Attachment-FINAL
REVIEW DRAFT

ENERGY, ECONOMIC, AND ENVIRONMENTAL ASSESSMENT OF U.S. LNG EXPORTS

FINAL REVIEW DRAFT September 5, 2023

Prepared for:

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Acronyms and Abbreviations

AEO	Annual Energy Outlook
BECCS	Bioenergy with carbon capture and storage
Bcf	Billion cubic feet
BIL	Bipartisan Infrastructure Law
BP	British Petroleum
BTU	British Thermal Unit
CAFE	Corporate Average Fuel Economy
CCS	Carbon capture and storage
CCUS	Carbon capture, utilization, and storage
CDR	Carbon dioxide removal
CH_4	Methane
CO_2	Carbon dioxide
DAC	Direct air capture
DOE	Department of Energy
EIA	Energy Information Administration
EJ	Exajoule (10^{18} joules)
EPA	Environmental Protection Agency
FECM	Fossil Energy and Carbon Management
GHG	Greenhouse gas
GCAM	Global Change Analysis Model
GNGM	Global Natural Gas Model
Gt	Gigaton
GWP	Global warming potential
HMM	Hydrogen Market Module
ITC	Investment tax credit
IRA	Inflation Reduction Act
Kwhr	Kilowatt-hour

LHV	Lower heating value
LNG	Liquefied natural gas
LULUCF	Land use, land use change, and forestry
MAF	Market Adjustment Factor
Mcf	Million cubic feet
MMT	Million metric Tons
NERA	NERA Economic Consulting
NEMS	National Energy Modeling System
NETL	National Energy Technology Laboratory
NGA	Natural Gas Act
NGP	Natural gas processing
NHTSA	National Highway Traffic Safety Administration
NREL	National Renewable Energy Laboratory
N2O	Nitrous oxide
OPEX	Operating Expenses
PNNL	Pacific Northwest National Laboratory
PTC	Production tax credit
S&P	Standard & Poor's
Tcf	Trillion cubic feet
Tg	Teragram (10^{12} grams)

I. Executive Summary

The Department of Energy (DOE) is responsible for authorizing exports of U.S. natural gas, including liquefied natural gas (LNG), to foreign countries pursuant to section 3 of the Natural Gas Act (NGA), 15 U.S.C. 717b. Under the NGA provisions, applications requesting authority for the import or export of natural gas, including LNG, from and to a nation with which there is in effect a free trade agreement (FTA) requiring national treatment for trade in natural gas, and/or the import of LNG from other international sources, are deemed consistent with the public interest and granted without modification or delay. For Authorizations relating to those countries with which the United States does not have an FTA ~~requiring national treatment trade in natural gas~~ and with which trade is not prohibited by U.S. law or policy, then pursuant to Section 3(a) of the NGA DOE is required to grant a permit to export domestically produced natural gas unless it finds that such action is not consistent with the public interest.

To inform its Public Interest determination, since 2012, the Office of Fossil Energy and Carbon Management (DOE-FECM) and its predecessor, the Office of Fossil Energy, previously commissioned five studies to assess the effects of different levels of LNG exports on the U.S. economy and energy markets. This sixth updated study, like the previous ones, serves~~d~~ as an input to be considered in the evaluation of applications to export LNG from the United States under Section 3 of the NGA.

The purpose of this latest study ~~was~~ is to examine the potential global and U.S. energy system and greenhouse gas (GHG) emissions implications of a wide range of economic levels of U.S. LNG exports. The study was comprised of three coordinated analyses: 1) **a Global Analysis** to explore a wide range of scenarios of U.S. LNG exports under alternative assumptions about future socioeconomic growth, regional preferences for domestically produced natural gas, pace of technological change in competing technologies (e.g. renewables), and countries' announced GHG emissions pledges and policies; 2) **a U.S. Domestic Analysis** of the implications of the various U.S. LNG export levels derived from the Global Analysis for the supply and demand of natural gas within the U.S. and the U.S. economy; and 3) **a Life Cycle Analysis** to examine the life cycle emissions implications of the various levels of U.S. LNG exports derived from the Domestic and Global analyses.

As part of the **Global Analysis,** ~~we~~ DOE-FECM explored seven scenarios spanning a range of plausible U.S. LNG export outcomes by 2050 using the Pacific Northwest National Laboratory's Global Change Analysis Model (GCAM). GCAM is a model of the global energy, economy, agriculture, land use, water, and climate systems with regional detail in 32 geopolitical regions. This includes major economies as single-country regions (e.g., U.S., Canada, China, India, Russia). The seven scenarios explored in this study are shown in Table ES-1.

Table ES-1. Scenario Descriptions

Scenario	Description	U.S. LNG Export Volumes (Bcf/d)
***S1*: Reference Exports**	Reference scenario in which U.S. LNG exports follow EIA's 2023 Annual Energy Outlook (AEO). Incorporates U.S. policy assumptions (including the 2022 Inflation Reduction Act). Assumes existing policies and measures, globally.	Grows to 27.34 Bcf/d by 2050
***S2*: Market Response**	Assumes policies consistent with *S1*, but U.S. LNG exports are determined by global market equilibrium.	GCAM Market Response
***S3*: High Global Demand**	Same assumptions as *S2*, U.S. LNG exports determined by global market equilibrium, but assumes higher population growth outside of the U.S.	
***S4*: Regional Import Limits**	Same assumptions as *S2*, U.S. LNG exports determined by global market equilibrium, but includes constraints on importing and exporting natural gas with a global focus to maximize use of domestic gas.	
***S5*: Low-cost Renewables**	Same assumptions as *S2*, U.S. LNG exports determined by global market equilibrium, but assumes lower capital costs for renewable energy technologies.	
***S6*: Energy Transition (Ref Exp)**	Assumes an emissions pathway consistent with a global temperature change of 1.5°C by end of century. Countries' emissions are constrained to announced GHG pledges, including the U.S. following a path to net-zero GHG emissions by 2050. NEMS follows CO_2 emissions constraint from GCAM. U.S. LNG exports are limited to the values from the AEO 2023 Reference scenario.	Grows to 27.34 Bcf/d by 2050
***S7*: Energy Transition**	Same emissions pathway assumptions as *S6*, but U.S. LNG exports are determined by global market equilibrium.	GCAM Market Response

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All of the scenarios include representations of the 2022 Inflation Reduction Act (IRA) in the U.S. and existing emission policies in the rest of the world. The scenarios also include a constraint on Russian exports. The modeling and analysis for this report was completed by August 2023.

The **U.S. ~~D~~Domestic ~~A~~Aanalysis** was conducted using the National Energy Modeling System (NEMS). U.S. LNG exports (for all scenarios except *S1*) and CO_2 emissions (in scenarios *S6* and *S7*) used in NEMS were harmonized to values from GCAM. NEMS was then used to explore the implications of the seven global scenarios ~~for~~ on domestic gas prices, the energy system, and the macro-economy within the U.S.

Finally, the **Life Cycle Analysis** of natural gas used for export was enhanced by comparing the results provided from the domestic and global analyses to previously completed NETL studies of the natural gas life cycle. GCAM results were assessed against existing DOE life cycle studies of natural gas and aligned to have the same GHG intensity for the purposes of consistency. The main results of this analysis were a series of estimated market adjustment factors that supplement the previous life cycle analyses and better represent the total global change in emissions per unit of U.S. LNG exported.

A number of key insights emerged from this study:

1. Across all modeled scenarios, U.S. LNG exports and U.S. natural gas production increase beyond current levels-through 2050 (Figure ES-1).
2. Global natural gas consumption increases only slightly (<1 percent) under a scenario with increased availability of U.S. natural gas in the global market that reflects economically driven LNG export levels (S2) compared to the reference scenario (S1). The majority of the additional U.S. natural gas substitutes for other global sources of natural gas.
3. U.S. natural gas prices as measured at the Henry Hub increase modestly when comparing a scenario that reflects global market demand for exports (S2) to the reference scenario (S1). Across those scenarios, 2050 Henry Hub prices ~~were~~ are projected to increase from $3.61/Mcf to $4.74/Mcf, both of which are less than the reference 2050 price expected in the most recent study[5] commissioned on the economic impacts from U.S. LNG exports in 2018.
4. U.S. residential prices ~~were~~ are projected to be 4% higher in 2050 when comparing a scenario that reflects global market demand for exports (S2) to the reference scenario (S1).
5. The value of industrial shipments remains essentially unchanged (increasing less than 0.1% by 2050) under a scenario that reflects global market demand for exports (S2) compared to the reference scenario (S1). The impact of increased LNG exports on GDP is essentially flat: positive by less than 0.1% across scenarios through 2045 while all changes are within 0.3% in 2050.
6. Global and U.S. GHG emissions do not change appreciably across the scenarios with current climate policy assumptions (S2 to S5) even though these scenarios vary widely in terms of U.S. LNG export outcomes. In these scenarios, global emissions range from 47.5-50.3 Gt CO_2e and U.S. emissions range from 4.3-4.6 Gt CO_2e while U.S. LNG exports range from 23 to 47 Bcf/day.
7. The induced global market effects per unit of increased LNG exports in a scenario that reflects global market demand for exports (S2) compared to the reference scenario (S1) are equivalent to an overall reduction in GHG emissions that is about 70% of the estimated upstream emissions associated with production through delivery of the natural gas through the transmission system in the U.S.
8. Relative to the other scenarios, the scenarios in which countries are assumed to achieve GHG emissions pledges and pursue ambitious GHG mitigation policies (S6 and S7) are characterized

by lower energy consumption; lower fossil fuel consumption without carbon capture, utilization, and storage (CCUS); higher deployment of renewables and fossil fuels and biomass with CCUS; and higher deployment of carbon dioxide removal strategies.

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What supports this finding?

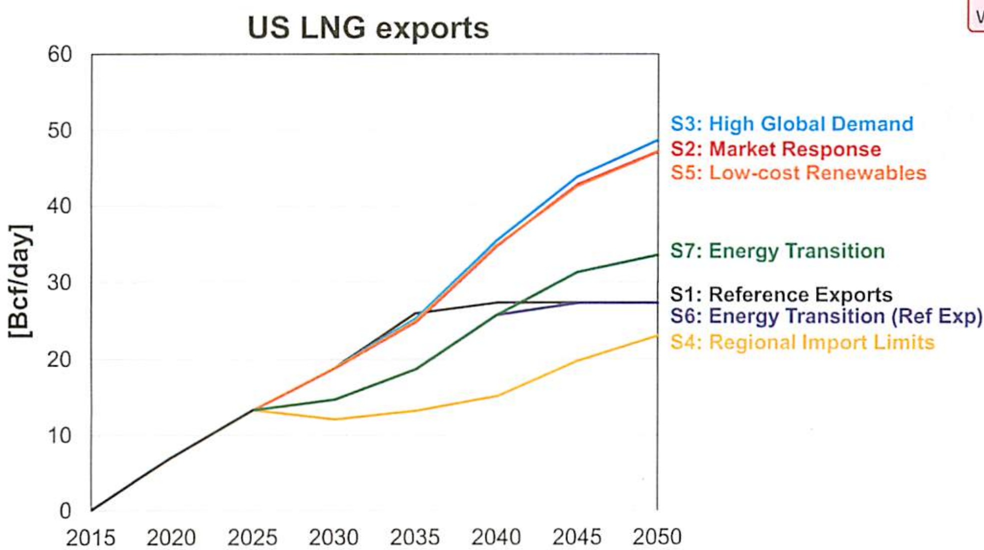

Figure ES-1. U.S. LNG exports across the scenarios explored in this study. Note that the U.S. LNG export outcomes for S2 and S5 were very close to each other.

II. Background on LNG Export Studies Commissioned by Department of Energy

Since 2012, the Office of Fossil Energy and Carbon Management (DOE-FECM) and its predecessor, the Office of Fossil Energy, previously commissioned five studies on the effects of increased LNG exports on the U.S. economy and energy markets. The previous studies of the impact of LNG exports are listed in Table 1.

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The EIA 2012 study examined four different levels of exports across four domestic natural gas supply scenarios for a total of 16 scenarios. Exports ranged from 6 to 12 Bcf/day with varying trajectories. The supply scenarios were: AEO2011 Reference, High Shale Estimated Ultimate Recovery (EUR), the Low Shale EUR, and High Economic Growth. Key results demonstrate that natural gas markets balanced the increased exports through increased supply and prices and a reduction in demand for power generation and in the other sectors.

The NERA 2012 report used NERA's Global Natural Gas Model (GNGM) and NewERA energy-economy model to look at the domestic economic effects of LNG exports. Building upon the EIA 2012 study, the NERA 2012 report examined sixteen scenarios from the earlier study using different assumptions on natural gas supply and demand. The report additionally included scenarios examining the global demand for U.S. LNG exports and the macroeconomic impact of increased LNG exports on the economy.

The EIA 2014 study included updated export scenarios from 12 to 20 Bcf/day and domestic natural gas supply scenarios from AEO2014: the Low and High Oil and Gas Resource scenarios, High Economic Growth, and Accelerated Coal and Nuclear Retirements. Increased exports led to increased natural gas production and prices relative to respective base scenarios, though also higher primary energy consumption and energy-related CO_2 emissions.

Table 1. Previous Studies

Report Name	Organization	Short Name
Effect of Increased Natural Gas Exports on Domestic Energy Markets[1]	EIA	EIA 2012
Effect of Increased Natural Gas Exports on Domestic Energy Markets[2]	NERA	NERA 2012
Effect of Increased Levels of Liquefied Natural Gas Exports on U.S. Energy Market[3]	EIA	EIA 2014

[1] U.S. EIA. (2012). Effects of Increased Natural Gas Exports on Domestic Energy Markets. Available at: https://energy.gov/sites/prod/files/2013/04/f0/fe_eia_lng.pdf
[2] NERA Economic Consulting. (2012). Macroeconomic Impacts of LNG Exports from the United States. Available at: https://energy.gov/sites/prod/files/2013/04/f0/nera_lng_report.pdf
[3] U.S. EIA. (2014). Effect of Increased Levels of Liquefied Natural Gas Exports on U.S. Energy Markets. Available at: https://www.eia.gov/analysis/requests/fe/pdf/lng.pdf

Report Name	Organization	Short Name
The Macroeconomic Impact of Increasing U.S. LNG Exports[4]	Baker Institute/ Oxford Economics	Baker 2018
Macroeconomic Outcomes of Market Determined Levels of U.S. LNG Exports[5]	NERA	NERA 2018

The Baker 2015 study examined U.S. LNG exports of 12 and 20 Bcf/day. Two models were used: an international natural gas model (from the Baker institute) and a global economic model from Oxford Economics. This study outlined the international conditions that could result in a market for over 20 Bcf/day of LNG exports and examined in the impact on the U.S. economy of scenarios with 12 and 20 Bcf/day of LNG exports and with low gas resource recovery, high gas resource recovery and high demand.

The NERA 2018 study again used NERA's Global Natural Gas Model and the NewERA energy-economy model to look at the domestic economic effects of LNG exports. LNG exports were determined by the model for each scenario. The study included 54 different scenarios capturing a broad range of domestic and international gas supply and demand conditions, and probabilities on the likelihood of each of the 54 export scenarios. In general, high levels of LNG exports corresponded to high oil and gas supply but higher prices. Since approximately 80% of the exports resulted from increased production rather than decreased demand, the general economic impact was positive across the scenarios. The report concluded that the impact on energy-intensive~~sensitive~~ industries was ~~very small~~minimal while increased investment attributed to LNG exports raised GDP.

[4] Cooper, A., Kleiman, M., Livermore, S., & Medlock III, K. B. (2015). The Macroeconomic Impact of Increasing US LNG Exports. Available at: https://energy.gov/sites/prod/files/2015/12/f27/20151113_macro_impact_of_lng_exports_0.pdf

[5] NERA Economic Consulting. (2018). Macroeconomic Outcomes of Market Determined Levels of U.S. LNG Exports. Available at: https://www.energy.gov/sites/prod/files/2018/06/f52/Macroeconomic%20LNG%20Export%20Study%202018.pdf

III. Introduction

A. Project Background

The Department of Energy (DOE) is responsible for authorizing exports of natural gas, including LNG, to foreign countries pursuant to Section 3 of the Natural Gas Act (NGA), 15 U.S.C. 717b. Under the NGA provisions, applications requesting authority for the import or export of natural gas, including LNG, from and to a nation with which there is in effect a free trade agreement (FTA) requiring national treatment for trade in natural gas, and/or the import of LNG from other international sources, are deemed consistent with the public interest and granted without modification or delay. For Authorizations relating to those countries with which the United States does not have an FTA ~~requiring national treatment trade in natural gas~~ and with which trade is not prohibited by the United States law or policy, pursuant to Section 3(a) of the NGA, requires DOE to grant a permit to export domestically produced natural gas unless it finds that such action is not consistent with the public interest.[6]

DOE has identified a range of factors that it evaluates when reviewing an application for LNG export authorization. Specifically, DOE's review of export applications has focused on: "(i) the domestic need for the natural gas proposed to be exported, (ii) whether the proposed exports pose a threat to the security of domestic natural gas supplies, (iii) whether the arrangement is consistent with DOE's policy of promoting market competition, and (iv) any other factors bearing on the public interest as determined by DOE, such as international and environmental impacts."[7]

To inform its Public Interest determination, since 2012, the Office of Fossil Energy and Carbon Management (DOE-FECM) and its predecessor, the Office of Fossil Energy, commissioned five studies on the effects of increased LNG exports on the U.S. economy and energy markets. The studies examined the impacts of increasing demand, including exports, on the domestic natural gas market.

This updated study, similar to the previous studies, ~~was~~ is intended to serve as an input to be considered in the evaluation of applications to export LNG from the United States under Section 3 of the Natural Gas Act. DOE-FECM commissioned OnLocation, Inc., Pacific Northwest National Laboratory (PNNL), and the National Energy Technology Laboratory (NETL) to assess the economic level of U.S. LNG exports across seven scenarios representing a broad range of economic, environmental, and political scenarios, along with changes to global greenhouse gas emissions at differing levels of U.S. LNG exports. U.S. LNG exports volumes(?) were found using a global equilibrium model and were then input~~ted~~ into the domestic model to examine the market effects of increased LNG exports, including natural gas price and consumption across sectors and changes in U.S. greenhouse gas emissions. Finally, the incumbent life cycle analysis of U.S. LNG exports was expanded to incorporate market effects from the results of this study.

[6] Natural Gas Act. 15 U.S.C. 717b.

[7] Order Amending Long-Term Authorization to Export Liquefied Natural Gas to Non-Free Trade Agreement Nations at 43, Magnolia LLC, Docket 13-132-LNG (April 2022).

B. Purpose of Study

Since the NERA 2018 report was published, several events altered the explicit and implicit assumptions underpinning the global and U.S. natural gas markets. These include: i) the issuance of additional DOE LNG export authorizations, ii) the Russia-Ukraine war, iii) global and U.S. greenhouse gas policy developments, iv) technological change in production, transmission, storage, and end-use of natural gas, iv) and the passage of significant energy-related legislation in the U.S. (Bipartisan Infrastructure Law (BIL) and Inflation Reduction Act (IRA)). This report updated previous analytical work in line with current laws and regulations, as well as economic and technology conditions using newly derived scenarios. The defined seven scenarios included:

***S1*: Reference Exports** (Reference scenario in which U.S. LNG exports follow the Reference case from the U.S. Energy Information Administration's 2023 Annual Energy Outlook (AEO))

***S2*: Market Response** (U.S. LNG exports determined by global market equilibrium)

***S3*: High Global Demand** (U.S. LNG exports determined by global market equilibrium, higher population growth outside of the U.S.)

***S4*: Regional Import Limits** (U.S. LNG exports determined by global market equilibrium, global focus on maximizing consumption of local energy sources)

***S5*: Low-cost Renewables** (U.S. LNG exports determined by global market equilibrium, lower costs for variable renewable energy technologies)

***S6*: Energy Transition (Ref Exp)** (U.S. LNG exports are limited to the values from the AEO 2023 Reference case, countries achieve emissions pledges and pursue ambitious GHG mitigation policies consistent with limiting global warming to 1.5°C, U.S. emissions to net-zero by 2050)

***S7*: Energy Transition** (U.S. LNG exports determined by global market equilibrium, countries achieve emissions pledges and pursue ambitious GHG mitigation policies consistent with limiting global warming to 1.5°C, U.S. emissions to net-zero by 2050)

These scenarios are described in more detail in Section 1.A.

Several considerations were required in interpreting this study and its results. Foremost, this study was not intended to serve as forecasts of U.S. LNG exports, rather, it was an exercise in exploring alternative conditional "what-if" scenarios of future U.S. LNG exports and examining their implications for the global and U.S. energy and economic systems, and GHG emissions. Such scenario analysis is a well-established analytical approach for exploring complex relationships across a range of variables. In addition, the scenarios explored in this study were meant to span a range of plausible U.S. LNG export outcomes by 2050. However, they hinged on many assumptions about a wide range of domestic and international, and economic and non-economic factors such as future socioeconomic development, technology and resource availability, technological advance, institutional change, etc. A full uncertainty analysis encompassing all of the above factors was beyond the scope of this study. This study did not attach probabilities to any of the scenarios and no inference about the likelihood of these scenarios occurring should be made.

C. Organization of the Report

Following the Background of LNG Export Studies and Introduction sections of the Report, Section IV presents a more detailed review of the study methodology, scenario design, and key assumptions. The section introduces the scenarios, the versions of GCAM and NEMS models used for the analysis, and the life cycle analysis methodology. Section V of the report includes key results by scenario:

- U.S. LNG exports
- Global gas and primary energy consumption
- Implications for U.S. energy systems
- Life cycle analysis

IV. Scenarios, Methodology, and Key Assumptions

Three primary analytical frameworks were used for this analysis: i) the Global Change Analysis Model (GCAM) developed and maintained at the Pacific Northwest National Laboratory's (PNNL's) Joint Global Change Research Institute, ii) the National Energy Modeling System (NEMS) developed by EIA and modified for this study by OnLocation, and iii) the natural gas system life cycle analysis (LCA) model developed and maintained by NETL. These frameworks and key assumptions are described below.

A. GCAM Model and Global Scenarios Design

GCAM is a model of the global energy, economy, agriculture, land use, water, and climate systems.[8] These systems are represented in 32 geopolitical regions, 384 land subregions, and 235 water basins across the globe. GCAM operates in five-year time-steps from 2015 (calibration year) to 2100 by solving for equilibrium prices and quantities of various energy, agricultural, water, land use, and greenhouse gas (GHG) markets in each time period and in each region. Outcomes of GCAM are driven by exogenous assumptions about population growth, labor participation rates and labor productivity in the 32 geopolitical regions, along with representations of resources, technologies, and policy.

GCAM tracks emissions of twenty-four gases, including GHGs, short-lived species, and ozone precursors, endogenously based on the resulting energy, agriculture, and land use systems. GCAM's energy system contains representations of fossil resources (coal, oil, and gas), uranium, and renewable sources (wind, solar, geothermal, hydro, biomass, and traditional biomass) along with processes that transform these resources to final energy carriers (electricity generation, refining, hydrogen production, natural gas processing, and district heat), which are ultimately used to deliver goods and services demanded by end use sectors (residential buildings, commercial buildings, transportation, and industry). Natural gas competes for share with other fuels in the electricity generation sector, and with other fuels and electricity in the buildings, industrial, and transportation sectors. Each of the sectors in GCAM includes technological detail. In every sector within GCAM, individual technologies compete for market share based on the levelized cost of a technology (see appendix for more details). The version of GCAM used in this study also included a representation of three carbon dioxide (CO_2) removal strategies that were deployed in scenarios with emissions policies, namely, direct air capture (DAC), bioenergy in combination with carbon capture, utilization, and storage (BECCS), and afforestation.

The version of GCAM used in this study includes a representation of natural gas trade that creates price-based competition between domestic and imported natural gas. This representation introduces realistic inertia in the evolution of trade from current patterns. Natural gas can be imported as liquefied natural gas (LNG) or through pipelines. Traded LNG is represented as a single global market. All producers of natural gas can export to a global LNG pool from which importers can import. While the price of domestic gas is based on extraction costs that are derived from long-term regional resource supply curves, the price of imported LNG includes costs for shipping, liquefaction, and regasification in addition to extraction costs. Traded pipeline gas is represented in six regional markets (North America, Latin America, Europe, Russia+, Africa and Middle East, and Asia-Pacific). Exporters of pipeline gas export to one of the six regional pipeline blocs from which importers can import. Inter-pipeline bloc trade can also occur. For example, GCAM's China region exports only to the "Asia-Pacific" pipeline bloc but can import

[8] The full documentation of the model is available at the GCAM documentation page (http://jgcri.github.io/gcam-doc/), and the description here and in the appendix is a summary of the online documentation.

from the "Russia+" pipeline bloc and the "Asia-Pacific" pipeline bloc. These pipeline trade relationships are based on existing relationships. The price of imported pipeline gas includes the costs of building and operating pipeline infrastructure in addition to resource extraction costs. Gross exports and imports of LNG and pipeline gas are calibrated to historical data in GCAM's historical calibration year (2015). In a future model period, trade volumes evolve from historical patterns depending on future demands and prices. For the purposes of this project, historical natural gas producer prices in the U.S. are calibrated to the Henry Hub prices from the Energy Information Administration (EIA)[9] and in Canada, they are calibrated to Alberta marker prices from the BP Statistical Review.[10] For the rest of the world, natural gas producer prices in each GCAM region are based on the cost, insurance, and freight (CIF) prices from S&P.[11] In a future model period, as demand changes, the change in regional producer prices from the historical calibrated values are calculated endogenously using regional supply curves that represent increasing cost of extraction as cumulative extraction increases. GCAM also tracks turnover of trade infrastructure (e.g., liquefaction and regasification units, and pipelines). Trade infrastructure can either retire naturally or in response to economic changes (e.g., those driven by an emissions policy).

