From: Skone, Timothy
Sent: Wed, 16 Aug 2023 13:40:38 +0000
To: Matthews, Howard Scott (CONTR); Jamieson, Matthew B.
Subject: RE: File for Matt and Tim
Attachments: lng_nems_gcam_08072023-for-review.docx

Matt and Scott,

Some initial comments on the draft up to the Appendix section. Look forward to the discussion today.

Tim

From: Matthews, Howard Scott (CONTR) <Scott.Matthews@netl.doe.gov>
Sent: Monday, August 14, 2023 6:25 PM
To: Jamieson, Matthew B. <matthew.jamieson@netl.doe.gov>; Skone, Timothy <timothy.skone@hq.doe.gov>
Subject: FW: File for Matt and Tim

Tim:

DRAFT-DELIBERATIVE-PRE-DECISIONAL

Got your email about wanting to see results before briefing in parallel to finishing this draft memo (what will eventually go into the chapter of the report). I had some to share Thursday last week, but missed you with OOO. It also turned out that we didn't immediately realize that the latest GCAM results are formatted differently (they added subsector detail not previously available) and frankly had to make tons of changes to the code that we had all ready to go for when they sent the new results.

Enclosed please find a draft of results. A few notes to be clear of up front:

1. As you'll see GCAM and NETL results are pretty close! **Thus, no adjustments or normalizations have been made to GCAM results** to better align with NETL (we can easily – but keep reading)
2. The adders in here are focused only on S2 - S1 and S7-S6 due to tons of discussions in the last week or so on the Friday meetings. We still internally have the adder results for S3/4/5 (all vs S1) and FYI they are (200, 0, -50)
3. Harsh and I finalizing the SCC results (not very exciting of course, just informational and meeting the original requested item)

Its still a draft, so please don't spend time thinking about formatting/etc - I know there are lots.

That said, happy to hear any comments. You mentioned wanting to talk before Friday, which is fine – we have all hands in MGT all day tomorrow but my NETL calendar is updated – best times would be wed before 10, 1130-1, or Thurs at 11. If these don't work please reply all (has my KL address so I can see it tomorrow while on site) and we can find another time.

Scott

From: Scott Matthews <scott.matthews@keylogic.com>
Sent: Monday, August 14, 2023 6:15 PM
To: Matthews, Howard Scott (CONTR) <Scott.Matthews@netl.doe.gov>
Subject: [EXTERNAL] File for Matt and Tim

Scott Matthews | **Principal Scientist**
he/him
m: (b) (6) | keylogic.com
3168 Collins Ferry Rd, Morgantown, WV 26505



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DRAFT-DELIBERATIVE-PREDECISIONAL

To: Matt Jamieson and Tim Skone
From: Priyadarshini and Scott Matthews
CC: CC Name
Date: August 14, 2023
RE: Comparing the NETL Baseline Results and Framework with that of the Global Change Assessment Model (GCAM)

Note: this memo is now morphing between an informational memo updating on results and the imminently needed LCA section/chapter that will appear in the LNG report.

Some values in this memo are still using the June 22 basis GCAM results (will not affect message).

1 INTRODUCTION

The LNG Analysis project is a collaborative effort between NETL (specifically the LCA competency), On-Location (specifically the National Energy Modeling System (NEMS) modeling team), and Pacific Northwest National Laboratory (PNNL, specifically the Global Change Assessment, or GCAM, modeling team). This project seeks to quantitatively assess the expected global effects of different quantities of US LNG exports.

Past studies done by NETL on LNG have largely been techno-economic analyses focused on expected costs per unit delivered (landed) or attributional life cycle analyses that only estimate the emissions and other impacts associated with units of LNG delivered. These LCA studies are limited in that they 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, 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 increases or decreases in GHG emissions.

In this project, the three components are being done as follows:

- The National Energy Modeling Systems (NEMS) model component uses the energy-economics integration and energy technology performance basis to provide future predictions of production, imports, and energy consumption within the US macroeconomics.
- The PNNL/GCAM component is doing time-series modeling of different scenarios, with and without constraints on the US LNG market, to estimate future global greenhouse gas (GHG) emissions worldwide.
- The LCA component seeks to determine the consequences of additional exported volumes of US LNG, such as how additional available quantities of natural gas led to changes in the energy sectors of countries that purchase the LNG and the country that exports the LNG. These consequential effects will be estimated by tracking differences in global CO2 emissions and quantities of LNG exported from the GCAM model scenarios.

Commented [P1]: Sounds correct?

Commented [ST2]: One could state that comparison of GCAM scenarios results provides this value. What value does the LCA provide beyond the GCAM comparative conclusion?

In this memo, we seek to describe in detail 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 ensure they are correct in order to subsequently assess the differences in the two models at more detailed levels. We also expect that much of this text can/will be reused in the LCA section/chapter that will be a part of the overall LNG Analysis project report.

1.1 NETL Natural Gas Baseline Report

The NETL Natural Gas model (2020 data version) is separated into five separate stages which generally aligns with categories used in the US EPA GHGRP and GHGI products. Similarly, past work by NETL modeling LNG has added another four stages, the data for these UPs ~~however~~ is based on peer reviewed industry data representative of 2017 technology~~use older data (2017)~~. The relative boundaries / included activities in these stages are listed in Table 1.

Table 1. Global Warming Potential of the Natural Gas Life Cycle Stages and Liquified Natural Gas Supply Chain Stages, (GWP gCO2e/MJ)

Stage Name	Description	gCOe/MJ or gCO2e/kg of LNG
Natural Gas Only		
Production	Exploration, drilling, construction of conventional and unconventional wells (e.g., from hydraulic fracturing), and extraction of gas, including liquids unloading operations	1.62E+00
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.	1.76E+00
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.	2.09E+00
Transmission and Storage	Construction of pipelines, and movement of bulk quantities of natural gas in large pipelines to large users or city gates for subsequent distribution. Typically includes compressor stations along pipelines. Storage includes insertion of gas into	1.97E+00 Transmission Station: 1.82E+00 Storage: 1.48E-01

Commented [SM3]: Let's also verify year/etc basis of this data (20177). also can you grab those and paste in below? We can ask Harsh to verify if needed.

Commented [P4R3]: I think its 2020?

Commented [P5]: If this is the correct interpretation, i.e. referring to the stages of Natural Gas as Life Cycle stages those of Liquified Natural Gas as Supply Chain stages/sectors, should this be highlighted elsewhere in the document (this might also justify the large difference in reported values and how the stages are described)

Commented [ST6]: Is production based on a kg of LNG FU then?

This header needs some clarity as to what the values represent. Are they all gate-to-gate values or cradle-to-gate values?

Commented [ST7]: Please confirm if "exploration" activities prior to establishment of a production well is included in the NETL Model. I don't think we include exploration or other pre-production site activities.

Commented [ST8]: Should this cell show a range plus mean value to demonstrate known variability and uncertainty?

	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.	
Subtotal without distribution		**7.44 (7.29 without storage)**
Distribution (include?)	Movement of gas from transmission or storage facilities to city gates for subsequent to smaller consumers via small diameter pipelines.	9.89E-01 Transmission Pipeline: 8.74E-03 Distribution: 9.80E-01
Additional Stages for LNG		
Liquefaction	Pre-treatment of gas, liquefaction to low temperatures and storage	0.0219233 gCO2e/kg of LNG
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.	0.03179 gCO2e/kg of LNG*
Regasification	Regasification of LNG and injection into transmission pipelines.	2.3745 gCO2e/kg of LNG
Transmission / Dist (include?)	Similar processes as described above, and not functionally different than as described for the natural gas only part.	

Commented [P9]: Aggregated from the Liquefaction UP using

Total gCO2e/MJ = (GWP_CO2_flared * CO2_flared) + (GWP_CO2_fugitive * CO2_fugitive) + (GWP_CH4_flared * CH4_flared) + (GWP_CH4_fugitive * CH4_fugitive)

Commented [ST10R9]: Emissions from natural gas for power production onsite are not included in the CO2 combustion values reported in the liquefaction UP. I don't see these elements in the equation above.

Commented [SM11]: Pri - can you grab these and paste in?

Commented [P12R11]: Is this what you were referring to in the comment at the first line of this section?

* Note that this value is extracted from a result for transporting US LNG from the Gulf Coast to Rotterdam. Values for transport to Asian ports

Graphically, using this same source (Natural Gas Extraction and Power Generation: U.S. 2020 Emissions Profile[2]), has estimated impacts by stage as shown in Figure 1. In short, from the perspective of upstream domestic natural gas production, without considering the impacts of the distribution stage, the US average total CO2-equivalent emissions are about 7.3 g CO2e/MJ.

