Sources of ignition for a fire or explosion are typically plentiful and difficult to eliminate entirely, as illustrated in the number of possible ignition sources available in the Cabin Creek penstock; as such "there is no ready assurance that all sources of ignition could be eliminated" (McManus, 1999, p.746).

4. Lacking specific regulatory requirements based upon measureable parameters, employers may fail to establish adequately protective limits for working in potentially flammable atmospheres. In this incident, neither Xcel nor RPI had established safe entry conditions for flammable atmospheres based upon a percentage of the LFL in their procedures and permits.

5. Failure to establish safe flammable limits undermines the importance of monitoring in permit-required confined spaces; the need for periodic or continuous monitoring will not be understood by employers and personnel if no limits are specified. This safety gap can lead to a failure to conduct critical combustible gas testing in appropriate locations and with the needed frequency, as was the case in the Cabin Creek penstock.

6. Unlike flammable atmospheres, other atmospheric hazards have explicit and measureable requirements elsewhere in the OSHA regulatory scheme to confirm compliance with the Permit-Required Confined Spaces Rule. For example, OSHA standards for toxic substances establish quantitative permissible exposure limits and other standards require quantitative monitoring of potentially oxygen-deficient atmospheres.[108]

7. Confined space entry is a frequent activity in U.S. workplaces-OSHA estimates that more than 4.7 million permit-required confined spaces are entered by workers annually (OSHA, September 2008).

8. A flammable atmosphere is a serious confined space hazard. According to noted confined space expert McManus (1999), fires and explosions are a “major cause” of deaths and injuries in confined spaces and have led to a relatively “large portion of fatalities per incident compared to other situations” (p. 112). The CSB concluded that serious confined space incidents involving flammable atmospheres are still a significant problem and that adequate combustible gas monitoring, clearly defined limits for working safely in potentially flammable atmospheres, and other control measures such as eliminating the hazard or adequate ventilation of the space can prevent these accidents (Section 11.0).

10.2 Other Regulations and Safety Guidelines Set Protective LEL Limits for Work in Potentially Flammable Atmospheres

The approach in the Confined Spaces Rule sharply contrasts with more stringent, recently promulgated OSHA standards, such as those for confined spaces in shipyard employment [29 CFR 1915, Subpart B], which limit work activities that can be conducted in atmospheres that exceed 10 percent of the LEL. The shipyard standard requires that confined spaces containing a flammable concentration of 10 percent of the

[108] For example, see OSHA’s Table Z-1, “Limits for Air Contaminants”; 29 CFR 1910.1000; and the Respiratory Protection Standard, 29 CFR 1910.134.

LEL or higher be labeled as "Not Safe for Workers" [29 CFR 1915.12(b)(2)]. In the discussion related to the final rule for confined spaces in shipyard employment, OSHA argued that adopting 10 percent of the LEL limit for safe occupancy was more appropriate than other proposed levels: "The Agency believes that a compartment in which any portion is above 10% of the LEL is unsafe" [59 FR 37816-37863].

Yet the general industry Permit-Required Confined Spaces Rule allows employers to adopt limits higher than 10 percent of the LEL as an acceptable entry condition. McManus, in *Safety and Health in Confined Spaces* (1999), defends the use of lower LEL limits, noting that conducting a confined space hazard analysis can be difficult and uncertain because of several factors: 1) the accurate detection of ignitable atmospheres depends on the position of the intake of the instrument relative to the source, 2) the relative response of the sensor based the on substance(s) being sampled to the substance(s) used to calibrate the sampler, and 3) the timing of the samples (pp. 745-752).[109]

A number of organizations, standard-setting bodies, and other government regulatory agencies have also adopted guidelines that prohibit or limit work activities in confined spaces in atmospheres above 10 percent of the LEL (Appendix G). McManus (1999) suggests that "[t]he consensus expressed through more recent standards indicates decreased tolerance" for hazardous flammable atmospheres (p. 745). An important example of this trend can be found in the 2008 edition of NFPA 1006, Standard for Technical Rescuer Professional Qualifications. This consensus standard addresses acceptable entry conditions for confined space rescue and states in its explanatory material that "[r]escuers should not enter confined spaces containing atmospheres greater than 10 percent of a material's LEL, regardless of the personnel protective equipment worn. There is no adequate protection for an explosion within a confined space" [NFPA 1006, 2008, Annex A.7.1.1].

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[109] Webber (2007) summarizes relevant research showing conditions where flammable vapors can be ignited even when concentrations are below the LEL that result in localized flash fires.

A number of other confined space consensus safety standards and industry guidelines recommend special precautions to detect and control flammable atmospheres and explicitly establish safe work limits for confined spaces that are substantially below the LFL, such as 10 percent of the LFL [ANSI Z117.1, 2009, p.24; ASTM D4276-02, 2007, p.3; NFPA 326, 2005; API 2015, 2001a, p.28; API 2016, 2001b, pp.43, 60; IChemE, 2005, p.66].

NFPA 326, Standard for the Safeguarding of Tanks and Containers for Entry, Cleaning, or Repair, requires that "[a]ll work in or around the tank or container shall be stopped immediately when the flammable vapors in the atmosphere exceed 10% of the lower flammability limit (LFL). The source of the vapors shall be located and eliminated or controlled" [NFPA 326, 2005, p.9]. A number of countries including Australia, New Zealand, and nearly all Canadian provinces prohibit confined space entry above a defined safe flammable atmosphere limit that is substantially below the LEL (Appendix G).

Therefore, in light of the existing consensus of confined space codes and regulations establishing lower LEL limits for safe entry and the improved understanding of the increased hazards of working in permit spaces in atmospheres above 10% of the LEL, the CSB recommends that OSHA limit confined space work activities in the presence of flammables in the same manner and to the same degree as the agency has done in shipyards and as many other consensus standards recommend.

10.3 Colorado Public Utilities Commission

The Colorado Public Utilities Commission (PUC) is a state regulatory agency that oversees a wide variety of electric power and other utilities. Xcel is one of two investor-owned electric utilities operating in Colorado that are regulated by the PUC. The stated mission of the PUC is to serve the public interest "by effectively regulating utilities and facilities so that the people of Colorado receive safe, reliable, and reasonably priced services consistent with the economic, environmental and social values of our state."[110] The PUC has promulgated the Rules Regulating Electric Utilities (4 Code of Colorado Regulations 723-3, Part 3) that address a range of subjects including safety; construction, maintenance, and operation of electric utility facilities; and competitive bidding processes related to areas such as the acquisition of new utility resources.

The PUC rules require that the construction, maintenance, and operation of a utility be "in accordance with accepted engineering practice in the electric industry to assure continuity of service, uniformity in the quality of service, and the safety of persons and property."[111] The PUC rules provide that in the event of an incident resulting in death, serious injury, or significant property damage, the regulated utility shall inform the Commission within two hours of learning of the incident and submit a written report within 30 days.[112] The only content requirements of the written report are the date, time, place, location, and type of the incident; names of persons involved; and nature and extent of injury and damage. For the Cabin Creek incident Xcel sent a one-page letter to the PUC on November 1, 2007, briefly describing the incident and the number of people killed and injured. PUC rules state that if a utility conducts an internal investigation of an incident that any report developed shall be made available to the Commission upon request.[113] The PUC Commission was not notified of the availability of any internal investigation report by Xcel nor did the Commission receive any report. Xcel did not inform the Commission of the root causes of the Cabin Creek incident, recommendations for prevention, or any subsequent preventative measures taken by Xcel.

PUC electric utility contracting rules describe procedural requirements and criteria other than price to consider in the competitive bidding process but the provisions do not include any safety considerations.

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[110] Mission of the Public Utilities Commission, http://www.dora.state.co.us/puc/about/AboutMission.htm accessed 7-13-10.
[111] Colorado Department of Regulatory Agencies, 4 Code of Colorado Regulations (CCR) 723-3, Part 3, Rules Regulating Electric Utilities, Rule 3200(a), Construction, Installation, Maintenance, and Operation.
[112] Id. Section 3204(a) and (b).
[113] Id. Section 3204(c).

The rules contain provisions that regulate resource planning such as those resources that provide electrical capacity and renewable energy. The acquisition of utility resources can include new construction, maintenance, and repairs that significantly impact capacity or prevent service interuption. PUC rules favor competitive bidding for the acquisition of new resources and address requirements for the competitive bidding processes, requests for proposals (RPFs) and bid evaluation criteria. In 2010, the Colorado General Assembly approved renewable energy legislation that requires the Colorado Public utilities Commission to implement new "best value" contracting bid criteria for electric resource acquisition[114]. The additional criteria that need to be considered in the competitive bidding process include workforce training certifications, long-term career opportunities, and industry standard health care benefits. However, neither the existing PUC rules nor the new mandated criteria require that past safety performance be considered as a factor in the competitive bidding process, nor do they include safety prequalification or disqualification procedures.

[114] The 2010 Colorado General Assembly amended Colorado Revised Statutes 40-2-124 by House Bill 10-1001, http://www.dora.state.co.us/PUC/rulemaking/HB10-1001/HB10-1001_enr.pdf , accessed 7-13-10.

11.0 Flammables Used in Confined Spaces: Other Incidents

As part of its investigation of the Xcel penstock case, the CSB collected and compiled confined space incident data from the past 17 years to ascertain the prevalence of confined space flammable incidents and determine if the rate has been impacted by the promulgation of the Permit-Required Confined Spaces Rule. The CSB has determined that the hazard of flammable atmospheres in confined spaces has been a significant workplace safety issue since the promulgation of OSHA's Permit-Required Confined Space Rule on April 15, 1993.

The CSB compiled and researched incident data on 105 previous confined space incidents; of these, 53 were determined to be the result of a flammable atmosphere in a confined space. (Appendix I describes CSB's incident data collection methodology used to obtain this data.) The CSB also found that the number of confined space flammable incidents has increased the past nine years, as a majority of the 53 incidents from 1993 until April 2010 occurred since 2003. These flammable atmosphere confined space incidents include two the CSB investigated in 2009 that resulted in four fatalities (Appendix J).

The 53 identified confined space flammable incidents caused 45 fatalities and 54 injuries from 1993 to April 2010; approximately 57 percent included a fatality. The number of fatalities and injuries increased in the 17 years, with 49 percent of the total fatalities and approximately 57 percent of total injuries occurring since 2003. In the past 14 months, from February 2009 to April 2010, the CSB identified seven additional confined space incidents that resulted in six fatalities and four injuries.

The CSB analysis shows that a flammable atmosphere was present in the confined space prior to entry in 60 percent of the incidents sampled. Flammables were brought into the confined space for activities like painting/recoating, cleaning, or welding in the remaining approximately 40 percent. This data underscores the importance of monitoring the confined space both before entry and continuously in the work area where the confined space work activity includes the use of flammables. Continuous monitoring under these circumstances combined with flammable atmosphere limits established in procedures and permits are likely to alert workers to the importance of rapid changes that can lead to a flammable atmosphere so that workers can evacuate.[115]

The data suggest that, even after the promulgation of the Permit-Required Confined Space Rule, a significant number of confined space incidents with fatalities and serious injuries were attributed to flammable atmospheres. Furthermore, the increasing numbers of fatalities and injuries post-promulgation of the Permit-Required Confined Spaces Rule suggests the need for more protective requirements for work in potential flammable atmospheres in confined spaces.

[115] An example of how continuous monitoring can prevent worker fatality or injury is evident from a confined space incident that occurred on January 7, 2010 in Amsterdam, NY. Two telephone workers were conducting repair work in a telephone vault (similar to a manhole) when their combustible gas meter alarmed. They were able to evacuate the confined space prior to a small fire breaking out.

12.0 ROOT AND CONTRIBUTING CAUSES

12.1 Root Causes

1. Xcel and RPI management did not ensure effective planning and coordination of the Cabin Creek penstock recoating project to control or eliminate the serious confined space hazards that were present.

   - An effective hazard evaluation of the penstock confined space was not performed; the work required the use of a solvent to clean the epoxy sprayer and associated equipment in the open penstock atmosphere, yet the serious safety hazards of using a flammable solvent inside the confined space were not identified or addressed.
   - Substituting a non-flammable solvent was not considered.
   - Important safety precautions when using a flammable in a confined space, such as continuous monitoring in the work area, providing adequate ventilation, and eliminating or controlling ignition sources, were not implemented.

2. Xcel's and RPI's corporate safety policies and permits did not effectively establish safe limits for flammable atmospheres in permit-required confined spaces that would prohibit entry or occupancy when those limits were exceeded.

3. Early in the planning process, Xcel identified the Cabin Creek penstock's single point of egress in the event of an emergency as a major concern; RPI personnel also raised safety issues about a single exit. However, neither Xcel nor RPI management took remedial action.

   - American Society of Civil Engineering (ASCE) published safety guidance addressing penstock inspections advises on the importance of alternative escape routes in the event of an emergency (ASCE, 1998, p.2-8).

- As a result of the flash fire, five RPI workers, who were located on the side of the sprayer opposite the sole exit, were trapped by the growing flames and eventually succumbed to smoke inhalation.

4. Xcel management did not provide effective oversight of RPI to ensure the penstock recoating work was safely conducted.

   - Due to concerns about RPI's record of injuries and fatalities in past projects, Xcel added a "Safety Addendum" to the penstock recoating contract affirming that Xcel would closely observe RPI's safety performance. However, Xcel managers conducted safety observations of RPI on only two documented occasions in the 29 days that RPI personnel were on the job. During the penstock recoating work prior to the incident, Xcel managers were aware of several significant safety problems attributable to RPI, yet Xcel did not increase scrutiny of RPI's safety performance or implement corrective actions.

12.2 Contributing Causes

1. Xcel's corporate policies and practices addressing contractor selection did not adequately ensure contractor safety performance for the penstock recoating project.

   - During the contractor selection process, Xcel managers graded RPI safety performance as a zero, the lowest possible score; however, Xcel's contractor selection practices typically provided only for disqualification from the bidding process based upon financial capacity, not safety criteria.