Using GCAM, we explored seven scenarios spanning a range of plausible U.S. LNG export outcomes by 2050 (Table 2). All of our scenarios include the 2022 Inflation Reduction Act in the U.S. and current emission policies in the rest of the world. The scenarios also include a constraint on Russian exports such that Russian pipeline exports to EU declined to a level below current levels by 2035 and then remain flat, LNG exports from Russia remain flat beyond 2025, and Russian pipeline exports to the east (e.g., to China) continue to increase. Our scenarios include planned and existing LNG capacity additions in major economies including the U.S., Middle East, Australia, Canada, Southeast Asia, and Africa. Socioeconomic (population and economic growth) assumptions for the U.S. were harmonized to the AEO2023 Reference.

The seven scenarios include:

> ***S1: Reference Exports.*** This scenario assumes that the U.S. LNG exports follow the trajectory from the Reference case of the U.S. Energy Information Administration's (EIA's) 2023 Annual Energy Outlook (AEO2023) to grow to 27.34 Bcf/day in 2050. The AEO2023 Reference case incorporated U.S. LNG export projects that were either operating or under construction as of August 2022 and then added capacity based on the cost-competitiveness of exporting U.S. LNG to the international market including an annual capacity build-constraint. More specifically, in AEO2023, LNG export facilities had a combined operating capacity of 10.3 Bcf/d with an additional 4.5 Bcf/d of operating capacity under construction. AEO2023 projected an additional 12.6 Bcf/d of operating capacity that was assumed to be constructed in response to international demand for U.S. LNG.

[9] U.S. EIA (2023). Henry Hub Natural Gas Spot Price. Available at: https://www.eia.gov/dnav/ng/hist/rngwhhda.htm

[10] BP (2022). bp Statistical Review of World Energy. 71st edition. Available at: https://www.bp.com/content/dam/bp/business-sites/en/global/corporate/pdfs/energy-economics/statistical-review/bp-stats-review-2022-full-report.pdf

[11] S&P Global (2023). S&P Global Commodity Insights. Historical and forecasted LNG prices data sheet.

S2: Market Response. This scenario has assumptions consistent with S1 and assumes economically driven, market-based outcomes for U.S. LNG exports.

S3: High Global Demand. This scenario includes the same assumptions as in *S2*, but assumes a higher population growth in regions outside of the U.S. consistent with the Shared Socioeconomic Pathways – 3.[12] This results in ~1 billion more people globally in *S3* by 2050 compared to *S1 and S2* and explores the effects of higher U.S. LNG exports driven by higher demand for all energy sources (including natural gas) compared to *S2*.

S4. Regional Import Limits. This scenario includes the same assumptions as in *S2*, but with constraints on natural gas imports globally to maximize the use of domestically produced natural gas across the world (Table A-1). This scenario explores the effects of lower U.S. and global LNG exports driven by global energy security concerns and trade limitations.

S5: Low-cost Renewables. *S5* includes the same assumptions as in *S2* but assumes lower capital costs for renewable energy technologies such as onshore and offshore wind, solar photovoltaic, concentrated solar power, and geothermal. This scenario explores the effects of faster technological improvements in competing technologies. While technology cost assumptions in other scenarios are consistent with NREL's Annual Technology Baseline (ATB) "Medium" assumptions, capital cost assumptions for onshore and offshore wind, solar photovoltaic, concentrated solar power, and geothermal technologies under *S5* are based on the "Low" assumptions.

S6: Energy Transition (Ref Cap) and ***S7: Energy Transition.*** Both scenarios assume an emission pathway that is consistent with a global temperature change of 1.5°C by 2100 derived from published peer-reviewed literature.[13,14,15] Both of these scenarios assume that countries achieve their emission pledges as made during the 26th Conference of Parties of the United Nations Framework on Climate Change held in Glasgow. The pledges include nationally-determined contributions that outline emission reduction plans through 2030, long-term strategies, and net-zero pledges through mid-century. The U.S. is assumed to reduce economy-wide greenhouse gas emissions by 51% in 2030 and 100% by 2050. Countries without pledges are assumed to follow an emissions pathway defined by a minimum decarbonization rate of 8% that is indicative of strong mitigation policies and significant departure from historically observed decarbonization rates. The scenarios assume that countries achieve their pledges within their geographic boundaries without trading emissions. Scenario *S6* differs from *S7* in that it also limits U.S. LNG exports to the values from the AEO2023 Reference case. A key distinction between scenarios *S1* and *S6* is that while the former assumes the U.S. LNG exports to follow the AEO2023 Reference case exactly, the latter assumes the values from the AEO2023

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[12] Samir, K. C., & Lutz, W. (2017). The human core of the shared socioeconomic pathways: Population scenarios by age, sex and level of education for all countries to 2100. Global Environmental Change, 42, 181-192.
[13] Fawcett, A. A., et al. (2015). Can Paris pledges avert severe climate change? Science, 350(6265), 1168-1169.
[14] Ou, Y., Iyer, G., et al. (2021). Can updated climate pledges limit warming well below 2°C? Science, 374(6568), 693-695.
[15] Iyer, G., Ou, Y., et al. (2022). Ratcheting of climate pledges needed to limit peak global warming. Nature Climate Change, 12(12), 1129-1135.

Reference case to be an upper bound. Nevertheless, scenario *S6* enables comparisons with *S1*, and scenario *S7* enables comparisons with *S2*.

Table 2. Scenario Descriptions

Scenario	Description	U.S. LNG Export Volumes (Bcf/d)
***S1*: Reference Exports**	Reference scenario in which U.S. LNG exports follow EIA's 2023 Annual Energy Outlook (AEO). Incorporates U.S. policy assumptions (including the 2022 Inflation Reduction Act). Assumes existing policies and measures, globally.	Grow to 27.34 Bcf/d by 2050
***S2*: Market Response**	Assumes policies consistent with *S1*, but U.S. LNG exports are determined by global market equilibrium.	GCAM Market Response
***S3*: High Global Demand**	Same assumptions as *S2*, U.S. LNG exports determined by global market equilibrium, but assumes higher population growth outside of the U.S.	
***S4*: Regional Import Limits**	Same assumptions as *S2*, U.S. LNG exports determined by global market equilibrium, but includes constraints on importing and exporting natural gas with a global focus to maximize use of domestic gas.	
***S5*: Low-cost Renewables**	Same assumptions as *S2*, U.S. LNG exports determined by global market equilibrium, but assumes lower capital costs for renewable energy technologies.	
***S6*: Energy Transition (Ref Exp)**	Assumes an emissions pathway consistent with a global temperature change of 1.5°C by end of century. Countries' emissions are constrained to announced GHG pledges, including the U.S. following a path to net-zero GHG emissions by 2050. NEMS follows CO_2 emissions constraint from GCAM. U.S. LNG exports are limited to the values from the AEO 2023 Reference scenario.	Grow to 27.34 Bcf/d by 2050
***S7*: Energy Transition**	Same emissions pathway assumptions as *S6*, but U.S. LNG exports are determined by global market equilibrium.	GCAM Market Response

B. NEMS Models and Analysis Methodology

NEMS is an energy-economic model of the U.S. It projects supply, demand conversion, imports, and exports of major energy commodities, drivers such as macroeconomic conditions, world energy markets, technology choices and costs, resource availability, and demographics. The NEMS model includes both cost minimization representative of competitive markets and behavioral representations of the energy market.

NEMS is a modular energy system model. There are four supply modules covering oil, natural gas, coal, and renewables. There are two conversion modules: converting primary fuels into electricity and petroleum and other liquids into liquid fuel products, respectively. There are four demand modules covering the residential, commercial, industrial, and transportation sectors. Other modules include the macroeconomic module, emissions policy modules, and an integrating module that synthesizes the output across all other modules. NEMS solves iteratively to reach a general market equilibrium across the energy economy. The EIA provides an archive of the NEMS model with source code and input sufficient to reproduce the reference and side cases comprising the Annual Energy Outlook.

1. AEO2023-NEMS

AEO2023-NEMS is OnLocation's version of the NEMS model, modified to allow exogenous input of U.S. LNG exports. The AEO2023 reference scenario has a macroeconomic growth assumption of 1.9% average growth per year. The model has the EIA's interpretation of the IRA which includes most major provisions of the policy. The model does not include carbon capture at industrial sites (ethanol, hydrogen, NGP, and cement) or direct air capture (DAC). Therefore, the IRA 45Q credit for DAC is not included. Similarly, IRA 45V hydrogen credits are also not represented in the AEO2023 version of NEMS as it does not have the hydrogen module.

2. FECM-NEMS

FECM-NEMS is a version of NEMS that includes updates that allow for the modeling of deep decarbonization technologies and strategies. FECM-NEMS models the Inflation Reduction Act based on FECM's interpretation of the policy. It includes major IRA energy-related provisions including but not limited to the extension of 45Q CO_2 sequestration credits, clean vehicle tax credits, energy efficient home tax credits and rebate programs, clean energy PTC and ITC, zero emission nuclear credits, and hydrogen tax credits. Additional modeling updates include provisions from the Bipartisan Infrastructure Law (BIL) such as funding for carbon capture demos, CO_2 transportation and storage infrastructure, and updated EPA/NHTSA CAFE standards.

Given the carbon capture opportunities and the net negative carbon technologies such as DAC and BECCS, the FECM-NEMS model allows the economy to achieve a net-zero carbon emission scenario.

FECM-NEMS is based on OnLocation's version of the Annual Energy Outlook 2022 (AEO2022) NEMS model. For consistency with updated economic assumptions, FECM-NEMS uses the low economic growth assumption from AEO2022, assuming a real GDP average growth of 1.8% per year to 2050. Under the Office of Carbon Management Policy & Analysis, DOE-FECM, the standard NEMS has been enhanced to represent several CO_2 mitigation technologies including carbon capture and sequestration (CCS), DAC, bioenergy with CCS (BECCS), and the Hydrogen Market Module (HMM). Industrial carbon capture is found in the liquid fuels module which allows for the construction of new hydrogen and ethanol facilities with CCS. It also allows for existing hydrogen, ethanol, and natural gas processing plants to retrofit CCS capability. The cement industry has also been enhanced to include CCS opportunities. Industries have the option to send captured CO_2 to an enhanced oil recovery market or store it in saline aquifers.

The HMM is integrated into NEMS to produce hydrogen via conventional and low carbon processes. The hydrogen production technologies available in the HMM include steam methane reformation (SMR), SMR with CCS, biomass gasification with CCS, and electrolysis.

3. Harmonizing GCAM and NEMS

While GCAM and NEMS are distinct models, coordination between them was necessary to maintain consistency and tie the NEMS results back to the global LNG market forecast. Harmonization efforts ensured that LNG exports (for all scenarios) and CO_2 emissions (in the net-zero scenarios) were consistent between the two models.

The EIA's AEO2023 reference case was selected to define *S1*. In AEO2023-NEMS, the AEO2023 reference case solution file was adopted for all variables. LNG exports from the AEO2023 reference case were then used as exogenous inputs into the GCAM model in place of endogenous estimates. For *S2* through *S7*, the process was reversed: the scenarios were first run in the GCAM model, from which endogenously calculated LNG export curves were taken and input exogenously into AEO2023-NEMS. The endogenous algorithm used by NEMS to calculate LNG exports was turned off for these scenarios. Since a key driver of LNG exports is the differential between domestic and world natural gas prices, domestic natural gas prices from NEMS were then compared with North American prices in GCAM. In all scenarios except *S5*, technology and resource were aligned between GCAM and the AEO2023 reference scenario. In *S5*, both models adjusted power generation technology assumptions consistent with the AEO2023 Low Renewable Cost scenario from the AEO.

For *S6* and *S7*, the net-zero scenarios were first run in the GCAM model, which uses global interactions and feedback to model U.S. LNG under a criteria of net-zero GHG by 2050. As part of the modeling process, GCAM generates a set of emissions curves that list quantities of GHG emissions of various sectors and gases (CO_2, CH_4, N_2O, F), as well as emissions and removals from land use, land-use change, and forestry (LULUCF). These curves were outputs of the model, although the sum of individual emissions was defined in the model inputs such that they reached or exceeded a net-zero target in 2050. The output emissions curves from GCAM were used to specify how the net-zero scenario was implemented in FECM-NEMS.

The values of CO_2 emissions from the energy sector were taken from the GCAM output and used explicitly as the carbon cap in FECM-NEMS to model the net-zero scenarios. The carbon cap curve (used to define both *S6* and *S7*) is plotted in Figure 1.

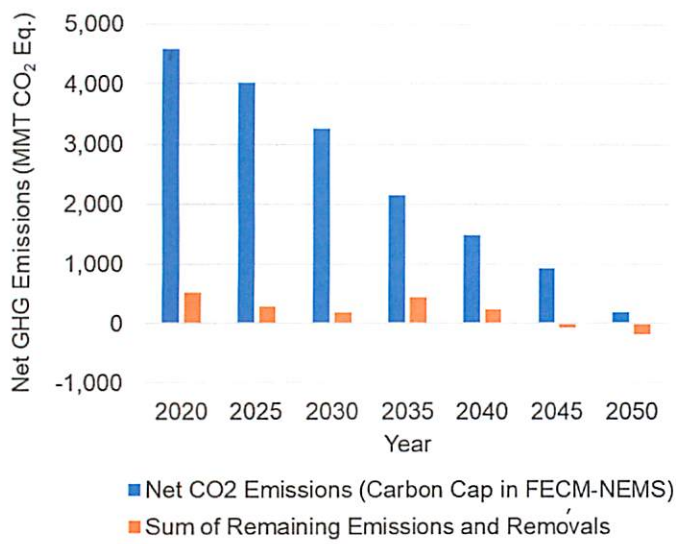

Figure 1. U.S. GHG emissions and removals in the net-zero scenarios

Referring to this carbon cap each model year, FECM-NEMS calculates emissions and removals throughout the model and adjusts a carbon price to equalize them with the carbon cap. With this method, FECM-NEMS ensures that the CO_2 emissions from the energy sector match the corresponding emissions from GCAM. Although FECM-NEMS calculates CH_4 emissions from natural gas systems, they were excluded from the carbon cap in favor of adopting the values calculated by GCAM.

The carbon cap used in FECM-NEMS for both net-zero scenarios ended with 187 MMT CO_2 in 2050. Although this value does not equal zero, it was balanced by the sum of non-energy CO_2, non-CO_2 GHGs, and LULUCF-sector emissions and removals calculated by the GCAM model which added together total -185 MMT CO_2 equivalent (the total was negative because of large quantities of LULUCF-sector removals). The remaining emissions and removals (non-energy CO_2, non-CO_2 GHGs, and LULUCF) were treated as exogenous to FECM-NEMS and could be added with the endogenous CO_2 emissions to calculate net total GHG emissions (which would equal near-zero in 2050). The sum of non-energy CO_2, non-CO_2 GHGs, and LULUCF-sector emissions and removals is also plotted in Figure 1.

C. NETL Life Cycle Analysis Model Methodology

Past life cycle studies conducted by NETL on natural gas and LNG have been attributional studies that estimate the emissions and other impacts associated with current units of natural gas/LNG delivered. These LCA studies have not, to date, considered the *consequences* of delivering LNG, such as how domestic or foreign energy markets may be affected by increasing the supply of natural gas (e.g., whether different sources of natural gas compete in the market, or whether, given additional supply, natural gas-fired power plants in Europe might take market share from other types of electric plants).

Such market-based effects could lead to consequential increases or decreases in GHG emissions. As part of this study, these consequential effects were estimated by tracking differences in global GHG emissions and quantities of LNG exported from the GCAM model results.

This section details the various existing representations of the natural gas supply chain within the context of the NETL natural gas model and the GCAM model. The purpose of documenting these representations is to subsequently apply the insights from the GCAM model to the NETL LCA framework.

1. Past NETL Natural Gas Life Cycle Reports

As shown in the top half of Table 3, the NETL Natural Gas model[16] is separated into five stages that generally align with categories used in other federal efforts such as the US EPA's Greenhouse Gas Reporting Program (GHGRP)[17] and Greenhouse Gas Inventory (GHGI)[18]. Results of this model are provided for two scopes: Production through Transmission (e.g., for large scale industrial users, like power plants and LNG facilities that are directly connected to a pipeline), and Production through Distribution (e.g., for residential or smaller industrial users where the natural gas is delivered through smaller distribution pipelines). Results are provided for various techno-basins of production, regions, and U.S. average production, using a variety of IPCC Assessment Report Global Warming Potential (GWP) values on 100-year or 20-year basis.

Commented [ST4]: The 2020 report and model are not public. The reference will need updated upon release of the 2020 report.

I checked the ISSST Presentation and it is marked "do not cite" and does not contain the production thru transmission result of 7.4 g. Not a good reference.

Evaluating U.S. Natural Gas Environmental Performance, ISSST 2023 Conference, June 14, 2023, Fort Collins, CO.

In addition, past work by NETL has modeled the additional processing stages to produce and deliver LNG, adding another four stages in the bottom half of Table 3.

Table 3. Natural Gas and Liquefied Natural Gas Life Cycle Stages

Stage Name	Description
Natural Gas Production Only Stages	
Production	Drilling and construction of conventional and unconventional wells (e.g., from hydraulic fracturing), and extraction of gas, including liquids unloading operations.
Gathering and Boosting	Movement of natural gas from wells via gathering pipelines and delivered to treatment and/or processing plants. Boosting systems may include compressors, dehydration, and pneumatic devices and pumps.
Treatment and Processing	Removal of impurities and compression of input gas to meet transmission pipeline standards. May include acid gas removal (AGR), dehydration), NGL recovery, etc.
Transmission and Storage	Construction of pipelines, and movement of bulk quantities of natural gas in large

[16] Khutal, H., et al. Life Cycle Analysis of Natural Gas Extraction and Power Generation: U.S. 2020 Emissions Profile. National Energy Technology Laboratory, Pittsburgh, July 7, 2023

[17] US EPA Greenhouse Gas Reporting Program, https://www.epa.gov/ghgreporting, last accessed Sept 1, 2023.

[18] US EPA , Inventory of U.S. Greenhouse Gas Emissions and Sinks, https://www.epa.gov/ghgemissions/inventory-us-greenhouse-gas-emissions-and-sinks, last accessed Sept 1, 2023.

	pipelines to large users or city gates for subsequent distribution. Typically includes compressor stations along pipelines. Storage includes insertion of gas into units such as underground storage facilities as well as additional gas processing and compression after removal from storage before injection into the transmission pipeline network.
Distribution*	Movement of gas from transmission or storage facilities to city gates for subsequent delivery to smaller consumers via small diameter pipelines. (*may or may not be included depending on scope)
Additional Stages to Produce and Deliver LNG	
Liquefaction	Pre-treatment of gas, liquefaction to low temperatures and storage.
Loading/Unloading	Process to load (and unload) LNG to and from tankers to facilities.
Ocean Transport	Shipment of LNG on ocean-going vessels of varying technology types to distant ports for subsequent regasification. Depending on technology, may use LNG as fuel.
Regasification	Regasification of LNG and injection into transmission pipelines.
Destination Transmission / Distribution	Similar processes as described above, and not functionally different than as described for the natural gas only part.

Quantitatively, the NETL natural gas model has estimated ranges of GHG emissions by species and by stage for the domestic natural gas supply chain as shown in Figure 2. Given the scope of domestic natural gas production through the transmission stage, the mean U.S. average total CO_2-equivalent emissions are about 7.44 g CO_2e/MJ (IPCC AR6, 100-year basis), with a confidence interval of the mean of 4.6-11.1 g CO_2e/MJ. This report also estimated GWP intensity of natural gas extraction in different geographic regions of the US, which have higher or lower intensity, as compared to the U.S. average. Note that these results are in terms of Higher Heating Value (HHV) of natural gas, while the GCAM model uses Lower Heating Value (LHV), so needed to be subsequently adjusted.

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Need to provide/cite the HHV to LHV values for the adjustment factor.

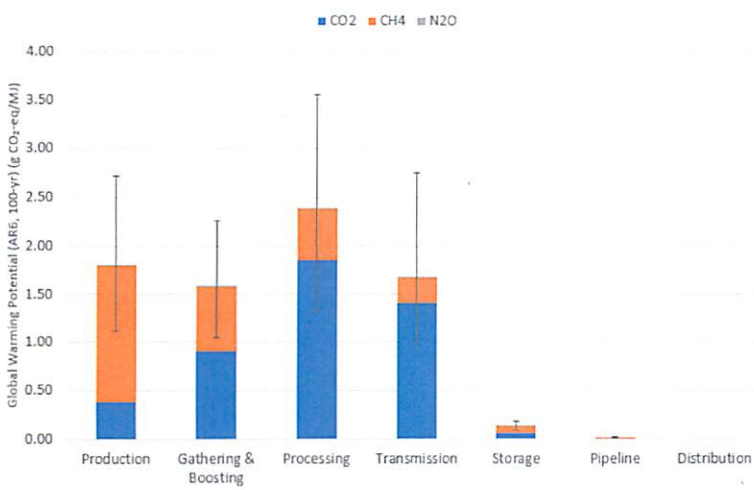

Figure 2. Life cycle GHG emissions from the 2020 U.S. average Natural Gas supply chain, HHV basis (Source: NETL 2023)

Past work by NETL also estimated the greenhouse gas emissions implications of the additional stages to produce and deliver U.S. average LNG around the world[19]. While these values are estimated on a per-MJ delivered basis, their presentation is complicated by the variability associated with the distance shipped, which can be large in many cases (LNG shipped relatively short distances has a significantly smaller GWP footprint than that shipped long distances). Using data from the 2019 NETL LNG report (cite), and adjusting to the basis here, LNG delivered from New Orleans to Rotterdam (8,990 km) would be expected to result in 17.9 g CO_2e/MJ delivered (IPCC AR6, 100-year basis, HHV). In short, the additional processes and natural gas needed to liquefy, ship, and regasify natural gas to Rotterdam adds about 10 g CO_2e/MJ delivered, which is more than double the impact of ~~merely~~ producing the gas and transmitting it to large scale users domestically (of 7.44 g CO_2e/MJ, HHV basis, given above). The GHG emissions intensity result on a per MJ NG delivered to liquefaction plant basis is 7.44 g CO_2e/MJ (AR6, 100-yr, HHV) but accounting for NG losses that occur in the downstream stages results in a higher volume of NG upstream, leading to an upstream emissions intensity of 8.44 g CO_2e/MJ NG delivered through low pressure distribution pipelines to small volume end users (e.g., commercial, residential, and some industrial users)~~to power plant~~ (AR6, 100-yr, HHV). Given the many possible delivery routes and distances for such LNG, these specific results are intended only to provide contextual perspective of the GWP intensity of the added LNG stages.[20]

[19] Roman-White, S., Rai, S., Littlefield, J., Cooney, G., & Skone, T. J. (2019). Life cycle greenhouse gas perspective on exporting liquefied natural gas from the Unites States: 2019 update. National Energy Technology Laboratory (NETL), Pittsburgh, September 12, 2019.

[20] Results from Roman-White 2019, Exhibit A-2, adjusted from g CO_2e/MWh to g CO_2e/MJ using heat rate of 145 kg natural gas/MWh, and higher heating value of 54.3 MJ/kg.

Commented [ST6]: Y-axis: units should read g CO2e/MJ before AR6, 100-year.

CO2e: removed hyphen between the "2" and "e".

Legend: need to subscript "2" and "4".

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Commented [ST9]: Per the 2020 report, this is the US average through distribution

The previous NETL work on natural gas cited above are attributional studies of the domestic natural gas system. The results sought to identify and attribute the emissions associated with the various unit processes that created them. These methods differ in scope than consequential analysis which more broadly considers the global changes in GHG emissions when additional volumes of U.S. natural gas are produced and delivered across the world, or, in other words, the market-based effects of producing domestic natural gas and exporting it. Further discussion on how the LCA section of this project can support consequential analysis is discussed in Section V.G.

2. Market Adjustment Factors

In order to quantify the broad and global market effects associated with increasing exports of U.S. LNG, the GCAM results were used to estimate the change in global GHG emissions per unit of LNG exported between various scenarios. This market adjustment factor (MAF) is defined as:

Commented [ST10]: Page 51: MAF is defined as "market effect adjustment factor". Recommend removing effect for consistency with in the report.

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$$MAF_{scenario\ n} = \frac{Global\ Emissions_{scenario\ n} - Global\ Emissions_{scenario\ 1}}{US\ LNG\ Exports_{scenario\ n} - US\ LNG\ Exports_{scenario\ 1}}$$

and represents a ratio of the change in GHG emissions for a given scenario compared to a base scenario, versus the change in U.S. LNG exports between the same two scenarios. For example, a comparison of Scenario *S2* vs. Scenario *S1* would compare the differences in GCAM values for these two scenarios. This MAF can be calculated for every model year (2015-2050) and can also use linearly interpolated values for the non-modeled years.

V. RESULTS

The following sections describe the results of the global analysis using GCAM, the U.S. analysis using NEMS, and the life-cycle analysis in that order. To highlight the implications of the availability of additional U.S. LNG in the global market, we first compare *S1* and *S2*. We then discuss *S6* and *S7* to illustrate the implications of additional U.S. LNG in the global market under a global transition toward 1.5°C. Subsequently, we discuss results from the remaining scenarios (*S2-S5*).

A. U.S. LNG exports

Across all the scenarios, the U.S. is a net exporter of natural gas. As shown in Figure 3, U.S. LNG exports increased beyond existing and planned capacity in all scenarios by 2050, except *S1* in which U.S. LNG export volumes followed AEO2023 and *S6* in which export volumes were limited to AEO2023 by design. Under *S2,* in which all outcomes – including U.S. LNG exports – are economically driven and market-based, U.S. LNG exports increased to ~47 Bcf/day in 2050.