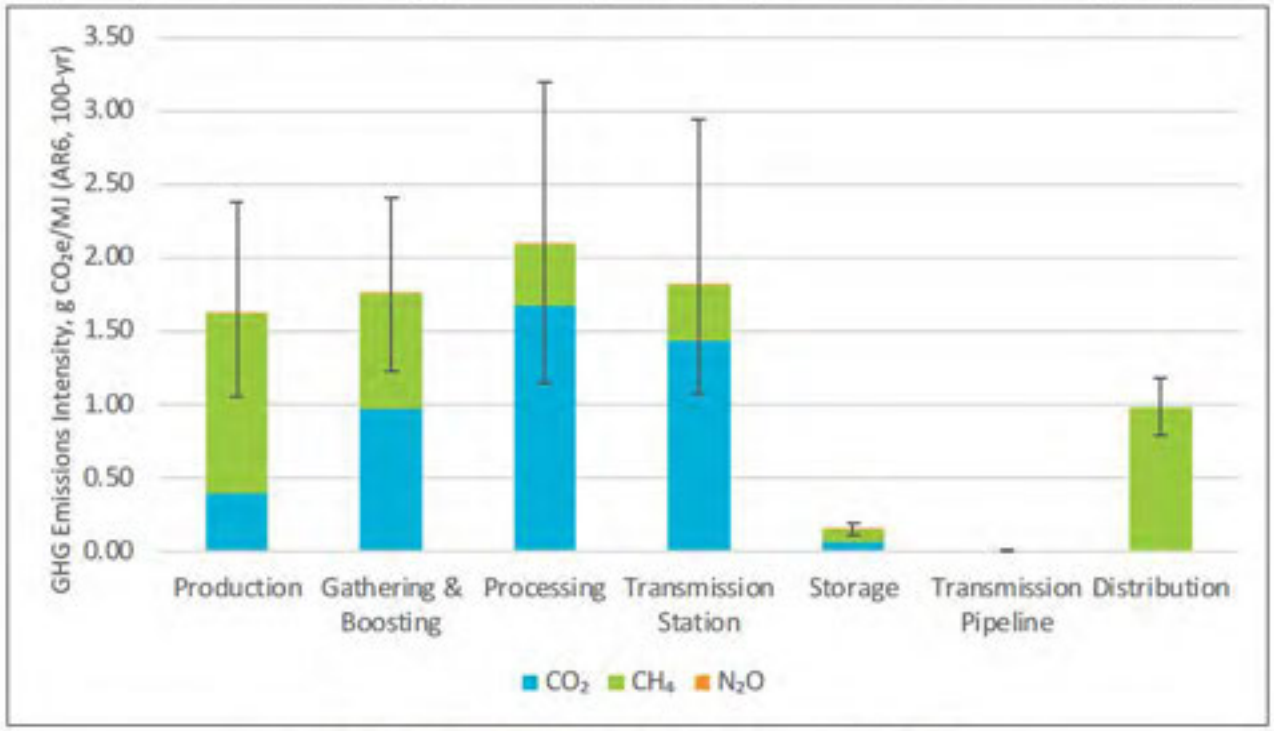


Figure 1. Life cycle GHG emissions from the 2020 U.S. average NG supply chain

The NETL natural gas model is an attributional study of the domestic natural gas system. It seeks only to identify and attribute the emissions associated with various processes that create them. It does not seek to more broadly consider the "what if" cases of what happens if there is additional US natural gas produced and delivered across the world, or, in other words, the market-based consequences and effects of producing domestic natural gas and exporting it (which are represented in the GCAM model).

Thus, an initial area of exploration of this study was to attempt to compare the upstream natural gas GWP impacts as represented in the GCAM model, which has similar but different data sources given its global nature. These comparisons are necessary because the DOE is familiar with the past NETL work, and if the GCAM results are substantially different, then accommodations would need to be made to rationalize the two models to more clearly identify effects.

As such, three goals of the LCA component of this project were to:

- Compare, to the best extent possible, the information regarding upstream supply chains in past NETL studies, and the NEMS and GCAM results of this study, and also against the US EPA's Greenhouse Gas Inventory (GHGI).
- Determine the appropriate incremental global GWP impacts associated with increasing exports of US LNG. This has been envisioned as a "consequential adder" that would be in addition to those shown above. However, as will be described below, a key challenge in determining this adder is coordinating the basis of systemwide emissions estimated from the GCAM model to those ~~previously~~ estimated in the NETL NG model and which are familiar to US DOE.
- To calculate the social cost of carbon associated with the various scenarios of the model, following previous guidance by US EPA and past work done by NETL/DOE.

NEMS vs. NETL Section - Placeholder for Pri's assessment of upstream NG forecasts in NEMS vs technobasins around here

- The basic issue we are about – is the carbon intensity of supplied domestic gas expected to change through 2050?
- What data did we get from the NEMS team – brief desciroption
- How we mapped it to our 2020 technobasin level analysis
- Using 2020 basis, how we think the carbon intensity of the mix will change based on what NEMS says
- Overall, is this an important effect?

Commented [ST13]: This is not a justification for conducting the comparison.

Commented [ST14]: No, current NETL NG model.

Commented [ST15]: This bullet should also state "why" we developed the comparison.

Commented [ST16]: This was not part of the scope.

Commented [ST17]: Not a justification.

Commented [ST18]: Did EPA do that work or the White House?

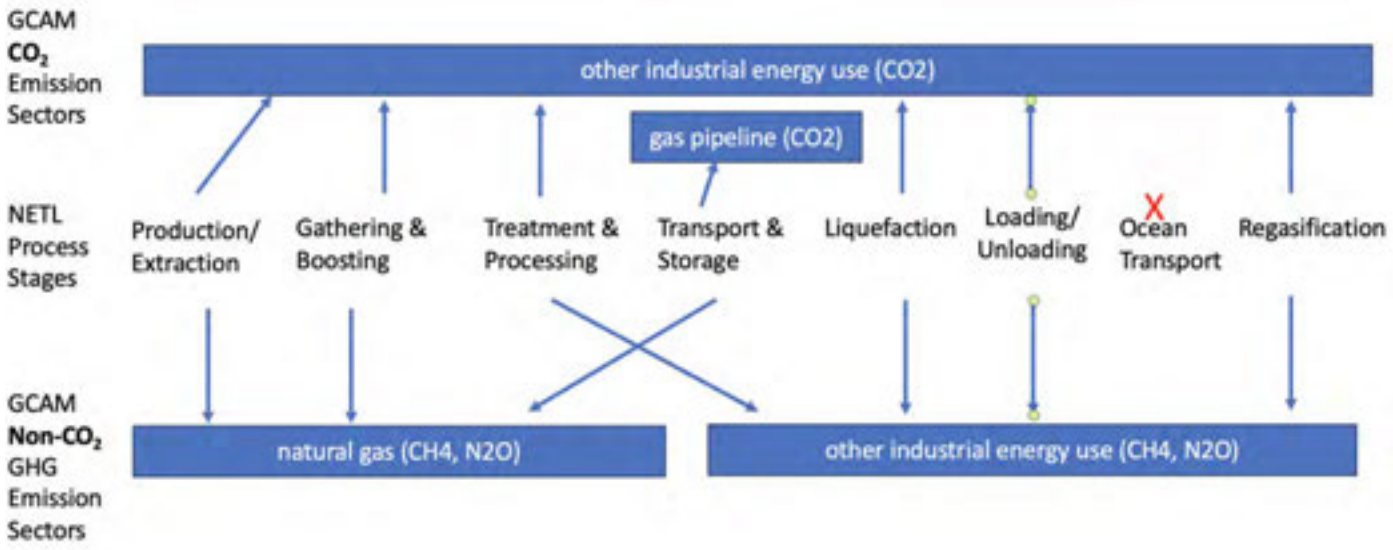
GCAM vs. NETL comparison

As described above, The GCAM model is 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 are relevant to this analysis (i.e., with a focus on the domestic natural gas sector). Detailed investigation and discussion with the GCAM team identified that only three sectors in the model need to be considered in order to encompass the greenhouse gas emissions of the natural gas sector (natural gas, gas pipeline, and other industrial energy use, see Appendix for more detail). Using the basis of process stages as represented in the NETL Natural Gas model, Figure 2 below shows the relevant GCAM sectors that represent CO2 and non-CO2 emissions. In short, all stages are directly represented in GCAM except for Ocean Transport. GCAM results will not explicitly represent LNG transport via ocean. These (relatively small, in global terms) emissions should also be contained within GCAM's "other industrial energy use" sector. However, due to data limitations it was not deemed possible to explicitly extract these transport emissions from that sector. This is a limitation of this comparative analysis.