   - The evaluation rating form stated that the score of zero did not met Xcel's minimum requirements and required automatic rejection; however, RPI was still allowed to compete for the penstock recoating contract. RPI's proposal was ranked as the best overall based primarily on its low price.

- RPI did not disclose to Xcel regulatory violations resolved within the requested three-year period as part of the RFP evaluation process. Xcel's corporate policies addressing contractor selection relied upon self-reporting and did not include specific procedures to verify the contractor's submissions.

2. Xcel and RPI managers did not plan and coordinate the immediate availability of qualified confined space technical rescuers outside the penstock, although the use of flammable solvent in the open atmoshere of the permit space created the need for immediate rescue due to the potential for IDLH conditions.

   - Neither company ensured that emergency response organizations or personnel with confined space technical rescue qualifications were immediately available with the necessary fire-fighting equipment outside the penstock.
   - The approximate travel time of the closest identified public emergency response organization with confined space technical rescue qualifications was approximately 1 hour and 15 minutes.
   - After the penstock fire erupted, firefighting and rescue activities likely would have been sucessfully provided to prevent the fatalities had qualified personnel and equipment been immediately available; the trapped RPI workers were in radio communication with coworkers and emergency responders for 45 minutes after the initial 9-1-1 call.

3. RPI did not ensure that the majority of its workforce at Cabin Creek had received comprehensive formal safety training, effective training on company safety policies, or site-specific instruction addressing confined space safety, the safe handling of flammable liquids, the hazard of static discharge, emergency response and rescue awareness, and fire prevention.

13.0 RECOMMENDATIONS

Occupational Safety and Health Administration (OSHA)

2008-01-I-CO-R1 Amend the OSHA Permit-Required Confined Spaces Rule for general industry (29 CFR 1910.146) to establish a maximum permissible percentage substantially below the lower explosive limit (LEL) for safe entry and occupancy in permit-required confined spaces.

2008-01-I-CO-R2 Publish a "Safety and Health Information Bulletin" addressing the hazards and controls when using flammable materials in confined spaces that includes actionable guidance regarding:

a. The importance of implementing a hierarchy of controls to address hazards in a confined space that first seeks to eliminate hazards or substitute with a less hazardous material(s) or method(s). Examples include performing work outside of a confined space where reasonably practicable or substituting a flammable material with a non-flammable one.

b. The necessity of establishing a maximum permissible percentage substantially below the lower explosive limit (LEL) for safe entry and occupancy of permit required confined spaces.

c. The need to comprehensively control all potential ignition sources and continuously monitor the confined space at appropriate locations and elevations when work activities involve the use of flammable materials or where flammable atmospheres may be created.

d. The importance of treating confined spaces with the potential for flammable atmospheres above 10 percent of the LEL as a hazard immediately dangerous to life or health (IDLH) that requires rescuers to be stationed directly outside the permit space and available for immediate rescue with appropriate fire-extinguishing and rescue equipment.

e. The requirement that confined spaces such as penstocks be managed as permit-required that are so large or part of a continuous system that they cannot be fully characterized from the entry point. Such spaces need to be monitored for hazardous atmospheres both prior to entry and continuously in areas where entrants are working.

The Governor of the State of Colorado

2008-01-I-CO-R3 Implement, through the Division of Fire Safety, an accredited firefighter certification program for technical rescue that encompasses appropriate specialty areas including confined space rescue.

The Colorado Public Utilities Commission

Revise your rules regulating electric utilities, 4 Code of Colorado Regulations 723-3, to:

2008-01-I-CO-R4

a. Require regulated utilities to investigate the facts, conditions, and circumstances of all incidents resulting in death, serious injury or significant property damage as defined in Section 3204

b. Require utilities to submit a written investigation report to the Commission within one year of the incident that contains the investigation findings, root causes and recommendations for preventing future incidents that focus on needed changes to utility safety systems. All reports shall be made public.

c. Authorize the commission to issue orders addressing needed corrective actions to be taken as a result of the incident.

d. Require utilities to submit periodic reports to the Commission detailing action taken on the incident report recommendations and Commission orders. All reports shall be made the public.

2008-01-I-CO-R5

Require all regulated utilities to fully cooperate with all government safety investigations including facilitating access to witnesses, facilities, and equipment; providing copies of requested records; and responding to interrogatories and other investigative requests for information as expeditiously as possible.

2008-01-I-CO-R6

Require that competitive bidding and contractor selection rules for construction, maintenance or repair of regulated utilities include procedures for prequalifying or disqualifying contractors based on specific safety performance measures and qualifications.

Director of the Division of Fire Safety and the Director the Division of Emergency Management for the State of Colorado

2008-01-I-CO-R7 Publish a safety communication that will inform fire service and emergency planning organizations in the state about the confined space safety lessons learned from the Cabin Creek incident including

a. The need to train and certify emergency response personnel who perform technical, including confined space, rescue.

b. The importance of a written confined space rescue plan for each designated permit space that includes

i. Methods of rescue and determination of whether a rescue team is required to standby outside the space.

ii. Rescue equipment requirements and plan of action.

c. The importance of treating confined spaces with the potential for flammable atmospheres above 10 percent of the LEL as a hazard immediately dangerous to life or health that requires rescuers to be stationed directly outside the permit space and available for immediate rescue with appropriate fire-extinguishing and rescue equipment.

d. The need for confined space rescue procedures to instruct emergency responders to not enter or occupy a confined space containing a flammable atmosphere 10 percent of the LEL or greater. Personal protective equipment (PPE) will not protect rescuers from an explosion in a confined space.

Xcel Energy, Inc.

2008-01-I-CO-R8 Revise your policies for solicitation and procurement of construction services to

a. Ensure that requests for proposals (RFPs) and selection processes include criteria and procedures for prequalifying or disqualifying contractors based on specific safety performance measures and qualifications.

b. Implement written verification procedures for the safety information and documentation submitted by contractors during the bidding and selection process.

2008-01-I-CO-R9 Revise your contractor safety policies to require a comprehensive review and evaluation of contractor safety policies and procedures such as the permit-required confined space program and safety performance of contractors working in confined spaces to ensure that any bidding contractor meets or exceeds Xcel Energy safety requirements.

2008-01-I-CO-R10 Conduct periodic safety audits of contractor selection and oversight at your power-generating facilities to ensure adherence to corporate contractor procurement and safety policies.

2008-01-I-CO-R11 Report key findings, causes and recommendations of the CSB report to Xcel shareholders so that the owners of Xcel are fully informed of the report contents and how Xcel intends to prevent a similar accident in the future.

Xcel Energy, Inc. **2008-01-I-CO-R12**

See below for recommendation text.

RPI Coating Inc. **2008-01-I-CO-R13**

Revise your confined space entry program and practices. At a minimum

a. Require continuous monitoring for flammable atmospheres at appropriate locations and elevations within a confined space where work activities involve the use of flammables or where flammable atmospheres may be created.

b. Prohibit entry or require evacuation of a confined space if the atmospheric concentration of flammable vapors is 10 percent of the LEL or higher.

c. Ensure that confined spaces such as penstocks be managed as permit-required that are so large or part of a continuous system that they cannot be fully characterized from the entry point. Ensure that such spaces are monitored for hazardous atmospheres both prior to entry and continuously in areas where entrants are working.

d. Ensure that evacuation plans for penstocks that have only one egress point provide for alternative escape routes and/or refuge chambers.

e. Ensure the implementation of a written confined space rescue preplan for each designated permit space. Address staging and methods of rescue for each designated permit space including whether a rescue team is required to standby outside the space. Require that confined space rescue teams be standing by at the permit spaces where the hazards pose an immediate threat to life or health including the hazard of a potential flammable atmosphere.

RPI Coating, Inc.

2008-01-I-CO-R14 Based on the findings and conclusions of this report, hire a certified safety professional to conduct periodic safety audits at your worksites. At a minimum, assess safety training, confined space safety, safe handling of flammables, emergency response, rescue, and fire prevention.

2008-01-I-CO-R15 Ensure that all journeyman painters have received safety training equivalent in content to that covered in the Joint Apprenticeship program. At a minimum, address confined space safety, safe handling of flammables, emergency response and rescue, and fire prevention.

The Society for Protective Coatings (SSPC) **2008-01-I-CO-R16**

See below for recommendations text.

American Public Power Association (APPA) **2008-01-I-CO-R17**

Publish safety guidance addressing the hazards and controls for using hazardous materials including flammables in confined spaces and the unique hazards of penstocks. At a minimum

a. In controlling hazards in confined spaces, implement a hierarchy of controls by first attempting to eliminate hazards or substitute with a less hazardous material(s) or method(s). Examples include performing work outside of a confined space where reasonably practicable or substituting a flammable material with a non-flammable one.

b. Establish a maximum permissible percentage substantially below the LEL for safe entry and occupancy of permit-required confined spaces.

c. Recommend that confined spaces that are large, or part of a continuous system such as a penstock, always be managed as permit-required as defined in the OSHA Confined Space Standard, and that such spaces always be monitored for hazardous atmospheres both prior to entry and continuously in areas where work is being performed.

d. Ensure that evacuation plans for penstocks that have only one egress point provide for alternative escape routes or refuge chambers.

e. Provide guidance for implementing a written confined space rescue plan. Address staging and methods of rescue for each designated permit space including whether a rescue team is required to stand by outside the space. Require that confined space rescue teams be standing by at the permit spaces where the hazards pose an immediate threat to life or health, including the hazard of a potential flammable atmosphere.

Southern California Painting and Drywall Industries Joint Apprenticeship and Training Committee

2008-01-I-CO-R18 Require that all journeyman painters who are employees and/or members have received safety training equivalent in content to that covered in the Joint Apprenticeship program. At a minimum, address confined space safety, safe handling of flammables, emergency response and rescue, and fire prevention.

2008-01-I-CO-R19 Include a safety knowledge and skills component to your journeyman and apprentice evaluation criteria.

BY THE

U.S. Chemical Safety and Hazard Investigation Board

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Chair

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Date of Approval August 25, 2010

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APPENDIX A: INCIDENT TIMELINE

Date	Time	Detail
Summer 1964		Construction of upper dam and reservoir underway, as part of the Cabin Creek Pumped Storage Hydroelectric Project.
1967		Original coal tar-based epoxy coating applied in penstock.
September 20, 2000 - December 9, 2000		Initial inspection and evaluation of the penstock determines that the internal epoxy coating of the steel-lined section shows signs of deterioration, including blistering and cracking.
June 4, 2001		Xcel internal report on the 2000 inspection states that corrective action to repair the areas of deterioration must be implemented to prevent continued corrosion and unacceptable pitting damage.
September 25, 2001		Robison-Prezioso Bay Bridge project incident kills a private citizen.
January 4, 2002		Robison-Prezioso Bay Bridge project employee fatality incident.
2004		Xcel hires a contractor to explore the possibility of creating a permanent access to penstock, but the project is rejected due to insufficient time to obtain FERC approval. RPI interstate Experience Modification Rate (EMR) is 0.93.
~ October 2004		A decision is made to recoat the penstock during the 2004 outage as a result of a metallurgist's inspection, which notes that the interior liner is peeling up to the concrete section.
2005		RPI interstate EMR is 1.03
2006		2006 SSPC audit finds that RPI has "No documentation of craft-worker assessment." RPI interstate EMR is 1.28.
January 3, 2006		The KTA-Tator Coating inspection contractor submits proposal for the penstock recoating project to Xcel.
November 1, 2006		Xcel reviews the existing penstock recoating plan.
October 1, 2006		Xcel conducts "Safety and Health Hazard Assessment Survey," focusing on the abrasive blasting portion of the recoating project work, but not the risks of epoxy recoating work associated with using a solvent in a confined space.
2007		Robison-Prezioso, Inc. is renamed RPI Coating; the company is ranked the nation's seventh-largest specialty paint company based on revenues in 2005, according to Engineering News-Record.

January 16, 2007		The KTA-Tator coating assessment contractor contracts with Xcel to inspect and report on the quality of RPI's penstock re-coating work for 2007 penstock recoating project.
January 17, 2007		Xcel's internal hazard assessment of the penstock re-lining project identifies the penstock as having a confined space hazard.
Spring 2007		An Xcel civil engineer identifies "major items of concern" with the penstock recoating project, including a lack of an alternative exit.
April 2007		Xcel issues an RFP to multiple vendors to recoat the penstock. Proposal asserts that an Xcel project manager will be fully integrated into the contractor's safety program. Only one vendor meets criteria for successful completion of the job, but the vendor's cost estimate exceeds Xcel's anticipated budget.
June 2007		First bid submissions evaluated; one company meets criteria but cost estimate is $450,000 over Xcel's estimated budget; Xcel resubmits the project for additional bids.
July 11, 2007		Clear Creek County Fire Authority conducts an emergency drill at the Cabin Creek facility, rehearsing a fire response to the power production office facility; this drill does not involve the penstock or a confined space rescue.
Late July 2007		RPI and one other company meet the criteria for consideration as the potential recoating contractor; although the competing bidder is more technically qualified and RPI Coating's safety record is poor, RPI is selected due to cost.
August 27, 2007		RPI requests a copy of Xcel's Cabin Creek site confined space procedures from the penstock recoating project team leader and the Xcel Cabin Creek plant manager. Plant manager states information will be covered in contractor orientation.
Late August – mid September 2007		RPI contractors begin arriving at the Xcel Cabin Creek site.
September 4, 2007		KTA-Tator project engineer sends review of RPI coating application plan, project schedule, coating application procedures, and product data sheets for epoxy materials to the Xcel recoating project team leader. The Xcel project scheduler provides contractor orientation with an RPI foreman and five contractors (of the 14 RPI employees involved in the penstock work).The orientation form indicates that all contractors are trained for confined space entry and that MSDSs have been provided to Xcel plant management. RPI notifies the Xcel scheduler that the contractors will be using a "ketone" solvent to clean the sprayer inside the penstock.
September 5, 2007		Xcel and RPI Coating hold a "Preconstruction Meeting" where project-specific safety concerns are to be identified; however, the use of flammables within a confined space and the need for emergency response and rescue plans are not discussed. Xcel identifies RPI's high EMR rate during the meeting and requires RPI to take extra precautions and informs RPI that Xcel's Stop Work Policy will be enforced during the penstock recoating project.
September 4-9, 2007		The upper reservoir is dewatered.