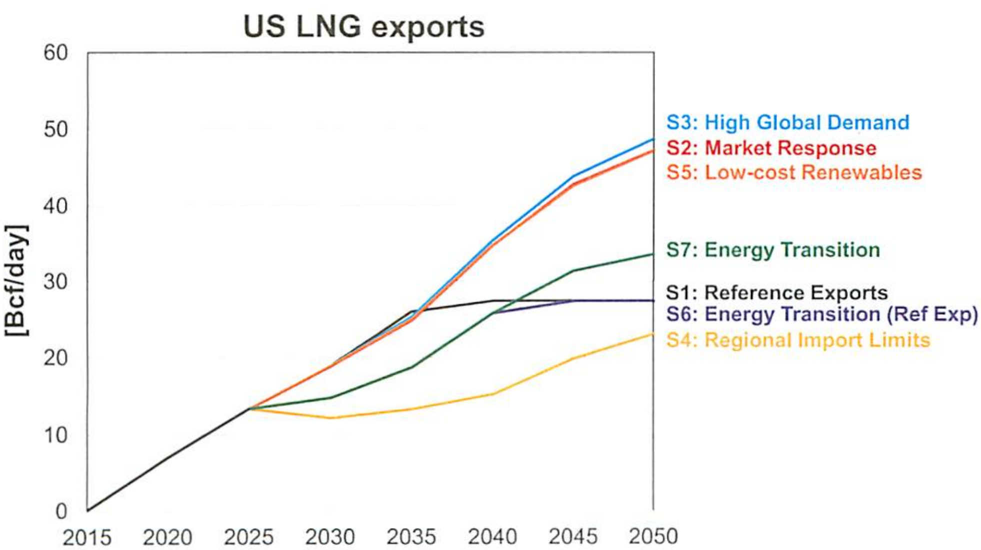


Figure 3. U.S. LNG exports across the scenarios. Note that the U.S. LNG export outcomes for S2 and S5 are very close to each other.

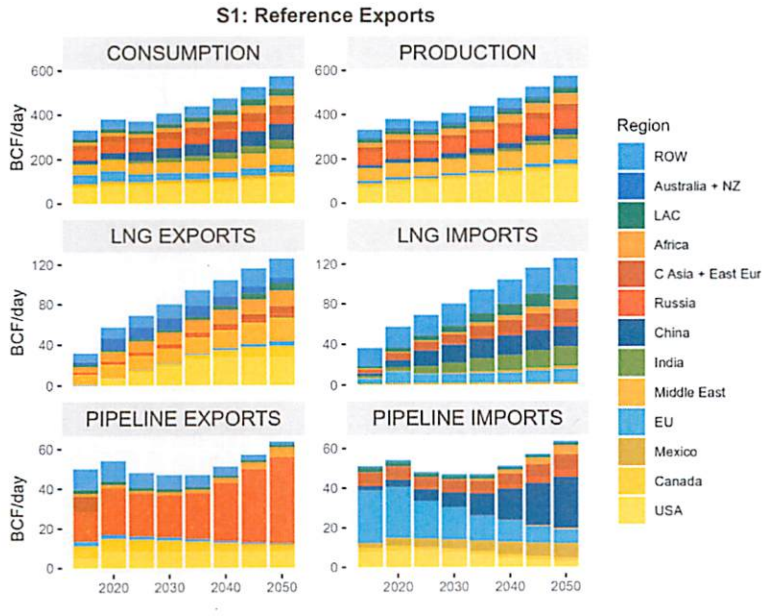
U.S. LNG exports under *S3*, the scenario with increased global population, increased to 49 Bcf/day in 2050, emerging as the upper bound. With higher population assumptions in *S3*, total energy demand – and consequently natural gas demand – outside the U.S. increased compared to *S2*, resulting in an increase in U.S. LNG exports to satisfy the increased international demand. However, the increase was not proportional to the increase in population because part of the higher demand in *S3* was supplied by an increase in international production.

U.S. LNG exports under *S4* increased only to ~23 Bcf/day in 2050, emerging as the lower bound. The lower increase in U.S. LNG exports in *S4* compared to other scenarios was driven by international limits on natural gas imports to maximize the use of locally produced gas.

U.S. LNG exports under *S5* increased to approximately the same level as *S2* in 2050. This was mainly because cheaper solar and wind technologies in this scenario mostly displaced fuels other than natural gas (e.g., biomass). Hence, the demand for natural gas and consequently, U.S. LNG exports, remained materially unaffected compared to *S2*. Under *S7,* which assumes a global transition toward 1.5°C, U.S. LNG exports continued to increase, albeit at a lower level than *S2,* to ~34 Bcf/day in 2050. As discussed below, the lower increase in U.S. LNG exports in this scenario compared to *S2* was driven by the economy-wide transition to low-carbon fuels to meet emission reduction commitments and pledges.

B. Global Natural Gas Consumption, Production, and Trade Under Scenarios *S1* And *S2*

As shown in Figure 4, under *S1*, production, consumption, and trade of natural gas increased in all regions, globally driven by growing demands in the electricity generation, industrial, and buildings sectors (see Figure A-1 in appendix A). Under *S1*, U.S. LNG exports followed the AEO2023 Reference case to grow to 27.34 BCF/day by 2050 (by design).



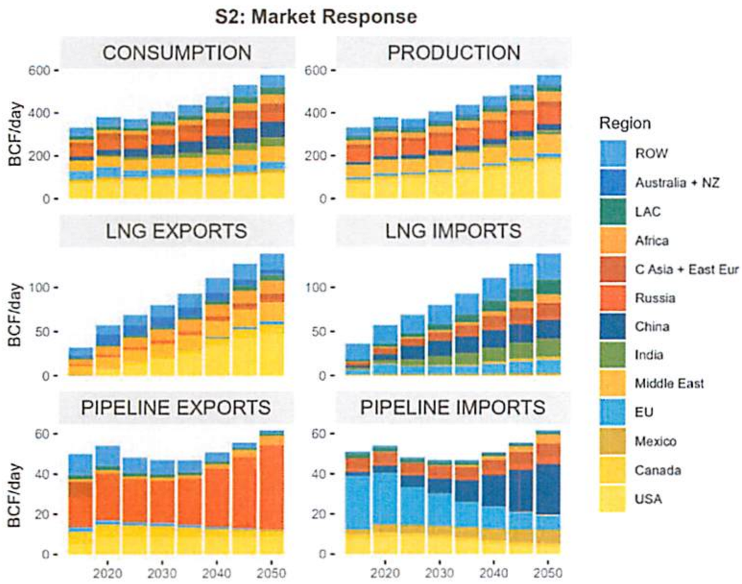


Figure 4 Natural gas consumption, production, and trade by region under S1 (upper) and S2 (lower)

As shown in Figure 5, under *S2*, in which U.S. LNG exports were determined by market equilibrium, U.S. natural gas production and LNG exports increased compared to *S1* to satisfy the growing demands of natural gas globally. Under *S2*, U.S. LNG exports grew to ~47 Bcf/day by 2050. In this scenario, the availability of additional U.S. natural gas in the global natural gas market at competitive prices resulted in a reduction in production and LNG exports from other parts of the world. The increased availability of U.S. LNG in the global market also resulted in higher LNG imports and reduced pipeline trade outside of the U.S. However, global natural gas consumption in *S2* increased only by a very small amount (<5% by 2050 globally compared to *S1*). This is mainly because the availability of additional U.S. LNG in the global market did not materially affect the relative competitiveness of natural gas compared to other fuels (e.g., coal, oil, renewables, and nuclear) globally. In addition, current emission reduction policies in the U.S. and internationally, which were included in the assumptions for all scenarios, limited the potential for global natural gas consumption to grow in response to the increased availability of U.S. natural gas. Consequently, global primary energy consumption and GHG emissions under *S2* did not change much compared to *S1*, as shown in Figure 6.

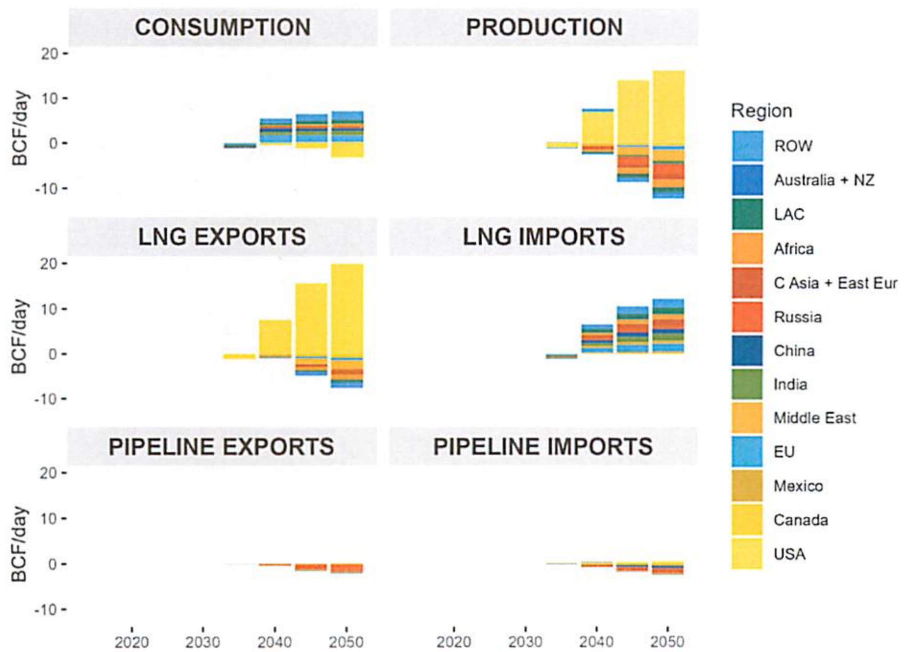


Figure 5. Changes in natural gas consumption, production, and trade by region in S2 vs. S1

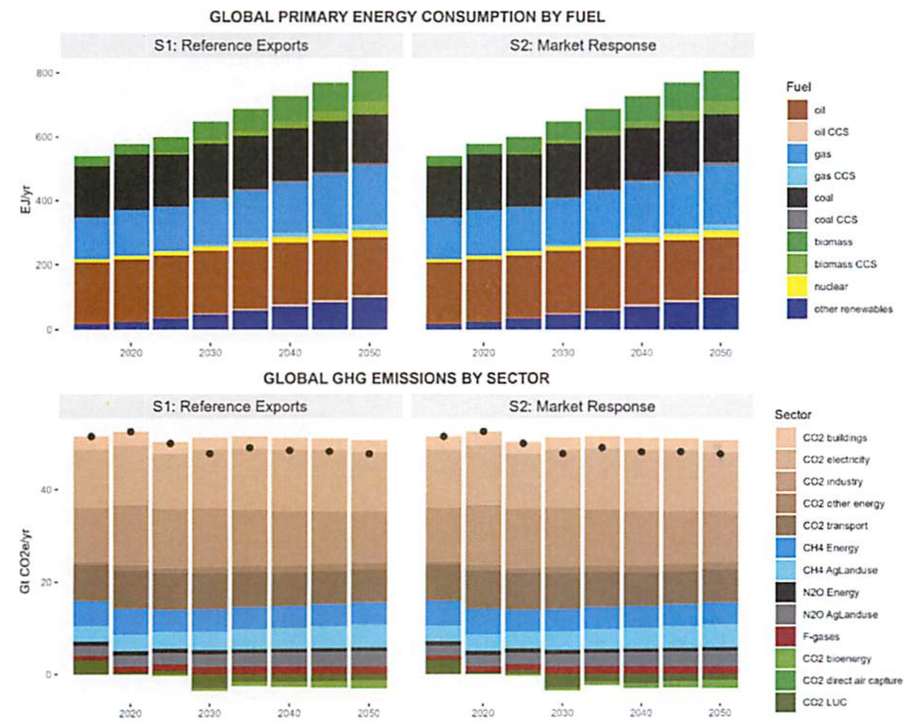


Figure 6. Global primary energy consumption by fuel and GHG emissions by sector under S2 and S1. Net GHG emissions are shown as a dot in each bar.

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C. Global Primary Energy Consumption by Fuel and GHG Emissions by Sector Under *S6* And *S7*

Under *S6* and *S7*, global GHG emissions from all sectors of the economy reduced significantly compared to *S1* and *S2* as shown in Figure 7 and Figure 8. This was by design as these scenarios were assumed to include emissions pledges and constraints on emissions consistent with limiting global temperature change this century to 1.5°C. These scenarios were characterized by a combination of the following decarbonization strategies: i) a reduction in fossil fuel consumption without carbon capture utilization and storage (CCUS), ii) increased deployment of CCUS with fossil fuels, iii) increased deployment of renewables, iv) a net reduction in energy consumption, and v) increased deployment of carbon dioxide removal (CDR) applications such as bioenergy in combination with CCUS (BECCS), afforestation, and direct air capture (DAC) compared with *S1* and *S2*.

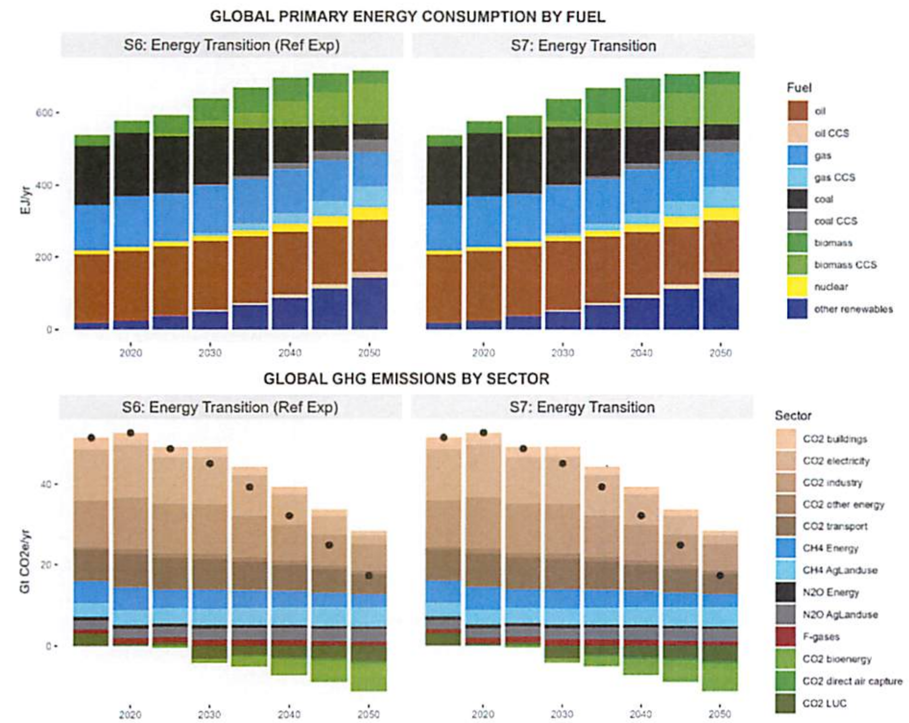

Figure 7. Global primary energy consumption by fuel and GHG emissions by sector under S6 and S7. Net GHG emissions are shown as a dot in each bar.

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Notably, the scale and distribution of CDR deployment varied by type and region. By 2050, about 6.8, 4, and 0.4 $GtCO_2e$ respectively of BECCS, afforestation, and DAC were deployed globally in *S6* and *S7*, as shown in Figure 9. While BECCS and afforestation were distributed more evenly across regions, most of the DAC was deployed in the U.S. primarily due to the availability of carbon storage.

Note that *S6* and *S7* did not assume the availability of any emissions trading or offset mechanisms. Hence, countries with net-zero pledges – such as the U.S. – were assumed to meet those pledges in the stated target years through a combination of the above decarbonization strategies including CDR deployment within their own geographic boundaries. Under these scenarios, although global GHG emissions are net-positive (~20 $GtCO_2e$), global CO_2 emissions were ~0 in 2050. These global emissions outcomes were broadly consistent with 1.5°C scenarios in the literature.[21]

[21] Riahi et al. 2022, Chapter 3 in the Sixth Assessment Report of the IPCC

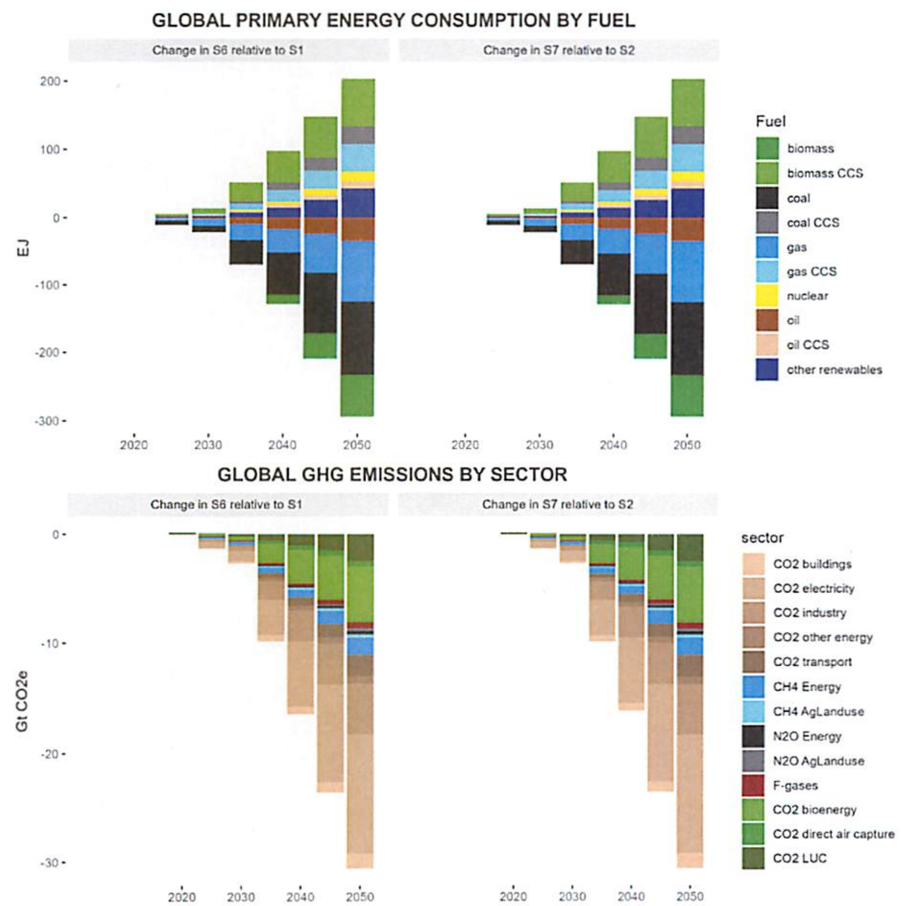

Figure 8. Changes in global primary energy consumption and GHG emissions under S6 and S7 relative to S1 and S2 respectively

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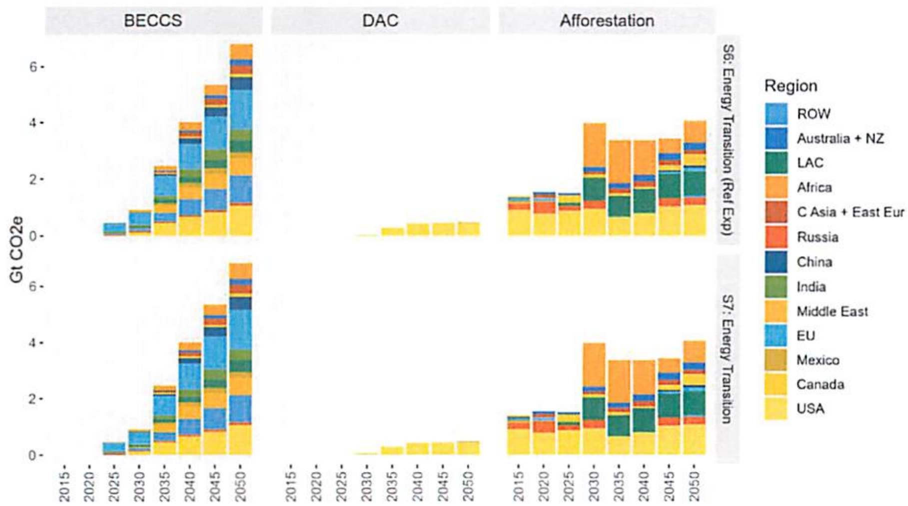

Figure 9. CDR deployment by type and region in S6 and S7

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The question of how/if renewables or other energy sources are displaced by natural gas is also not apparent in any of these results.

What countries changed their energy consumption profile because the US increased exports?

Did each countries response to change in energy consumption pattern increase or decrease their GHG emissions footprint?
...what sectors within each country?

Next - figures are nice, but would like to see full tabulated results in an Excel workbook be made available to provide transparency to the public on GCAM, NEMS, and LCA results.

D. Global Natural Gas Consumption, Production, and Trade Under Scenarios *S6* and *S7*

As shown in Figures 10 and 11, under *S6* and *S7*, natural gas consumption decreased compared to *S1* and *S2* in most regions largely driven by official net-zero pledges that require complete decarbonization of energy systems by 2050. However, in some regions with net-zero pledges that extend beyond 2050 (e.g., India), natural gas demand continued to grow through 2050 and consumption did not change much compared to *S1* and *S2*. Globally, although natural gas consumption in *S6* and *S7* was lower compared to *S1* and *S2*, it continued to grow due to the deployment of natural gas with CCUS in power and industrial sectors and direct air capture (DAC) applications (see Figure A-2 in appendix). The lower natural gas consumption in *S6* and *S7* compared to *S1* and *S2* resulted in lower global production, LNG exports, and LNG imports.

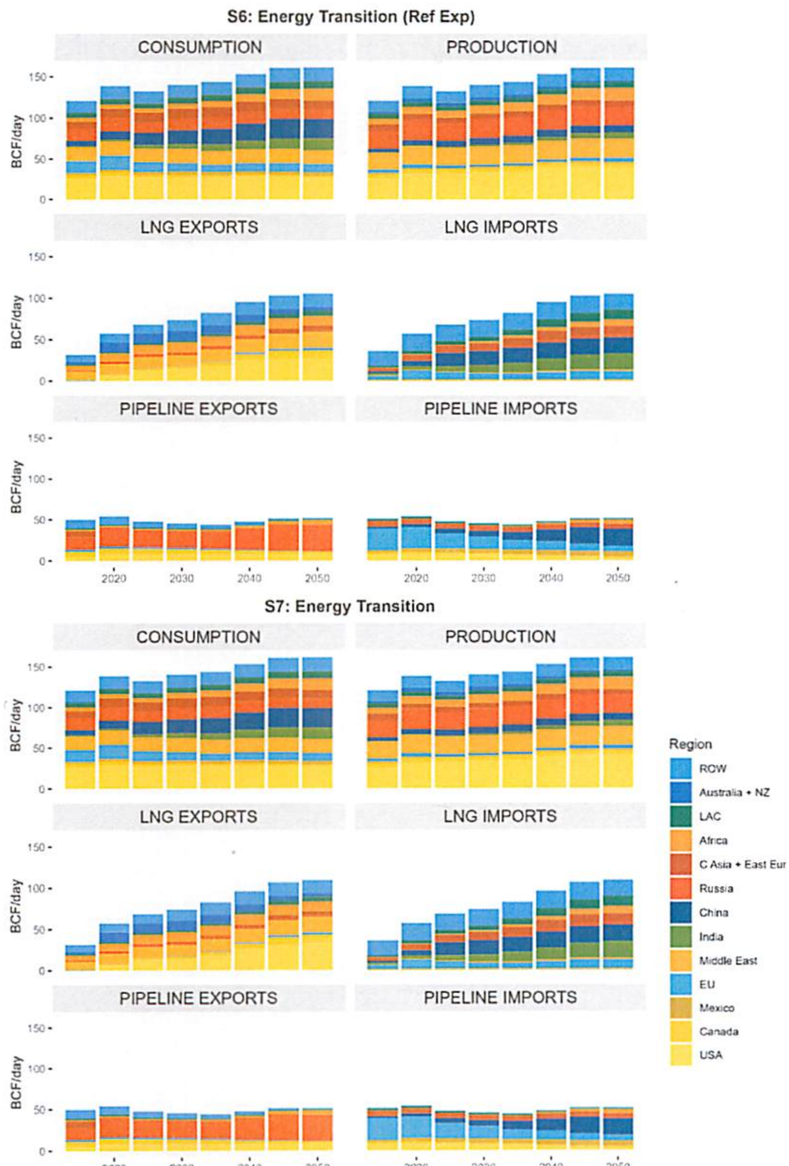

Figure 10. Natural gas consumption, production, consumption, and trade by region under S6 and S7

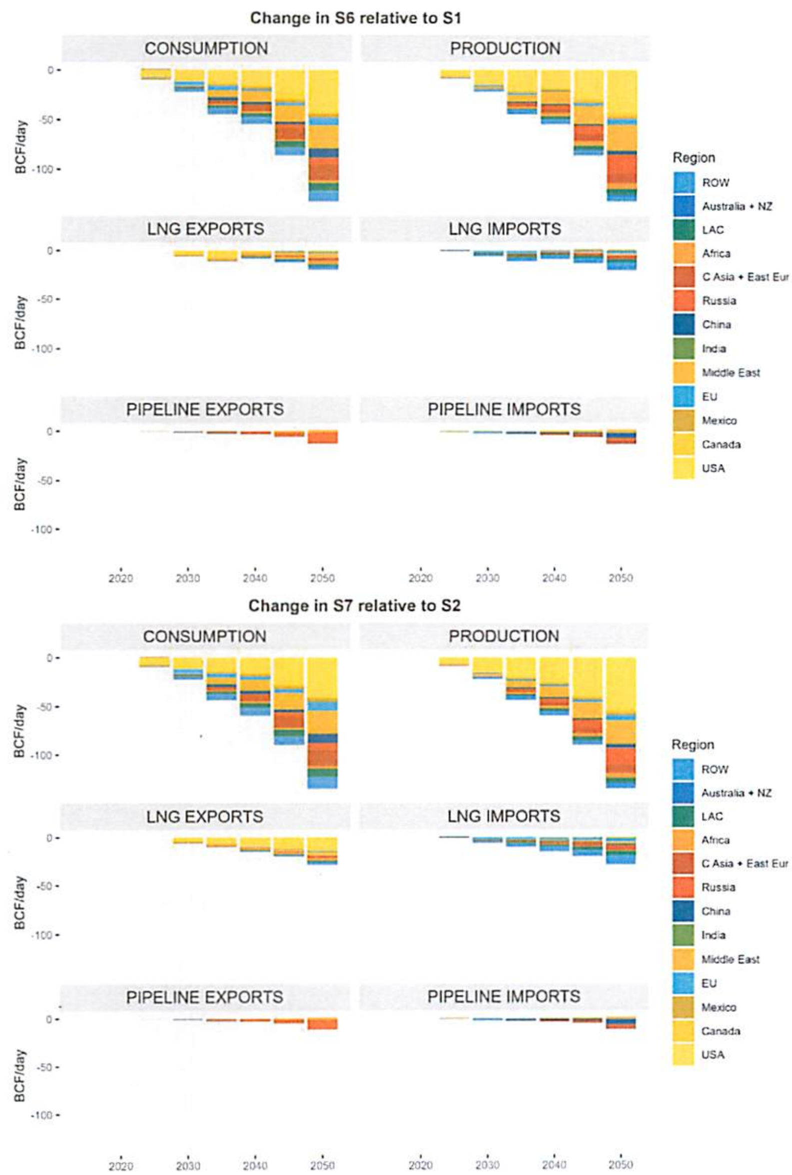

Figure 11. Changes in natural gas consumption, production, and trade by region: S6 vs S1 and S7 vs S2

As shown in Figure 12, *S6* and *S7* differed in the role of U.S. LNG exports in the global natural gas market. By 2050, U.S. LNG exports in *S6* were not different from *S1* because this scenario assumed the *S1* values (which are based on AEO2023) as an upper bound. Under *S7*, which assumes economically driven outcomes, U.S. LNG exports continued to grow and increase beyond *S6* – particularly after 2040 – to meet the global demand for natural gas, a growing share of which was deployed in combination with CCUS in the power and industrial sectors (see Figure A-1 in the appendix). Similar to the comparison between *S1* and *S2*, the availability of additional U.S. LNG in *S7* resulted in a very small increase in natural gas consumption, reduction in production, reduction in LNG exports, increase in LNG imports, and reduction in pipeline trade in the rest of the world compared to *S6*.