Commented [P19]: Is there a specific number of sector-technology pairs?

Commented [SM20R19]: On second thought I dont think we need to specify the NN pairs in the model, we will just worry about the ones we need to.

Figure 2: Mapping of NETL Natural Gas Stages to GCAM Sectors (still working on a better graphic)



Note however, that while the overall GCAM model has various species of GHG emissions, for the three sectors above relevant to the upstream natural gas sector, only emissions of CO2, CH4, and N2O are available. Table 1 shows the emissions of the various GCAM sectors for the USA region for the three natural gas-relevant sectors identified above. Note that the gas pipeline and natural gas sectors are assumed to wholly incorporate natural gas-relevant emissions, and so total emissions are shown. However, the other industrial energy use sector contains a diverse set of activities, thus it is difficult to completely identify those related to natural gas. As detailed in the Appendix, for this sector, data provided by the GCAM modeling team on IEA data on energy use were used to attempt to apportion GHG emissions associated with natural gas activity. A further challenge is that some of the IEA data singly represents extraction of both oil and gas, and so outputs from domestically produced oil and gas were identified in the GCAM model to create potential ranges of shares related to natural gas activity.

(*Note to team – we are still working with PNNL to further refine the GHG emissions of the other industrial energy use sector, based on CEDS data*).

The emissions intensity cells in Table 1 show the underlying equation used to generate values, where the numerator is the total emissions for the USA region for S1-2020 for each of the three greenhouse gases (if available), normalized by the total production of US natural gas in 2020 (33.13 EJ). Units of emissions intensity follow those of the GCAM model, which are Tg CO2 equivalent per Exajoule, which conveniently are equal to g CO2/MJ, the same units as used in the NETL model. Thus, in the bottom rows of the table are comparisons to those of the NETL model.

Table 2: CAM Emissions Intensities for Sectors (S1, 2020, USA region only, old June data still used)

			Estimated GCAM Emissions Intensity (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 (Storage too?)	Have assumed this fully represents the Transmission sector equivalent to the NETL NG model.	38.2/33.1 = 1.15	-	-
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.		171.4/33.1 = 5.18	.016/33.1 = 4.8 E-4
other industrial energy use (gas/gas cogen)[a]	**For 2015,** Extraction, Gathering & Boosting	Current estimates are from IEA energy shares, awaiting GHG values from PNNL. But does not distinguish oil/gas (in extraction)..	81.3/33.1 = 2.46 50% = 1.23 60% = 1.48	.04/ 33.1 = .001	xx

Commented [ST21]: Where is gas processing (G&B and Processing) CO2 emissions from AGR and compression captured?

What about flare CO2 emissions from production, G&B, and Processing plants?

other industrial energy use (liquids and liquids cogen)[a]		2015 crude oil – 24.7 EJ, natural gas 26.2 (50%) 2020 – 22.5, 33.1 (NG is 60%)	16.3/33.1 = 0.5 50% = 0.25 60% = 0.3	.4 / 33.1 = .01	xx
other industrial energy use (electricity)[a]			-	-	-
Total GCAM by gas (including all the *other industrial energy use* as above)			**= 1.15 + 2.46 + .5 = 4.11**	**5.18 + .001 + .01 = 5.19**	4.8 E-4
Total GCAM CO2e (including all the *other industrial energy use* as above)			**8.85**		
Total GCAM by gas (including only 50% gas shares of *other ind* above)			**= 1.15 + 1.23 + .25 = 2.63**	**5.18 + .0005 + .005 = 5.18**	4.8 E-4
Total GCAM by gas (including only 50% gas shares of *other ind* above)			**7.81**		
Subtotal from NETL Model without Distribution or Storage			**7.29**		

Overall, the best guess of upstream emissions in the GCAM model are about 7.8 g CO2e/MJ, which are slightly higher than those of the NETL model (7.3 g CO2e/MJ). In addition, the GCAM values for the three sectors were compared to the EPA GHGI for the natural gas sector for 2020, and found to be within 10% of the EPA values, despite using different data sources (see Appendix). Overall, given the uncertainty in underlying energy and emissions data sources, and the small difference between g/MJ results in the two models, no further modification of the GCAM supply chain was deemed necessary.

Commented [ST22]: The difference in these values is 7%.

Commented [ST23]: Need to state what the 7.3 value from NETL represents. 2020 national average for production through transmission to a large end user? With storage excluded? This seems odd to exclude storage rather than note it as an emission in GCAM.

Adders

In order to attempt to quantify the broad and global market effects associated with increasing exports of US LNG, an equation was proposed to use the available GCAM results to estimate the change in global GHG emissions per unit of LNG exported. This adjustment factor, or adder, is defined as:

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

and represents a ratio of change in GHG emissions for a given scenario compared to a specific base scenario, versus the change in US LNG exports between the same two scenarios. This result is presumed to be valid only across the entire time horizon of results (2015-2050), and so while annual deltas are calculated, only the cumulative effect over all 36 model years is used. The GCAM model was run in 5-year increments. Values of GHG emissions and LNG exports were linearly interpolated for intervening years.

An important consideration and decision by the project was to focus only on the adders that compare Scenario 2 to Scenario 1 (aka S2-S1), and Scenario 7 to Scenario 6 (aka S7-S6). There are many reasons for this choice, most notably the large amount of differences in the world economy as modeled by Scenarios 3 to 5 which make it difficult to compare to the reference case. In addition, given the large differences between Scenarios 6 and 7 as compared to Scenario 1, it made more analytical sense to compare S6 and S7 than to compare either to S1.

Note that unlike the natural gas system-specific emissions discussed above, the overall GCAM results contain details of non-CO2 gases for many more GHGs and all are included in the study. Results were created for various GWP values from IPCC reports. Currently included are those for IPCC's 5th Assessment Report, for 100-year time horizons, including the effects of climate carbon feedback (see Appendix for GWP values used). *Only IPCC AR5-100 are shown here at this point*. The Appendix shows the annual summaries of GHG emissions, LNG export volumes, and deltas compared to baselines for each year of GCAM model runs.

	Results (g CO2e/ MJ)

Commented [ST24]: Why do you think this is true? The rate of market effect change is dependent on the natural gas supply and demand balance at each 5 year increment time step in GCAM. Not sure I agree with this statement.

Commented [ST25]: I thought we were using these as uncertainty scenarios to bracket S2 with world economic variability?

S2 = Expecuted Case
S3= High Case
S4 = Low Case

Commented [ST26]: Need to explain why they have been separated; large difference is to vague for the reader.

Commented [ST27]: My views are much stronger. One should not compare S1 to S6/7 to assess the market effects of increased LNG because S1 and S6/7 represents very different states of the world due to the inclusion of climate policies in S67/7. This confounds the ability to assess the effects of changes in LNG exports from global climate policies effect on the energy market.

Commented [ST28]: Which ones and were can the results be found?

Adder Case	AR5, 100 with ccf	AR6	Others?
Scenario 2 vs. Scenario 1 (S2-S1)	-5.9		
Scenario 7 vs. Scenario 6 (S7-S6)	-3.5		

Interpretation of Adder Results

Following the broader conclusions already suggested by the GCAM section of the report on the GHG effects of the various scenarios, the adders estimated by this project, using the same GCAM simulation results, suggest that the consequences of increasing US LNG exports broadly lead to decarbonization in the global economy. For S2-S1, the adder result is approximately -6 g CO2e/MJ, or put another way, would almost fully eliminate the +7.3 g CO2e/MJ upstream values estimated by the NETL NG model. For S7-S6, the adder result is slightly lower (about -3.5 g CO2e/MJ), but would reduce the domestic upstream GWP impacts by about 5%.

These results are important as modeled, but also should be presented with various caveats:

- The GCAM simulations represent broad modeling of the global economy, and despite tremendous sectoral detail, can not represent all technologies in detail, or fully encapsulate all activities (e.g., see discussion of Ocean Transport above)
- What else?
- In short, while useful from this analytical method done here, it is not possible to explicitly say that every MJ of domestically produced natural gas approved for export would directly lead to negative GHG emissions results (or credits) when supplied around the world.