September 10, 2007		An instructor from Southern California Painting and Drywall Industries (SCPDI) District 36 Training Center conducts a six-hour safety refresher training session pertaining to OSHA-required topics at the Xcel Cabin Creek site for nine of the 14 RPI industrial painters at the request of RPI's safety director. This training consists of watching safety videos on each topic and multiple-choice exams on the information; the training is general in nature and not tailored to all site-specific safety risks of the penstock work.
September 11-October 2, 2007		A number of confined space entry permits and air monitoring logs are completed by RPI that indicate that continuous air monitoring is required inside the penstock. Logs reveal that KTA-Tator and Xcel employees entered the penstock on several occasions to inspect and/or review RPI Coating's work progress.
September 12, 2007		110 gallons of MEK (two 55-gallon drums) delivered to Cabin Creek site. RPI conducted a test spray with the epoxy and MEK at Cabin Creek site; the Xcel principle engineer was present during this test spray.
September 15, 2007		RPI reports trouble with 480 volt power feed to equipment in the penstock. Xcel employees enter the penstock to troubleshoot the electrical equipment. Incorrect wiring is modified.
September 16, 2007		Entry into the penstock is delayed 2 hours due to high carbon monoxide (CO) levels. RPI experiences additional electrical service problems inside penstock. Foreman rewires an electrical spider box in the penstock for RPI Coating.
September 19, 2007		Xcel Cabin Creek personnel leave high bay fans on to ventilate errant CO from coming down penstock to hydroelectric plant's substation lower level.
September 21, 2007		RPI Coating begins sandblasting inside the penstock; the company is 5 days behind its tight 10-week schedule.
September 22, 2007		The Xcel Penstock Reline Project Manager observes RPI Coating conducting abrasive blasting inside the penstock and notes: "Work conditions inside the penstock are highly hazardous on many levels. In the best of conditions, the coating removal is dirty, nasty work." KTA-Tator conducts an initial pre-job hazard assessment of the penstock, noting that the MSDSs for all coatings and solvents used in the project are available. Inspector also notes that RPI and the Xcel penstock recoating project manager were advised on the MSDSs.
September 26, 2007		Xcel employees enter the penstock to perform welding on weep holes to stop leaks. The KTA-Tator inspector conducts a "Task Summary: Coating Observation Hold Points" inspection of the penstock interior. Inspection identifies the use of thinner as part of the coating materials mixing and pre-application process, and documents the necessity of using thinner/solvent to flush the sprayer system equipment (including hoses, nozzles, and the sprayer itself).

October 1, 2007	8:00 AM	Xcel personnel conduct a safety evaluation of RPI's sandblasting work inside penstock; no unsatisfactory items are noted.
	~12:00 PM	An Xcel welder enters with the RPI Coating foreman to begin welding around the leaking seep hole/cap in the penstock. The welder does not sign into the log book at the penstock's entrance.
October 2, 2007	Morning of	Sand-blasting activities, including hand sanding and grinding of the walls, are completed. RPI employees began the preparatory steps for applying the new coating onto the penstock interior. No special precautions are taken beyond those in place prior to starting the sandblasting operation.
	8:00 AM	Xcel welder completes welding job around the leaking seep hole/cap in the penstock.
	1:10 PM	RPI project supervisor and KTA-Tator inspector leave for lunch. RPI employees continue attempts to apply epoxy to the first 12-15 feet of the penstock's interior, but difficulties with the sprayer and epoxy mixture prevent satisfactory application.
	~1:55 PM	**A flash fire ignites at the sprayer in the immediate vicinity of the base hopper while the contractors flush the system with MEK solvent. This rapid fire catches one contractor's sleeve on fire and quickly engulfs a number of buckets of solvent located on and around the scaffold of the epoxy sprayer.**
	1:59 PM	A worker rapidly exits from the penstock access door and runs to notify the Xcel control board operator about the fire in the penstock.
	~2:00 PM	The Xcel employees at upper reservoir mushroom hear a "whoosh," followed by yelling, but what is being said is unintelligible.
	2:03 PM	Clear Creek County dispatch receives a 9-1-1 call from the Xcel control board operator regarding the fire and initiates emergency response.
	2:11 PM	The Clear Creek County Sheriff's officers' response vehicle arrives at the Cabin Creek site.
	2:20 PM	Xcel operator log book documents: "Emergency services w/o confined space fire training arrived. They have summoned a Denver team."
	2:22 PM	Additional emergency responders from various districts/units arrive at Cabin Creek site.
	2:25 PM	West Metro Rescue asked to respond to Cabin Creek site.
	2:30 PM	An RPI contractor retrieves and gives the MSDSs to the Georgetown Police Department. Henderson Mine Rescue team asked to respond to Cabin Creek site.
	~2:45 PM	Final radio communication from the trapped workers is received by emergency responders and co-workers.

	2:47 PM	A small group of responders and an RPI employee enter the penstock through the access door, travel up the penstock, but exit shortly thereafter due to the thick black smoke conditions.
	~3:00-3:15 pm	Xcel employees at the upper reservoir mushroom intake report seeing ash and flecks of burned material come out of the penstock.
	3:15 PM	SCBA oxygen tanks are dropped into mushroom upper end of penstock.
	3:25 PM	Residual smoke evident from penstock access door.
	3:30:37 PM	A growing smoke cloud is evident around the penstock access door.
	3:40 PM	West Metro Fire Rescue arrives at Cabin Creek.
	3:54 PM	A cloud of smoke remains evident in front of the penstock access door.
	4:10 PM	Henderson Mine Rescue arrives at Cabin Creek
	4:45 PM	Emergency responders wearing SCBA enter the penstock
	5:35 PM	Emergency responders on site receive the first order from Incident Command to fight/extinguish the fire; Henderson Mine team to enter.
	5:45 PM	Henderson Mine team enters the penstock through the access door to check air quality, size up the fire, and locate/rescue the trapped contractors.
	~9:00 PM	Xcel personnel allowed back into the Cabin Creek substation building, as air monitoring results are found to be at safe levels.
October 3, 2007	2:00 PM	Fatally injured workers are removed from the penstock.
	8:00 PM	The incident scene is released back to Xcel.

APPENDIX B: REGULATORY HISTORY OF RPI COATING, INC.

OSHA Inspection and Citation History
Robison-Prezioso Inc. (RPI Coating, Inc.)
5/27/88 - 12/31/2008

Date	Inspection Number	Location	State	Inspection Type	Emphasis Program	Citation Summary	Initial Penalty	Final Penalty	Resolution
10/7/2008	312279870	Overton	NV	Planned - Safety		OSHA 300 log errors	$0	$0	Closed
5/14/2008	311643977	Jean	NV	Referral - Health		None			Closed
11/5/2007	311634307	Las Vegas	NV	Compliant - Health	Special - Construction	None	$0	$0	Closed
10/2/2007	310470034	Georgetown	CO	Accident - Safety; 5 fatalities	National - Lead; Special - Electrical; Special - Fall from Height; Special - Lead; Special - Powered Industrial	Working surfaces; flammable liquids; respirators; confined space; welding; electrical wiring; hazard communication	$845,100		Contested
12/29/2005	125529636	Santa Rosa	CA	Planned - Safety	Special - Construction	No ROPS or seatbelt installed on equipment	$150	$150	Closed
10/13/2005	110569803	Davis Monthan AFB	AZ	Program Related[1] - Safety		No body belt worn on vehicle-mounted rotating work platform	$1,375	$1,375	Formal Settlement Agreement (FSA); Closed

[1] A Program Related inspection is one where OSHA conducted an unannounced programmed inspection at an establishment and also inspected RPI, who was working at the establishment as a contractor.

OSHA Inspection and Citation History Robison-Prezioso Inc. (RPI Coating, Inc.) 5/27/88 - 12/31/2008									
Date	**Inspection Number**	**Location**	**State**	**Inspection Type**	**Emphasis Program**	**Citation Summary**	**Initial Penalty**	**Final Penalty**	**Resolution**
10/5/2005	125529289	Santa Rosa	CA	Planned - Safety	Special - Construction	Flaggers not used at a construction site when warning signs and barricades could not be used to control traffic	$150	$150	Closed
9/27/2002	305639262	Vantage Bridge I-90	WA	Complaint - Health		None	$0	$0	Closed
9/23/2002	305551491	Vantage Bridge I-90	WA	Planned - Safety	Local - Construction	No written fall protection work plan; No fall restraints/fall arrest systems;	$600	$600	State Decision
5/10/2002	300891090	San Francisco	CA	Complaint - Health	National - Lead; Special - Construction	Cadmium - Improper removal and storage practices	$13,500	$280	FSA; 24 citations deleted; closed
1/4/2002	300890555	San Francisco	CA	Accident - Safety; 1 fatal; 4 hospitalized		Improper scaffold design; Rated load capacity exceeded on suspended scaffold; Platform on suspended scaffold not wide scaffold not wide enough or missing a guardrail; Improper erection or dismantling of scaffolds; Scaffold overloaded	$41,400	$41,400	Open
9/25/2001	300890100	San Francisco	CA	Accident - Safety	Special - Construction	Framed panels not securely anchored, guyed, or braced; Machinery and equipment components not designed, secured, or covered to minimize hazards caused by breakage, release of mechanical energy (e.g., broken	$18,000	$18,000	Open

OSHA Inspection and Citation History Robison-Prezioso Inc. (RPI Coating, Inc.) 5/27/88 - 12/31/2008									
Date	**Inspection Number**	**Location**	**State**	**Inspection Type**	**Emphasis Program**	**Citation Summary**	**Initial Penalty**	**Final Penalty**	**Resolution**
						springs), or loosening and falling			
6/19/2001	304706450	Cape Canaveral AFS	FL	Program Related - Safety	Local - Fall, FLCare; Special - Construction, Construction Fatalities	No medical services/first aid available; Unsafe abrasive blasting respirators; **Flammable liquid dispensing units not protected against collision damage; "No smoking" signs were not posted in flammable liquid areas**; Spinner knobs were attached on steering wheels of equipment; Industrial truck did not meet ANSI standard requirements	$9,375	$5,250	FSA; Closed
4/23/2001	304422132	Henderson	NV	Planned - Safety	Special - Construction	None	$0	$0	Closed
4/23/2001	304425416	Henderson	NV	Planned - Health	Special - Construction	None	$0	$0	Closed
3/20/2001	126030634	Coalinga	CA	Accident - Safety; 1 hospitalized		Injury not immediately reported to Cal-OSHA; Forklift operating rules not enforced	$935	$935	Closed

OSHA Inspection and Citation History
Robison-Prezioso Inc. (RPI Coating, Inc.)
5/27/88 - 12/31/2008

Date	Inspection Number	Location	State	Inspection Type	Emphasis Program	Citation Summary	Initial Penalty	Final Penalty	Resolution
3/7/2001	125637058	San Francisco	CA	Planned - Health	National - Lead; Special - Construction	Cadmium - No regulated area or demarcation, no monitoring, prohibited activities conducted, no medical for respirator use, torn PPE not replaced; Machinery not maintained in safe condition; Separate shower facilities not available for females; Safety glasses interfere with respirator; Compressed gas cylinder not secured while being transported; Pinch points on machinery not guarded	$83,925	$20,250	FSA; 19 violations deleted; open
2/27/2001	125619239	San Francisco	CA	Accident - Safety; 1 hospitalized		Ramps/Runways not 20-inches wide; Metal scaffolds - Railings and planks not secured; Improper anchorages for personal fall protection equipment	$26,100	$18,000	FSA; One item deleted; Closed
10/11/2000	300888401	Bay Bridge - Lower Deck, San Francisco	CA	Accident - Safety		None	$0	$0	Closed
12/17/1999	120266846	Pasadena	CA	Complaint - Health	Local – Regulated carcingen	None	$0	$0	Closed
5/28/1999	302528437	Spring Mountain Overpass, Las Vegas	NV	Complaint - Safety		None	$0	$0	Closed

OSHA Inspection and Citation History Robison-Prezioso Inc. (RPI Coating, Inc.) 5/27/88 - 12/31/2008									
Date	**Inspection Number**	**Location**	**State**	**Inspection Type**	**Emphasis Program**	**Citation Summary**	**Initial Penalty**	**Final Penalty**	**Resolution**
3/2/1999	119737997	Yeruba Buena Island, San Francisco	CA	Planned - Safety	Local - Regionp1[2]	None	$0	$0	Closed
12/28/1998	11967461	Yeruba Buena Island, San Francisco	CA	Planned - Health		Cadmium - No initial monitoring; Respirators not worn; Torn PPE not replaced; Fall protection - Positioning systems not used	$2,495	$1,685	FSA; Closed
10/13/1998	302524384	Las Vegas	NV	Planned - Safety		**More than 25 gallons of flammable or combustible liquids stored in a room outside of an approved storage cabinet; No portable fire extinguisher, having a rating of not less than 20-B units, located outside of, but not more than 10 feet from, the door opening into any room used for storage of more than 60 gallons of flammable or combustible liquids; Flammable liquids were used where there were open flames or other sources of ignition within 50 feet of the operation**	$375	$375	Review Commission Decision

[2] This is a code for a state of California local emphasis program.