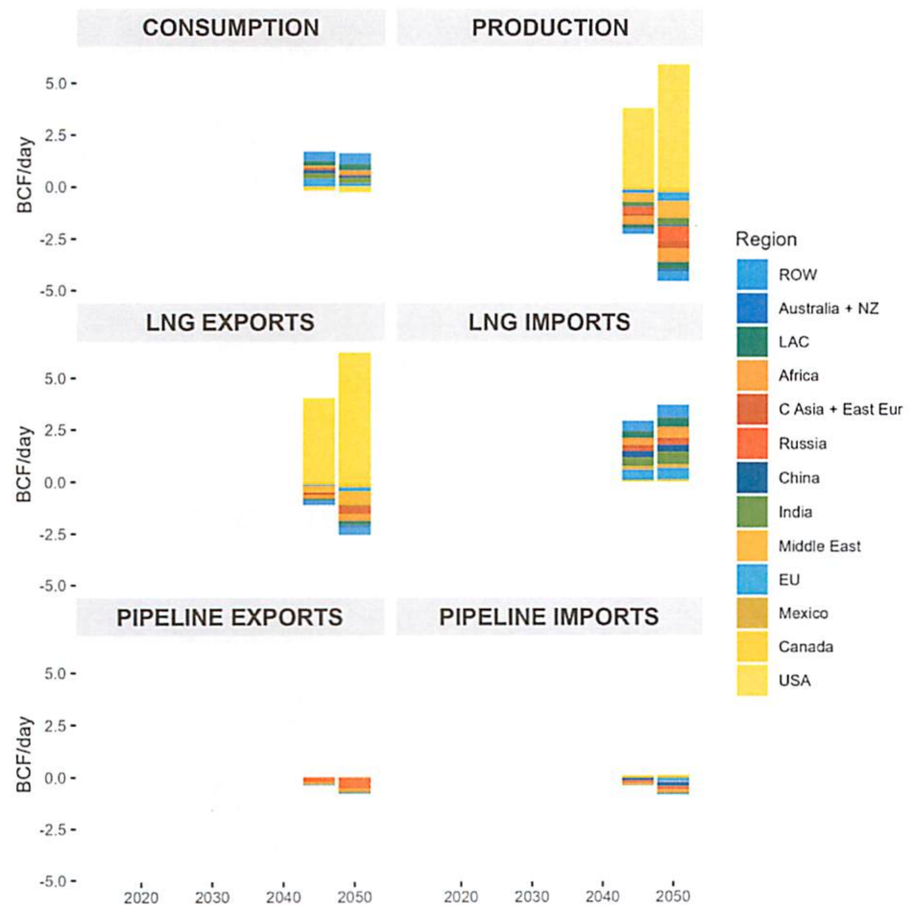

Figure 12. Changes in natural gas markets in S7 vs. S6

E. Global Primary Energy Consumption and GHG Emissions Across All Scenarios

Overall, the seven scenarios explored in this study resulted in a range of outcomes for global primary energy consumption and emissions by 2050. As shown in Figure 13, the fuel composition of primary energy consumption and the sectoral allocation of GHG emissions were not very different across scenarios *S1* through *S5*. Total primary energy consumption and GHG emissions were highest under the S3 scenario driven by higher population growth and associated increases in energy demand.

Total emissions in 2050 under scenarios *S1* through *S5* were relatively similar to 2015 levels because these scenarios included current policies and measures to deploy lower emission technologies. However, total primary energy consumption in 2050 under these scenarios was significantly higher compared to 2015 primarily driven by population and economic growth.

By contrast, total energy and emissions were lowest in scenarios *S6* and *S7* due to assumptions about countries meeting emission pledges and further emission declines to reach a global temperature change of 1.5°C by the end of century. As described earlier, these scenarios were also characterized by significant changes in the fuel composition of global energy consumption and the deployment of carbon dioxide removal technologies.

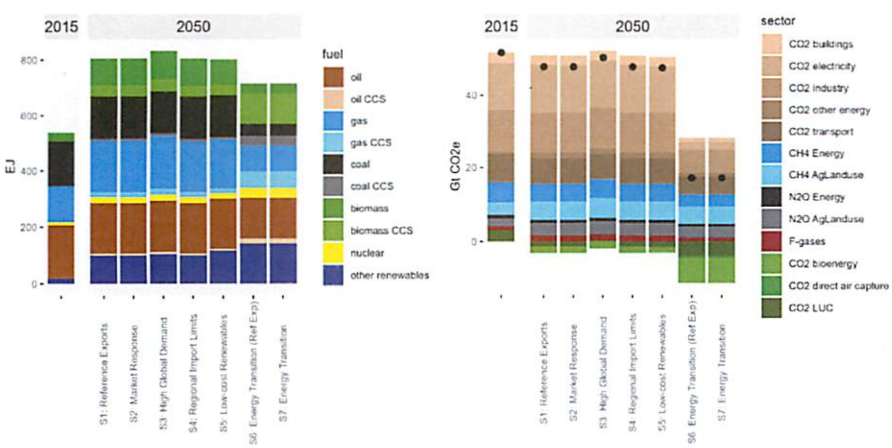

Figure 13. Primary energy consumption by fuel and GHG emissions by sector under all scenarios

F. NEMS Analysis: Implications for U.S. Energy Systems

1. Energy Impacts

AEO2023-NEMS and FECM-NEMS were used to model U.S.-specific results for *S1* through *S5* and *S6* through *S7*, respectively. Similar to global energy consumption, primary energy consumption in the U.S. grew over time in each scenario.

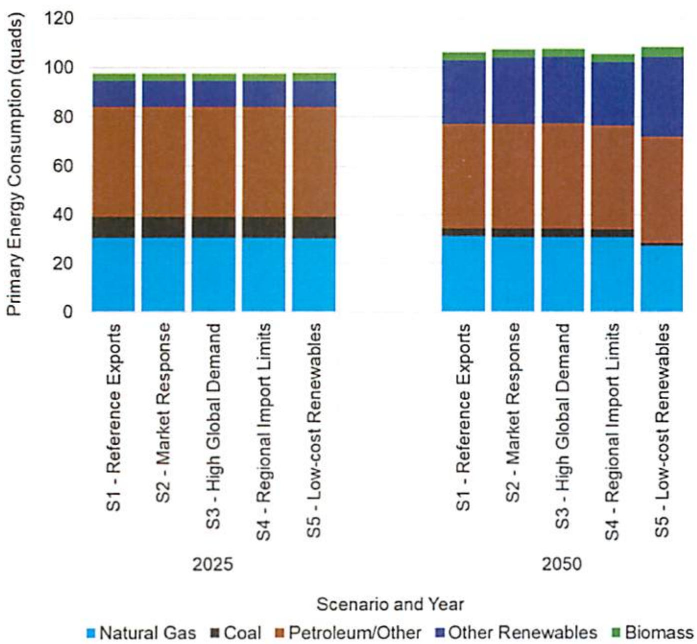

Figure 14. U.S. primary energy consumption, S1 through S5

In 2025, the primary energy consumption was at approximately 98 quadrillion BTUs in scenarios *S1* through *S5,* as shown in in Figure 14. By 2050, all scenarios saw an increase in total energy consumption, exceeding 105 quadrillion BTUs. The highest energy consumption was recorded in scenario *S5* at 109 quadrillion BTUs, and the lowest consumption was in scenario *S4* at 105 quadrillion BTUs.

The availability of low-cost renewables in scenario *S5* fosters the deployment of biomass and other renewable energy sources. A substantial decrease was noted in coal usage, with the most significant reduction occurring in scenario *S5*. Natural gas consumption remained steady across scenarios *S1* through *S4*, hovering around 31 quadrillion BTUs, but experienced a decline to 27 quadrillion BTUs in scenario *S5*.

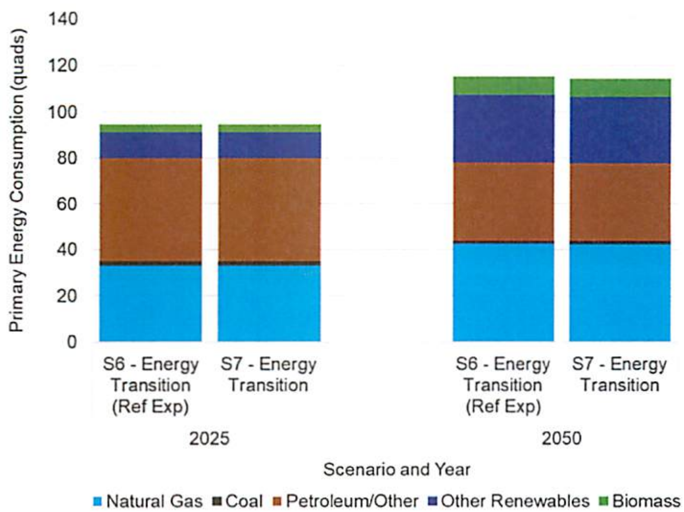

Figure 15. U.S. primary energy consumption S6 and S7

Figure 15 shows U.S. primary energy consumption across *S6* and *S7* in 2025 and 2050. In 2025, U.S. primary energy consumption was predominantly driven by fossil fuels, which accounted for 85% of the total energy use. By 2050, energy consumption rose across both scenarios relative to 2025, distinguished by a notable increase in biomass and other renewables. Relative to *S6*, increased LNG exports in *S7* put pressure on the natural gas market, leading to slightly higher end-use prices and more expensive GHG mitigation strategies. Biomass and other renewable sources grew by 22.3 and 22.1 quadrillion BTUs from 2025 in the *S6* and *S7* cases respectively, thereby contributing 32.1% of the total energy consumption in both cases. Natural gas consumption increased from 33 quadrillion BTUs in 2025 to 42.5 and 42.1 quadrillion BTUs in the energy transition scenarios *S6* and *S7* respectively. Remaining primary energy, primarily petroleum, decreased across both cases from 45.2 quadrillion BTUs in 2025 to 34.4 quadrillion BTUs in *S6* and 34.0 quadrillion BTUs in *S7* by 2050.

2. Natural Gas Production and Consumption Impacts

U.S. natural gas production increased across most cases to maintain projected export volumes. U.S. natural gas consumption, on the other hand, was relatively unchanged across the first four scenarios. Figure 16 plots total U.S. natural gas production, consumption, and export values over time. The LNG export values were identical to those plotted in Figure 3 and are included here as reference.

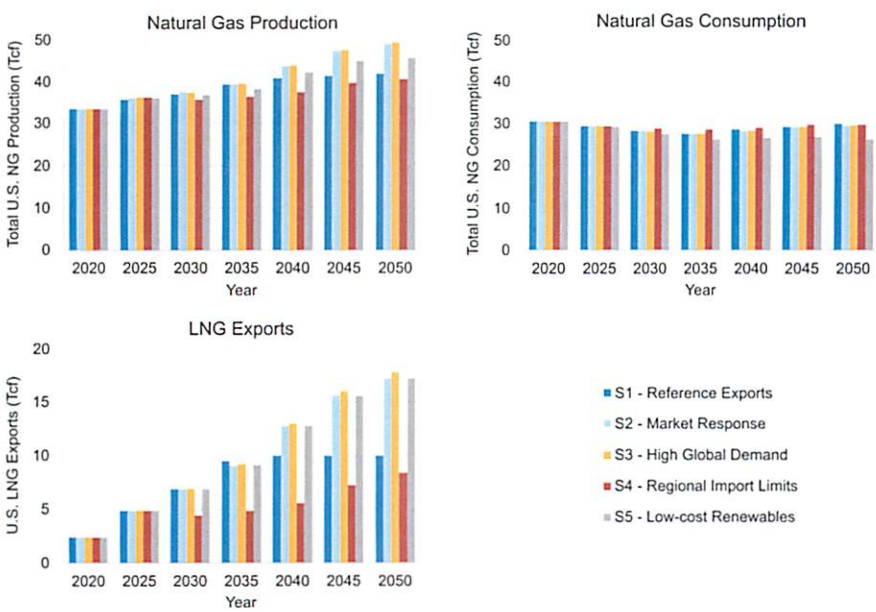

Figure 16. Total U.S. natural gas production, consumption, and export volumes over time, by scenario

From a starting point of 33.5 Tcf (91.5 Bcf/d) of natural gas production in 2020, production in each scenario increased, following a path that correlated with their LNG export curve. Natural gas production in *S1*, *S2*, and *S3* followed a similar trajectory by 2035, reaching 39.4-39.5 Tcf. *S1* production then slowed through 2040 and reached a peak of 42.0 Tcf by 2050. *S2* and *S3* production values accelerated through 2050, reaching 49.0 Tcf and 49.5 Tcf, respectively. Similar to the trends in LNG exports, *S4* production exhibited the lowest values, ending slightly below *S1* at 40.7 Tcf in 2050. *S5* production exhibited the same general path as *S2* and *S3*, but grew more slowly, reaching 38.2 Tcf and 45.7 Tcf in 2035 and 2050, respectively.

The natural gas consumption volumes from *S1-S3* followed similar paths, dipping from 30.5 Tcf in 2020 to 27.4-27.6 Tcf in 2035 before ramping up to 29.6-29.8 Tcf in 2050. Although *S4* had exhibited lower LNG export and natural gas production quantities, the consumption volumes in *S4* remained slightly higher than the volumes in *S1-S3* through most of model years, equalizing with *S1-S3* in the final timestep. *S4* reported 28.5 Tcf of natural gas consumption in 2035 and 29.8 Tcf in 2050. *S5* was the largest outlier with the lowest consumption of 26.2 Tcf in 2035 and almost no change in consumption values between 2035 and 2050.

The lower natural gas production and consumption volumes in *S5* (when compared to *S2* and *S3*) are explained by the effect of low renewables costs on the energy system. *S5* adopted many of the same inputs as EIA's AEO2023-NEMS low zero-carbon technology cost case. These inputs drove down the cost of renewables and caused *S5* to switch from natural gas to cheaper renewable energy sources, affecting both production and consumption. The remaining scenarios showed similar levels of natural gas consumption, but different levels of natural gas production, suggesting that most increases in natural gas production were passing directly to LNG exports.

Figure 17 plots the natural gas production, consumption, and exports for the two net-zero scenarios. Natural gas production in Scenarios *S6* and *S7* is 37.6 Tcf and 37.1 Tcf in 2035, respectively, but quickly rise to 54.7 Tcf and 56.5 Tcf by 2050. *S6* and *S7* exhibited a flatter trend in total consumption through 2040, but reached 41.9 Tcf and 41.5 Tcf, respectively, by 2050. The differences between the two net-zero scenarios were similar to differences observed between *S1* through *S5*: changes in production were correlated with changes in LNG exports, but differences in consumption between scenarios were minimal.

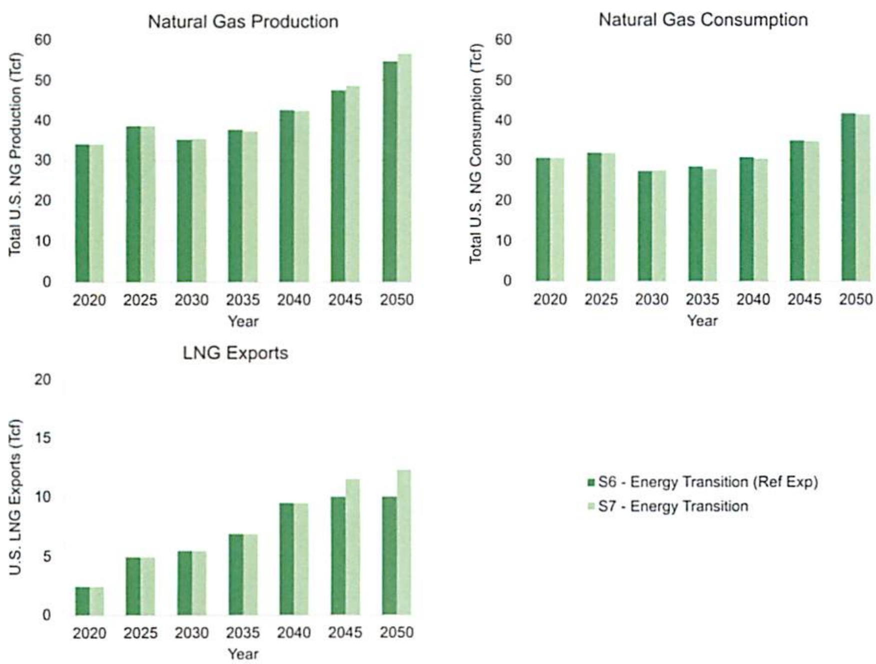

Figure 17. Total U.S. natural gas production, consumption, and export volumes, net-zero scenarios

The rapid increase in natural gas production and consumption for the net-zero scenarios after 2040 came from a substantial increase in natural gas to power direct air capture (DAC) facilities, plotted in Figure B-5 of the appendices. Natural gas consumption accounted for 16.8 Tcf and 16.2 Tcf in 2050 for *S6* and *S7*, respectively. More detail on CO_2 emissions and removals is provided in Section 1.F.5: "U.S. Greenhouse Gas Results".

3. Natural Gas Henry Hub Prices Impacts

Although total U.S. natural gas consumption volumes were similar across the first five scenarios, the increased LNG exports had a moderate effect on natural gas prices. The natural gas price of the net-zero scenarios rose above the prices from *S1* through *S5*, driven mostly by demand for natural gas to power DAC facilities. Figure 18 plots the natural gas price at the Henry Hub in $2022/Mcf over time for all scenarios.

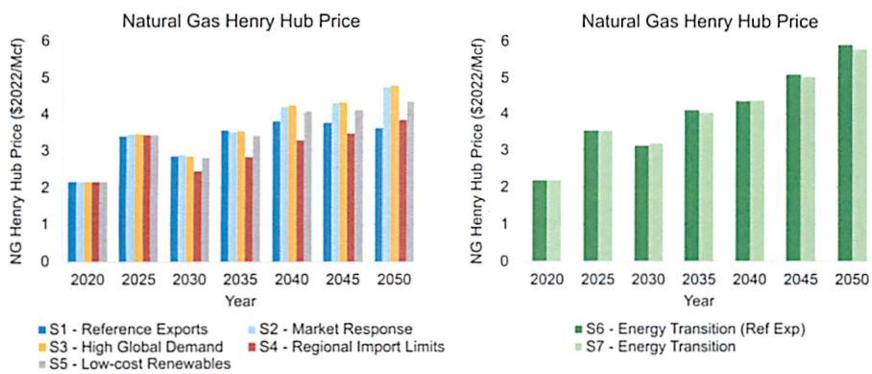

Figure 18. Total U.S. natural gas Henry Hub price by scenario ($2022)

The natural gas price in *S1* increased to a maximum of $3.80/Mcf in 2040 before moderating to $3.61/Mcf in 2050. The natural gas prices in *S2*, *S3*, and *S5* were mostly consistent with the reference case through 2035 but ultimately rose to levels of $4.74/Mcf, $4.79/Mcf, and $4.35/Mcf, respectively, by 2050. The difference in prices correlated with the differences in LNG export curves, while LNG exports in *S1* plateaued after 2035 and saw a drop in natural gas prices. Scenarios *S2*, *S3*, and *S5* all exhibited both increasing exports and prices. *S4* had lower natural gas prices over most of the modeling period, but ultimately exceeded *S1* in 2050 with a price of $3.84/Mcf; the persistent increase in *S4* prices after 2030 was consistent with increases in LNG exports throughout the same time period. Prices remained below $5.00/Mcf for all timesteps in *S1* through *S5*.

The influence of LNG exports on natural gas prices shown in Figure 18 was similar to the effect reported by EIA in their May 2023 "Issues in Focus" report on LNG.[22] The EIA's "Fast Builds Plus High LNG Price" case, which modeled the effect on U.S. energy markets of accelerated construction of LNG infrastructure in an environment with elevated international demand for LNG, reported a 2050 natural gas price of $4.81/MMBtu (equal to $4.64/Mcf) at 48.2 Bcf/d of exports. These values are close to the results from *S2* of $4.74/Mcf at 47.2 Bcf/d of exports and demonstrate good agreement between the two studies on the relationship between LNG exports and natural gas prices.

Overall U.S. natural gas consumption did not change appreciably in response to higher prices, but there were some shifts in consumption behavior on a sector-by-sector basis. These sector-specific differences are presented in greater detail in the Appendix in Figure B-3.

The natural gas price of the net-zero scenarios rose above the prices from *S1* through *S5*, driven mostly by demand for natural gas to power DAC facilities. Natural gas prices for S6 and S7 were similar to prices in *S1* through 2030, but afterwards rapidly increased on a trajectory consistent with the growth of DAC.

[22] U.S. EIA (2023). AEO2023 Issues in Focus: Effects of Liquefied Natural Gas Exports on the U.S. Natural Gas Market. Available at: https://www.eia.gov/outlooks/aeo/IIF_LNG/pdf/LNG_Issue_in_Focus.pdf.

S6 and *S7* reached prices of $5.90/Mcf and $5.77/Mcf, respectively, by 2050. The difference in price between *S6* and *S7* was within the tolerance of the model.

4. U.S. Macroeconomic Outcomes

While NEMS has rich detail about the energy system, a separate macroeconomic activity module (MAM) provides projections of economic drivers underpinning NEMS' energy supply, demand, and conversion modules. The MAM incorporates IHS Markit's (now S&P Global's) model of the U.S. economy, along with EIA's extensions of industrial output, employment, and models of regional economies. The S&P Global module is modified to include EIA's assumptions on key assumptions, such as world oil price, yielding a baseline trajectory of the economy. The baseline cannot appropriately respond to the wider economic changes in the net-zero scenarios, so such analysis is not included here. Within a NEMS scenario, feedback from the other NEMS modules includes:

- Production of energy, including coal, natural gas, petroleum, biomass, and other fuels;
- Trade in energy, including net exports coal, petroleum, natural gas, and biofuels;
- Total and end-use demand for energy, including sales of electricity;
- Consumer spending on energy, disaggregated to fuel oil motor fuels, electricity, natural gas, and highway consumption of gasoline;
- Energy prices, including a price index for consumer prices and wholesale prices; and
- Industrial production indices for oil and gas extraction and coal mining.

Since the MAM does not track individual projects, GDP estimates do not include economic activity associated with specific export facilities and thus the impacts are approximate.

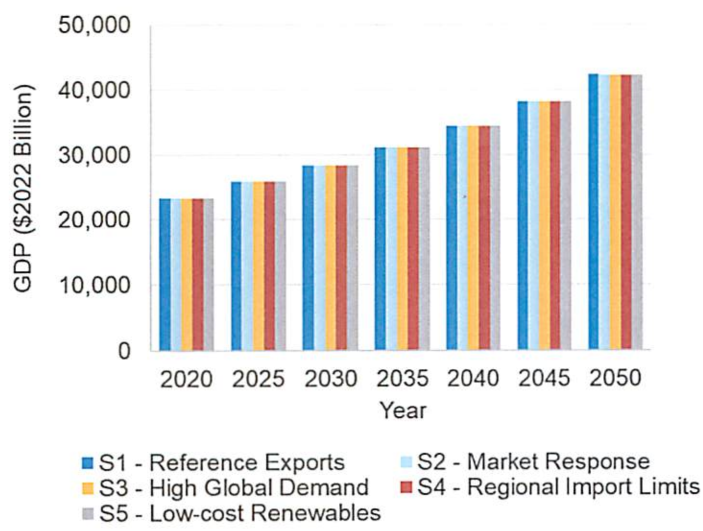

Figure 19. U.S. real GDP changes

As shown in Figure 19, U.S. GDP growth rate through 2045 remained essentially constant across all five scenarios, increasing at 1.9% annually. Higher natural gas exports resulted in higher prices, reducing economic activity in some sectors but increasing in others. The impact of increased LNG exports was positive on GDP by less than 0.1% across scenarios the through 2045. Accelerating natural gas prices in the last five years of the projection period in S2 reduced consumption on other products and tended to slightly reduce the overall rate of economic growth relative to *S1*. Overall, GDP changes in 2050 relative to 2020 were within 0.3% across all five scenarios.