Social Cost of Carbon (still in progress)…

Following previous DOE and NETL studies, this part of the project also estimated the annual and cumulative social costs of carbon (SCC) of each of the seven Scenarios over the 2015-2050 time horizon. Table X shows the annual values of SCC in dollars (see Appendix for the detailed values of underlying emissions used).

Commented [ST29]: We need detailed data to support this value. Where does the market change occur?

Region, economic sector, change in energy sources within a country, does the change occur early or late in the 30 year temporal window?

DOE Sr. Leadership wants us to fully explain where the market change occurs as a result of the change in US LNG exports.

This is why we developed the index approach to align foreign natural gas production operations to the NETL US data. This would help align the data to remove/reduce the uncertainty from using two different models.

The consequential adder needs aligned to the NETL data because that is what the Regulatory Program uses to evaluate LNG export requests.

Commented [ST30]: This seems to be a GCAM number and not an aligned NETL value - as suggested in your email.

Commented [ST31]: 5%? I am not sure I am interpreting this sentence correctly. 7.3 minus 3.5 =3.8; a 48% reduction in GWP.

Commented [ST32]: Ocean transport is about 10% of the cradle to regas profile. Not insignificant.

Commented [ST33]: How do you support this conclusion? The analysis needs to support the conclusion.

Effects of future mitigation in GCAM…. Not sure we still need to be modeling this..

Scroll down to see Appendix..

Appendix to LCA section (not very well organized yet)

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 are relevant to this analysis (i.e., with a focus on the natural gas sector).

Commented [P34]: Is there a specific number of sector-technology pairs?

Commented [SM35R34]: On second thought I dont think we need to specify the NN pairs in the model, we will just worry about the ones we need to

We used R code explicitly developed for this project to process the CSV file results provided by PNNL for the various Scenarios (1-7 and years modeled. Specifically, we were provided data files described in Table 3.

Table 3. 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 ($MtCO_2$/yr) for various sectors, energy sources or "technology" for 6 different scenarios across each of 37 regions.
co2_seq_tech_2023.06.22	Provides data showing CO_2 emissions in megatons per year ($MtCO_2$/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, 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.
luc_em_2023.06.22	contains information about CO2 emissions (in million metric tons per year) for different regions and years.
Columns	**Description**
scenario	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 CO2 emissions values are provided, this ranges from 2015 to 2050.

value	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 CO2 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., HFC125, HFC134a, HFC143a, HFC23, HFC32, SF6, HFC245fa, HFC365mfc, 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).

Amongst many data sources used in GCAM relevant to the natural gas and LNG, two are of importance – IEA data on energy and GHG emissions flows and the Community Emissions Data System (CEDS). We were provided detailed information on how the sectors of the NETL natural gas model may best align with those in the GCAM model, as in the table below.

Table XX

LCA stage	**IEA energy flow**	**GCAM sector – energy & CO_2**	**CEDS sector**	**GCAM sector – nonCO_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

Initially, to aid in identifying supply connections in the model, our team scripted separate R code to perform a "backward trace" of outputs of interest to see the inputs from sector-technology "pairs" and connect them throughout the upstream supply chain. The focus was on exemplar of pairs relevant to this analysis. In producing **Error! Reference source not found.**, a trace was run on the "delivered gas" output – the name of the output of natural gas that is ready to be used by large-scale customers such as power plants. Connected outputs and inputs can be seen in alternating rows (the blue arrow demonstrates the first such connection).

As shown in Table 4, our analysis uncovered the input-output pairs for each sector which is used to generate the emission values by dividing the GCAM output values with the total gCO2 equivalent for each sector. For comparability purposes, this value is further scaled based on scaling factors for both input and output to then generate the "scaled" emissions in gCO2e/MJ of output.

However, subsequent analysis has suggested that the trace algorithm is insufficient in tracking the entire upstream supply chain of activities, as there are various GCAM sectors that support natural gas activity but that are disconnected from the supply chain that is identified using the described algorithm. Nonetheless, the backwards trace example is maintained here to help to explain upstream supply chain connections in GCAM. Additional sectors from GCAM have been added at the bottom of Table 3 to account for these activities.

In the final columns of Table 3 are the global and US-only estimated GCAM emissions associated with natural gas for Scenario 1 for the Year 2020. (Note these are still using the mid-June values but are not expected to significantly differ in the final report).

Table 4. Traced GCAM CO2 and non-CO2 emissions for each sector and corresponding technology (Scenario 1, Year 2020, mid June results)

					Global GHG Emissions	**US GHG Emissions**

Sector	Technology	Input	Output	Description	CO_2 (Tg)	Non-CO2 (Tg)	CO_2 (Tg)	Non-CO2 (Tg)
Pairs from trace of NG sector								
Delivered gas	Delivered gas	Gas pipeline	Delivered gas	Seems to only be a market exchange sector	0	0	0	0
Gas pipeline	Gas pipeline	Gas processing	Gas pipeline	PNNL confirms this to be the expected pair, but IEA data may be spotty	186.2	0	38.2	0
Gas processing	Natural gas	Regional natural gas	Gas processing	We assume this is intended to be comparable to gas processing in NETL model, but e-mail discussions with PNNL have indicated their scope is not as comprehensive as ours.	0	0	0	0
Regional natural gas	Domestic natural gas	Natural gas	Regional natural gas		0	0	0	0
Regional natural gas	Imported LNG	Traded LNG	Regional natural gas		0	0	0	0

Regional natural gas	Imported N American pipeline gas	Traded N. Amer pipeline gas	Regional natural gas		0	0	0	0
Additional sectors separately identified as relevant								
Other industrial energy use	gas/gas cogen	N/A		Mentioned by PNNL as sector where emissions from extraction, G&B, processing, liquefaction, regasification would occur	255[b]	2.4	81.3	.03
Other industrial energy use	Refined liquids/refined liquids cogen				39[a]	5.7	16.3	.4
Natural gas	Natural gas			Identified by PNNL team	0	1164.2	0	171.5
Total (GCAM)					**480**	**1172**	**42.4**	**171.5**
Total (GHGI)							**36.5**	**185.3**

Commented [P36]: no more regional gas related sector (within scenario 1)

In terms of validation, the US values in Table 3 (which sum to 214 Tg CO2e) have been compared to the US EPA Greenhouse Gas Inventory (GHGI) for 2020. GHGI suggests that the total emissions of "Natural Gas Systems" are 36.5 Tg CO2 and 185.3 Tg of

[b] The values currently listed here are generated from allocations of energy use from the underlying IEA data – they will be replaced with direct estimates of GHG emissions when provided by PNNL. Total GHG emissions from GCAM in these two sector-technology pairs are 1514 and 731 Tg, respectively **and are NOT separated between oil and gas**. We do not expect significant differences when these are received.

methane in CO2e (221.8 Tg CO2e total). Both the CO2 and non-CO2 values are within 10% of the EPA GHGI value. The total values differ only by about 5**%. Note however that the GHGI does not include CO2 emissions other than flaring in those of the "Natural Gas Systems" category – other non-flaring CO2 emissions from natural gas are in the broadly used "Fossil fuel combustion" category and can not easily be disaggregated.**

In addition, the GCAM values can be normalized by the modeled final demands of natural gas produced in the US in S1/2020,

For appendix: In terms of comparing GCAM results of the natural gas sector with the NETL model, the emissions from appropriate total production value for a country is given by the output 'natural gas' from the sector-technology pair 'natural gas'. In 2020, the US total production in 'natural gas' is 33.13 EJ.

Old Mapping text

Given the information identified above, Table 4 demonstrates the intended correspondence of categories between the NETL NG model results and the GCAM model results.

Table 5. Potential Mapping of GCAM sector-technology pair with NETL stages

GCAM Sector	NETL LCA Stage	Comments/Potential mapping inaccuracy
delivered gas	NA	No CO2 or non-CO2 emission values for this GCAM sector (possible market exchange sector), therefore the mapping of this sector with the NETL stage isn't feasible.
gas processing	NA	No CO2 or non-CO2 emission values for this GCAM sector therefore the mapping of this sector with the NETL stage isn't feasible.
regional natural gas	NA	No CO2 or non-CO2 emission values for this GCAM sector therefore the mapping of this sector with the NETL stage isn't feasible.