OSHA Inspection and Citation History Robison-Prezioso Inc. (RPI Coating, Inc.) 5/27/88 - 12/31/2008									
Date	**Inspection Number**	**Location**	**State**	**Inspection Type**	**Emphasis Program**	**Citation Summary**	**Initial Penalty**	**Final Penalty**	**Resolution**
7/15/1998	126141324	Oxnard	CA	UnProgrammed Related[3] - Health		Cadmium	$185	$185	FSA; Closed
1/8/1998	115218703	Highway 17N, Soap Lake	WA	Complaint - Health		None	$0	$0	Closed
5/28/1997	125658047	Los Vacqueros Dam, Brentwood	CA	Planned - No Inspection	Local-Tunnel	None			
5/27/1997	126207984	Santa Maria	CA	Accident - Safety; 1 hospitalized		Improper portable wooden ladders; Injuries not immediately reported; no Injury and Illness Prevention Program	$150	$150	Closed
5/23/1997	126053537	Los Angeles	CA	Complaint - Health		No Injury and Illness Prevention Program	$185	$185	Closed
1/17/1997	115236564	Highway 17N, Soap Lake	WA	Complaint - No Inspection/Process Inactive		None			

[3] An UnProgrammed Related inspection is one where OSHA was conducting a fatality, compliant, or referral inspection at an establishment and also inspected RPI, who was working at the establishment as a contractor.

OSHA Inspection and Citation History
Robison-Prezioso Inc. (RPI Coating, Inc.)
5/27/88 - 12/31/2008

Date	Inspection Number	Location	State	Inspection Type	Emphasis Program	Citation Summary	Initial Penalty	Final Penalty	Resolution
10/11/1996	119772846	Los Vacqueros Dam, Brentwood	CA	Planned - No Inspection	Local-Tunnel	None			
2/5/1996	119874667	Los Angeles	CA	UnProgrammed Related - Health		None	$0	$0	Closed
9/26/1995	11966949	Rodeo	CA	UnProgrammed Related - Health		None			
5/9/1995	112130059	Carson	CA	Accident; 1 hospitalized		No training on aerial lifts; Foundation soil not maintained in safe condition	$5,525	$600	FSA; 1 citation deleted
3/10/1994	123834228	Tracey	NV	Planned - Safety		Hazard communication - improper labeling, MSDS, training; no respirators	$3,000	$3,000	FSA; Closed
12/1/1993	112173331	Calabasas	CA	UnProgrammed Related - Health		No monitoring for hazardous substances (deleted); No eyewash	$900	$225	Administrative Law Judge (ALJ) Decision; 1 citation deleted; Closed
4/8/1993	12386675	Las Vegas	NV	Planned - Safety		**No bonding/grounding when transferring flammable liquids between containers**; Containers not provided for waste rags; Improper	$125	$125	State Decision; Closed

OSHA Inspection and Citation History Robison-Prezioso Inc. (RPI Coating, Inc.) 5/27/88 - 12/31/2008									
Date	**Inspection Number**	**Location**	**State**	**Inspection Type**	**Emphasis Program**	**Citation Summary**	**Initial Penalty**	**Final Penalty**	**Resolution**
						temporary wiring; Unapproved forklift			
9/24/1992	119989457	Cardiff	CA	Complaint - Health		Improper temporary wiring, ladders, floor openings	$2,770	$2,475	ALJ Decision; Closed
9/23/1992	119988425	Carlsbad	CA	Complaint - Health - No Inspection		None			
8/7/1992	107108474	Alyeska Pipeline Marine Terminal, Valdez	AK	Compliant - Safety		Improper air compressors for abrasive blasting; HAZCOM labeling and MSDSs; No first aid training; No washing facilities; No respirators; Temporary heaters too close to combustibles; Improper electrical wiring; No fall protection	$14,300	$4,054	Informal Settlement; 4 citations deleted; Closed
7/7/1992	114570963	Henderson	NV	Planned - Safety		Smoking not prohibited where flammable liquids are present; Hazard communication; **Flammable liquids stored or transferred in unapproved containers**; Respirators; Air powered tools	$4,650	$2,325	Informal Settlement; Citation Amendments; Closed
6/9/1992	11566424	Phoenix	AZ	Complaint - Health		None			
6/9/1992	115561169	Phoenix	AZ	Complaint - Safety		None			

OSHA Inspection and Citation History Robison-Prezioso Inc. (RPI Coating, Inc.) 5/27/88 - 12/31/2008									
Date	**Inspection Number**	**Location**	**State**	**Inspection Type**	**Emphasis Program**	**Citation Summary**	**Initial Penalty**	**Final Penalty**	**Resolution**
5/5/1992	112051784	Lancaster	CA	Accident; 2 hospitalized		No head protection; Improper rolling platform scaffold planks and construction	$2,250	$2,250	Closed
4/3/1992	111872867	Playa Del Ray	CA	Accident - 1 Hospitalized		Portable ladders not secured	$0	$0	ALJ Decision; Closed
1/10/1992	11199040	Playa Del Ray	CA	UnProgrammed Related - Safety		Personal Fall Protection not used	$600	$600	ALJ Decision; Closed
10/30/1991	112088117	Carson	CA	Program Related - Safety	Local - Refinery	Respiratory protection not used	$0	$0	Closed
8/8/1991	111994851	Oakley	CA	UnProgrammed Related - Safety		Safe Code of Practices not posted	$0	$0	Closed
5/16/1991	112223318	Goleta	CA	UnProgrammed Related - Health		Respiratory protection no used	$0	$0	Closed
4/24/1991	111979316	Fountain Valley	CA	UnProgrammed Related - Safety		None			
4/5/1991	111869483	Playa Del Ray	CA	UnProgrammed Related -Safety		None			
1/7/1991	112113501	Playa Del Ray	CA	UnProgrammed Related - Safety		**Flammable vapors were not controlled**; Flammable liquid containers not marked; No portable fire extinguisher outside flammable storage room; Open flames not prohibited in flammable liquid	$0	$0	Closed

OSHA Inspection and Citation History Robison-Prezioso Inc. (RPI Coating, Inc.) 5/27/88 - 12/31/2008									
Date	**Inspection Number**	**Location**	**State**	**Inspection Type**	**Emphasis Program**	**Citation Summary**	**Initial Penalty**	**Final Penalty**	**Resolution**
						storage rooms			
12/4/1990	112117767	Playa Del Ray	CA	UnProgrammed Related - Safety		Improper temporary stairs	$0	$0	Closed
10/26/1990	112082862	Wilmington	CA	Program Related - Safety	Local - Refinery	Lack of suitable eye and face protection; Hazard communication	$0	$0	Closed
5/27/1988	106775455	New Hall	CA	UnProgrammed Related - Safety		Respirators; PPE; **Flammable liquids in unapproved containers**	$540	$540	Closed

APPENDIX C: INVENTORY OF FLAMMABLE AND COMBUSTIBLE MATERIAL IN PENSTOCK

Flammable and Combustible Material in Penstock	Distance from Sprayer	Number of buckets[119]
One (2-gal) bucket with MEK, heavily melted at scaffolding[120]	Between 79 ft and 91 ft	1
Three 5-gallon buckets of epoxy/MEK mixture (~12 gallons, of which ~5 gallons were MEK) on penstock floor, adjacent to sprayer stage	On floor, adjacent to sprayer	3
Three buckets of MEK (~11-12 gallons) and at least eight buckets of epoxy (epoxy buckets completely melted and, therefore, unable to determine if base or hardener; only handles survived fire)	On stage with sprayer	11
Eight (5-gal) buckets of base; three (5-gal) additional melted buckets of base; one (2-gal) bucket of hardener; and indeterminate number of completely melted buckets	13 ft, 9 3/8 in	12+
Twelve (2-gal) buckets of hardener; indeterminate number of completely melted buckets	101 ft, 1 in	12+
Ten (5-gal) buckets of base; 20 (2-gal) buckets of hardener	172 ft, 11 7/8 in	30
Four (2-gal) buckets of hardener	228 ft, 3 ¾ in	4
Ten (5-gal) buckets of base at 500’ mark in penstock	380 ft, 3 5/16 in	10
Nineteen (5-gal) buckets of base	532 ft, 2 7/8 in	19
TOTAL NUMBER OF BUCKETS INSIDE PENSTOCK		**102+**

[119] The number of buckets, instead of actual volumetric quantity, of the epoxy and MEK are provided here because a number of the buckets were destroyed in the fire; only the wire handles of these buckets remained post-incident. As a result, the CSB could not determine if the handles belongs to 2-gallon or 5-gallon buckets.

[120] The exact location of this bucket is unknown because it was moved while victims were being removed; distance estimate is based on CBI initial entry report that buckets were located on and under scaffolding, and knowledge that scaffolding was 12 feet long, adjacent to the west bulkhead.

APPENDIX D: EVALUATION OF IGNITION SOURCES

As Section 5.2.2 explains, numerous potential ignition sources existed in the immediate area of the sprayer at the time of the fire. Below is a detailed analysis of each potential ignition source the CSB considered. Supporting evidence for each analysis is based on examination of physical evidence, interviews with witnesses, tests on equipment preserved from the scene as evidence, and the physical and chemical properties of the materials involved at the time of the incident based on local environmental conditions inside the penstock. In certain cases, conflicting witness statements and extensive fire damage to the equipment made it impossible for the CSB to determine events and/or exact equipment configurations just before the fire; as a result, the CSB could not positively rule out several potential ignition sources due to lack of evidence.

D.1 Static Ignition of Explosive MEK Vapor-Air Mixture inside Sprayer Base Hopper

The CSB concluded that static electricity generated while flushing MEK in the base hopper was the most likely source of ignition. One worker testified that he was looking into the base hopper and saw the initial flash of MEK near the bottom of the hopper. The worker stated that he was holding a 3/8-inch diameter braided nylon, non-metal reinforced, hose with a metal JIC[121] swivel connector at the end, close to the inside wall of the metal hopper. This was about 6 inches (15 centimeters) from the top and about 1foot (30 centimeters) above the MEK surface. The hopper contained a 3-inch (8-centimeter) depth of MEK, or about one-half gallon (2 liters). The MEK was being circulated from the base hopper through the sprayer's air-driven piston pump, electric heater, piping, and hose, back into the base hopper to flush remaining epoxy particles from the sprayer.

[121] JIC stands for Joint Industrial Council, which revised specifications for these types of connectors in the 1960s.

Assuming that the electric heater for the base hopper on the sprayer was not operating and the temperature of the MEK was the same temperature as the penstock[122] (approximately 47-53 °F or 8-12 °C), the CSB determined that the hydrocarbon-air mixture in the region where the journeyman painter was holding the swivel connector was likely near its most easily ignitable composition (Appendix E). Once ignited, the brightest flame would have appeared in the bottom of the base hopper where the hydrocarbon-air mixture was optimal for combustion. Ignition inside the base hopper would have produced a rapid deflagration with an outwardly directed pressure wave, thus producing a “fireball.” This scenario matches descriptions given by the workers who saw the initial flash.

After the incident, the JIC swivel and the base hopper hose could not be located. However, the fitting on the other end of the base hopper hose was still attached to the valve on the sprayer. This fitting had an internal diameter of 0.117 inches (0.297 centimeters). In addition, remnants were found of an inner woven metal sheath that had belonged to the hose used to circulate MEK in the hardener hopper. The lack of a similar metal sheath on the base hopper hose led the CSB to conclude that the base hopper hose was most likely constructed from a non-conductive material, which was likely consumed by the fire.

Based on testimonial evidence that the pump was being operated with an air supply pressure of 10-15 psig (0.7-1.0 barg) and using the performance curves for the 56:1 King piston pump supplied by the sprayer manufacturer, the CSB estimated a maximum liquid flow rate of 4-5 gallons (15-19 liters) per minute during circulation. The maximum flow velocity of MEK through the JIC swivel was then estimated to be 12-16 feet (3.7-4.9 meters) per second. This estimate neglects the pressure drop from the King Pump to the JIC swivel connector outlet by extrapolating the pump curves to ambient pressure. Frictional losses would have occurred in the heater, the quarter-turn valve, piping, hoses, and the JIC swivel connector

[122] The air temperature inside the penstock was fairly constant, as demonstrated by daily temperature readings taken by the KTA-Tator inspector from the beginning of the project.

itself. Since the MEK was being used to clean residual epoxy base resin from the system, it is plausible that the narrowest parts of the system (i.e., the quarter-turn valve and JIC swivel connector) could have, at least periodically, become partly blocked with resin. Therefore, a range of different flow velocities, up to a maximum of 16 feet (4.9 meters) per second, was possible during circulation, accompanied by a range of different pressures at the JIC swivel connector, depending on its orientation and any additional restrictions created by resin blockage.

The JIC swivel connector operated as a spray nozzle with pulsed flow produced by the King piston pump. Consequently, MEK liquid flowing through the JIC swivel connector would have broken up into droplets. This shearing action would have resulted in electrical charge separation with respect to the metal connector, leaving a net charge on the spray and an equal but opposite charge on the ungrounded JIC swivel connector.

The potential for static charges to accumulate on the isolated JIC swivel connector increases as the length of the hose increases and as the hose diameter decreases. The electrical resistance is proportional to hose length and inversely proportional to the hose cross-sectional area. Static charge accumulation in the swivel also becomes more likely as the MEK velocity through the swivel end connector increases, as the rate of charge separation increases, and as the operation more closely resembles a spray nozzle. Provided the liquid breaks up into a spray, the only continuous electrical path from the JIC swivel connector to ground is through the column of MEK liquid in the hose. Since circulation was carried out using a King piston pump, pulsation spraying increases the probability of a non-continuous outlet jet. Charging may have been further increased if suspended epoxy particles were present in the MEK, especially if these particles created flow restrictions at narrow points in the valve and/or JIC swivel.