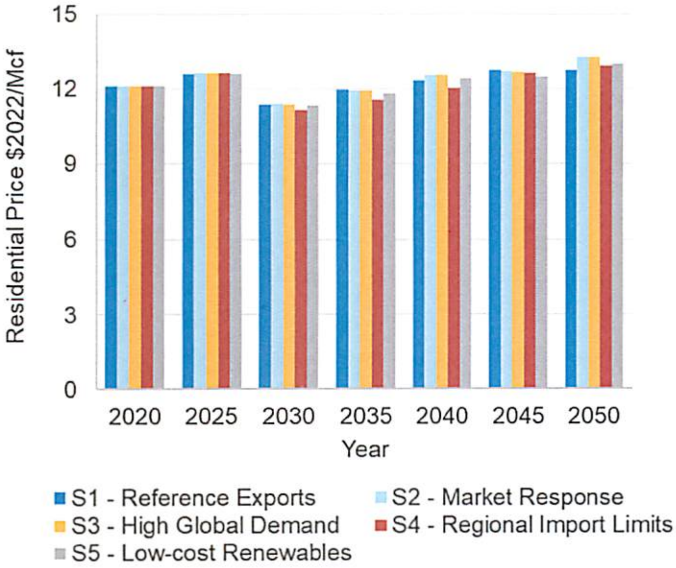

Figure 20. U.S. residential natural gas prices

Figure 20 shows the residential natural gas price in each of the five key scenarios. In 2050, natural gas prices in *S3* (when exports are the highest) were 4% higher than S1, when exports were the lowest. Overall, natural gas price differences between the scenarios were generally close to 1-2% across the scenarios.

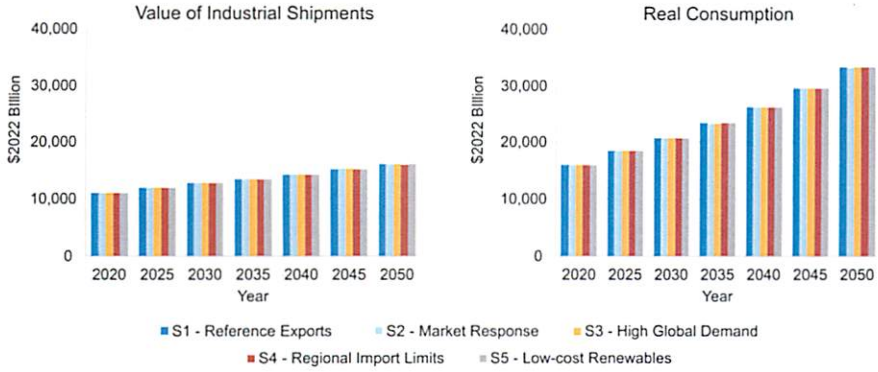

Figure 21. U.S. value of industrial shipments and real consumption

One component of GDP tracked by NEMS is the value of industrial shipments, shown in Figure 21. Industrial processes are sensitive to natural gas prices, which were generally higher than *S1*. However, increased production, processing, and transportation of natural gas requires additional equipment which tends to increase industrial shipments. Overall, NEMS showed a very slight increase in the value of industrial shipments in *S2* relative to *S1* of 0.2% in 2050. The value declined in S4 vs S1, reflecting lower natural gas production and exports.

The NEMS analysis shows NG exports could benefit consumers through increased labor income and the return on capital expended on facilities to produce and export the commodity. Exports increased the value of the dollar, decreasing the cost of some imports. However, increased demand for natural gas, including exports, raised the price of natural gas and the costs of products that require natural gas as an input. This can be observed in the change in aggregate consumption which is another component of GDP. When energy prices rise, consumers must pay more for natural gas, but purchases of other goods decrease. Across all the scenarios, this effect was small, and, while wealth transfers may occur between consumers as some groups benefit more than others through increased production, this was not reflected in the aggregate output of the model. Changes across all the scenarios were essentially flat. Overall, by 2050 consumption changes were less than 0.2%.

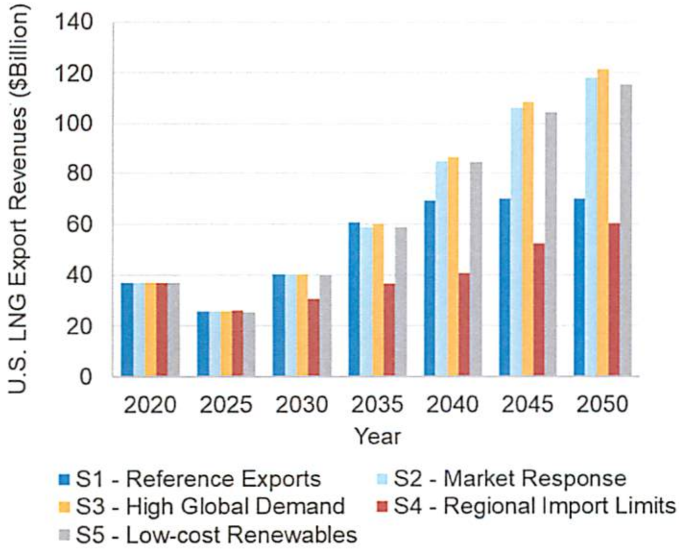

Figure 22. U.S. LNG export revenues

In a fully competitive market, the delivered price of LNG should be sufficient to fully accommodate the cost of production, liquefaction, and transportation of natural gas. Since much of this activity occurs domestically, it is a rough proxy for economic activity engendered by LNG exports. A representative price would be the price of imports to the EU. Figure 22 shows estimates of export revenues as the product of the LNG export volumes and the EU LNG price.

5. U.S. GHG Results

AEO2023-NEMS tracks CO_2 emissions from the combustion and use of fossil fuels. These CO_2 emissions did not change significantly between scenarios in response to varying LNG export levels. Figure 23 plots CO_2 emissions from fossil fuels for *S1* through *S5*.

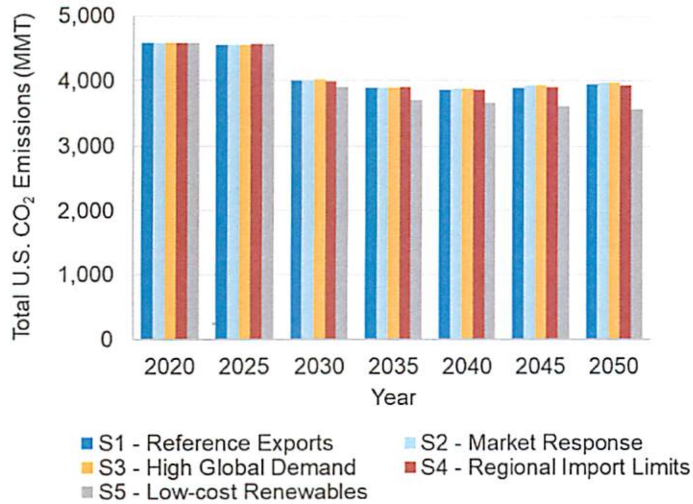

Figure 23. Total U.S. CO_2 emissions from fossil fuel combustion

From a starting point of 4,580 MMT CO_2 emissions in the U.S. in 2020, the first four scenarios declined to between 3,990 and 4,020 MMT CO_2 in 2030 and followed a flatter trajectory to 3930-3980 MMT CO_2 in 2050. There was a weak connection between LNG exports and CO_2 emissions: cases with the highest exports (*S2* and *S3*) had slightly higher CO_2 emissions levels in 2050 of 3970 and 3980 MMT, respectively, whereas cases with lower exports (*S1* and *S4*) reported respective CO_2 emissions of 3040 and 3030 MMT. The relationship was small, however, and accounted for only a 1% difference in emissions. The small differences between the first four scenarios were consistent with the relatively unchanged natural gas consumption volumes observed in Figure 16. *S5* was an outlier, continuing to decrease through 2030 (3910 MMT CO_2) and reaching 3570 MMT CO_2 emissions by 2050. The lower emissions from *S5* were explained by the assumptions used for low renewable costs rather than by changes in LNG exports.

S6 and *S7* were modeled in FECM-NEMS, which endogenously calculated some additional emissions that AEO2023-NEMS is missing (most relevant being CH_4 leakage from natural gas production and processing infrastructure). To retain consistency between the two models, only the CO_2 emissions reported by FECM-NEMS were included in the analysis and used to define the net-zero GHG scenarios. The remaining non-CO_2 emissions (which still contributed to the overall net-zero GHG cap) were calculated endogenously within GCAM and used in FECM-NEMS as an exogenous input.

Figure 24 plots the CO_2 emissions and removals for *S6* and *S7*. Both scenarios had both lower emissions than *S1* and significant amounts of CO_2 removals, reaching net-zero by 2050.

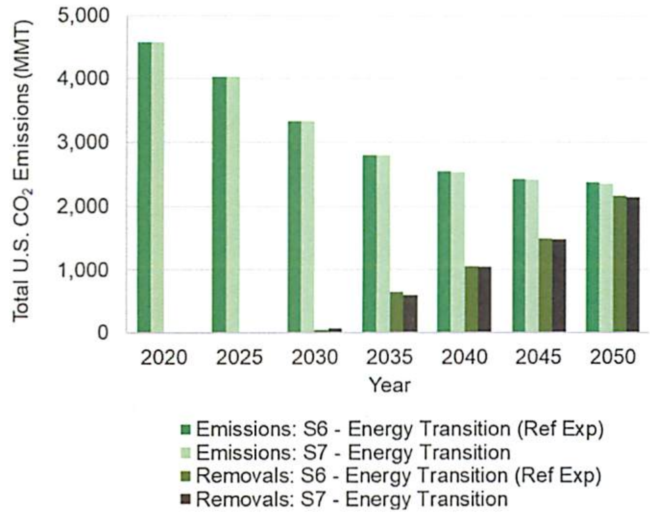

Figure 24. Total U.S. CO_2 emissions from fossil fuel combustion and removals, S6 and S7

CO_2 emissions from *S6* and *S7* began at 4,580 MMT and declined continuously through 2050, ending at 2,370 and 2,350 MMT CO_2, respectively. These declines were primarily driven by electrification of broad sections of the economy with a combination of renewables and CCS. The decline in emissions was accompanied by an increase in removals, which started growing rapidly in 2030 and eventually reached 2,160 MMT CO_2 for *S6* and 2,130 MMT CO_2 for *S7* in 2050. The majority of removals (87-89% by 2050) came from DAC, with the remainder coming from H_2 production with biomass and BECCS. The specific breakdown of removal technologies is explored in Section D of Appendix B. While the removals did not completely cancel out the 2,350-2,370 MMT of CO_2 emissions, the difference is balanced out by the non-CO_2 emissions calculated within GCAM and used as exogenous inputs, which were net negative.

G. NETL Life Cycle Analysis

The goals of the LCA component of this project were twofold: first, to help contextualize how the other results of this study (i.e., NEMS and GCAM models) connect to past studies of U.S. natural gas and LNG operations and, second, to leverage the results of the other models to quantitatively represent the international global warming potential (GWP) consequences from changes in quantities of U.S. exported LNG.

In support of the first goal, the following work was completed:

- Assessed whether NEMS results suggested significant changes in domestic supply (and thus, resulting in potential future upstream GWP intensity or emissions changes).
- Compared and aligned GCAM and NETL results to create a representation of the global natural gas supply chain that is consistent with existing NETL natural gas LCA studies.

In support of the second goal, the following work was completed:

- Developed a quantitative "market effect adjustment factor" that represents the consequences of additional export volumes of U.S. LNG, such as how additional available quantities of natural gas led to changes in the energy sectors of countries that purchase the LNG. These consequential effects were estimated by tracking differences in global GHG emissions and quantities of U.S. LNG exported from the GCAM model scenarios and assessed in comparison to existing NETL quantitative estimates of the upstream natural gas production.

In this project, the NEMS and GCAM models sought to represent economic and environmental changes associated with the defined changes in U.S. LNG exports. The GCAM model estimated global GHG emissions effects, including emissions associated with upstream natural gas. To compare the GCAM results with ~~past~~ the NETL life cycle analysis work used by DOE in support of natural gas and LNG export decisions, NETL assessed and aligned the emissions estimates per unit of gas produced and delivered to large end users (e.g., LNG export facilities) of the ~~two~~ GCAM and NEMS models to the NETL life cycle GHG intensity for U.S. average natural gas production and delivery to large end users. Non-U.S country natural gas production and delivery GHG emissions intensity values were also adjusted to align with NETL life cycle GHG intensity values based on the difference between the GCAM U.S. GHG emissions intensity for natural gas compared to each non-U.S. natural gas exporting countries GHG emissions intensity in GCAM. This process was conducted for each year reported by GCAM.

Commented [ST16]: Results were not aligned to the past NETL work on LNG exports. Work was aligned to the current NETL 2020 natutal gas upstream thru transmission to a large end user U.S. average GHG emissions per unit of natual gas delivered.

1. Assessment of NEMS Domestic Natural Gas Production by Region

The NEMS modeling focused on domestic changes that would be expected to occur in the seven scenarios modeled. NETL evaluated the regional sources of natural gas using outputs from NEMS to compare them to the mix of regions NETL uses in existing assessments of upstream natural gas emissions.

As shown in Appendix C, the NEMS results suggested only modest changes in the production mix by region and thus would not be expected to substantially change the domestic average GHG intensity per MJ of natural gas produced compared to previous analyses. As such, no regional adjustments were made to the U.S. results.

2. Comparison of GCAM and NETL Estimates of GHG Emissions of the Natural Gas sector

As discussed above, the GCAM model represents economic activity (and associated GHG emissions) by sectors and technologies, and their respective inputs and outputs, for regions, years, and scenarios. However, only a subset of these was relevant to the scope of the natural gas LCA-focused effort.

Only three sectors in the GCAM model include greenhouse gas emissions of the natural gas sector: *natural gas*, *gas pipeline*, and *other industrial energy use* (see Appendix C for more detail). Using the basis of process stages as represented in the NETL Natural Gas model, Figure 25 shows the relevant GCAM sectors that have associated CO_2 and non-CO_2 emissions. While the overall GCAM model has 16 species of GHG emissions, for the three sectors above relevant to the upstream natural gas sector, only emissions of CO_2, CH_4, and N_2O were represented.

As summarized in Figure 25, all stages of the NETL LCA are explicitly represented in GCAM except for Ocean Transport, which was included as part of other industrial energy use but could not be separated out for this analysis. As a result, the comparison in this report was focused on a comparison of emissions from production of natural gas in the U.S. through delivery to a large end user rather than LNG delivered around the world.

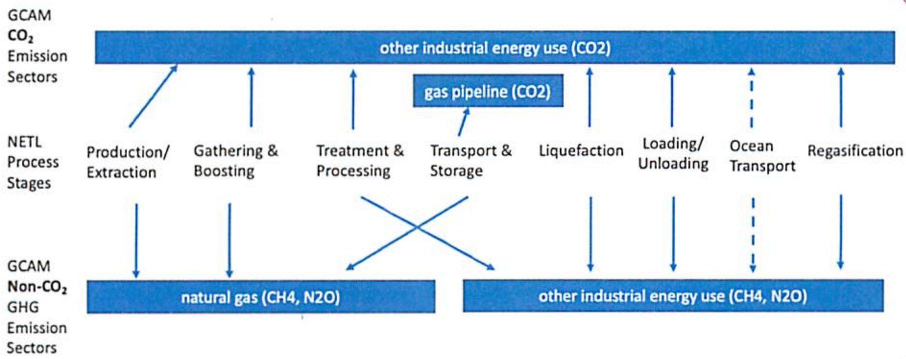

Figure 25. Mapping of NETL natural gas stages to GCAM sectors

Quantitative values of emissions intensities in the year 2020 of the various GCAM sectors for the USA region for the three natural gas-relevant sectors are listed and compared to NETL natural gas model results in Appendix C. Note that in order to compare NETL and GCAM results, NETL model results were regenerated using LHV basis and differ from those published (as HHV by default) in the report.

Overall, the estimated upstream emissions for the USA in the GCAM model in the year 2020 were about 8.52 g CO_2e/MJ (on an IPCC AR6 100-year, LHV basis), which is slightly higher than those of the NETL model for the boundary of production through transmission to large end user (8.18 g CO_2e/MJ, LHV basis). Using the relationship between those estimates, emissions results in the three GCAM natural gas sectors were adjusted by a factor of 8.18/8.52, or 0.96 (a 4% reduction) to maintain consistency with past NETL studies. This adjustment factor was used for all regions and for all years in the model. Similar adjustment factors were found for IPCC AR6 20-year and IPCC AR5 100-year and 20-year bases (see Appendix C for further details).

For context, in the GCAM results for *S1* in Year 2020, total global GHG emissions are approximately 53,000 Tg. The NETL adjustment post-processing of the GCAM model results on the IPCC AR6 100-year basis of the *gas pipeline* and *natural gas* sectors reduces emissions by about -7 and -35 Tg CO_2e, respectively, when considering those of *S1* in the Year 2020. Post-processing adjustments of the GCAM model results of the *other industrial energy use* sector reduce emissions by about -10 Tg CO_2e when considering those of *S1* in the Year 2020. The adjustments for these three sectors needed to align with past NETL studies have the cumulative effect of reducing estimated emissions from the GCAM model by about 0.2% (in *S1* in the Year 2020).

This same process was undertaken for different IPCC GWP values, and the resulting alignment tables and adjustment factors are provided in Appendix C.

Commented [ST17]: Labels in "blue" boxes need capitalized.

Subscript the 2 and 4 in CO2, CH4, and N2O.

NETL Process Stage labels should be centered with the arrows.

Commented [ST18]: The rest of the report uses "U.S." instead of "USA".

Commented [ST19]: See previous comment, this numeric values used need to be stated.

Commented [ST20]: Is the GCAM value consistent over the 35 year time horizon?

Is this the levelized average over 35 years that includes performance improvements within GCAM? Or is it the year 2020 value?

Are the values different for S7/S6 when climate pledges and net zero are considered? How did this effect the MAF calculation when considering temporal and economic variability?

Commented [ST21R20]: Need to state that the 8.52 is **the year 2020 GHG emissions intensity.**

Added to text - please confirm edit.

After reading the report, I don't think the value is levelized over 35 years. Unclear how GCAM GHG intensity per unit of LNG changes over time within the GCAM model (or NEMS).

Commented [ST22]: Why the italicized label? Not italicized in other parts of the report?

3. Market Adjustment Factor Results

Market adjustment factors (MAF) quantitatively estimate the consequential effect on global emissions as a function of U.S. LNG exported. MAFs for *S2* were estimated versus a baseline of *S1*, while the MAF for *S7* was estimated versus a baseline of *S6* given the significantly different global economy modeled in these scenarios.

MAFs were calculated using the post-processed NETL-adjusted GCAM results described previously. The MAF was calculated for each scenario by aggregate annual values over the time horizon of the model (i.e., the MAF for *S2* versus *S1* was defined as the total difference in annually-estimated global emissions over the 35-year period divided by the total difference in annually estimated exported LNG over the same period).

All MAFs were found using a variety of IPCC Assessment Report GWP values over 20- and 100-year time horizons, and with the raw and post-processed NETL adjusted GCAM results. MAF results from the IPCC Sixth Assessment Report on a 100-year time horizon are presented, and results for other IPCC Assessment Report and time horizons (and all raw GCAM results) are shown in Appendix C.

Table 4 shows the MAFs for *S2* (vs. *S1*), which varied from -5.34 to -5.35 g CO_2e/MJ on a 100-year time horizon (LHV basis). Also included is a summary reminder of the differences in the modeled scenarios (e.g., where *S1* is the baseline and *S2* added an economic solution for LNG exports, making a direct comparison of the two appropriate).

Commented [ST23]: All results need to be on a HHV basis to document what will actually be used by NETL when added to the attributional results.

I am okay with report comparing to GCAM in LHV, however, that is not the result that needs documented for use in future export analyses that include consequential market effects. This report needs to document the values that will be used in future work.

Commented [ST24]: Add HHV results.

Table 4. Market Adjustment Factors for S2 vs. S1 (IPCC AR6, 100 year)

MAF Case	Results (g CO_2e/ MJ LHV) GCAM	GCAM with LHV NETL adjustment	Scenario Difference
S2 vs. *S1*	-5.34	-5.35	Adds economic solution for LNG exports.

Table 5 shows market adjustment factors for *S7* vs. *S6*, both of which represented significantly different energy and economic investments in support of a low-carbon economy through climate policies. The *S7* MFAs vary from -2.81 to -3.01 on a 100-year time horizon (LHV).

Table 5. Market Adjustment Factors for S7 vs. S6 (IPCC AR6, 100 year)

Commented [ST25]: Add HHV results.

MAF Case	Results (g CO_2e/ MJ LHV) GCAM	GCAM with LHV NETL adjustment	Scenario Difference
S7 vs. *S6*	-3.01	-2.95	S6 1.5°C pathway, economic solution for LNG exports

4. Interpretation of Market Adjustment Factor Results

On an IPCC AR6 100-year basis, for *S2-S1*, the MAF result was approximately -5.4 g CO_2e/MJ (LHV). For purposes of comparison, NETL estimated natural gas upstream emissions prior to delivery to a large industrial end user (like an LNG terminal) are 8.18 g CO_2e/MJ (LHV), equivalent to 7.4 g CO_2e/MJ (HHV). The MAF indicated that as U.S. LNG exports increased, the induced global market effects result in an

Commented [ST26]: Reported as 7.44 previously in the report.

Commented [ST27]: Also report the result in LHV with the HHV result. (8.18 g CO2e/MJ, LHV basis) overall reduction in GHG emissions that is about 70% of the estimated upstream emissions associated with production through delivery of the natural gas to a large industrial end user in the U.S.

The MAF result for *S7-S6* was about -3 g CO_2e/MJ (LHV). In a decarbonizing world, the overall reduction in emissions was 56% of the estimated upstream emissions associated with production through delivery of the natural gas to a large industrial end user in the U.S. This is consistent with the idea that as the global economy decarbonizes, the induced global decarbonization benefit of increased U.S. LNG will be less. Overall, both of these results were consistent with the overall GCAM results that increased U.S. exports did not lead to increased global GHG emissions. Global changes in GHG emissions were constant to slightly negative as U.S. natural gas exports increased and global energy demand increased. The GHG reductions represented by the negative MAF were not so large that U.S. LNG should be regarded as a global climate reduction strategy but, at the same time, a negative MAF suggested that increased U.S. LNG exports could be compatible with global decarbonization efforts. A positive MAF would suggest U.S. LNG was leading to overall increased global emissions.

The results were aggregated in relation to estimated future volumes of exported LNG from the U.S. in the context of a global model. They represent overall expected effects and not those of individual shipments or authorizations of LNG. It is not possible to conclude that every MJ of exported LNG from domestic natural gas sources would directly lead to lower GHG emissions results when supplied around the world.

VI. Conclusions

The purpose of this study was to examine the potential global and U.S. energy system and greenhouse gas (GHG) emissions implications of a wide range of economic levels of U.S. LNG exports. The study comprised three coordinated analyses: 1) **a Global Analysis** to explore a wide range of scenarios of U.S. LNG exports under alternative assumptions about future socioeconomic growth, regional preferences for domestically produced natural gas, pace of technological change in competing technologies (e.g., renewables), and countries' announced GHG emissions pledges and policies; 2) **a U.S. Domestic Analysis** of the implications of the various U.S. LNG export levels derived from the Global Analysis for the supply and demand of natural gas within the U.S. and the U.S. economy; and 3) **a Life Cycle Analysis** to examine the life cycle emissions implications of the various levels of U.S. LNG exports derived from the Domestic and Global analyses. A number of key insights from this study are summarized below. Table 6 includes a summary of the key results across scenarios.

1. Across all modeled scenarios, U.S. LNG exports continue to grow beyond current operational export capacity (14.3 Bcf/day) through 2050. In addition, U.S. natural gas production grow beyond current levels through 2050. Across all the scenarios, LNG exports range from 23-47 Bcf/day. The range of U.S. LNG exports from this study is consistent with the U.S. EIA's analysis (15-48 Bcf/day.)[23] Compared to a scenario in which U.S. LNG exports follow the Reference Case from the AEO2023 (*S1*, growing to 27.3 Bcf/day by 2050), a scenario that assumes economically-driven LNG export levels (*S2*) results in significant growth in U.S. LNG exports to 47 Bcf/day by 2050. The availability of additional U.S. natural gas at competitive prices in the global natural gas

Commented [ST28]: I calculate a 66% reduction. 70% is generous rounding.

Commented [ST29]: Results need to be also reported in context of delivered LNG to provide a more complete perspective on the actual magnitude of percent change in delivered LNG cargo.

I understand that distance, and their emissions, from LNG facility to receiving country varies. However, some perspective is needed for the reader here and in the main conclusions. On page, x, you state that liquefaction plus ocean transport is "more than double" the upstream GHG footprint. This perspective through delivered LNG is an equally if not more important framing for the context of global market effects of "LNG exports". As written, the take-aways are grounded in production to delivery to a LNG facility only.

See page 26 for delivered LNG reference; excerpt below for reference:

Commented [ST30]: Add: result through delivered LNG.

E.g.