		Also, “Region” in GCAM model stands for geopolitical region, which for the NETL stage was assumed as consisting of all the natural gas production through storage stages, since it considers the case of United States only.
gas pipeline	Transmission (Storage too?)	Have assumed this fully represents the Transmission sector equivalent to the NETL NG model.
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.
other industrial energy use (gas/gas cogen and liquids and liquids cogen)	WHAT HERE	WHAT HERE

Table 5 was the potential GCAM Sector mapping with NETL LCA Stages, prepared in order to analyze the relation between the two methodologies concerning natural gas processing, pipeline and distribution. The mapping is not accurate for reasons such as the geographical and technological context of data coverage and calculations within the two models/methodologies creates varying values (with vastly differing units) with do not perfectly align with one another in order to make a direct comparison, which was attempted in **Error! Reference source not found.**.

GWP Values used in this section (IPCC AR5, 100-yr with ccf)

1	CH4	36
2	CH4_AGR	36
3	CH4_AWB	36
4	N2O	298
5	N2O_AGR	298
6	N2O_AWB	298
7	HFC125	3691

8	HFC134a	1549
9	HFC143a	5508
10	HFC23	13856
11	HFC32	817
12	SF6	26087
13	HFC245fa	1032
14	HFC365mfc	966
15	C2F6	12340
16	CF4	7349
17	HFC43	164
18	HFC152a	167
19	HFC227ea	3860
20	HFC236fa	9810

S2-S1 – Detailed Background Data

	Scenario 1			Scenario 2				
year	global_lng	us_export_lng	global_co2_eq	global_lng_s2	us_export_lng_s2	global_tg_co2_eq	Δ_co2_eq	Δ _us_export_lng
2015	11.858	0.018	52488.031	11.858	0.018	52488.031	0.000	0.000
2016	13.753	0.538	53270.409	13.753	0.538	53270.409	0.000	0.000
2017	15.648	1.058	54052.788	15.648	1.058	54052.788	0.000	0.000
2018	17.543	1.578	54835.166	17.543	1.578	54835.166	0.000	0.000
2019	19.438	2.097	55617.545	19.438	2.097	55617.545	0.000	0.000
2020	21.333	2.617	56399.923	21.333	2.617	56399.923	0.000	0.000
2021	22.180	3.086	55750.013	22.180	3.086	55750.013	0.000	0.000
2022	23.027	3.555	55100.103	23.027	3.555	55100.103	0.000	0.000
2023	23.874	4.023	54450.193	23.874	4.023	54450.193	0.000	0.000
2024	24.722	4.492	53800.283	24.722	4.492	53800.283	0.000	0.000
2025	25.569	4.961	53150.373	25.569	4.961	53150.373	0.000	0.000
2026	26.428	5.372	53501.087	26.428	5.372	53501.087	0.000	0.000
2027	27.287	5.782	53851.802	27.287	5.782	53851.802	0.000	0.000
2028	28.147	6.193	54202.516	28.147	6.193	54202.516	0.000	0.000
2029	29.006	6.603	54553.230	29.006	6.603	54553.230	0.000	0.000
2030	29.865	7.014	54903.945	29.865	7.014	54903.945	0.000	0.000
2031	30.896	7.544	54924.381	30.811	7.462	54924.986	0.605	-0.082
2032	31.928	8.074	54944.818	31.756	7.910	54946.028	1.210	-0.164
2033	32.959	8.605	54965.254	32.702	8.358	54967.069	1.815	-0.246
2034	33.991	9.135	54985.691	33.648	8.806	54988.111	2.420	-0.328
2035	35.022	9.665	55006.127	34.594	9.254	55009.152	3.025	-0.411
2036	35.768	9.766	54910.372	35.911	9.996	54909.429	-0.943	0.230

2037	36.514	9.867	54814.616	37.229	10.738	54809.706	-4.910	0.871
2038	37.260	9.968	54718.861	38.546	11.481	54709.983	-8.877	1.513
2039	38.005	10.069	54623.105	39.864	12.223	54610.260	-12.845	2.154
2040	38.751	10.170	54527.350	41.182	12.965	54510.537	-16.812	2.795
2041	39.631	10.170	54466.246	42.361	13.561	54447.487	-18.760	3.391
2042	40.511	10.170	54405.143	43.540	14.157	54384.436	-20.707	3.987
2043	41.391	10.170	54344.040	44.719	14.753	54321.385	-22.655	4.583
2044	42.271	10.170	54282.937	45.898	15.350	54258.335	-24.602	5.180
2045	43.151	10.170	54221.834	47.077	15.946	54195.284	-26.550	5.776
2046	43.875	10.170	54100.302	47.928	16.271	54067.774	-32.528	6.101
2047	44.600	10.170	53978.770	48.779	16.597	53940.263	-38.507	6.427
2048	45.324	10.170	53857.239	49.629	16.922	53812.753	-44.486	6.752
2049	46.048	10.170	53735.707	50.480	17.248	53685.243	-50.464	7.078
2050	46.773	10.170	53614.176	51.331	17.573	53557.732	-56.443	7.403

S7-S6 – Detailed Background Data

	Scenario 6			Scenario 7				
year	global_lng	us_export_lng	global_co2_eq	global_lng_s2	us_export_lng_s2	global_tg_co2_eq	Δ_co2_eq	Δ _us_export_lng
2015	11.858	0.018	52488.032	11.858	0.018	52488.032	0.000	0.000
2016	13.753	0.538	53270.734	13.753	0.538	53270.734	0.000	0.000
2017	15.648	1.058	54053.436	15.648	1.058	54053.436	0.000	0.000
2018	17.543	1.578	54836.137	17.543	1.578	54836.137	0.000	0.000
2019	19.438	2.097	55618.839	19.438	2.097	55618.839	0.000	0.000
2020	21.333	2.617	56401.540	21.333	2.617	56401.540	0.000	0.000
2021	22.169	3.086	55465.461	22.169	3.086	55465.461	0.000	0.000
2022	23.005	3.555	54529.382	23.005	3.555	54529.382	0.000	0.000

2023	23.841	4.023	53593.303	23.841	4.023	53593.303	0.000	0.000
2024	24.677	4.492	52657.223	24.677	4.492	52657.223	0.000	0.000
2025	25.513	4.961	51721.144	25.513	4.961	51721.144	0.000	0.000
2026	25.931	5.067	51838.068	25.931	5.067	51838.068	0.000	0.000
2027	26.349	5.173	51954.992	26.349	5.173	51954.992	0.000	0.000
2028	26.766	5.278	52071.916	26.766	5.278	52071.916	0.000	0.000
2029	27.184	5.384	52188.840	27.184	5.384	52188.840	0.000	0.000
2030	27.602	5.490	52305.764	27.602	5.490	52305.764	0.000	0.000
2031	28.237	5.782	50941.678	28.237	5.782	50941.679	0.001	0.000
2032	28.871	6.075	49577.593	28.871	6.075	49577.595	0.002	0.000
2033	29.506	6.367	48213.507	29.506	6.367	48213.510	0.003	0.000
2034	30.141	6.659	46849.421	30.141	6.659	46849.425	0.004	0.000
2035	30.776	6.951	45485.335	30.776	6.951	45485.340	0.005	0.000
2036	31.740	7.481	44135.034	31.740	7.481	44135.038	0.004	0.000
2037	32.705	8.010	42784.733	32.705	8.010	42784.736	0.002	0.000
2038	33.669	8.539	41434.433	33.669	8.539	41434.434	0.001	0.000
2039	34.633	9.068	40084.132	34.633	9.068	40084.131	0.000	0.000
2040	35.598	9.597	38733.831	35.598	9.598	38733.829	-0.002	0.000
2041	36.181	9.712	37288.808	36.398	10.012	37287.814	-0.994	0.300
2042	36.764	9.827	35843.786	37.199	10.427	35841.799	-1.987	0.601
2043	37.347	9.941	34398.763	37.999	10.842	34395.784	-2.979	0.901
2044	37.930	10.056	32953.741	38.800	11.257	32949.769	-3.972	1.201
2045	38.513	10.170	31508.718	39.600	11.671	31503.754	-4.964	1.501
2046	38.673	10.170	30133.387	39.817	11.836	30127.643	-5.745	1.666
2047	38.833	10.170	28758.057	40.034	12.001	28751.532	-6.525	1.831
2048	38.992	10.170	27382.726	40.251	12.166	27375.421	-7.305	1.996
2049	39.152	10.170	26007.395	40.468	12.331	25999.310	-8.085	2.161
2050	39.312	10.170	24632.065	40.685	12.496	24623.199	-8.865	2.326

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[1] "Technology needs for net-zero emissions – Energy Technology Perspectives 2020 – Analysis," IEA. https://www.iea.org/reports/energy-technology-perspectives-2020/technology-needs-for-net-zero-emissions (accessed Jul. 13, 2023).