The following analysis estimates the potential "spark energy" that could be stored by an isolated JIC end connector and demonstrates that the spark energy was sufficient to ignite the MEK vapor-air mixture inside the base hopper. This discussion assumes that the resistance of the hose is infinite (i.e., constructed of a non-conductive material) compared to that of the column of conductive MEK contained within it; that the MEK was ejected as a pulsating spray jet offering no continuous conductive path to ground; and that the JIC swivel connector was held close to the hopper wall creating a potential spark gap of a few millimeters:

- The CSB calculated that the Minimum Ignition Energy (MIE) of an optimum MEK vapor-air mixture under penstock conditions to be about 0.5 mJ (Appendix E).
- Although the capacitance of the isolated JIC swivel end connector might be only 3-5 pico Farads (pF), which is typical for a small metal object, this would have increased several-fold by coupled capacitance with both the hopper wall and journeyman painter's gloved hand. The estimated range of capacitance ("C") is 7-15 pF, although larger values are possible.[123]
- Using the formula $W = ½(CV^2)$ to describe the energy of charged capacitors, where W is the stored energy (Joules), C is the estimated capacitance (Farads), and V is the spark voltage (Volts), the voltage required to yield an incendiary spark of 0.5 mJ is in the range 8,160-12,000 volts.
- The resistance to ground (R) via the column of conductive MEK contained within the hose is determined by the formula $R = \rho L/A$, where ρ is the resistivity of MEK (approximately 1×10^5 ohm-meters); L is the length of the hose (7.0 feet or 2.1 meters); and A is the internal cross sectional area of the hose (approximately 31.7 mm^2 or 3.17×10^{-5} m^2). If these values are substituted, the resistance to ground via the hose is approximately 6.6×10^9 ohms (or on the order of 10^{10} ohms).

[123] An experimental simulation would be needed to obtain a more accurate value.

- Using Ohm's Law (I = V/R), where I is the charging current (Ampere); V is the required voltage of the isolated end connector (V = 8,160-12,000 volts); and R is the ground resistance through the MEK in the hose (6.6×10^9 ohms), the required charging current is in the range of 1.2-1.8 microamperes (µA). This is the charging current needed to support a voltage of 8,160-12,000 volts on the swivel connector given the leakage resistance of 6.6×10^9 ohms back to ground through the MEK in the hose.

- The estimated voltage of 8,160-12,000 volts could have produced a spark several millimeters long. Spark energies of 0.5 mJ are very small (roughly 1 percent of an automobile spark plug) and unlikely to be observed, even if a succession of such sparks were to occur.

- A circuit containing a resistor and capacitor is called an "RC" circuit. In this type of a circuit, current varies with time. The RC time constant of the JIC swivel is about 0.1 seconds—this is the product of resistance to ground (on the order of 10^{10} ohm) and capacitance (on the order of 10^{-11} F). The connector would be capable of charging to its maximum voltage in about five time constants, or one-half second. Sparks could therefore have occurred on a frequency of about two per second given these assumptions. Incendiary sparking would have been prevented by gaps much larger than a few millimeters or by a continuous stream of liquid from the swivel to the wall. The worst case (most frequent sparking) is for the liquid to continuously break up into spray and the swivel to be held about 0.12 inches (3 millimeters) from the hopper wall and spraying downwards. This is consistent with journeyman painter's testimony of how the hose was positioned to minimize splashing the MEK inside the base hopper.

High-velocity MEK spraying through an isolated JIC swivel connector (i.e., "nozzle") with a charging current of 1.2-1.8 µA could have accumulated sufficient stored energy to produce a series of incendiary sparks capable of igniting the MEK vapor-air mixture (i.e., having at least 0.5 mJ energy). The ignition probability would have been greatly increased by the large number of sparks possible during circulation, plus the variety of charging conditions, spark gap geometries, and mixture compositions involved.

Although the journeyman painter was not electrically grounded, the CSB considers it unlikely that static ignition occurred from a "doorknob type" spark between the journeyman painter and the sprayer. The CSB also considers it unlikely that electrical charging of the journeyman painter's Tyvek® coveralls[124] could have resulted in brush static discharges because evidence indicates that he was essentially stationary on the sprayer platform during the circulation operation. However, the painter might have become charged while holding the circulation swivel nozzle, which is considered a variation of this ignition source scenario. Had the painter's glove had a hole, notably in the thumb or index finger holding the nozzle, he could have become charged to many kilovolts while the nozzle was not contacting the hopper wall. This would have allowed a spark to subsequently occur once the nozzle approached the hopper wall. Assuming his capacitance was 200 pF,[125] an incendiary spark would require a voltage of 2.2 kV and a charging current of about 0.33 μA. Accordingly, there is less than an order-of-magnitude reduction in the charging current requirement to give an incendiary static spark and this variation has little practical importance.

Lundquist et al. (1975) observed charging currents up to about 6 μA during airless paint spraying of conductive liquids. Although the MEK circulation operation was being carried out at much lower pressures and with a larger nozzle diameter than those used for airless paint spraying, the Lundquist et al. work shows that conductive liquids such as alcohols produce higher charging currents than less conductive liquids and that larger diameter nozzles and higher pressures (i.e., higher liquid velocities) produce higher charging currents. Their article implies that charging currents vary widely with conditions,

[124] The manufacturer of Tyvek coveralls cautions users against wearing this type of protective clothing in flammable or explosive atmospheres as doing so can generate static.

[125] 200 pF is frequently used as an average value for the capacitance of a person (Britton, 1999, p. 44).

and overall, supports the static charging scenario, although the magnitude of the charging current would need to be resolved experimentally. The need for proper grounding of paint spray nozzles is stressed in the Lundquist article. In addition, NFPA 77 (2007), the operating manual for the sprayer, and even RPI's safety program, contain safety warnings about proper grounding of equipment and the need to use conductive hoses.

D.2 Stray Current Ignition of Explosive MEK Vapor-Air Mixture inside the Sprayer Base Hopper

Some RPI workers' statements reveal that a dimming of the lights at the work area inside the penstock nearly coincided with the initial flash of the fire. These lights were powered from PDC 3, the power distribution center closest to the sprayer. PDC 3 also powered the 240-volt heaters on the pump outlets. During interviews with the CSB, these workers associated the dimming lights with the base heater coming on, but the CSB found no other evidence to support this. It can be inferred only that the voltage supplying the lights suddenly dropping was caused by increased power load as a result of the base heater turning on. The dimming lights could equally well have been caused by events outside the penstock. Power distribution center PDC 3 was preserved as evidence and examined closely by the CSB and other parties at an offsite location; no evidence of internal ignition (such as shorting) was found inside. However, the examination did reveal that the 240-volt power supply for the heaters was wired with a three, rather than a four, -prong connector. Thus, there was no ground connection in the circuit and the sprayer was operated with a floating neutral.[126] Although the sprayer was equipped with an independent

[126] A floating neutral means no neutral-to-ground bond in the electrical distribution system, which causes the neutral conductor to "float," or lose its reference to ground. Should the loading become unbalanced or an electrical short occur, the phase voltages fluctuate severely. This spider box had been damaged as a result of electrical problems early in the recoating project and repaired by an RPI employee. This individual was not a licensed electrician and lacked training certifications to perform electrical work.

grounding wire, the ground wire was not connected to any ground point when it was examined after the incident.

At the time of the flash, two spray hoses (one containing the base, the other the hardener) were attached to the sprayer, each going out to the metal mixing block. While preparing the spraying equipment inside the penstock, an apprentice painter stated that he saw a series of "sparks" jumping from the sprayer unit to one of the spray hoses when he connected it with a crescent wrench, implying faulty bonding in the spray hose. The CSB physically examined the spray hoses after the fire. Both hoses were metal-reinforced and thus, should have had electrical continuity to the mixing block, although no continuity measurements could be made due to fire damage. These sparks may have been caused by a stray current arc between the floating neutral of the sprayer chassis and the grounded metal hose connector. A ground path was likely provided, via the metal reinforcement sheath inside the hose, to the metal mixing block lying on the steel tunnel floor.

Grounding via the spray hoses to the mixing block is likely, but required the mixing block to have been in good electrical contact with the floor of the steel tunnel. The CSB noted that the position of the box on the drain pipe may have produced only intermittent contact grounding. Similarly, grounding via a spray wand requires electrical continuity through the mixing block out to the spray wand, which would also need to be in electrical contact with the steel tunnel. After the incident, the spray wands were found laying on the wood deck platform of the sprayer scaffold, so they were not grounded. The CSB concluded that at the time of the flash, the sprayer may have been grounded, but it is unlikely that the sprayer was reliably grounded.

Assuming that current was flowing to ground from the floating neutral connection, different metal components of the sprayer would have been at slightly different voltages, depending on the impedances between the components. Thus, a change in load on the 240-volt supply, caused by a sudden voltage drop at PDC 3 (resulting in the observed dimming of the lights), may have produced a change in the floating neutral voltage on the sprayer chassis. The outcome may have been an electrical arc caused by a high voltage transient between the base hopper and the metal nozzle on the circulation hose physically held inside the base hopper by the journeyman painter. An arc could have occurred during contact/separation between the nozzle and the hopper wall. However, the use of a non-conductive hose (Section D.1) rules out a stray current arc as the ignition source.

D.3 Ignition of Explosive MEK Vapor-Air Mixture by Halogen Lights atop the Sprayer

The sprayer unit was mounted on a wheeled cart sitting on a wheeled portable tube and coupler scaffold positioned about 100 feet (30 meters) from a plywood bulkhead that had been erected to block off the steel section of penstock. The only source of illumination for the workers on the scaffold[127] on which the sprayer was sitting was a dual fixture halogen light assembly. Based on examination of physical evidence[128] and employee statements, the CSB determined that the halogen light assembly was placed on top of the sprayer pumps. Each halogen light fixture contained two 300-watt halogen bulbs. The CSB concluded that neither light had been equipped with a glass lens; witness testimony substaintiated the lack of glass lenses and insufficient glass residue was found in the area after the fire to account for them.[129] The lamps were swivel-mounted on an assembly and could be oriented to point down. The base and hardener hoppers were situated below and to either side of the sprayer, with the top of each hopper approximately 25 inches (64 centimeters) from the nearest bulb, depending on the lamp orientation.

As worker statements (Section D.1) place the initial flash of the MEK vapor-air mixture inside the base hopper, ignition of a flammable (i.e., greater than LEL) MEK vapor-air mixture in the atmosphere by hot

[127] A second scaffold, positioned near the west bulkhead, had explosion-proof lights mounted to it to provide illumination for the two painters applying the epoxy to the penstock walls.

[128] The charred and melted remains of the halogen light were found on top of the sprayer pumps after the incident.

[129] The only remains of glass found in the fire debris were identified as coming from the sprayer control panel.

halogen lights, followed by an unobserved flashback into the base hopper, is possible, but considered unlikely. One of the experienced painting contractors told the CSB that the explosion-proof light on the scaffold dimmed, which he caught out of the corner of his eye while looking down primarily into the base hopper to ensure that the MEK being dispensed from the hose was not splashing – and then he saw the flash inside the base hopper. During this short period of distraction, it may not have been possible for the contractor to discern flashback from an ignition source outside the hopper. Flashback of a lean flame would have occurred in just a few seconds, and the flame would likely have been bluish. However, the CSB considers it unlikely that the contractor would not have seen the flashback from the location of the halogen lamps.

As discussed in Section D.1, it is also unlikely that an optimum vapor-air mixture (approximately 5.5 volume percent MEK) would have existed at the elevation of the halogen lights unless the base heater was operating. It is possible that a flammable mixture (>1.8 volume percent MEK) migrated by convection to the location of the halogen lights, if air ventilation was minimal, but a mixture near the LEL would have been more difficult to ignite. The work area was provided with forced, clean air ventilation conveyed through a 20-inch (51-centimeter) diameter plastic duct, magnetically attached to the metal wall of the penstock near the floor. It is unknown whether there was any appreciable air movement in the zone between the hoppers and halogen lights. The lights were located approximately at the axis of the 12-foot (3.7-meter) diameter tunnel. Assuming the air flow from the duct was directed toward the bulkhead at the time of the incident, the flow velocity back toward the tunnel entry would have been slow; the average upstream velocity in the penstock would be reduced by a factor of approximately 52 relative to the duct outlet velocity. Air velocity would have been highly variable across the tunnel at the location of the sprayer unit, and additional evidence suggests that a stagnation region may have existed on the upstream side of the unit. After using MEK to clean the spray wands on the scaffold near the west bulkhead, one of the two contractors at the bulkhead left the work area to get a fan due to the buildup of MEK "fumes." He told the CSB that, as he squeezed past the scaffold holding the sprayer, there was “no air movement at all” in the vicinity of the sprayer.

Since the MEK was being sprayed into the hopper at about 12-16 feet (3.7-4.9 meters) per second, it is possible that some liquid mist would have migrated toward the lamps by convection, increasing the overall fuel concentration and/or that some splashing of coarse droplets occurred (Section D.3.3). However, ignition of the MEK vapor-air mixture at the halogen lamps would have produced an unconfined flash fire centered at the contractor’s head, rather than a deflagration inside the base hopper that propagated toward him.

While an eyewitness statement indicates that the base heater was turned off, this would not rule out the possibility of a sudden catastrophic failure of the base heater thermostat. If the 3.4 kW electric heater did come on, causing the observed dimming of the lights, the MEK temperature could have increased very rapidly. A malfunctioning thermostat may have led to unregulated heating; the set point of 95 ºF (35 °C) for the base epoxy corresponded to a level of 5.5 on the thermostat dial, which had a scale of 1-9. Under penstock conditions, MEK boils at 154 ºF (68 °C). Only a small volume of MEK was in the lines between the heater and the end of the hose. It is plausible that this volume was heated sufficiently to convect “easily ignitable” concentrations of vapor up to the halogen lights. For this to occur, the entire volume of MEK in the hopper would not have had to have been heated to the same temperature, since heated liquid would have been sprayed over a large area inside the hopper, creating a large surface for evaporation. However, this scenario represents a great deal of inference from the fact that the lights dimmed just before the flash and is inconsistent with eyewitness accounts that the initial flash was inside the base hopper. Since the thermostat was destroyed by the fire, the CSB cannot rule out the possibility that the thermostat failed catastrophically.

D.3.1 Ignition Caused by Halogen Lamps

The CSB also evaluated four distinct sub-cases involving ignition by halogen lamps.