7.44 g HHV, equals 8.18 g LHV

HHV to LHV Adjustment Factor: 1.0995

17.9 g HHV (delivered to Europe), equals... 19.6811

Commented [ST31]: This paragraph needs to explain how -3 translates to a 56% reduction upstream NG emission profile to support the key insights.

I also prefer it be converted and discussed in terms of US LNG delivered to Europe and Asia markets.

See prior comment on S1/S2 above.

Commented [ST32]: Was there any change in the upstream profile in S7/S6 when compared to S2/S1 for the US gas?

S2/S1 data:
For purposes of comparison, NETL estimated natural gas upstream emissions prior to delivery to a large industrial end user (like an LNG terminal) are 8.18 g CO2e/MJ (LHV), equivalent to 7.4 g CO2e/MJ (HHV).

[23] U.S. EIA. (2023). Issues in Focus: Effects of Liquefied Natural Gas Exports on the U.S. Natural Gas. Available at: Markethttps://www.eia.gov/outlooks/aeo/IIF_LNG/

market in the latter scenario (*S2*) results in a reduction in production, reduction in LNG exports, increase in LNG imports, and reduction in pipeline trade outside of the U.S.

2. Global natural gas consumption increases only slightly (<1 percent) under a scenario with increased availability of U.S. natural gas in the global market that reflects economically driven LNG export levels (*S2*) compared to the reference scenario (*S1*), as the availability of additional U.S. natural gas in the global market does not materially affect the competitiveness of natural gas relative to other fuels globally. Instead, it results in a shift in the regional composition of natural gas production and trade. The majority of U.S. natural gas substitutes for other global sources of natural gas.
3. U.S. natural gas prices as measured at the Henry Hub increases modestly when comparing a scenario that reflects global market demand for exports (*S2*) to the reference scenario (*S1*). Across those scenarios, 2050 Henry Hub prices are projected to increase from $3.61/Mcf to $4.74/Mcf, both of which are less than the reference 2050 price expected in the most recent study DOE[5] commissioned on the economic impacts from U.S. LNG exports in 2018.
4. U.S. residential prices are projected to be 4% higher in 2050 when comparing a scenario that reflects global market demand for exports (*S2*) to the reference scenario (*S1*). In none of the scenarios did the change in residential prices exceed 4% and generally by substantially less.
5. The value of industrial shipments remains essentially unchanged (increasing less than 0.1% by 2050) when comparing a scenario that reflects global market demand for exports *(S2)* to the reference scenario *(S1)*. The impact of increased LNG exports on GDP is essentially flat, positive by less than 0.1% across scenarios through 2045 while all changes are within 0.3% in 2050.
6. Even though U.S. LNG exports continue to grow beyond existing and planned nameplate capacity across scenarios *S1* through *S5* to 23-47 Bcf/day by 2050, global and U.S. GHG emissions do not change appreciably. Global emissions in these scenarios range from 47.5-50.3 $GtCO_2e$ and U.S. emissions range from 4.3-4.6 $GtCO_2e$ across these scenarios.
7. The induced global market effects of a case that reflects global market demand for exports (S2) compared to the reference case (*S1*) are equivalent to an overall reduction in GHG emissions of about 70% of the estimated upstream emissions associated with production through delivery of the natural gas to a large industrial end user (e.g., to an LNG export facility) in the U.S.
8. When compared to the other scenarios, *S6* and *S7* – in which countries are assumed to achieve their GHG emissions pledges and pursue ambitious GHG mitigation policies consistent with limiting global warming to 1.5°C – are characterized by a global transition resulting in lower in natural gas, coal, and oil consumption without CCUS; higher deployment of gas, coal and biomass with CCUS, and renewables; higher deployment of carbon dioxide removal strategies; and lower overall energy consumption. While in scenario *S6*, in which U.S. LNG exports are limited to the values from the AEO2023 Reference case (by design) and grow to 27.34 Bcf/day by 2050, *S7* assume economically-driven outcomes resulting in U.S. LNG exports growing to 34 Bcf/day by 2050. The higher growth in U.S. LNG exports in *S7* compared to *S6* is driven by increased global demand for natural gas with CCUS in the power and industrial sectors. Similar to the comparison between *S1* and *S2*, the availability of additional U.S. LNG in *S7* in the global natural gas market results in a very small increase in natural gas consumption, reduction in production, reduction in LNG exports, increase in LNG imports, and reduction in pipeline trade in the rest of the world compared to *S6*. Furthermore, with the higher U.S. LNG exports in *S7*

Commented [ST33]: Consider splitting the conclusions into two parts: S1/S2 and S6/S7 to improve clarity.

Commented [ST34]: Did we run another set of S6 and S7 results with and without CCUS? Where do these findings come from without CCUS?

compared to *S6*, U.S. natural gas prices are essentially unchanged within modeling tolerance, reaching $5.90/Mcf in *S6* and $5.77/Mcf in *S7* by 2050.

Commented [ST35]: Equivalent level of results are missing for S6/S7 as reported in Items #1 thru #7. MAF for S6/S7 is not discussed in the conclusion section, for example.

Table 6. Key Results for U.S. and globe in 2050 across scenarios

Scenarios	U.S. LNG Exports (Bcf/d)	U.S. NG Henry Hub Price ($2022/Mcf)	US Net GHG Emissions ($GtCO_2e$)	Global Net GHG Emissions ($GtCO_2e$)
S1	27.3	$3.61	4.5	48
S2-S5	23.1 – 48.7	$3.84-$4.79	4.3-4.6	47-50
S6-S7	27.3 – 33.6	$5.77-$5.90	0	17

APPENDIX A: GLOBAL ANALYSIS AND DESCRIPTION OF GCAM

A. Additional detail about GCAM's energy system

GCAM's energy system contains representations of fossil resources (coal, oil, gas), uranium, and renewable sources (wind, solar, geothermal, hydro, biomass, and traditional biomass) along with processes that transform these resources to final energy carriers (electricity generation, refining, hydrogen production, natural gas processing, and district heat) which are ultimately used to deliver goods and services demanded by end use sectors (residential buildings, commercial buildings, transportation, and industry). Each of the sectors in GCAM includes technological detail. For example, the electricity generation sector includes several different technology options to convert coal to electricity such as pulverized coal with and without carbon capture, utilization, and storage (CCUS), and coal integrated gasification combined cycle (IGCC) with and without CCUS. The full list of technologies in various sectors in GCAM is documented in the GCAM documentation page (http://jgcri.github.io/gcam-doc/).

In every sector within GCAM, individual technologies compete for market share based on the levelized cost of a technology. The cost of a technology in any period depends on (1) its exogenously specified non-energy cost, (2) its endogenously calculated fuel cost, and (3) any cost of emissions as determined by the climate policy. The first term, non-energy cost, represents capital, fixed and variable operating and maintenance (O&M) costs incurred over the lifetime of the equipment (except for fuel or electricity costs), expressed per unit of output. For example, the non-energy cost of coal-fired power plant is calculated as the sum of overnight capital cost (amortized using a capital recovery factor and converted to dollars per unit of energy output by applying a capacity factor), fixed and variable operations and maintenance costs. The second term, fuel or electricity cost, depends on the specified efficiency of the technology, which determines the amount of fuel or electricity required to produce each unit of output, as well as the cost of the fuel or electricity. The various data sources and assumptions are documented in the GCAM documentation page (http://jgcri.github.io/gcam-doc/). The prices of fossil fuels and uranium are calculated endogenously. Fossil fuel resource supply in GCAM is modeled using graded resource supply curves that represent increasing cost of extraction as cumulative extraction increases. Wind and rooftop PV technologies include resource costs that are also calculated from exogenous supply curves that represent marginal costs that increase with deployment, such as long-distance transmission line costs that would be required to produce power from remote wind resources. Utility-scale solar photovoltaic and concentrated solar power technologies are assumed to have constant marginal resource costs regardless of deployment levels.

In GCAM, technology choice is determined by market competition. The market share captured by a technology increases as its costs decline, but GCAM uses a logit model of market competition. This approach is designed to represent decision making among competing options when only some characteristics of the options can be observed and avoids a "winner take all" response.

B. Additional detail about scenario design

Table A-1. Detailed assumptions in the S4: Regional Import Limits scenario

Region Type	GCAM Regions	High-level target / sanction
Developed countries, natural gas importers with sufficient domestic resources	EU-12, EU-15, Europe_Eastern, Europe_Non_EU	Reduce gross imports to 90% by 2035 and zero by 2040
Developed countries, natural gas importers with low domestic natural gas resources	Japan, South Korea, Taiwan	Maintain current import dependence through 2050
Developing countries, natural gas importers	Brazil, China, India, Pakistan, Southeast Asia, Mexico, South Africa	Maintain current import dependence through 2050
Natural gas exporters	USA, Africa_Eastern, Africa_Northern, Africa_Southern, Africa_Western, Australia_NZ, Canada, Central America and Caribbean, Central Asia, European Free Trade Association, Indonesia, Middle East, South America_Southern, South America_Northern, South Asia, Colombia, Argentina	Reduce gross imports to 90% by 2035 and zero by 2040
Russia	Russia	Same as *S2*

C. Additional GCAM results

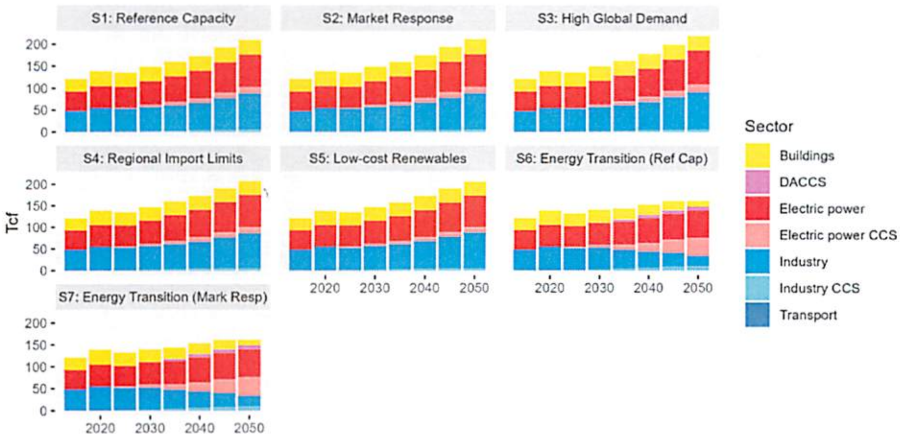

Figure A-1. Global natural gas consumption by sector across all scenarios

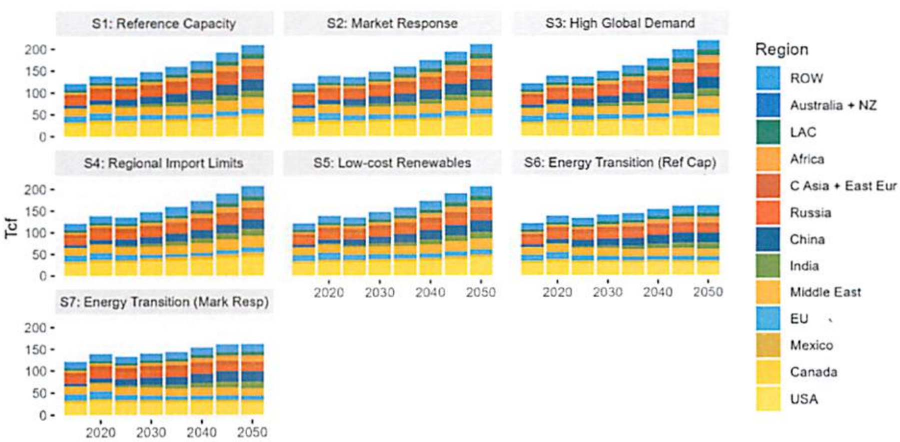

Figure A-2. Global natural gas consumption by region across all scenarios

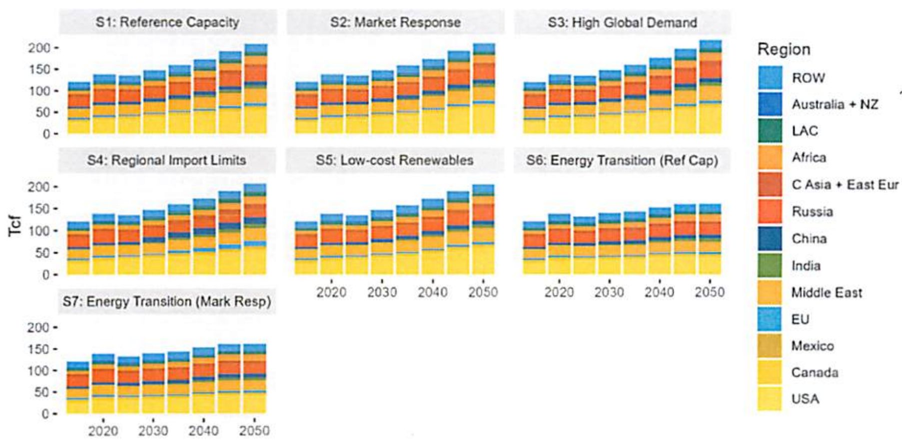

Figure A-3. Global natural gas production by region across all scenarios

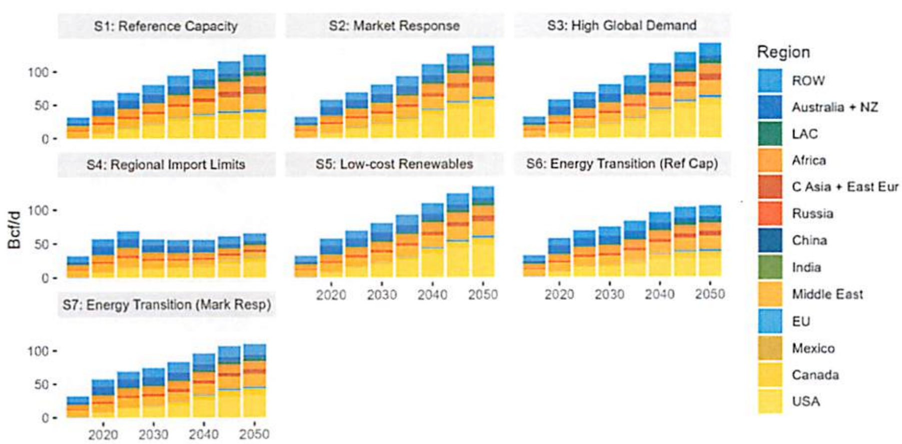

Figure A-4. Global LNG exports by region across all scenarios

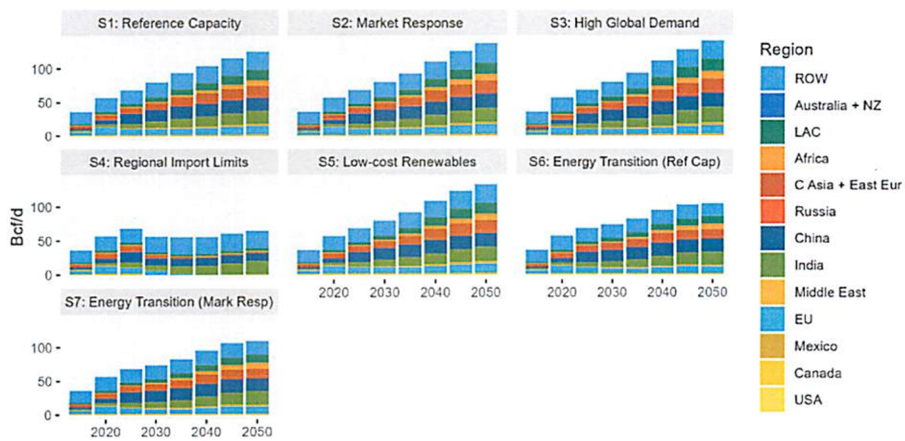

Figure A-5. Global LNG imports by region across all scenarios

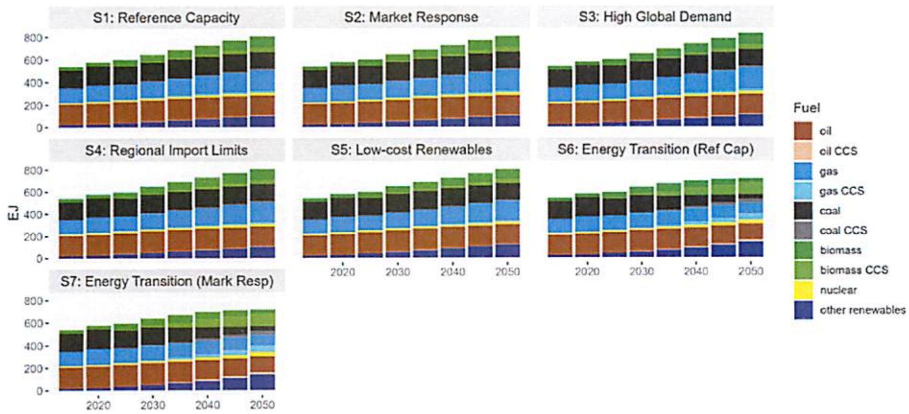

Figure A-6. Global primary energy consumption by fuel across all scenarios

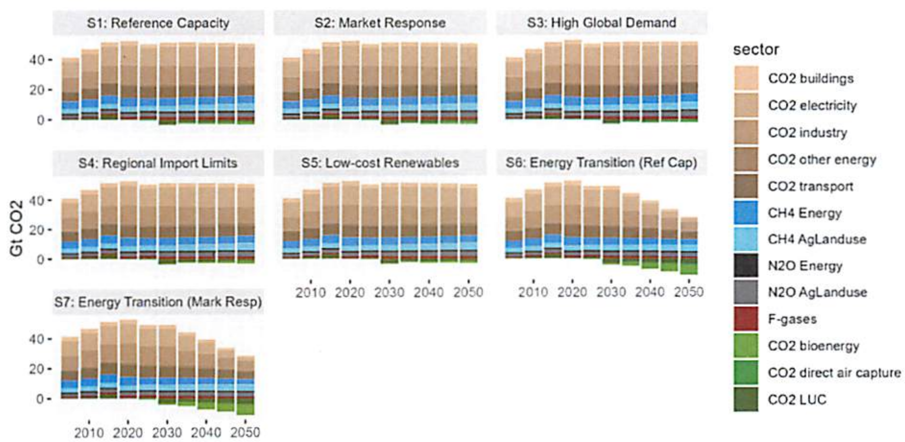

Figure A-7. Global GHG emissions by sector across all scenarios

APPENDIX B: U.S. ANALYSIS AND DESCRIPTION OF AEO2023-NEMS AND FECM-NEMS

A. Modeling U.S. LNG exports

AEO2023-NEMS and FECM-NEMS have two methods available to calculate LNG export capacity: endogenous and exogenous. There is a switch in the input files that can be toggled between the two methods before executing a run. *S1* uses the EIA AEO2023 reference case, which calculates LNG export capacity endogenously; *S2* through *S6* are initialized with exogenous export capacity, which use exogenous LNG export values from the GCAM model for each scenario. Both AEO2023-NEMS and FECM-NEMS follow a similar process with only minor differences in a small number of input values. In most cases (including all cases discussed in this report) LNG exports will equal LNG export capacity because the cost to construct capacity is so high that capacity will rarely be left unused once built. Therefore, the following description can be treated as an explanation for how AEO2023-NEMS and FECM-NEMS calculate LNG Export volumes.

The algorithm for calculating LNG export capacity endogenously has two steps. In the first step, AEO2023-NEMS considers LNG exports from existing or planned LNG export facilities. Beginning with Cheniere's Sabine Pass facility, which started exporting LNG in 2016, AEO2023-NEMS runs through a list of export facilities specified in an input file. This list is updated with each version of the AEO; AEO2023-NEMS includes existing and planned facilities expected to start or expand production by the end of 2025. For each facility, AEO2023-NEMS slowly increases production over the first few months to represent an export facility ramping up to full capacity.

The second step in the endogenous algorithm involves a prediction of future LNG exports. AEO2023-NEMS uses a set of exogenous values in an input file to specify how much demand Europe and Asia will have for LNG imports, as well as how much supply of non-U.S. LNG will exist on the market. Then, considering the volume of U.S. LNG exports at a given model year, AEO2023-NEMS calculates how the ratio of supply and demand changes over time. This ratio, together with the world oil price, is used to calculate the price at which international customers will purchase U.S. LNG. The purchase price algorithm is constructed in such a way that rises in the oil price, decreases or slowdowns in future LNG supply, or increases in future LNG demand will all increase the purchase price of LNG, and vice-versa. The influence that each factor has on LNG purchase price is controlled by several input parameters.

In addition to a purchase price, AEO2023-NEMS calculates the price at which U.S. LNG could be sold for. This "sale price" combines the natural gas Henry Hub price with various costs that represent the stages of preparing pipeline gas for LNG transport (including liquefaction, fuel consumption, shipping, and regasification). AEO2023-NEMS then compares the sale price to purchase prices at different destinations and determines a discounted net present value (NPV) of new LNG construction over the subsequent 20 years. Depending on the NPV, AEO2023-NEMS will decide to increase LNG export capacity by 0 to 600 Bcf/d. The increase in capacity takes effect after a four year "construction" period and brief "phase-in" period.

The algorithm in AEO2023-NEMS to calculate LNG export capacity exogenously is far simpler. A table in an input file lists LNG export capacity by year; these values are used by AEO2023-NEMS to set LNG exports for that year. In *S2* through *S6*, various parameters, including LNG export volumes, are calculated by the GCAM model. The LNG export volumes are converted to the correct input format and adopted by AEO2023-NEMS as the exogenous LNG export capacity.

B. Additional detail on U.S. natural gas markets

1. Regional natural gas production

Figure B-1 and Figure B-2 plot onshore natural gas production by region for the first five scenarios and the net-zero scenarios, respectively, in 2025 and 2050. Offshore natural gas production comprises a small portion of the total (<4 % in all scenarios and years) and is omitted from these figures.

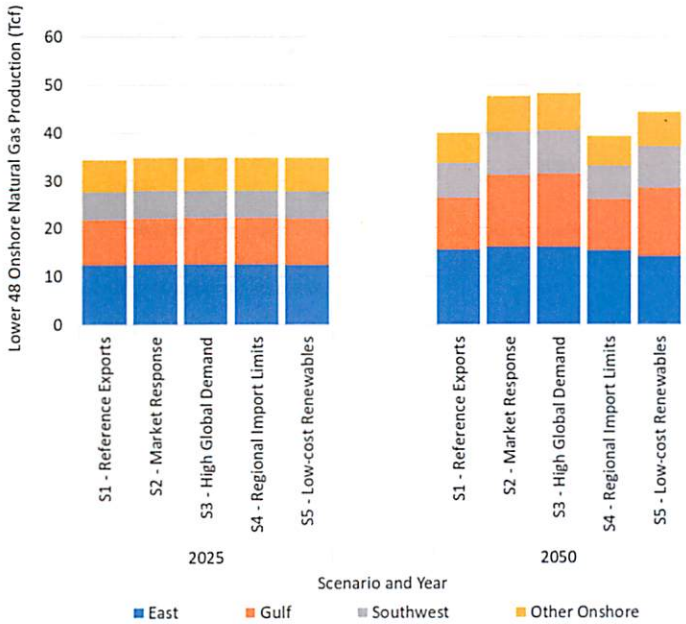

Figure B-1. U.S. Regional Natural gas production, S1 through S5

Natural gas production experienced an upward trend across all scenarios by 2050, equaling or exceeding 39 Tcf. *S3* exhibited the highest production level at 48 Tcf, influenced by the global demand for natural gas. Expansion is primarily characterized by a significant increase in production in the Gulf region, subsequently followed by the Southwest and the East. Conversely, scenario *S4* sees the lowest natural gas production at 39 Tcf with least production growth in the Gulf region.

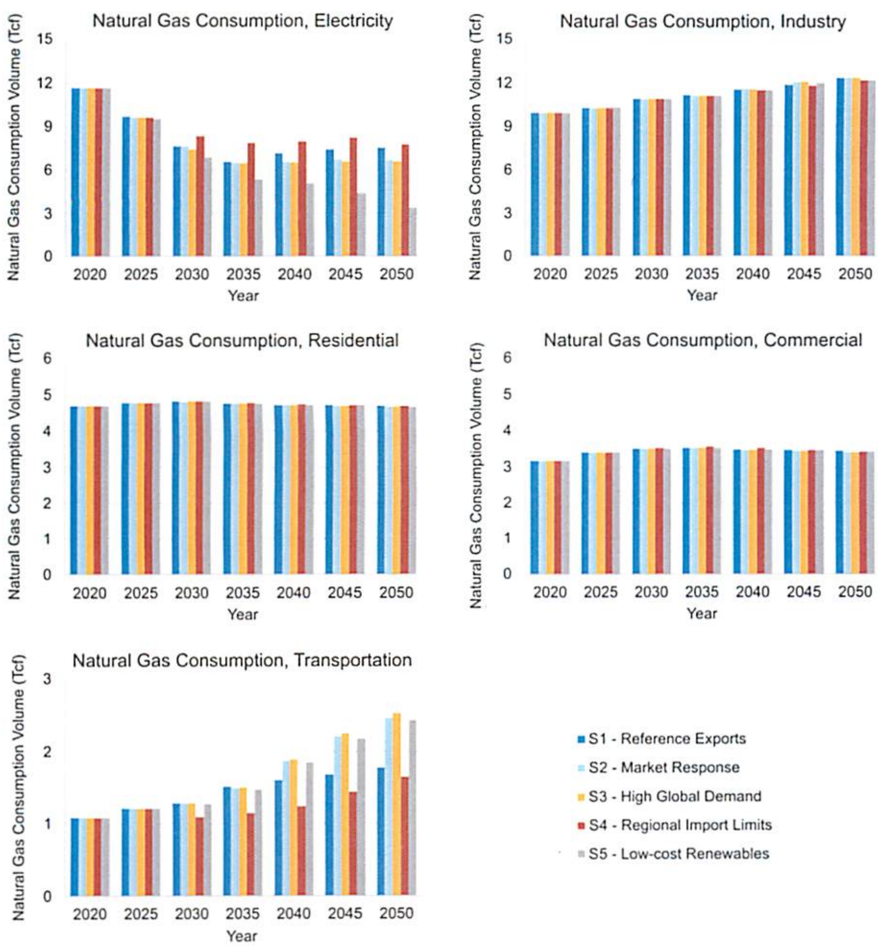

Figure B-3. U.S. natural gas consumption by sector, S1 through S5

Natural gas consumed for electricity was inversely correlated with LNG exports and natural gas prices for *S1-S4*. From a starting point of 11.6 Tcf in 2020, the first three scenarios drop to similar consumption volumes of 6.5-6.6 Tcf in 2035 before slightly increasing to 7.6 Tcf (*S1*) or plateauing at 6.7 and 6.6 Tcf (*S2* and *S3*, respectively) in 2050. The increased consumption of natural gas for electricity in *S1* can be explained as a response to price reductions caused by plateauing LNG exports, whereas high prices and exports in *S2* and *S3* lead to a flat consumption trend. *S4* – the scenario with the fewest exports and lowest prices through the first half of the model – exhibited the highest consumption for electricity in 2035 of 7.9 Tcf, which rises and falls slightly to a similar level to *S1* in 2050 (7.8 Tcf). *S5* is again an outlier here, reporting consistently lower natural gas consumption that hit a minimum of 3.4 Tcf in 2050. This trend is a consequence of its low renewable costs reducing the demand for natural gas in the electric sector.