[2] H. Khutal, K. Kirchner-Ortiz, M. Blackhurst, N. Willems, H.S. Matthews, S. Rai, G. Yanai, K. Chivukula, Priyadarshini, H. Hoffman, M. B. Jamieson, T. J. Skone, "Life Cycle Analysis of Natural Gas Extraction and Power Generation: U.S. 2020 Emissions Profile," National Energy Technology Laboratory, Pittsburgh, July 7, 2023.

From: Skone, Timothy
Sent: Tue, 11 Jul 2023 16:38:43 +0000
To: Jamieson, Matthew B.
Subject: FW: Connect on LCA analysis
Attachments: LCA-Consequential-Modeling-Approach.docx

From: Skone, Timothy
Sent: Wednesday, June 21, 2023 11:19 AM
To: Francisco De La Chesnaye <francisco.delachesnaye@onlocationinc.com>
Cc: Curry, Thomas <thomas.curry@hq.doe.gov>
Subject: RE: Connect on LCA analysis

Paco,

Please find attached the working methodology for development of the consequential adder.

We will use this as a guide for our discussion today.

Thanks,

Tim

-----Original Appointment-----
From: Francisco De La Chesnaye <francisco.delachesnaye@onlocationinc.com>
Sent: Friday, June 16, 2023 5:25 PM
To: Francisco De La Chesnaye; Skone, Timothy
Subject: Connect on LCA analysis
When: Wednesday, June 21, 2023 1:00 PM-2:00 PM (UTC-05:00) Eastern Time (US & Canada).
Where: Microsoft Teams Meeting

Thanks.

Microsoft Teams meeting

Join on your computer, mobile app or room device
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Meeting ID: (b) (6)
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From: Skone, Timothy <timothy.skone@hq.doe.gov>
Sent: Friday, June 16, 2023 5:19 PM
To: Francisco De La Chesnaye <francisco.delachesnaye@onlocationinc.com>
Cc: Curry, Thomas <thomas.curry@hq.doe.gov>
Subject: RE: Connect on LCA analysis

[EXTERNAL EMAIL] This email originated from outside of the organization. Do not click links or open attachments unless you recognize the sender and know the content is safe. If you are unsure and require assistance, Contact Technical Support at support@keylogic.com.

How about Wednesday 1-2 PM?

From: Francisco De La Chesnaye <francisco.delachesnaye@onlocationinc.com>
Sent: Friday, June 16, 2023 5:17 PM
To: Skone, Timothy <timothy.skone@hq.doe.gov>
Cc: Curry, Thomas <thomas.curry@hq.doe.gov>
Subject: [EXTERNAL] Connect on LCA analysis

Hi Tim,

Let me know if you have some time next week for a one-on-one of the LCA part of the LNG Export Analysis. I have some questions about the approach and think if I better understand what NETL needs and the approach, I can better support the effort. I am available during the following times:

Tuesday: 10a - 12p, 1:30 - 3:30 p
Wednesday: 10 – 11a, 12 – 2:30p

Thanks, Paco

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DRAFT*DELIBERATIVE*PRE-DECISIONAL

Methodology for Estimating the International Energy Market Life Cycle Consequences from Changes in U.S. Liquefied Natural Gas Export Volume

Methodology Description

The objective of this project is to determine the greenhouse gas emissions from indirect market consequences that will be "added" to the NETL attributional LCA results for a specific US supply chain and delivery location to estimate both direct and indirect greenhouse gas emissions from US LNG exports.

The current life cycle analysis (LCA) modeling of U.S. LNG exports does not account for the indirect market consequences from changes in energy production and consumption, globally, that result from changes in U.S. LNG export volumes. This project will use energy supply and consumption general equilibrium model results provided by the coordinated efforts of PNNL from the Global Climate Assessment Model (GCAM) and OnLocations from the National Energy Modeling System (NEMS) to estimate the changes in macro-level GHG emissions by economic sector. A series of economic "Scenarios" have been developed and implemented within the GCAM framework. The resulting volumes of US LNG exports, in 5-year time intervals from 2020 to 2050, from GCAM where then applied as exogenous inputs to the NEMS to align forecasted LNG export volumes. The GCAM results are used in this effort to determine the change in energy flows and consumption on the global market by region, economic sector, and related technology. The NEMS, aligned to GCAM LNG export volumes by Scenario and 5-year time interval, are used to estimate changes in the U.S. domestic market as well as provide enhanced regional variability within the natural gas sector.

Commented [ST1]: Need to confirm if this is the correct general description for GCAM and NEMS modeling approaches.

Modeled Future Market Scenarios (LCA Scope and System Boundary)

The following six scenarios are modeled within this project:

- Scenario (S1). Existing and Under Construction Capacity
  - Baseline or reference comparison scenario.
- Scenario (S2). Remove US LNG Export Capacity Constraint
  - Unconstrained, economic solution.
- Scenario (S3). Higher Global Demand
  - Higher population and economic growth.
- Scenario (S4). Regional Import Limits
  - Global focus on maximizing local energy resources.
- Scenario (S5). Low Renewable Cost
  - Increase competitiveness of renewable technology by lowering capital and operating costs.
- Scenario (S6). Energy Transition
  - 1.5 Degrees Celsius consistent pathway, US to Net Zero greenhouse gas emissions by 2050.

Each scenario within the project was designed to model a different perspective of future energy market conditions. Scenario 1 maintains a constant US LNG export capacity equal to the current, April 2023,

DOE authorized export volume of 27.xx Bcf/day. Scenarios 2 through 5 remove the GCAM model constraint on US LNG Export volume to estimate how the global market reacts (changes) due to the increased availability of US LNG on the market and the change in one additional economic parameter per scenario to model a different perspective of the future energy market. Scenarios 1 through 5 provide a set of potential future market outcomes based on the modeled conditions. The scenarios in aggregate bracket the modeled uncertainty in future outcomes when the total Global Energy Consumption, functional unit, is held reasonably constant. The indirect energy market consequences are determined by comparing the change in global energy consumption and their resulting life cycle greenhouse gas emission for Scenarios 2 through 5 to Scenario 1 for each 5-year time interval on a unit of change in US LNG exports. The unit of change in US LNG exports across the 5-year time interval can be positive (increase in exports) or negative (a decrease in exports) when compared to equivalent time-interval for Scenario 1.

Commented [ST2]: Need to confirm volume.

Scenario Comparability (LCA Functional Unit)

Determining the indirect market consequences from a unit change in one economic activity, US LNG exports within this project, requires the functional unit for the scenarios to be held constant, i.e., equivalent service to society. The functional unit for determining global market consequences from a unit of US LNG export is set to total Global Energy Consumption by 5-year time interval. This is not feasible within general equilibrium models to hold Global Energy consumption exactly constant. This is a known and accepted uncertainty in the consequential life cycle modeling within this project. Uncertainty in the functional unit equivalence is minimized by selecting and comparing project scenarios with nearly equivalent levels of Global Energy Consumption. This includes Scenarios 1 through 5 within this project. Scenario 6, Energy Transition, results in a XX% change in Global Energy Consumption from the Scenario 1, Existing and Under Construction baseline scenario. Therefore, Scenario 6, Energy Transition, cannot be directly compared to Scenarios 2 through 5 results because the functional unit of each scenario are not reasonably equivalent.

Commented [ST3]: Need final value inserted.

Estimating Indirect Market Consequences

The comparison of change in global greenhouse gas emissions resulting from a unit change in US LNG export volume, as modeled within GCAM, determines the non-US indirect greenhouse gas market consequences based on the change in energy supply and consumption patterns. U.S. indirect market consequences are informed by the NEMS for the equivalent GCAM modeled scenario. The resulting change in global greenhouse gas emissions estimated within GCAM are based on the change in energy supply and consumption patterns multiplied by a representative greenhouse gas emission factor for carbon dioxide, methane, and other greenhouse gases on a mass basis. The emission factors are representative, from a life cycle analysis perspective, of the gate-to-gate emissions profile of a specific energy consuming economic activity by technology type. The resulting greenhouse gas emission can be summed across the global modeling result to imply a life cycle result inclusive of operations from extraction of raw materials to end use. The GCAM model represents significant carbon dioxide, methane, and other greenhouse gas emissions by economic activity relevant to the global scale of emissions. The comparative results estimate the indirect energy market consequences from exporting US LNG. Directly adding the GCAM resultant to the NETL attributional (direct LNG production, delivery, and end use) LNG LCA model would add additional uncertainty from known differences in completeness and representativeness of supply chain emissions from both direct and indirect energy market activity.