D.3.1.1 Ignition Caused by Halogen Bulb Breakage

Halogen bulbs can break spontaneously and explode, due to the pressurized gas inside. Bulb breakage can be caused by contamination of the quartz surface, such as by a fingerprint, or via halide migration (Babrauskas, 2003). The internal filament of a halogen bulb can operate at 5,072 °F (2,800 ºC) with somewhat lower temperatures on the support. The inside bulb wall temperature may be around 1,382 °F (750 ºC) (Cayless & Marsden, 1983). These temperatures certainly would have been capable of igniting an explosive MEK vapor-air mixture. In the current case, bulb breakage might have been attributed to excessive vibration from the pumps or impact of MEK droplets sprayed from the hoppers. A portion of a hot filament from a bulb could have even fallen into the base hopper. However, the CSB ruled out halogen bulb breakage as a potential ignition source, when intact bulbs from both halogen lamp fixtures were found still mounted in their ceramic housings on top of the sprayer after the fire. All the bulbs were covered in soot, but that can be attributed to rich combustion of MEK during the fire.

D.3.1.2 Ignition by Bulb Terminal Arcing

In this scenario, a loose electrical connection at one end of a halogen bulb would periodically arc at the spring contact fitting. This arcing could be exacerbated by vibration from the pump fixture on which the lamps were positioned. It is unlikely a standard torque was applied to the mounting plates, so these might also have been subject to excessive vibration.

If the lamp prongs were made from hard tungsten or tungsten alloy, evidence of arcing (local melting or pitting) is more likely to be found on the spring contacts in the ceramic connectors. The spring contacts have a much lower melting point than the lamp prongs, assuming they are made of brass or steel. While arcing at the bulb terminals was not specifically investigated, visual inspection of these terminals did not reveal arcing patterns.

D.3.1.3 Ignition by Hotspot on Bulb

In a published account describing a vapor ignition by a 300-watt halogen bulb involving gasoline vapor (Babrauskas, 2003), violent impact caused the filament to move, which created an external hotspot on the quartz envelope without bulb breakage. In the absence of hotspots, gasoline vapor ignition did not occur. Most gasoline listed in NFPA 325 (NFPA, (out of print)) have roughly the same autoignition temperature as MEK. No violent impact occurred in the penstock; however, a hotspot could have developed via impact of coarse droplets from the base hopper.

If a droplet of MEK containing dissolved "base" resin were splashed onto the hot bulb region, the result could have been formation of a transient hotspot on or near the bulb. The nominal 1,832 °F (1,000 ºC) hotspot would be created as residual epoxy resin decomposed and combusted either as a glowing ember or small flame.

Upon impact of an MEK-based mixture on a hot surface at approximately 932 °F (500 ºC) or more, the MEK solvent will immediately evaporate. If the MEK vapor does not ignite first, the residual base might decompose and combust either as a glowing hotspot or small flame, which would create very high local temperatures commensurate with MEK's lower limit flame temperature of about 2,192 °F (1,200 ºC). It is well known that the hotspot ignition temperature of ignitable gas mixtures is a strong function of hotspot size and contact time, although the ignition phenomenon is complex. At temperatures close to the lower limit flame temperature, hotspots on the order of 1 millimeter in diameter can cause almost immediate ignition of optimum vapor-air mixtures. As the halogen bulbs were covered by soot during the fire, the CSB cannot determine if a hotspot occurred on one or more of the bulbs.

D.3.1.4 Autoignition of Heated MEK Vapor Volume

A review of the literature shows that the surface temperature of individual 300-watt halogen bulbs in torchiere lamps is about 968 ºF (520 ºC) (CPSC, 1996); higher values approaching 1,100 ºF (593 ºC) have also been reported. The temperature varies with bulb diameter, design, and degree of confinement. The halogen lights had top reflectors and should have achieved higher temperatures than torchiere lamps, which are open at the top and lose heat by free convection.

The halogen lamp fixtures used in the penstock each contained two closely spaced 300-watt bulbs, so the bulb surface temperatures would have been greater than for single bulbs, especially on the adjacent hot quartz surfaces. To the CSB's knowledge, no relevant tests have been done on the type of halogen lamp fixtures involved in the MEK fire. Bulb surface temperatures could, in principle, be measured by two-color pyrometry or other means, but no such testing was performed.

An experiment would need to be devised and run to determine whether an MEK vapor-air mixture could be ignited by a hot halogen bulb fixture at optimum concentration; if not, it would rule out autoignition at all concentrations. Standard autoignition temperature (AIT) tests hold the vapor-air mixture for several minutes in a glass vessel at the test temperature; they are conservative relative to transient heating by a hot halogen bulb surface. The lack of confinement (i.e., lenses not present) means that transitioning from cool to hot flames could not have occurred via pressure increase.[130] The CSB found various published values for the AIT of MEK, but the most reliable is reported to be 887 ºF (475 ºC) at one atmosphere (760 mmHg) (Brandes, et al., 2005, pp.1-5); this corresponds to the minimum temperature for spontaneous ignition of the optimum MEK-air mixture in a 200 milliliter (ml) glass flask using the IEC 60079-4 test method. However, the low atmospheric pressure in the penstock may have elevated the MEK AIT.

The CSB concluded that the halogen bulb surface temperatures would likely need to be significantly higher than the AIT of MEK (at least 125-212 °F (52-100 ºC) above the standard AIT) for MEK vapor ignition. Ignition is far more likely had a hotspot (or small flame) been created on a bulb or an adjacent hot surface.

[130] MEK is subject to forming cool flames, a phenomenon that can result in a range of reported AITs.

D.4 Hot Surface Ignition by the Sprayer Heater(s)

The CSB determined that even if the sprayer base heater had been operating at full output, its surface temperature would be too low to create MEK vapor-air ignition. The heater was rated for a Class 1, Division 2 atmosphere, with a T2 (482 °F/250 ºC) rating; the standard AIT of MEK is 887 °F (475 ºC).

In addition, both heaters (base and hardener) were radiographed, electrically tested, and physically examined after the fire by an independent consultant hired by OSHA. The consultant determined that the heaters did not provide an ignition source for the fire, nor did they contribute to the spread of the fire.

D.5. Compression Ignition inside One of the Sprayer Piston Pumps

In theory, if an air-operated piston pump runs "dry," adiabatic compression of air plus residual vapor could lead to temperatures that exceed the MEK AIT. The CSB was able to rule out this potential ignition source, as both hoses were reportedly circulating MEK at the time of the fire. The journeyman painter also reported a level of about 3 inches (8 centimeters) of MEK in the base hopper where the initial flash was observed.[131] Thus, neither piston pump could likely have been running "dry" at the time of ignition.

D.6 Electrical Spark from Heater Control Box

Electrical power for the two heaters was supplied by the heater control panel. Unlike the sprayer control panel, which used low voltage electronics supplied from a pneumatic generator and was approved for use in flammable atmospheres, the heater control box was an aftermarket addition and was not rated for use in flammable atmospheres. Although the heater control box was severely damaged by the fire and its internal components were charred,[132] visual examination by the CSB revealed that the incoming power to

[131] The CSB could not determine the amount of MEK inside the hardener hopper at the time of the incident, but survivor statements indicate that MEK was also being circulated in this hopper at the time of the incident.

[132] The CSB found no evidence that an internal deflagration had occurred inside the box.

the box was 240-volts and fuses. The heater control box was found to contain open circuits, relays, and other solid-state components. Consequently, the CSB determined that it was possible for an electrical spark generated inside this box to ignite an explosive MEK vapor-air mixture, but for the same reasons described in Section D.2, this ignition source is unlikely because the heater controls were not likely being used at the time of the incident; an explosive MEK vapor-air mixture probably did not exist outside the base hopper, and a spark, if it did occur, would have had to flash back into the base hopper unobserved.

APPENDIX E: MEK FLAMMABILITY PROPERTIES AT PENSTOCK CONDITIONS

Flammability data, such as flashpoints and lower and upper explosive limits are typically measured at standard atmospheric conditions. As this incident occurred inside a penstock at an elevation of 10,050 feet (3,063 meters) above sea level, the CSB needed to recalculate this data to account for the effects of the elevation.

Using data showing changes in atmospheric pressure at various site elevations (UIG, 2004), the CSB calculated the atmospheric pressure at the penstock fire location to be 523 mmHg.

Next, the equilibrium vapor pressure equation is given by

$$EVP = \exp\left(A + B/T + C\ln T + DT^{E}\right)$$

Obtaining constants A-E from the Design Institute for Physical Properties Research (DIPPR) database,[133] the boiling point of MEK at 523 mmHg was calculated to be 154 ºF (67.8 ºC). This compares with the "normal" value of 175 ºF (79.4 ºC) at 760 mmHg (standard atmospheric pressure).

[133] The DIPPR database stores thermophysical properties and parameters for correlations of temperature-dependent property models of over 1,900 components. It has been under development since 1980 and is continuously updated and enhanced. DIPPR is an industrial consortium, operating as part of AIChE.

At 523 mmHg, the vapor-liquid equilibrium curve (Figure E-1) shows that the lower and upper flammable limits of MEK in air (1.8-11 volume percent) are attained at respective equilibrium temperatures of 3 to 60 ºF (-16 to 15 ºC). Between these temperatures, MEK vapor in equilibrium with liquid, such as deep inside the liquid hoppers on the sprayer, is ignitable. MEK vapor becomes most easily ignitable at an “optimum” concentration of about 5.5 volume percent, attained at an equilibrium temperature of about 36 ºF (2.4 ºC).

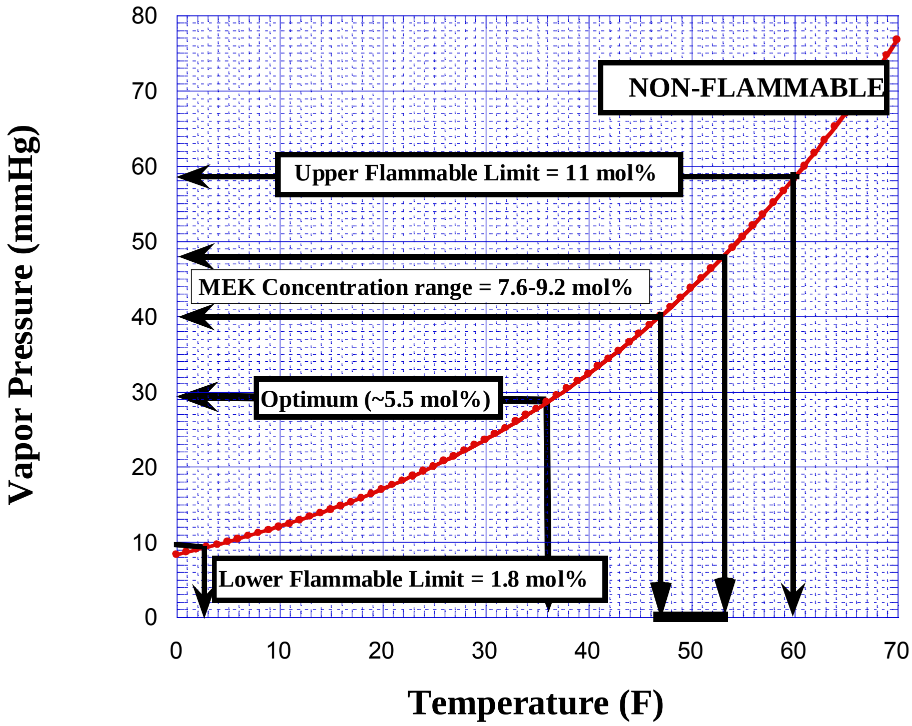

Figure E- 1. Equilibrium vapor pressure of MEK near liquid surface in base hopper

Although the low atmospheric pressure in the penstock (523 mmHg) has negligible effect on the flammable limits, it significantly increases the mole fraction of vapor in air at any given temperature; consequently the flash point is decreased (Figure E-2). The calculated lower theoretical flash point, temperature limit of flammability (TLF), is -16 ºC (3.4 ºF). For ignition in the base hopper, this TLF should be more accurate than a measured flash point because of the ambient pressure and upwards flame propagation, which occurs at lower vapor concentrations than in a standard flash point test apparatus (where flame propagation is downward).

Similarly, the "upper temperature limit of flammability" (UFL) can be calculated. The UFL is generally not sensitive to pressure in the range being considered, so the corresponding MEK vapor pressure is 57.5 mmHg to achieve 11 mole percent MEK in the vapor and the theoretical upper flammability limit (TUF) is found to be 15 ºC (60 ºF). This result shows that MEK in the penstock could be within the flammable range (ignitable) at all times inside a pail or hopper.