Unlike for electricity, there was no significant difference between scenarios in the rate of natural gas consumption in the industrial, residential, or commercial sectors. Industrial natural gas consumption rises from 9.9 Tcf in 2020 to 12.2-12.4 Tcf in 2050 across the five scenarios; residential consumption remains relatively unchanged at 4.7 Tcf from 2020 to 2050 with some small variations; and commercial consumption rises and falls slightly from 3.2 Tcf in 2020 to 3.4 Tcf in 2050.

Natural gas consumed for transportation has a different response to changes in LNG exports, compared with the other consumptions sectors. The transportation category is dominated by pipeline fuel: natural gas consumed to power infrastructure underlying the natural gas supply chain, which includes LNG exports. Increases in natural gas consumption for transportation therefore correlate strongly with the quantity of LNG exports; *S3* exhibits the highest consumption in the transportation sector by 2050, followed by *S2* and *S5*, *S1*, and finally *S4*.

The sector-by-sector changes across the five scenarios end up cancelling each other out for *S1-S4*, leading to nearly identical total natural gas consumption values, as seen in Figure 16 in the main text. Only *S5*, thanks to its low renewable costs, exhibits a lower overall U.S. natural gas consumption trend.

Comparisons of *S1* through *S5* with *S6* and *S7* are complicated because of the many significant changes to the energy economy (going from AEO2023-NEMS to FECM22-NEMS) that occur to satisfy the net-zero criteria. Relative to *S1*, natural gas consumption values decline across most sectors in *S6* and *S7* but are substantially higher in the industry sector (where DAC consumption is categorized). Figure B-4 plots natural gas consumption for the net-zero cases on a sector-by-sector basis.

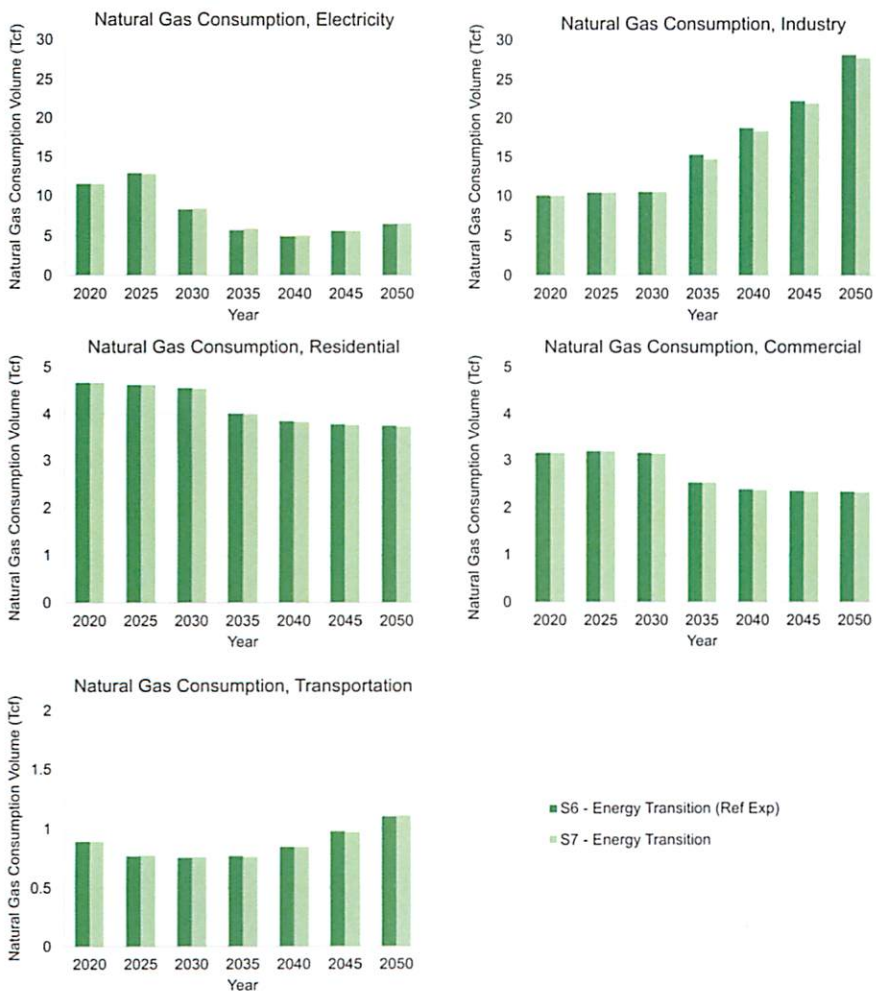

Figure B-4. U.S. natural gas consumption by sector, net-zero scenarios

Differences in historical natural gas consumption and subsequent short-term effects cause a difference in natural gas consumption for electricity in 2020 and 2025 between *S6* and *S7* (from the FECM-NEMS model) and *S1* through *S5* (from the AEO2023-NEMS model). Similar differences in the historical data exist for all sector-specific consumption values. Volumes of natural gas consumed for electricity track closely between the two net-zero cases across most of the modeling years, ranging from 5.7 to 5.9 Tcf in 2035 for *S6* and *S7*, respectively, and rising in later years to 6.5 Tcf and 6.6 Tcf. *S6* reports a lower natural gas consumption value in 2050 than *S1* (7.6 Tcf), but the corresponding result for *S7* is fairly close to *S2* (6.7 Tcf).

Industry-sector natural gas consumption exhibits the largest change between S6 and S7 and *S1* through *S5*, thanks to the strong influence of DAC. Whereas industry consumption of natural gas in *S1* and *S2* both increase from 9.9 Tcf to 12.3 Tcf over the 50 model years, the net-zero scenarios diverge after 2030 and grow rapidly to 28.2 and 27.8 Tcf for *S6* and *S7*, respectively, by 2050. The difference in consumption values is consistent with the natural gas consumption for DAC, which is plotted below in Figure B-5.

Residential- and commercial-sector natural gas consumption follow similar behavior. These values decrease in both net-zero scenarios across the model years from 4.7 to 3.7 Tcf (residential) and from 3.2 to 2.3 Tcf (commercial). By comparison, both *S1* and *S2* have static or slightly increasing trends, with both reporting 4.7 Tcf in 2020 and 2050 for residential consumption and 3.2 to 3.4 Tcf from 2020 to 2050 for commercial consumption.

Transportation is the smallest of the five sectors in terms of natural gas consumption volumes, and calculation differences between AEO2023-NEMS and FECM-NEMS lead to large impacts on the consumption values. As a result, these values are not directly comparable between the three scenarios. *S6* and *S7* have nearly identical volumes of natural gas consumed for the transportation sector, varying from 0.9 Tcf in 2020 to 0.8 Tcf in 2035 and 1.1 Tcf in 2050. By comparison, *S1* and *S2* report consistently higher natural gas consumption for transportation across the model years, ranging from 1.1 Tcf in 2020 to 1.8 and 2.3 Tcf, respectively, in 2050.

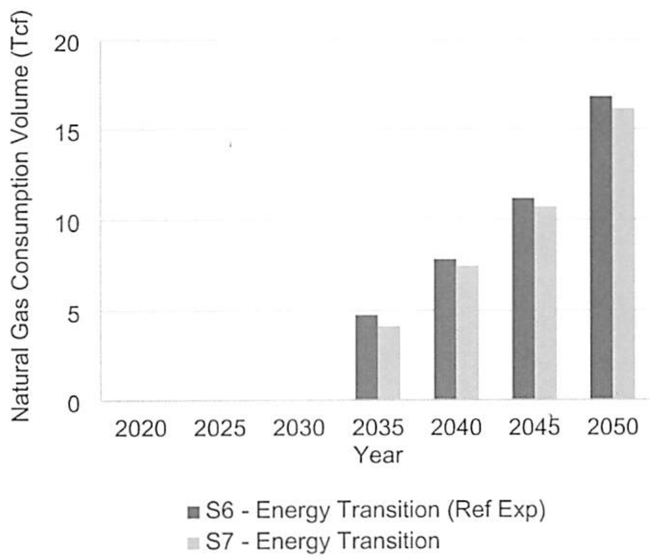

Figure B-5. Natural gas consumed for DAC, net-zero scenarios

DAC is the main technology used by FECM-NEMS to meet the CO_2 cap and by 2050 is responsible for removing 1930 MMT CO_2 per year in *S6* and 1850 MMT CO_2 per year in *S7*. A considerable amount of natural gas is consumed to support these levels of DAC: 16.8 Tcf and 16.2 Tcf in 2050 for *S6* and *S7*, respectively. More detail on CO_2 removal technologies in FECM-NEMS is given in the section below.

In conclusion, even though four out of the five sectors exhibit decreases when comparing natural gas consumption in the net-zero scenarios to *S1* and *S2*, the strong increases in the industrial sector (mainly from increases in DAC) cause overall U.S. natural gas consumption to be significantly higher by 2050 in *S6* and *S7*. There is minimal difference between the *S6* and *S7* results, suggesting that the differences in LNG exports between the net-zero scenarios play a limited role in altering natural gas consumptions trends.

C. CO_2 removal technologies in FECM-NEMS

CO_2 removals in FECM-NEMS are driven by three technologies: production of hydrogen with sequestered biomass, BECCS, and DAC. Figure B-6 plots CO_2 removals for each technology and scenario by year.

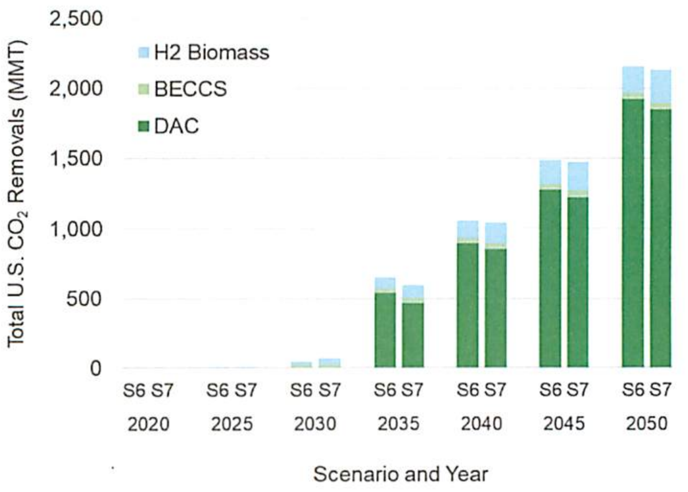

Figure B-6. U.S. CO_2 emissions and removals, net-zero scenarios

DAC is most widely used in both net-zero scenarios and scales up rapidly after 2030 to account for 1930 MMT CO_2 removed in *S6* and 1850 MMT CO_2 removed in *S7* (89% and 87% of total removals, respectively) by 2050. H2 biomass and BECCS see significantly less adoption by 2050 in both scenarios; the former reaches 200 (9% of total) and 240 (11% of total) MMT CO_2 removed in *S6* and *S7*, respectively, whereas the later reaches approximately 40 MMT CO_2 removed in both scenarios (2% of total removals).

FECM-NEMS relies on two sets of DAC technology assumptions: "grid", and "NG only," derived from the literature using updated cost and performance data from FECM.[24] Both use natural gas to power the capture process; DAC-grid offsets some of the natural gas demand by using electricity as well as lists the specific technical assumptions underlying the two DAC options.

Table B-1. DAC technology assumptions in FECM-NEMS

	Capex, $/ton-year	CRF	Capex, $/ton	Opex, $/ton	Electricity demand, kwhr/ton	Natural gas demand, MMBtu/ton
Grid	$1,300	7.1%	$112	$71	450	8.75
NG Only	$1,500	7.1%	$129	$83.6	0	9.27

The effect of DAC on natural gas markets in *S6* and *S7* can be seen in the rapid growth of total natural gas consumption and subsequent rise in natural gas prices (Figure 18) in the main text. By 2050, natural gas consumption equals 16.8 Tcf and 16.2 Tcf for *S6*, and *S7*, respectively, reaching natural gas prices of $5.90 2022/Mcf and $5.77 2022/Mcf.

FECM-NEMS models the deployment of carbon removal technologies by determining a CO_2 price that represents the market equilibrium cost to capture and abate CO_2 emissions. FECM-NEMS adjusts the CO_2 price in accordance with the imposed carbon cap to ensure that the correct number of CO_2 emissions are abated each year.

[24] National Academies of Sciences, Engineering, and Medicine. (2019). Negative Emissions Technologies and Reliable Sequestration: A Research Agenda. Washington, DC: The National Academies Press. https://doi.org/10.17226/25259.

Appendix C: Supporting LCA Analysis

A. NEMS and NETL LCA model comparison

The NEMS modeling done in this project focused on domestic changes that would be expected to occur in the seven scenarios modeled. NETL reviewed the NEMS data to evaluate if the regional production mix of natural gas would be expected to change over time. If the NEMS results suggested that production would be expected to shift significantly from the current mix of regions, and especially if to distinctly higher or lower intensity regions, then adjustments would be recommended to the assumed GHG intensity for U.S. natural gas in the results.

For *S1 - S7*, NEMS modeled data of dry natural gas production of "Production by OGSM District" was mapped to a state and then to an NETL natural gas model region as shown in Table C- 1. Note that several "states" are offshore regions.

Table C- 1. Matching NEMS (OGMP States) to NETL states and subsequently regions

Production by OGSM District	State	Region
Alabama, North	Alabama	Southeast
Alabama, South	Alabama	Southeast
Arizona	Arizona	Southwest
Arkansas	Arkansas	Southeast
California	California	Pacific
Colorado	Colorado	Rocky Mountain
Connecticut	Connecticut	Northeast
Delaware	Delaware	Northeast
Washington, D.C.	Washington	Pacific
Florida	Florida	Southeast
Georgia	Georgia	Southeast
Idaho	Idaho	Rocky Mountain
Illinois	Illinois	Midwest
Indiana	Indiana	Midwest
Iowa	Iowa	Midwest
Kansas	Kansas	Midwest
Kentucky	Kentucky	Southeast
Louisiana, North	Louisiana	Southeast
Louisiana, South	Louisiana	Southeast
Maryland	Maryland	Northeast
Massachusetts	Massachusetts	Northeast
Michigan	Michigan	Midwest
Minnesota	Minnesota	Midwest
Mississippi, North	Mississippi	Southeast
Mississippi, South	Mississippi	Southeast
Missouri	Missouri	Midwest

Commented [ST36]: Washington, D.C. is not a match for the State of Washington.

Are these intended to align OMGP States to NETL States?

Production by OGSM District	State	Region
Montana	Montana	Rocky Mountain
Nebraska	Nebraska	Midwest
Nevada	Nevada	Rocky Mountain
New Hampshire	New York	Northeast
New Jersey	New Jersey	Northeast
New Mexico, East	New Mexico	Southwest
New Mexico, West	New Mexico	Southwest
New York	New York	Northeast
North Carolina	North Carolina	Southeast
North Dakota	North Dakota	Midwest
Ohio	Ohio	Midwest
Oklahoma	Oklahoma	Southwest
Oregon	Oregon	Pacific
Pennsylvania	Pennsylvania	Northeast
Rhode Island	Rhode Island	Northeast
South Carolina	South Carolina	Southeast
South Dakota	South Dakota	Midwest
Tennessee	Tennessee	Southeast
Texas RRC 1	Texas	Southwest
Texas RRC 2	Texas	Southwest
Texas RRC 3	Texas	Southwest
Texas RRC 4	Texas	Southwest
Texas RRC 5	Texas	Southwest
Texas RRC 6	Texas	Southwest
Texas RRC 7B	Texas	Southwest
Texas RRC 7C	Texas	Southwest
Texas RRC 8	Texas	Southwest
Texas RRC 8A	Texas	Southwest
Texas RRC 9	Texas	Southwest
Texas RRC 10	Texas	Southwest
Utah	Utah	Rocky Mountain
Virginia	Virginia	Northeast
Washington	Washington	Pacific
West Virginia	West Virginia	Northeast
Wisconsin	Wisconsin	Midwest
Wyoming	Wyoming	Rocky Mountain
North Atlantic State Offshore	North Carolina	Southeast
South Atlantic State Offshore	South Carolina	Southeast
Alabama State Offshore	Alabama	Southeast
Louisiana State Offshore	Louisiana	Southeast

Commented [ST37]: Should this be NH to NH?

Commented [ST38]: Would this be north of the mason dixon line?

Commented [ST39]: Should all "offshore" align to an NETL off-shore profile instead of and end-use/consumption region?

Production by OGSM District	State	Region
Texas State Offshore	Texas	Southwest
California State Offshore	California	Pacific
North Atlantic Federal Offshore	North Carolina	Southeast
Mid Atlantic Federal Offshore	Federal Offshore - GoM	Southeast
South Atlantic Federal Offshore	South Carolina	Southeast
Eastern GOM Federal Offshore	Federal Offshore - GoM	Southeast
Central GOM Federal Offshore	Federal Offshore - GoM	Southeast
Western GOM Federal Offshore	Federal Offshore - GoM	Southeast
California Federal Offshore	California	Pacific
Northern Pacific Federal Offshore	Federal Offshore - GoM	Southeast
Alaska Federal Offshore	Federal Offshore - GoM	Southeast

This classification enables the aggregation of dry production data (excluding extraction losses) by region for each respective year, as summarized with every 10 years of data in Table C-2.

Table C-2 Regional dry production (trillion cubic feet) between 2020 and 2050, S1

Region	2020	2030	2040	2050
Midwest	3.26778	2.82406	2.40796	2.094116
Northeast	9.540964	11.14082	13.03394	14.08478
Pacific	0.163061	0.285247	0.296763	0.280681
Rocky Mountain	3.328845	2.899944	2.796355	2.687115
Southeast	4.587738	6.084166	6.64734	5.720366
Southwest	12.2792	13.3737	15.27886	16.65195

From this aggregated data, the production ratio is calculated by dividing the region-specific production by the total U.S. production for each year and summarized in Table C-3.

Table C-3 Regional dry production ratio, S1

Region	2020	2030	2040	2041	2050
Midwest	9.85	7.71	5.95	5.79	5.04
Northeast	28.77	30.43	32.21	32.75	33.92
Pacific	0.49	0.78	0.73	0.71	0.68
Rocky Mountain	10.04	7.92	6.91	6.94	6.47
Southeast	13.83	16.62	16.43	15.94	13.78
Southwest	37.02	36.53	37.76	37.87	40.11

Figure C-1 shows the percent of natural gas dry production for each region of *S1* as compared to total production in each year between 2020 and 2050. The same process was done for the other scenarios.

Commented [ST40]: Why every 10 years of data when the raw data is provided on an annual basis from NEMS?

Commented [ST41]: How much variability in dry production volume is considered significant? Northeast is a 55% increase. 60% decrease in Midwest.

Commented [ST42]: No discussion of Table C-3.

Ratio compared to what?

I think these are annual percentages. Column sums to 100%.

Caption needs better clarity.

Commented [ST43]: Why 2041 results?

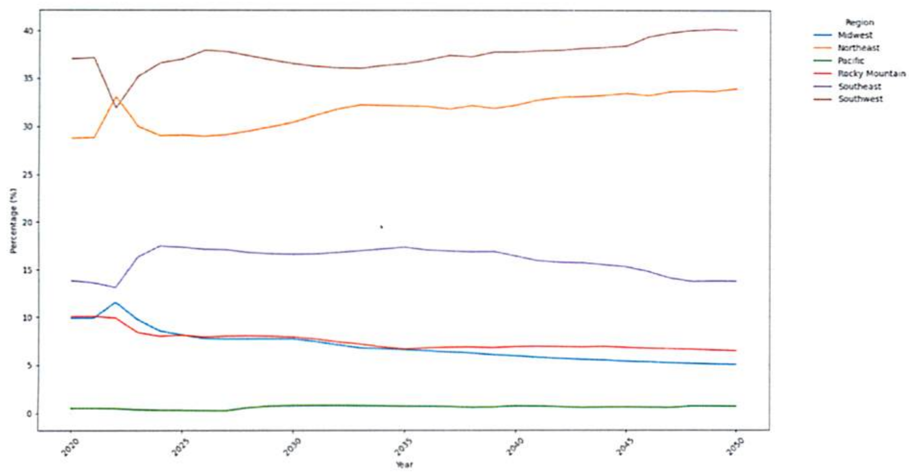

Figure C-1. Dry NG production percentage time-series for each region

This percentage can be multiplied with the 2020 GHG intensity values for each region from the NETL Natural Gas report[16] (shown in Table C-4) to estimate future GHG intensity results, as described in this mathematical representation:

$$GHG_{Midwest,2021} = GHG_{Midwest,2020} \times \, dry\ production\ ratio_{Midwest,\,2021}$$

and finding the weighted US average GHG intensity across regions.

Table C-4. Regional GHG Intensities (g CO_2e/MJ) from 2020 NETL Natural Gas Report

Region	GHG (g CO_2e/MJ)
Midwest	8.44
Northeast	6.23
Pacific	11.3
Rocky Mountain	10.01
Southeast	9.02
Southwest	8.80

Overall, Figure C-2 suggests that the NEMS-modeled changes in domestic production by region across the scenarios are not expected to have a significant effect on the GHG intensity of domestic production (given the 2020 data on GHG intensity by region) if only the trend in "dry production" (based on delivery shares) is considered.

Commented [ST44]: Hanging text??? Old text???

Commented [ST45]: GHG Emissions Intensity

Commented [ST46]: There should be a space between the measurement unit and the descriptor of what was measured/reported.

E.g., g CO2e (with the 2 subscripted)

Commented [ST47]: How were the regional profiles converted to a single Weighted Average GHG Emissions Intensity value?

Commented [ST48]: GHG Emissions Intensity

Commented [ST49]: NEMS includes endogenous learning. How much did the GHG emissions intensity of natural gas by region change in the model?

Should be different for S1 set versus S6/S7 set of model runs.

Commented [ST50]: This is a large caveat! The analysis should consider both dry production and GHG emissions intensity differences by year.

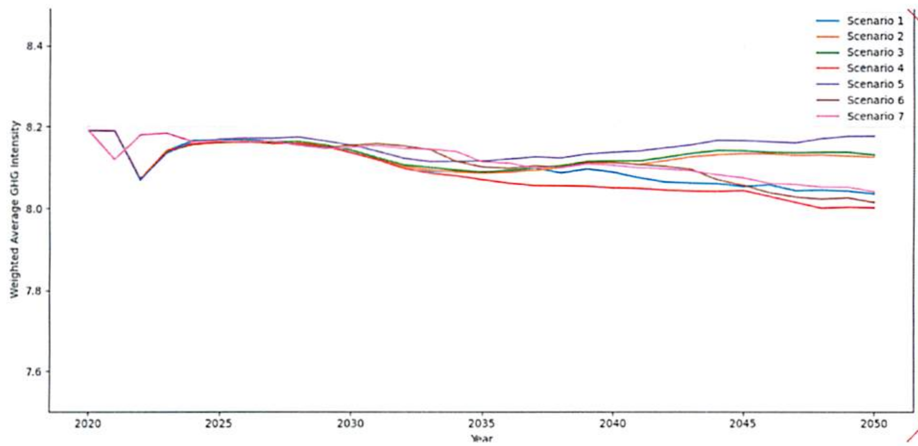

Figure C-2. Estimated U.S. Average GHG Intensity (g CO_2e/MJ) (S1 through S7), Production through Transmission (2020 - 2050)

B. Global Change Assessment Model – data inputs to LCA

The GCAM model is an input-output-based model primarily represented by sectors and technologies and their respective inputs and outputs for particular years and scenarios. Across all years and scenarios, GCAM has 105 discrete sectors, 377 discrete technologies, and many sector-technology pairs that can vary depending on the model configuration. However, only a subset of these factors is relevant to this analysis (i.e., with a focus on the natural gas sector).

Results provided by PNNL for the various Scenarios (1-7) and years modeled were provided as described in Table C-5, and were processed accordingly.