Aligning Life Cycle Greenhouse Gas Emissions Profiles to Indirect Market Consequences

The resulting GCAM consequential economic activity needs to be represented by the life cycle supply chain emissions consistent with the NETL LCA energy technology representations for each region of the globe for each end-use economic activity by technology type. This is accomplished by combining the strengths of the global economic and life cycle modeling capabilities. In general, the life cycle energy models developed by NETL are more detailed (comprehensive) in representation of supply chain activities and designed for high comparability across different energy technologies, current and future. The limitation is that the data is representative of US energy technology and supply chain operations and not representative of specific non-US operations. The GCAM model has been developed to represent regional differences at a macro level for energy technology and significant supply chain operations, among others. Each capabilities strengths are aligned by using the change in global energy consumption patterns by region, economic sector, and technology end-use from the GCAM model and the life cycle supply chain data from NETL per unit of energy consumption. Differences in regional energy technology profiles will be indexed to the change from the GCAM US energy technology emission profile. The index by technology/supply chain will be applied to the representative US life cycle emission profile to estimate greenhouse gas emission based on data that improves the alignment through enhanced consistency and data representativeness to the NETL LCA model. This does not eliminate data consistency and representativeness uncertainty, only minimizes it to the extent feasible within the existing modeling capabilities.

Managing Global Life Cycle Energy Technology Representativeness Uncertainty

Uncertainty resulting from the regional technology emission factor indexing approach is modeled by applying the minimum and maximum indexed values by region, economic sector, and technology to each scenario. This will provide an expected value based on the GCAM index values and then a resulting minimum and maximum value after replacement with the corresponding index values.

Managing Future Market Uncertainty

The result for each scenario pairing (S2:S1, S3:S1, S4:S1, S5:S1) are used to bracket the range of future market uncertainty under varying economic conditions when the total Global Energy Consumption, functional unit, is held reasonably constant. The likelihood of any single scenarios future energy market conditions from occurring is unknown and therefore assumed to be equally likely within this project. Each scenario pairings result for the change in global greenhouse gas emissions estimate the indirect market consequences from the change in US LNG exports. The scenario pairing results are used to bracket the range of future market uncertainty modeled within the project.

GCAM Economic Sectors Representation

GCAM is designed to balance supply and demand for energy services based on long-term market price, supply availability, and market demand. As a result, direct life cycle supply chains are not represented in the model by linked processes. The model draws from “pools” of economic resources to meet global demands. For example, global LNG export supply is aggregated “pooled’ to form a single non-source attributional LNG resource. Countries that have a demand for LNG imports are satisfied in the model by obtaining imports from the global LNG resource pool. Differentiation in LNG export volumes is

determined based on differences from country-to-country gas production costs. This determines the ratio of country LNG exports available for import within the aggregated global export supply pool.

This modeling decision is used throughout the model to enable a solution to converge without forming endless iterative calculation cycle resulting in non-model convergence.

This approach works very well for macro-economic modeling but is problematic for life cycle modeling that links each supply chain steps output to the input of the next supply chain step; therefore, creating direct model dependencies from extortion to end use of the energy resource to provide the energy service to society.

When aligning GCAM economic sector representation to applicable life cycle supply chain models it is important to emissions are not double counted across the modelling platforms. For example, "gas processing" is an economic sector within GCAM but is considered part of the life cycle supply chain that provides natural gas resources for export and the ultimate end use to provide a service to society (end use). When incorporating the NETL life cycle model data for LNG exports, it will include gas processing within the life cycle result. This would create double counting of global gas processing emission. The GCAM greenhouse gas emission from "gas processing" are removed from the aggregate GCAM results to avoid over estimation of greenhouse gas emissions.

Another example is "cement" identified within the "Industrial Sector" of GCAM. Concrete representation within GCAM includes three inputs: "process heat cement by wholesale gas", "electricity total demand by non-CCS electric generating sources", and ""electricity total demand by CCS electric generating sources". These are the only inputs to the "cement" industrial demand. Other material or energy inputs, combination with aggregates and water to form concrete, transport of concrete, and concrete end use is not reported within the GCAM model. In this case, only part of the concrete supply chain is represented in the GCAM model – cement production energy consumption. This represents an incomplete supply chain that would require expansion of the reported life cycle greenhouse gas emissions when modeled as the final end use product concrete.

Alignment of GCAM economic sector and life cycle model representation is an iterative evaluation step to determine if the entire supply chain should be represented by the life cycle data (cradle-to-gate) regionally indexed or portions of the supply chain should be represented by portions of the life cycle data (e.g., gate-to-gate profiles) that are regionally indexed.

The following identifies the economic sector representation within the GCAM model by primary economic sector that is reported as final energy consumption (final_en_cons):

Industrial Sector

1. Agricultural Energy Use
2. Alumina Production
3. Aluminum
4. Cement
5. Chemical Energy Use
6. Chemical Feedstocks
7. Carbon Dioxide Removal
8. Construction Energy Use
9. Construction Feedstocks

10. Desalinated Water
11. Industrial Wastewater Treatment
12. Industrial Water Abstraction
13. Industrial Water Treatment
14. Iron and Steel
15. Irrigation Water Abstraction
16. Mining Energy Use
17. Municipal Wastewater Treatment
18. Municipal Water Distribution
19. Municipal Water Treatment
20. Nitrogen Fertilizer
21. Other Industrial Energy Use
22. Other Industrial Feedstocks
23. Process Heat for Cement Production
24. Process Heat for Direct Air Capture

Building Sector

1. Commercial Cooling (comm cooling)
2. Commercial Heating (comm heating)
3. Commercial Other (comm other)
4. Residential Cooling (resid cooling)
5. Residential Heating (resid heasting)
6. Residential Other (resid other)

Transportation Sector

1. International Aviation (trn_aviation_intl)
2. Freight (trn_freight)
3. Freight Road (trn_freight_road)
4. Passenger (trn_pass)
5. Passenger Road (trn_pass_road)
6. Passenger Road, Light Duty Vehicle (trn_pass_road_LDV)
7. Passenger Road, Light Duty Vehicle, Four Wheel Drive (trn_pass_road_LDV_4W)
8. International Shipping (trn_shipping_intl)

Commented [ST4]: Verify - rail transport?

Commented [ST5]: Passenger rail transport? Domestic airline transport? Both?

Commented [ST6]: Mass transit, bus?

Commented [ST7]: Ocean Transport

Energy Inputs per GCAM Economic Sector

The three primary economic sectors (Industrial, Buildings, and Transportation) and their sub-sectors each have a general categories of energy inputs reported in terms of total energy demand. The following nine energy resources are included within the GCAM model. Each has various levels of technology type profile that vary based on regional performance profiles.

1. Biomass
2. Coal
3. District Heat
4. Electricity
5. Gas
6. Hydrogen
7. Process Heat Direct Air Capture (DAC)

8. Refined Liquids
9. Traditional Biomass

GCAM Greenhouse Gas Emissions Categories

Calculation of total global greenhouse gas emission requires the summation of carbon dioxide, methane and other greenhouse gases across the following GCAM reporting categories (data sets). The individual greenhouse gas species are then multiplied by the corresponding IPCC AR4, 100-year global warming potentials to report an aggregated result in terms of carbon dioxide equivalents.

GCAM greenhouse gas emissions data that is not replaced with life cycle analysis data will be maintained to inform the estimate of indirect market consequences for emission sources not captured by the life cycle analysis data. The following nine greenhouse gas emission categories are reported within GCAM:

1. Energy Operations, Carbon Dioxide
2. Energy Operations, Methane
3. Energy Operations, Nitrous Oxide
4. Agricultural Operations, Methane
5. Agricultural Operations, Nitrous Oxide
6. All Sectors, Fluorinated Gases (F-Gases)
7. Bioenergy with Carbon Capture and Storage (BECCS), Carbon Dioxide Removal and Sequestration from the Atmosphere
8. Direct Air Carbon Capture and Storage (DACCS), Carbon Dioxide Removal and Sequestration from the Atmosphere
9. Land Use Change, Carbon Dioxide Emissions

Total global greenhouse gas emissions are determined in GCAM by the following equation:

Global GHG Emissions per year per scenario = CO2_Tech + CH4_energy + CH4_AgLandUse + N2O_energy + N2O_AgLandUse + F-Gases + BECCS Biomass Uptake + DACCS CO2 Removal from Atmosphere + CO2 Land Use Change

Commented [ST8]: Need GCAM response on where to find this data.

Commented [ST9]: Need GCAM response on where to find this data.