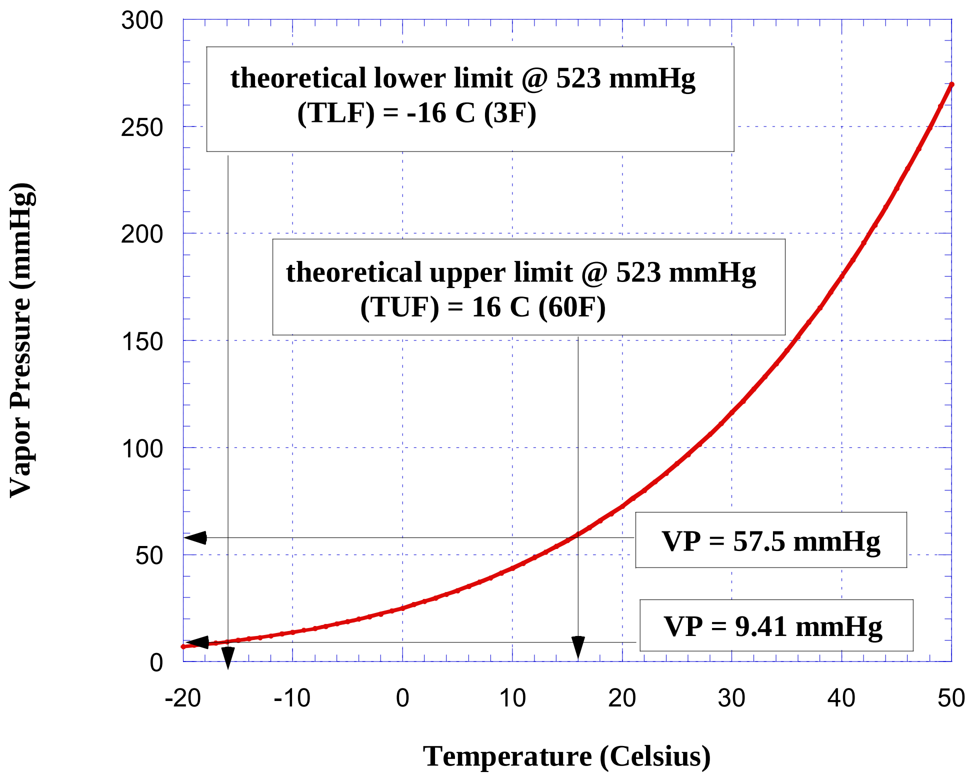

Figure E- 2. Theoretical MEK flammability limits at penstock conditions

With the base side pump heater not operating, the CSB determined that the circulated MEK would have been at 50 ± 3 ºF (10 ± 2 °C). This range compares favorably with the unheated base resin temperature of

47 °F (8.3 °C) measured by the journeyman painter with a laser temperature indicator, and the air temperature of 53 °F (12 °C) inside the penstock measured earlier that day by the KTA inspector. Hence, near the liquid surface in the bottom of the hopper (i.e., where the vapor-liquid equilibrium assumption is most applicable), the MEK vapor concentration should have been in the range of 7.6-9.1 mole percent. This is slightly greater than optimum concentration (approximately 5.5 mole percent), but less than the upper flammable limit (UFL) of 11 mole percent. To summarize, with the heater not operating, the entire volume of the hopper should have been within the ignitable range and capable of deflagration (i.e., rapid burning with the creation of an upward pressure wave).

APPENDIX F: LOWEST MINIMUM IGNITION ENERGY AT PENSTOCK CONDITIONS

Calculation of this parameter is significant with respect to static ignition sources having very small energies. Faulty electrical equipment is unimportant since electrical arcs should be sufficiently energetic to ignite MEK vapor over the entire flammable range.

Calcote, et al. (1952) reported the Lowest Minimum Ignition Energy (LMIE) of MEK as slightly below 0.3 mJ. However, they reported the LMIE of n-pentane at about the same value, 0.28 mJ. This is higher than the approximately 0.24 mJ published for similar paraffin hydrocarbons such as butane and hexane (Lewis & von Elbe, 1961). The latter authors also reported a significantly lower value for cyclopropane, 0.17 mJ versus the 0.22 mJ found by Calcote et al. The CSB noted that the data of Calcote et al. tend to be high compared with other LMIE values. Indeed, most of the Calcote et al. data were measured at stoichiometric composition, and only a few compounds such as MEK were tested at optimum composition (approximately 1.5 times stoichiometric in the case of MEK). The test method used by Calcote et al. usually involved electrodes with 1/8-inch hemispherical tips versus the 1/16-inch tips used by Lewis & von Elbe. Quenching effects presumably caused the measured values of Calcote et al. to be somewhat high. It has been observed that the lowest LMIEs are found with pointed electrodes at very low circuit capacitance. Since Calcote et al. used various test procedures, it is not clear exactly which procedure was used for the MEK tests. It is possible that lower values would have been found by optimizing the circuit capacitance. In conclusion, the LMIE of MEK was found to be about the same as n-pentane, whose LMIE is about 0.24 mJ. No MEK tests have been reported under truly “optimum” conditions of spark gap geometry and circuit capacitance.

Britton’s method (2002) uses the heat of oxidation to estimate the LMIE of CH and CHO organic compounds:

$$\text{LMIE (mJ)} = 4.0056 - 0.06231\,(-\Delta H_C/S) + 0.00024333\,(-\Delta H_C/S)^2$$

Where (ΔH_C /S) = Heat of Oxidation (-100.07 kcal/mol for MEK)

Hence LMIE = 0.21 mJ

From the preceding discussion, the most easily ignitable composition should be about 1.5 times stoichiometric or 5.50 mol%.

Lowest MIE = 0.21 mJ (5.50 mol % MEK in dry air at 298 K, 1 atm)

However, the LMIE generally increases as pressure decreases. In the penstock, the ambient pressure was about 523 mmHg (0.69 atmospheres). By analogy with data for propane (Figure F-1), the LMIE of MEK at 0.69 atmospheres (523 mmHg) should be approximately 0.5 mJ. (Britton, 1999):

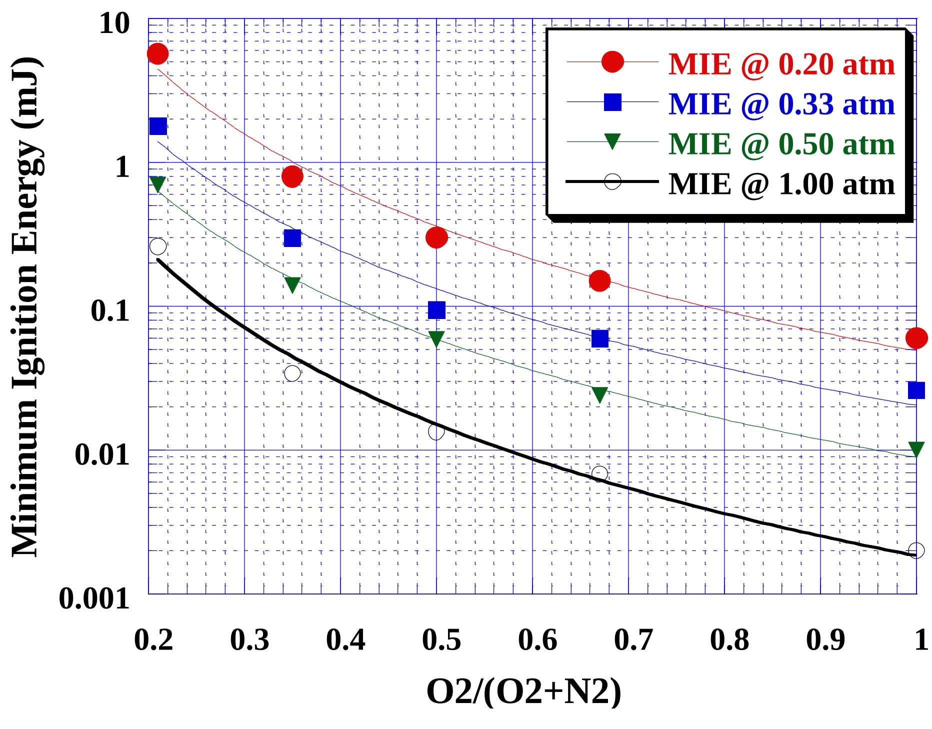

Figure F-1. Effect of pressure on MIE of propane in various oxygen-nitrogen mixtures

Hence, the lowest MIE for MEK is approximately 0.5 mJ (5.50 mole percent MEK in dry air at 298 K, 0.69 atm).

APPENDIX G: WORK ACTIVITIES ALLOWED IN POTENTIALLY EXPLOSIVE ATMOSPHERES

Source	Industry/Personnel	Citation/Reference	Requirement
OSHA	Permit-required confined spaces in general industry	1910.146(d)	Entry into permit-required confined spaces above 10% of the LFL is allowed provided that acceptable entry conditions for flammable vapors listed on the permit are followed.
		Appendix C Examples of Permit-Required Confined Space Programs	**Example 3. Workplace.** Workplaces where tank cars, trucks, and trailers, dry bulk tanks and trailers, railroad tank cars, and similar portable tanks are fabricated or serviced. **Sources of hazards.** In addition to the mechanical hazards arising from the risks that an entrant would be injured due to contact with components of the tank or the tools being used, the risk also exists that a worker could be injured by breathing fumes from welding materials or mists or vapors from materials used to coat the tank interior. In addition, many of these vapors and mists are flammable, so failure to properly ventilate a tank could lead to fire or explosion. **Application of interior coatings/linings.** Atmospheric hazards shall be controlled by forced air ventilation sufficient to keep the atmospheric concentration of flammable materials below 10% of the lower flammable limit (LFL) (or lower explosive limit (LEL)), whichever term is used locally). The appropriate respirators are provided and shall be used in addition to providing forced ventilation if the forced ventilation does not maintain acceptable respiratory conditions.
		Std Interpretation letter, 9/4/96	The permit-required confined spaces standard [29 CFR 1910.146] does not prohibit working in a permit-required space where the atmosphere is above 10% of the LFL. However, once the atmosphere is above 10% of the LFL, all requirements of the standard must be met. The employer must identify and evaluate each hazard to which entering employees will be exposed. Based on the hazard analysis, the employer must develop and implement the means, procedures, and practices necessary for safe permit space entry operations. If the flammable atmosphere is the result of a process involving equipment, there may be precautions with regard to the equipment that an employer would be required to follow.

Source	Industry/Personnel	Citation/Reference	Requirement
	Confined spaces using alternative entry provisions in general industry	1910.146(c)(5) OSHA Directive 2.100, page 19. 58 FR 4488	In confined spaces using alternative entry procedures, entry is permitted provided the concentration of the flammable substance does not exceed 50% of what would constitute a "hazardous atmosphere" (e.g., 5% of the LFL).
	Confined and enclosed spaces and other dangerous atmospheres in shipyard employment	1915.13(b)(3)	An employee may not enter a space where the concentration of flammable vapors or gases is equal to or greater than 10% of the LEL. Exception: An employee may enter for emergency rescue or for a short duration to install ventilation equipment necessary to start work, provided no ignition sources are present, the atmosphere in the space is monitored continuously, atmospheres at or above the upper explosive limit are maintained, and respiratory and other appropriate PPE and clothing are provided.
	Excavations	1926.651(g)(1)(iii)	In excavation and trenches, adequate precautions shall be taken, such as providing ventilation, to prevent employee exposure to an atmosphere containing a concentration of a flammable gas in excess of 20% of the lower flammable limit (LFL) of the gas.
	Underground construction (tunneling)	1926.800	When air monitoring shows, for 3 consecutive days, 10% or more of the LEL for methane or other flammable gases measured at 12 inches from the roof, face, floor, or walls in any underground work area, additional safety precautions are required. These include using more stringent ventilation requirements, using diesel equipment only if it is approved for use in gassy operations, posting each entrance with warning signs, prohibiting smoking and personal sources of ignition, maintaining a fire watch when hot work is performed, and suspending all operations in the affected area until all special requirements are met or the operation is declassified. Additional air monitoring is also required.
	Confined spaces in construction, except for diving, non-sewer excavations, and underground construction	1926.1028 (proposed)	Entry into permit-required confined spaces (PRCS) above 10% of the LFL is allowed provided conditions under which the authorized entrants can work safely are defined, including hazard levels and methods of employee protection. Monitoring procedures must also be in place to detect an increase in atmospheric hazard levels in sufficient time for the entrants to safely exit the PRCS in the event the ventilation system stops working.

Source	Industry/Personnel	Citation/Reference	Requirement
		72 FR 67391	OSHA requests comment on the advisability of reconciling the difference in LFLs between the excavation standard in subpart P and this proposed standard, including which LFL (that is, 10% or 20%) should be adopted.
MSHA	Underground Coal Mines	75 CFR 323	When 1.0% or more methane (20% of LEL) is present in a working place or an intake air course, including an air course in which a belt conveyor is located, or in an area where mechanized mining equipment is being installed or removed--except intrinsically safe atmospheric monitoring systems (AMS), electrically powered equipment in the affected area shall be de-energized, and other mechanized equipment shall be shut off; changes or adjustments shall be made at once to the ventilation system to reduce the concentration of methane to less than 1.0%; and no other work shall be permitted in the affected area until the methane concentration is less than 1.0%. When 1.5% or more methane (30% of LEL) is present in a working place or an intake air course, including an air course in which a belt conveyor is located, or in an area where mechanized mining equipment is being installed or removed--everyone except those persons referred to in §104(c) of the Act shall be withdrawn from the affected area and, except for intrinsically safe AMS, electrically powered equipment in the affected area shall be disconnected at the power source.
	Underground Metal Non-Metal Mines	57 CFR 22231- 22238	If methane reaches 0.25% (5% of LEL) in the mine atmosphere, changes shall be made to improve ventilation, and MSHA shall be notified immediately. If methane reaches 0.5% (10% of LEL) in the mine atmosphere, ventilation changes shall be made to reduce the level of methane. Until methane is reduced to less than 0.5%, electrical power shall be de-energized in affected areas, except power to monitoring equipment determined by MSHA to be intrinsically safe under 30 CFR part 18. Diesel equipment shall be shut off or immediately removed from the area and no other work shall be permitted in affected areas. If methane reaches 1.0% (20% of LEL) in the mine atmosphere, ventilation changes shall be made to reduce the methane. Until such changes are achieved--all persons other than competent persons necessary to make the ventilation changes shall be withdrawn from affected areas; electrical power shall be de-energized in affected areas, except power to monitoring equipment