Table C-5. Provided set of GCAM Data Documentation

File	Data Represented
co2_em_tech_2023.06.22	Provides data showing CO_2 emissions in megatons per year (Mt_CO_2/yr) for various sectors, energy sources or "technology" for 6 different scenarios across each of 37 regions.
non_co2_em_tech_2023.06.22	Provides data showing non-CO_2 emissions in Gigagrams (Gg) equivalent to metric kilotons or 1,000 metric tons, for various sectors, energy sources or "technology" and 6 different scenarios across each of 37 regions.
inputs.by.tech_2023.06.22	Provides detailed information about energy consumption and capacity in different regions and sectors along with specific technologies and years. It can be used to analyze and understand the energy landscape, make projections, and assess the impact of various factors on energy consumption and capacity (sub-sector is not applicable in this dataset).
outputs.by.tech_2023.06.22	Reports the energy production within the various regions, by sectors, (sub-sector is not applicable in this dataset) along with specific technologies and years.

Commented [ST51]: Y axis, add "Emissions" and units and GWP version to label; U.S. Weighted Average GHG Emissions Intensity, g CO2e/MJ (IPCC AR6 100-yr GWP)

Commented [ST52]: Why does S4 have a steeper and lower GHG emissions intensity per unit of gas produced in 2050 than S6 or S7?

Commented [ST53]: Quantitative data discussion is needed to justify why the change is "not significant" and that domestic market effects can be ignored.

The data and conclusion show that a change occurs. Southwest (permian) gas increase. Permian is high GHG intense gas. Why is this not a market effect that needs to be considered?

GCAM shows a reduction in GHGs from exports.

NEMS shows an increase in GHGs from exports.

The scale/magnitude of the GCAM results are -5 and -3 g CO2e/MJ.

What is the equivalent sum over 35 years for the change between S2 and S1, and S7 and S6? The 2050 value change appears very small.

I think the conclusion that domestic changes are less significant compared to non-US global changes is valid.

However, I am concerned about saying there is "no" domestic market effect which is the outcome when we choose to not include domestic market effects in the analysis.

We need to better defend and message this outcome, particularly when the NEMS data shows increases in GHG intense regions to meet future LNG export demand.

NETL - please provide more rationale and alternative concluding remarks/findings with respect to domestic market effects.

Commented [ST54]: Odd phrasing. The other "Data Represented" descriptions do not explain "how" to use the data set.

Columns	Description
scenario	~~s~~Scenario or context for which the data is provided such as "S1: Existing Capacity," which suggests that the data corresponds to the existing capacity or infrastructure in the region.
Region	This column specifies the geo-political region under consideration.
Sector	This column categorizes the different sectors or areas of activity for which carbon dioxide emissions are being measured, e.g., "agricultural energy use", "cement", "air_CO_2", etc.
sub-sector	Within each sector, there may be further divisions or subcategories to specify the specific aspect of the sector being measured, e.g., "mobile", "stationary," etc. indicating different types of energy use within a single sector.
technology	This column identifies the specific technology or energy source being utilized within the subsector. For example, "refined liquids" and "biomass".
year	The specific year or time period for which the CO_2 emissions values are provided, this ranges from 2015 to 2050.
value	~~corresponding~~ Corresponding carbon dioxide emissions values for the given combination of scenario, region, sector, subsector, technology, and year. The values represent the estimated or projected amount of CO_2 emissions in megatons per year in this specific file as depicted in the "Units" column (not mentioned separately in this table).
ghg	Refers to the greenhouse gas that is being emitted. It identifies the specific type of gas responsible for the emissions, e.g., CH4, N2O, HFC125, C2F6, etc.
input, output	Additional details or characteristics about the technology or process. It helps to differentiate between different aspects or variations within a specific technology. Examples in the datasets include "elect_td_ind" (electricity transmission and distribution for industrial use) and "H2 wholesale dispensing" (hydrogen wholesale dispensing).

Commented [ST55]: Capitalization of column heading names seems to vary in this table. Intentional?

Commented [ST56]: The label for S1 and S2 were changed after the submission of this report. Capacity was changed " Exports".

S1: Reference Exports

S6 Energy Transition (Ref Exp)

Ref Exp = Reference Exports

Commented [ST57]: Subscript

Commented [ST58]: Is this the column heading or column response?

C. GCAM and NETL emissions intensity comparison

As noted in the main report, only three sectors of the GCAM model have information relevant to the upstream natural gas supply chain. The GCAM *gas pipeline* and *natural gas* sectors are assumed to wholly incorporate natural gas-relevant emissions, and so total emissions are extracted from GCAM model output result files.

However, the *other industrial energy use* sector contains a diverse set of activities that are connected to overall gross domestic product (GDP) of each region, making it relatively difficult to explicitly identify emissions related to natural gas. GCAM incorporates a variety of data sources to represent activity in this sector. Relevant to natural gas activities for this sector, 2015 IEA data on energy use by oil and gas production activities used by the GCAM modeling team were provided and utilized to apportion GHG emissions associated with natural gas activity, as in Table C-6. The provided data (not shown) details what percent of energy use in the sector was from the IEA energy flows (e.g., 25% of total sectoral energy use in a region from Extraction and Gathering and Boosting). As 99.5% of GHG emissions in the *other industrial energy use* sector are CO_2, only the IEA data source was used and only CO_2 data for that sector was adjusted.

Table C-6. LCA Stage Cross-Mapping

NETL LCA stage	IEA energy flow	GCAM sector – energy & CO_2	CEDS sector	GCAM sector – non CO_2
Extraction	Oil and Gas Extraction	other industrial energy use	1B2b_Fugitive-NG-prod	natural gas
Gathering and Boosting	Oil and Gas Extraction	other industrial energy use	1B2b_Fugitive-NG-prod	natural gas
Processing	Gas works	other industrial energy use	1A1bc_Other-transformation	other industrial energy use
Domestic Pipeline Transport [1]	Pipeline Transport	gas pipeline	1B2b_Fugitive-NG-distr	natural gas
Liquefaction	Liquefaction (LNG) / Regasification Plants	other industrial energy use	1A1bc_Other-transformation	other industrial energy use
Ocean Transport	International Marine Bunkers [2]	trn_shipping_intl [2]	1A3di_International-shipping	trn_shipping_intl
Regasification	Liquefaction (LNG) / Regasification Plants	other industrial energy use	1A1bc_Other-transformation	other industrial energy use
Pipeline Transport (at destination) [1]	Pipeline Transport	gas pipeline	1B2b_Fugitive-NG-distr	natural gas

Commented [ST59]: ??? Not described in the text.

This IEA data is aggregated into oil and gas activities such as "Extraction, Gathering and Boosting", "Processing", and "Liquefaction and Regasification". However, a challenge is that the IEA data represent extraction of both oil and gas resources, which were variously allocated for the natural gas products. Given the lack of data on liquefaction and regasification in the 2015 IEA data (including for the U.S.), emissions from those activities are excluded from the analysis, consistent with the focus on upstream natural gas effects.

Commented [ST60]: What does this mean? Unclear.

The emissions intensity cells in Table C-7 show the underlying equation used to generate values on an AR6-100 basis, where the numerator is the total emissions from the GCAM model for the USA region for Scenario *S1* for the year 2020 for each of the three greenhouse gases (if available), normalized by the total production of U.S. natural gas and oil from the GCAM model in 2020 (32.46 EJ and 22.46 EJ, respectively). Units of emissions intensity follow those internal to the GCAM model, which are Tg CO_2 equivalent per Exajoule, which conveniently are equal to g CO_2e/MJ, the same units as used in the NETL model. Thus, the bottom rows in Table C-7show comparisons to those of the NETL model.

As implemented, this adjustment factor of 0.96 is directly applied to GHG emissions in all regions for the *natural gas* and *gas pipeline* sectors as they wholly related to natural gas activities. The existing methane mitigation trend in the GCAM emissions data for the *natural gas* sector was preserved by using this adjustment method.

Commented [ST61]: How was it preserved?

Does the MAF change every year (model time step) due to endogenous learning in the model?

For the *other industrial energy use* sector, the adjustment is complicated by the fact that the sector includes many activities beyond natural gas. If the adjustment factor were wholly applied to the GHG emissions of the sector, then the total emissions in GCAM would be reduced for both natural gas and non-natural gas activities. A compromise was made to estimate the total needed reductions in emissions associated with only natural gas activity for each region, and to reduce the emissions of the other industrial energy use sector by that amount. While this does not achieve a full alignment of these associated emissions (i.e., it does not lead to a 4% reduction in emissions intensity for the other industrial energy use sector), it avoids the outcome where that sector's emissions are reduced for all of the other activities.

These adjustments to emissions from all regions, all scenarios, and all years were applied to existing GCAM model results (i.e., the GCAM model was not re-run or scenarios optimized based on these adjustments).

Table C-7. GCAM Emissions Intensities for Sectors (S1, 2020, USA region, AR6-100 basis)

			Estimated GCAM Emissions Intensity (LHV) (Tg CO_2e / EJ, g CO_2e / MJ) [IPCC AR6 100 yr]		
GCAM Sector	NETL LCA Stage	Comments/Potential mapping inaccuracy	CO_2	CH_4	N_2O
gas pipeline	Transmission and Storage	Have assumed this fully represents the Transmission sector equivalent to the NETL NG model.	38.0/32.5 = 1.17	-	-
natural gas	Production + Gathering & Boosting + Processing	From discussions with GCAM team, this sector represents all other natural gas related activities, thus the mapping to all other NETL stages other than transmission.	-	139.0/32.5 = 4.28	.015/32.5 = 4.5 E-4
other industrial energy use (technology = gas or gas cogen)[a]	For 2015, Extraction, Gathering & Boosting	Estimates from IEA energy shares. For technology = gas or gas cogen, all GHG emissions allocated to the natural gas product. For technology = refined liquids or refined liquids cogen, GHG emissions are allocated to the	92.9/32.5 = 2.86	-	-
other industrial energy use (technology = refined liquids and refined liquids cogen)[a]			11/(32.5+22.5) = 0.2	-	-

other industrial energy use (electricity)[a]		natural gas and crude oil products on an energy (EJ) produced basis from GCAM output data.	-	-	-
Total GCAM by gas (LHV)			= 1.17 + 2.86 + .2 = 4.23	4.28	4.5 E-4
Total GCAM (LHV)				8.52	
Subtotal from NETL Model, Processing through Transmission boundary – LHV basis				8.18	
Adjustment factor (LHV)				8.18/8.52 = 0.96	

Using the same detailed approach, Tables C-8 through C-10 more succinctly summarize the provided GCAM values and adjustments identified for the IPCC AR values.

Table C-8. GCAM Emissions Intensities for Sectors (S1, 2020, USA region, AR6-20 basis)

	Estimated GCAM Emissions Intensity ($Tg\ CO_2e$ / EJ, $g\ CO_2e$ / MJ) [IPCC AR6 20 yr]		
GCAM Sector	CO_2	CH_4	N_2O
gas pipeline	1.17	-	-
natural gas	-	11.86	4.5 E-4
other industrial energy use (technology = gas or gas cogen)	2.86	-	-
other industrial energy use (technology = refined liquids and refined liquids cogen)	0.2	-	-
Total GCAM by gas (LHV)	= 1.17 + 2.86 + .2 = 4.23	11.86	4.5 E-4
Total GCAM (LHV)		16.1	
NETL (LHV basis)		13.8	
Adjustment Factor (LHV)		0.86	

Table C-9. GCAM Emissions Intensities for Sectors (S1, 2020, USA region, AR5-100 basis)

GCAM Sector	Estimated GCAM Emissions Intensity (Tg CO_2e / EJ, g CO_2e / MJ) [IPCC AR5 100 yr]		
	CO_2	CH_4	N_2O
gas pipeline	1.17	-	-
natural gas	-	5.18	4.9 E-4
other industrial energy use (technology = gas or gas cogen)	2.86	-	-
other industrial energy use (technology = refined liquids and refined liquids cogen)	0.2	-	-
Total GCAM by gas (LHV)	= 1.17 + 2.86 + .2 = 4.23	5.18	4.9 E-4
Total GCAM (LHV)	9.41		
NETL (LHV basis)	8.84		
Adjustment Factor (LHV)	0.94		

Table C-10. GCAM Emissions Intensities for Sectors (S1, 2020, USA region, AR5-20 basis)

GCAM Sector	Estimated GCAM Emissions Intensity (Tg CO_2e / EJ, g CO_2e / MJ) [IPCC AR5 20 yr]		
	CO_2	CH_4	N_2O
gas pipeline	1.17	-	-
natural gas	-	12.36	4.4 E-4
other industrial energy use (technology = gas or gas cogen)	2.86	-	-
other industrial energy use (technology = refined liquids and refined liquids cogen)	0.2	-	-
Total GCAM by gas (LHV)	= 1.17 + 2.86 + .2 = 4.23	12.36	4.4 E-4
Total GCAM (LHV)	16.6		
NETL (LHV basis)	14.2		
Adjustment Factor (LHV)	0.86		

Table C-11 shows the GWP of key greenhouse gases which were used in conjunction with the emissions factors to derive the overall life-cycle greenhouse gas intensity.

Table C-11. GWP Values used in this analysis

Greenhouse Gas	AR5-100 (with ccf)	AR5-20 (with ccf)	AR6-100	AR6-20
CH4 (fossil)	36	86	29.8	82.5
CH4 (non-fossil)	34	84	27.2	80.8
N2O (fossil)	298	268	273	273
N2O (non-fossil)	298	268	273	273
HFC125	3691	6207	3740	6740
HFC134a	1549	3789	1530	4140
HFC143a	5508	7064	5810	7840
HFC23	13856	11005	14600	12400
HFC32	817	2502	771	2690
SF6	26087	17783	24300	18200
HFC245fa	1032	2992	962	3170
HFC365mfc	966	2724	914	2920
C2F6	12340	8344	12400	8940
CF4	7349	4954	7380	5300
HFC43	1952	4403	1600	3960
HFC152a	167	524	164	591
HFC227ea	3860	3860	3600	5850
HFC236fa	8998	9810	8690	7450

Note that unlike the natural gas system-specific emission comparisons and adjustments discussed above which focus on CO_2, CH_4, and N_2O, GCAM estimates emissions of sixteen GHGs and all are included in this study.

1. Market Adjustment Factors for other IPCC GWP Values

Table C-12 shows all MAF results for Scenario 2.

Table C-12. NETL-adjusted MAF results for S2

	Results (g CO_2e/ MJ, LHV basis)				
MAF Case	AR5, 100 with ccf	AR5, 20 with ccf	AR6-100	AR6-20	Scenario Difference
***S2* vs. *S1* - unadjusted**	-5.85	-9.17	-5.34	-8.86	Adds economic solution for LNG exports.
***S2* vs. *S1* - adjusted**	-5.86	-9.12	-5.35	-8.74	

Table C-13 shows all MAF results for *Scenario 7*.

Table C-13 NETL-adjusted MAF results for S7

	Results (g CO_2e/ MJ, LHV basis)				
MAF Case	**AR5, 100 with ccf**	**AR5, 20**	**AR6-100**	**AR6-20**	**Scenario Difference**
***S7* vs. *S6* - unadjusted**	-3.54	-7.54	-3.01	-7.25	S6 1.5°C pathway, economic solution for LNG exports
***S7* vs. *S6* - adjusted**	-3.44	-7.26	-2.95	-6.61	

Table C-14 shows the underlying annual CO_2e emissions and US LNG export volumes used in the MAF calculations above for the AR6-100 case (with adjustments).

Commented [ST62]: What does "with adjustments mean?

Table C-14. Annual Export Volumes of US LNG and Adjusted Global CO_2 Emissions (IPCC AR6, 100-yr GWP-~~100 basis~~)

Commented [ST63]: Break this table by Scenario.

Add to S2, S3, S4, and S5 a column showing the change in GHG Emissions by year compared to the S1 (the reference scenario).

Same comment for S7 with S6 comparison by year.

Commented [ST64]: HHV or LHV results?

Scenario	Year	US Export LNG (EJ)	Global CO_2e Emissions (Tg)
S1	2015	0.018	49656.4
S1	2016	0.538	50410.5
S1	2017	1.058	51164.6
S1	2018	1.578	51918.8
S1	2019	2.097	52672.9
S1	2020	2.617	53427.0
S1	2021	3.086	52816.1
S1	2022	3.555	52205.2
S1	2023	4.023	51594.3
S1	2024	4.492	50983.3
S1	2025	4.961	50372.4
S1	2026	5.372	50692.9
S1	2027	5.782	51013.5
S1	2028	6.193	51334.0
S1	2029	6.603	51654.5
S1	2030	7.014	51975.0
S1	2031	7.544	51974.5
S1	2032	8.074	51973.9
S1	2033	8.605	51973.4
S1	2034	9.135	51972.9
S1	2035	9.665	51972.3
S1	2036	9.766	51862.9
S1	2037	9.867	51753.5
S1	2038	9.968	51644.2
S1	2039	10.069	51534.8
S1	2040	10.170	51425.4

Scenario	Year	US Export LNG (EJ)	Global CO_2e Emissions (Tg)
S1	2041	10.170	51339.6
S1	2042	10.170	51253.8
S1	2043	10.170	51168.0
S1	2044	10.170	51082.2
S1	2045	10.170	50996.5
S1	2046	10.170	50853.8
S1	2047	10.170	50711.2
S1	2048	10.170	50568.6
S1	2049	10.170	50426.0
S1	2050	10.170	50283.4
S2	2015	0.018	49656.4
S2	2016	0.538	50410.5
S2	2017	1.058	51164.6
S2	2018	1.578	51918.8
S2	2019	2.097	52672.9
S2	2020	2.617	53427.0
S2	2021	3.086	52816.1
S2	2022	3.555	52205.2
S2	2023	4.023	51594.3
S2	2024	4.492	50983.3
S2	2025	4.961	50372.4
S2	2026	5.372	50692.9
S2	2027	5.782	51013.5
S2	2028	6.193	51334.0
S2	2029	6.603	51654.5
S2	2030	7.014	51975.0
S2	2031	7.462	51975.0
S2	2032	7.910	51975.0
S2	2033	8.358	51975.0
S2	2034	8.806	51975.0
S2	2035	9.254	51975.0
S2	2036	9.996	51862.2
S2	2037	10.738	51749.4
S2	2038	11.481	51636.5
S2	2039	12.223	51523.7
S2	2040	12.965	51410.9
S2	2041	13.561	51323.2
S2	2042	14.157	51235.6
S2	2043	14.753	51147.9
S2	2044	15.350	51060.3

Scenario	Year	US Export LNG (EJ)	Global CO_2e Emissions (Tg)
S2	2045	15.946	50972.7
S2	2046	16.271	50824.2
S2	2047	16.597	50675.8
S2	2048	16.922	50527.3
S2	2049	17.248	50378.9
S2	2050	17.573	50230.4
S3	2015	0.018	49656.4
S3	2016	0.538	50440.8
S3	2017	1.058	51225.3
S3	2018	1.578	52009.7
S3	2019	2.097	52794.2
S3	2020	2.617	53578.6
S3	2021	3.086	52949.2
S3	2022	3.555	52319.7
S3	2023	4.023	51690.2
S3	2024	4.492	51060.8
S3	2025	4.961	50431.3
S3	2026	5.371	50776.7
S3	2027	5.781	51122.1
S3	2028	6.191	51467.5
S3	2029	6.601	51812.9
S3	2030	7.011	52158.3
S3	2031	7.486	52193.5
S3	2032	7.961	52228.6
S3	2033	8.435	52263.8
S3	2034	8.910	52298.9
S3	2035	9.385	52334.1
S3	2036	10.148	52260.8
S3	2037	10.910	52187.4
S3	2038	11.673	52114.0
S3	2039	12.435	52040.7
S3	2040	13.198	51967.3
S3	2041	13.826	51922.6
S3	2042	14.453	51877.9
S3	2043	15.081	51833.2
S3	2044	15.709	51788.5
S3	2045	16.337	51743.8
S3	2046	16.697	51646.1
S3	2047	17.057	51548.4
S3	2048	17.417	51450.7

Scenario	Year	US Export LNG (EJ)	Global CO_2e Emissions (Tg)
S3	2049	17.777	51353.0
S3	2050	18.136	51255.3
S4	2015	0.018	49656.4
S4	2016	0.538	50410.5
S4	2017	1.058	51164.6
S4	2018	1.578	51918.8
S4	2019	2.097	52672.9
S4	2020	2.617	53427.0
S4	2021	3.086	52816.7
S4	2022	3.555	52206.5
S4	2023	4.023	51596.2
S4	2024	4.492	50985.9
S4	2025	4.961	50375.7
S4	2026	4.873	50698.7
S4	2027	4.784	51021.8
S4	2028	4.696	51344.8
S4	2029	4.607	51667.8
S4	2030	4.519	51990.9
S4	2031	4.602	51989.4
S4	2032	4.685	51987.8
S4	2033	4.768	51986.3
S4	2034	4.851	51984.8
S4	2035	4.934	51983.2
S4	2036	5.080	51874.4
S4	2037	5.226	51765.6
S4	2038	5.371	51656.7
S4	2039	5.517	51547.9
S4	2040	5.662	51439.1
S4	2041	6.004	51348.5
S4	2042	6.345	51257.9
S4	2043	6.687	51167.4
S4	2044	7.028	51076.8
S4	2045	7.370	50986.3
S4	2046	7.612	50840.2
S4	2047	7.854	50694.2
S4	2048	8.096	50548.1
S4	2049	8.338	50402.1
S4	2050	8.580	50256.1
S5	2015	0.018	49656.4
S5	2016	0.538	50409.0

Scenario	Year	US Export LNG (EJ)	Global CO_2e Emissions (Tg)
S5	2017	1.058	51161.6
S5	2018	1.578	51914.1
S5	2019	2.097	52666.7
S5	2020	2.617	53419.3
S5	2021	3.086	52803.6
S5	2022	3.555	52187.8
S5	2023	4.023	51572.1
S5	2024	4.492	50956.3
S5	2025	4.961	50340.6
S5	2026	5.372	50661.1
S5	2027	5.782	50981.7
S5	2028	6.193	51302.2
S5	2029	6.604	51622.8
S5	2030	7.015	51943.3
S5	2031	7.467	51939.6
S5	2032	7.920	51935.9
S5	2033	8.373	51932.2
S5	2034	8.826	51928.5
S5	2035	9.279	51924.8
S5	2036	10.020	51808.5
S5	2037	10.760	51692.1
S5	2038	11.500	51575.8
S5	2039	12.241	51459.5
S5	2040	12.981	51343.2
S5	2041	13.561	51248.0
S5	2042	14.141	51152.9
S5	2043	14.722	51057.7
S5	2044	15.302	50962.5
S5	2045	15.882	50867.3
S5	2046	16.216	50710.9
S5	2047	16.550	50554.5
S5	2048	16.884	50398.1
S5	2049	17.219	50241.7
S5	2050	17.553	50085.3
S6	2015	0.018	49656.4
S6	2016	0.538	50410.9
S6	2017	1.058	51165.4
S6	2018	1.578	51920.0
S6	2019	2.097	52674.5
S6	2020	2.617	53429.0

Scenario	Year	US Export LNG (EJ)	Global CO_2e Emissions (Tg)
S6	2021	3.086	52542.1
S6	2022	3.555	51655.2
S6	2023	4.023	50768.2
S6	2024	4.492	49881.3
S6	2025	4.961	48994.3
S6	2026	5.067	49084.3
S6	2027	5.173	49174.3
S6	2028	5.278	49264.3
S6	2029	5.384	49354.3
S6	2030	5.490	49444.3
S6	2031	5.782	48082.7
S6	2032	6.075	46721.2
S6	2033	6.367	45359.6
S6	2034	6.659	43998.0
S6	2035	6.951	42636.4
S6	2036	7.481	41287.6
S6	2037	8.010	39938.9
S6	2038	8.539	38590.1
S6	2039	9.068	37241.3
S6	2040	9.597	35892.5
S6	2041	9.712	34455.5
S6	2042	9.827	33018.4
S6	2043	9.941	31581.4
S6	2044	10.056	30144.4
S6	2045	10.170	28707.3
S6	2046	10.170	27334.6
S6	2047	10.170	25961.9
S6	2048	10.170	24589.1
S6	2049	10.170	23216.4
S6	2050	10.170	21843.7
S7	2015	0.018	49656.4
S7	2016	0.538	50410.9
S7	2017	1.058	51165.4
S7	2018	1.578	51920.0
S7	2019	2.097	52674.5
S7	2020	2.617	53429.0
S7	2021	3.086	52542.1
S7	2022	3.555	51655.2
S7	2023	4.023	50768.2
S7	2024	4.492	49881.3

Scenario	Year	US Export LNG (EJ)	Global CO_2e Emissions (Tg)
S7	2025	4.961	48994.3
S7	2026	5.067	49084.3
S7	2027	5.173	49174.3
S7	2028	5.278	49264.3
S7	2029	5.384	49354.3
S7	2030	5.490	49444.3
S7	2031	5.782	48082.7
S7	2032	6.075	46721.2
S7	2033	6.367	45359.6
S7	2034	6.659	43998.0
S7	2035	6.951	42636.4
S7	2036	7.481	41287.6
S7	2037	8.010	39938.9
S7	2038	8.539	38590.1
S7	2039	9.068	37241.3
S7	2040	9.598	35892.5
S7	2041	10.012	34454.7
S7	2042	10.427	33016.8
S7	2043	10.842	31578.9
S7	2044	11.257	30141.1
S7	2045	11.671	28703.2
S7	2046	11.836	27329.8
S7	2047	12.001	25956.4
S7	2048	12.166	24583.1
S7	2049	12.331	23209.7
S7	2050	12.496	21836.3

Commented [ST65]: I expected to find the index of country GHG emissions intensity to show the relative differences before and after adjustment.

I also expected to see more detail on "what" changed within each countries energy portfolio as a result of increased US LNG exports.

There is a larger "report" decision that will need to be made regarding additional transparency needed to support the conclusions.

This would be more in-line with the expectations described in the August 17, 2023 email to Scott/Matt from Tim.

NO ACTION REQUIRED AT THIS TIME UNTIL FURTHE REPORT WIDE GUIDANCE ON TRANSPARNCY/LEVEL OF DETAIL PROVIDED