Source	Industry/Personnel	Citation/Reference	Requirement
			determined by MSHA to be intrinsically safe under 30 CFR part 18; and diesel equipment shall be shut off or immediately removed from the area. If methane reaches 2.0% (40% of LEL) in the mine atmosphere, all persons other than competent persons necessary to make ventilation changes shall be withdrawn from the mine until methane is reduced to less than 0.5% (10% of LEL).
Environmental Protection Agency (EPA)	Personnel activities at hazardous waste sites	*Standard Operating Guides,* EPA, December 1984	Less than 10% of LEL, continue investigation; 10 to 25% of LEL, continue onsite monitoring with extreme caution as higher levels are encountered; Above 25% of LEL, explosion hazard. Withdraw from area immediately.
ANSI	Confined spaces at normal atmospheric pressure. Not applicable to underground mining, tunneling, caisson work, or intentionally inert confined spaces	Z117.1-2003 Section 6.3.2	Entry into confined space prohibited until appropriate controls are implemented or appropriate personal protective equipment (PPE) is provided whenever atmospheric testing indicates flammable levels are greater than 10% of the LEL/LFL.
API	Personnel cleaning stationary, aboveground atmospheric and low pressure petroleum storage tanks	Standard 2015-2001 Section 8.3.3.2.	Entry into tanks is prohibited when the flammable vapor-air levels are above 10% LEL, unless there are extraordinary circumstances requiring such entries and employers (owners/operators and contractors) have established and implemented appropriate precautions and safeguards for permit required confined space entry.
NFPA	Vessels that carry, or burn as a fuel, flammable or combustible liquids and vessel that carry compressed gases, chemicals in bulk, or other products capable of creating a hazardous condition	Standard 306 – 2003 Section 4	Compartments where flammable vapor-air levels are less than 10% of the LEL are marked as “Safe for Workers” or “Safe for Hot Work”. Compartments with vapor-air levels that exceed 10% of the LEL are marked “Enter With Restrictions” and can be entered only with appropriate PPE to install ventilation or perform emergency rescue.
	Tanks or containers operating at normal atmospheric pressure that contain or have contained flammable or combustible liquids or other hazardous substances and related vapors and residues that are to be entered or cleaned	Standard 326 – 2005 Sections 6.3.2, 6.3.8, 6.3.9	All work in and around the tank or container shall be stopped immediately when flammable vapors in the atmosphere exceed 10% of the LFL. Source of the vapors located and eliminated or controlled. When a tank or container is tested prior to the start of hot work, any indication of flammable gas or vapor in excess of the established allowable limits shall require additional ventilation, purging, re-cleaning, or further safeguarding by

Source	Industry/Personnel	Citation/Reference	Requirement
			one of the methods described in this standard, as specified by the qualified person, prior to the issuance of a hot work permit. When testing a tank or container during hot work, any indication of flammable gas or vapor in excess of the established allowable limits shall require the immediate cancellation of the hot work permit.
	Emergency/fire personnel responding to releases of flammable or combustible liquid, gas, or vapor that can migrate to a subsurface structure	RP 329 – 2005 Sections 5.4.5.1 – 5.4.5.3	During initial response to a reported leak, the affected area should be evacuated when gas or vapor concentrations are above 50% of the LFL. The affected area should be ventilated to remove or reduce the flammable gas or vapor concentration and thus reduce the fire or explosion hazard. As soon as the flammable gas or vapor has been reduced below 50% of the LFL, entry can be made to locate and eliminate the source.
	Emergency/fire personnel performing rescue from confined spaces	Standard 1006 – 2008 Section A.7.1.1.(2)	Flammability is measured as a percentage of a material's LEL or LFL. Rescuers should not enter confined spaces containing atmospheres greater than 10% of a material's LEL, regardless of the PPE worn. There is no adequate protection for an explosion within a confined space.
NIOSH	Criteria for a Recommended Standard – Working in Confined Spaces	Publication No. 80-106 – 1987	Less than 10% of the LFL, no modification of work processes; between 10-19% of LFL, ventilation and protective measures; 20% of LFL or above, ventilation and protective measures.
International Union of Painters and Allied Trades, Joint Apprenticeship and Training Fund	Apprentice and Journeymen Painters	Confined Space Entry, Employee Handbook and Facilitator Guide (Summit Training Source, Inc.)	Permit Space Hazards Flammable Gas, Vapor, or Mist If the atmospheres contain flammable gas, vapor, or mist in excess of 10% of its LFL, that atmosphere is unacceptable for entry.
Pipeline Association for Public Awareness	Firefighters, law enforcement officers, emergency Medical technicians and all other emergency	Appendix B	Natural Gas Escaping Inside a Building EMERGENCY RESPONSE

Source	Industry/Personnel	Citation/Reference	Requirement
	responders responding to pipeline incidents		Monitor the atmosphere, using multiple monitors where possible ♦ Action Criteria: 0 to 10% of the LEL - Use Extreme Caution ♦ Action Criteria: 10% of the LEL or greater - DO NOT ENTER THE BUILDING TACTICAL CONSIDERATIONS ♦ Natural gas released inside buildings presents one of the greatest flammable hazards to emergency responders. ♦ Building full of natural gas should be approached only when needed with extreme caution and with a minimum number of personnel. CGI reading s in excess of 10% LEL require evacuation of the building.
Alberta	Worksite or work area	Handling and Storage of Flammable Materials at the Work Site (May 2007) OHS Code, Part 10	Work is prohibited in areas greater than 20% of the LEL, except for competent workers responding to emergencies
British Columbia	Confined Spaces	Confined Space Entrance Reference Manual (2007) Section 9.5, OH&SR	Workers not allowed entry into confined spaces under any circumstances when the flammability is greater than 20% of the LEL. Good practice to prohibit hot work in atmospheres providing a reading on the flammable gas meter above 1%. Any untested confined space is considered IDLH.
Ontario	Confined Spaces	Confined Spaces Guideline (1996)	Hot work permitted if concentration of flammable or explosive gas or vapor is less than 5% of LEL. Cold work permitted if concentration of flammable or explosive gas or vapor is less than 10% of LEL. Inspection permitted if concentration of flammable or explosive gas or vapor is less than 25% of LEL. No entry permitted if concentration of flammable or explosive gas or vapor exceeds 25% of LEL.
Australia	Confined Spaces	AS 2865 – 1995	No entry into a confined space permitted if the concentration of the flammable

Source	Industry/Personnel	Citation/Reference	Requirement
			contaminant in the atmosphere exceeds 5% of the LEL. When persons have entered a confined space and are using continuous monitoring, they may remain in the confined space at concentrations of flammable contaminant in the atmosphere of less than 10% of the LEL before evacuation of the confined space is necessary.
New Zealand	Confined Spaces	Safe Working in a Confined Space (no date)	Concentration of flammable contaminant in the atmosphere is 0% of the LEL if hot work is to be carried out, or 10% if cold work is to be varied out.
United Kingdom	Shipping Industry	IACS Confined Space Safe Practice Section 6.3 April 2007	A space with an atmosphere with more than 1% of the LFL or LEL on a combustible gas indicator should not be entered.

APPENDIX H: APPLICABLE OSHA CONFINED SPACE STANDARDS

H.1 OSHA General Industry Standards (29 CFR 1910)

The CSB reviewed OSHA safety and health regulations addressing confined space requirements applicable to general industry as well as those for construction. The CSB determined that OSHA general industry standards codified at 29 CFR 1910 apply to the penstock recoating project at the Xcel Cabin Creek facility based on OSHA definitions of construction versus maintenance [29 CFR 1910.12(b), 29 CFR 1926.13(a) and 1926.32(g)]. Although the contractor (RPI) was using construction practices (e.g., sandblasting and coating) to physically change the power plant, the penstock was existing equipment (constructed in 1967) that was being refurbished by removing the old coating and applying new. Consequently, this work activity is classified as maintenance rather than new construction and falls under the OSHA general industry standards.

H.2 Electrical Power Generation (29 CFR 1910.269)

Although the CSB found that OSHA's electrical power generation standards apply to the Xcel Cabin Creek hydroelectric power plant, these standards contain no specific regulations pertaining to penstocks, and the penstock does not meet the definition of an "enclosed space" as outlined in this standard. As discussed in Section 2.1, the Xcel Cabin Creek facility is a pumped hydroelectric power plant that supplies electricity to residential customers during peak demand periods. As its purpose is to generate electrical power, the Xcel Cabin Creek facility is subject to the regulations of OSHA's general industry standard that apply only to electrical power generation, transmission, and distribution codified at 29 CFR 1910.269. In fact, 29 CFR 1910.269(a)(i)(B)(2) specifically states that "water and steam installations, such as penstocks, pipelines, and tanks providing a source of energy for electric generators" are subject to these standards. A review of the 1910.269 standard reveals that it contains no specific requirements for penstocks, but does contain specific requirements for "enclosed spaces." Subparagraph (e) outlines safe work practices, evaluation of potential hazards, atmospheric testing, ventilation, attendants, and rescue provisions that are applicable to "enclosed spaces." However, the definition of an "enclosed space" at 29 CFR 1910.269(x) states that these spaces are "designed for periodic employee entry under normal operating conditions"; thus, the penstock cannot be classified as an "enclosed space" under the 1910.269 standard because under normal operating conditions the penstock is filled with water and employees do not enter. A note beneath the "enclosed space" definition states that if the space meets the criteria for a permit-required confined space then the provisions of 29 CFR 1910.146 apply.

H.3 Permit-Required Confined Spaces (29 CFR 1910.146)

See Section 10.0, "Regulatory and Industry Standards Analysis."

APPENDIX I: CSB CONFINED SPACE INCIDENTS DATA INCLUSION CRITERION AND LIMITATIONS

To determine the prevalence of confined space incidents attributable to a flammable atmosphere, the CSB researched and identified a number of confined space incidents from various sources.[1] Incidents were included in the CSB database if they occurred in a confined space and resulted from a fire or explosion where monitoring of the atmosphere and establishing safe flammable limits could have played a role in preventing entry or requiring exit from the space. The CSB search included only incidents that occurred in what was determined to be an OSHA defined confined space. Incidents were selected if they occurred after April 15, 1993, and if work was being performed inside the confined space where a flammable atmosphere was either created by the work being conducted or present prior to entry resulted in an explosion or fire.

The CSB obtained a majority of these incidents by using specific search terms to query OSHA's IMIS database where inspection records of OSHA investigations are recorded and categorized. The CSB's data search retrieved incidents containing the words ”confined space” in the summary words, incident summary description, or title of the inspection report. If an incident occurred in a confined space, but the words ”confined space” did not appear on that inspection report as a descriptor, it was not initially identified as an incident of interest. Only after subsequent queries into the IMIS system to identify incidents that contained a "flammable atmosphere," "explosion," or "chemical fire," among others, were additional confined space incidents identified. For example, a few of our incidents did not contain the

[1] Sources included the NIOSH Fatality Assessment and Control Evaluation (FACE) Program reports, the OSHA Inspection Data from OSHA's Integrated Management Information System (IMIS) from 1993 to the present, media reports and inquiry into the Agency of Toxic Substance and Disease Registry (ATSDR), and the Hazardous Substances Emergency Events Surveillance (HSEES) system to determine the prevalence of incidents attributed to a flammable atmosphere.

words ”confined space” but were retrieved under these search terms and found to contain OSHA confined space citations.

Additionally, a few of the incidents included in the CSB dataset were obtained through Internet media searches. These incidents were then checked in the OSHA IMIS database and matched with their correlating OSHA inspection number. If these media incidents contained OSHA confined space citations under the standard 1910.146, they were included into the CSB database. However, some incidents found through the media search had an OSHA inspection number but not an OSHA inspection report description or confined space citations indicating that the incident occurred in a confined space; thus, they were not included in the CSB dataset. Other OSHA IMIS incidents contained OSHA confined space citations but no incident summary indicating that the accident occurred in a confined space and were therefore excluded from the dataset. Incidents were included only in the CSB dataset if the OSHA confined space citations were connected to the explosion or fire. As a result of incomplete or inconsistent reporting of confined space incidents in the OSHA IMIS system, the voluntary nature of incidents reported to NIOSH to generate the NIOSH Fatality Assessment and Control Evaluation (FACE) reports and the lack of specific confined space data in ATSDR HSEES, the CSB concluded that there is a likely undercount in confined space incidents that occurred in a flammable atmosphere in our data.

Confined space incidents obtained from OSHA’s IMIS, the NIOSH FACE reports, ATSDR, and the media were categorized into two subgroups. Subgroup A contained incidents that matched our inclusion criterion, and subgroup B contained incidents that did not fully meet our inclusion criterion. Of the 105 incidents compiled by the CSB, 53 were subsequently categorized as A and determined to be a result of a flammable atmosphere in a confined space.

APPENDIX J: SIMILAR RECENT CONFINED SPACE INCIDENTS INVOLVING FLAMMABLES INVESTIGATED BY THE CSB

Since the Xcel penstock incident, the CSB has investigated two additional confined space incidents involving workers who were injured or fatally wounded by an explosion or fire involving flammables in a confined space.

13.1.1 ConAgra Foods Processing Plant Explosion

On February 16, 2009, a North West Metal Fabricators contractor was killed while attempting welding repair to a 1¼ by ½ inch (3.2 by 1.3 centimeters) crack on a clarifier tank at a ConAgra facility in Boardman, Oregon. The 23-foot (7-meter) tall, 12-foot (3.7-meter) diameter tank had an open top structure and cone-shaped bottom covered by a metal skirt. The tank, used in a potato-washing process for separating dirt and debris from waste water, was classified as a permit-required confined space.

The CSB investigators found an accumulation of approximately 14 inches (36 centimeters) of bacteria-rich debris and water under the tank's skirting as a result of the material leaking through the crack. Through sample analysis, the CSB determined that bacteria in this debris and waste water likely produced flammable gas. When the contractor started welding, the arc generated acted as the source of ignition, resulting in a confined vapor explosion. Air monitors were used to detect flammable vapors near the entrance of the tank but were not used in the vicinity where the hot work was conducted.

13.1.2 TEPPCO Terminal Explosion

Three contractors from C&C Welding, Inc. were fatally injured on May 12, 2009, in an explosion at the TEPPCO Partners LP McRae Terminal in Garner, Arkansas. The workers were using a cutting torch above the floating roof inside a 67,000-barrel (10,700 cubic meters) capacity gasoline storage tank when an internal explosion blew both the floating roof and the fixed roof off the tank. The contractors were preparing for the installation of a gauge pole, and at the time of the explosion were using an oxygen acetylene cutting torch to cut into the secondary roof of the internal floating roof of the tank. The contractors were issued both a hot work permit and confined space permit to flame-cut the roof and enter the tank. However, an evaluation of both the hot work and confined space entry permit and policies of TEPPCO Partners LP and C&C Welding Inc. reveals no maximum or minimum LEL limits for work within confined spaces. The flame-cutting activity most likely ignited flammable vapors inside the tank.