Calculation Procedure (copy from 5/24/2023 email to NETL)

Commented [ST10]: Needs updated to reflect the indexing approach and uncertainty modeling.

Yesterday you asked for more detail (steps) on how to create the LNG consequential adder and the interaction between GCAM and NETL work. Please note, the steps below are focused only on the GCAM aspect. There are NEMS runs that will provide domestic detail by production basin and export location. This is not outlined below but is part of the effort when creating the LCA profile for domestic gas production, use, and export.

Step 1 – Map the GCAM data files to track the technosphere flows from energy production, transport, industrial sub use (if relevant), transport to end use, and use of the energy carrier. This needs to be tracked at the regional level of GCAM representativeness.

Step 2 – Subtract S(n) from S1 to determine change in US LNG exports. [n = scenario 1 thru 6 iterations] This will provide a relationship in 5-year time increments for the change in US LNG exports (per 5 year time step).

Step 3 – Subtract S(n) from S1 to determine change energy consumption magnitude by sector and technology for same 5-year time increments as Step 2.

Step 4 – Divide Step 3 by Step 2 (for the same 5-year increment and S(n)-S1 pairing. This will create the "technosphere flow consequential adder" specific to each scenario pairing and provide a market consequence depending on the current LNG export base volume (volume of US LNG export activity at the start year of the 5-year time step) and the increment of change in US LNG export volume (over the 5 -year times step).

Note: We need to determine if the base amount of export volume is important or only the incremental change in export volume when evaluating market consequences. The answer will also vary based on the Scenario pairing. These have been designed within the project to "bracket" a range of incremental increases in export volume; High, Medium, Low.

Step 5 – Using the GCAM technosphere values, replace the GCAM emission factors for energy (specifically/especially: natural gas/LNG) supply chain stages and energy end use to provide a life cycle perspective. How to prioritize what gets replaced? The scope of work lists the resources that NETL will use to assess post processing replacement of emission estimates for the GCAM technosphere flows. Caution is required to ensure/prevent double counting. We can use US data as a proxy for international operations if we determine an improvement in consistency, comparability, and maybe accuracy (this is subjective at this state). The following are NETL SOW excerpts relevant to Step5:

- NETL will use the data to identify the production-to-consumption LNG pathways predicted by the economic equilibrium model. These pathways and their respective flows of natural gas will be used as inputs to the LCA. NETL will develop production-weighted average life cycle greenhouse emission factors for each production region, transportation mode and route, end-use sector, and end-use region and then apply these average factors to estimate the total emissions associated with each economic equilibrium scenario.
- Life cycle models will include all natural gas processes, starting with source extraction and extending to end-use combustion. NETL will provide emission comparisons for alternative primary energy source scenarios or energy sources estimated as displaced by natural gas as a result of the economic equilibrium modeling using existing NETL

lifecycle-based data and/or global modeling proxy data. The lifecycle-based models for alternative energy supplies and consumption, similar to natural gas and LNG pathways, data will not be representative of country specific performance parameters. NETL will use existing U.S. data and models as proxies where commensurate data and models for foreign operations are missing.

- NETL will use the following primary models:
  - NETL Natural Gas Baseline Model (2020 update to be completed in winter 2022)
  - 2019 LNG GHG Study
  - Alaska LNG Draft Supplemental Environmental Impact Statement (SEIS)
  - NETL U.S. Electricity Baseline Model (2020 update of thermal electric and renewable energy production pathways)
  - NETL Biomass and Renewable Natural Gas (RNG) Production Models (updated in 2022, as needed)
  - NETL Fossil Hydrogen Baseline Report
  - NETL Hydrogen and Water Analysis
  - NETL Unit Process Library and other LCA Resources, www.netl.doe.gov/LCA
- NETL will use the above models to develop packaged cradle-to-gate, gate-to-gate, and gate-to-grave unit process models to create GHG emission profiles for the applicable material and energy reference flows (technosphere flows of interest). The aggregated emission scalers will then be combined with scenario output data provided by ORS to determine the annual or 5 year time period GHG inventory data. End use emission factors will be applied to represent each economic sector's weighted average use of the delivered energy. The inventory data for each scenario will then be used to calculate the GWP and SCC results for each scenario.
- NETL will estimate model sensitivity to expected future technological change in the natural gas system.

Step 6 – Create a "emissions consequential adder" based on the technospere flow data from GCAM, NETL LCA data (and GCAM emissions data for data not replaced with NETL emission factors). This will improve consistency for "adding" the consequential adder to the NETL attributional LCA model for LNG exports (Task 3.2 in the NETL scope of work).

Step 7 –Documentation and reporting of LCA Results; scope excerpts related to this step:

- NETL will use existing life cycle modeling resources for energy supply and consumption (use) emission factors to estimate GHG intensity changes across modeled scenarios.
- The outcome of the consequential informed life cycle GHG results will report the change in terms of Global Warming Potential (GWP) based on the most recent Intergovernmental Panel on Climate Change report (the Sixth Assessment Report) for 20 and 100 year time frames for each scenario. The results will also be reported in terms of social cost of carbon (SCC) based on the most current U.S. guidance provided by ORS to NETL.
- NETL will provide a written report documenting the comparative findings of the LCA results for ORS use in developing the broader project level report. LCA results for all scenarios will be provided in Microsoft Excel.
- Methods/approach, data sources, and data limitations will be included in the written report along with a discussion of the study results.

- Methods/approach, data sources, and data limitations will be included in the written report along with a discussion of the study results.
- NETL will estimate model sensitivity to expected future technological change in the natural gas system.
- Uncertainty modeling is not included in this effort.
- The outcomes of the consequential LCA will be: (1) estimated unit life cycle emissions factor associated with major supply-to-consumption pathways expected from LNG imports, exports, and re-exports; (2) average total life cycle emissions associated with the range of global economic, policy, and security postures represented by the equilibrium models; and (3) improved empirical basis for emissions driven by the inclusion of the modeling of upstream processes involved in supplying, transporting, and consuming LNG.

Let me know if this helpful or adds confusion to the discussion.

Respectfully,

Tim Skone

Preliminary Review of Market Consequences in Terms of Changes in Global Energy Consumption per unit of US LNG Exports for Scenario 2, Year 2050

From: Matthews, Howard Scott (CONTR)
Sent: Wed, 23 Aug 2023 20:52:48 +0000
To: Jamieson, Matthew B.; Skone, Timothy
Cc: Priyadarshini; Whiston, Michael M (NETL)
Subject: Updated draft of LNG report (SA 02.021.003.002)
Attachments: lng_nems_gcam_08212023.docx

Tim and Matt:

As discussed earlier in the week, attached please find an updated draft of the LNG report, which is complete in terms of sections and conclusions. I know we lose both of you to some extent this week, and want to put it in front of you to get feedback. I wasn't sure that Tim could see NETL Sharepoint.

As Matt and I only agreed on the alignment method for the other industrial energy use sector yesterday, and it is core to all of the calculations, the report does not have all of the different results re-run, esp for the different IPCC methods. What is contained is largely the same values we looked at last week, to help with consistency and thoughts we had at the time (these were generally for AR5-100).

In the meantime, we pushed to get text, context, and synthesis done – the additional "results" arent going to be significantly different than the IPCC values contained in this document – there will just be more of them to show. I also borrowed Harsh for an hour to help get landed LNG numbers to Rotterdam to help with the contextual comparison of the adders to the NETL g CO2e/MJ results. I think it's a better discussion now, and helps with the questions Tom had on last week's call.

Of course any edits are welcomed, but please focus on the "takeaway messages". I tried to get in what we had discussed but don't assume I nailed it. Again, the numbers might change a little but at a high level, they're set (e.g., negative adders). Of course we are working to QA and update all of the numbers in the meantime, and will send along as soon as we have them.

One last thing – please advise on if/when/how we should be willing to share our text with others in FECM other than Tim (who are clamoring to see what we have). I defer to you on this.

Scott

H. Scott Matthews
NETL Support Contractor
Department of Energy National Energy Technology Laboratory
scott.matthews@netl.doe.gov

DRAFT-DELIBERATIVE-PREDECISIONAL

To: Matt Jamieson and Tim Skone
From: Scott Matthews, Michael Blackhurst, and Priyadarshini
Date: August 23, 2023
RE: Comparing the NETL Baseline Results and Framework with that of the Global Change Assessment Model (GCAM)

Note: this memo is now morphing into the imminently needed LCA section/chapter that will appear in the LNG report.

Some values in this memo are still using AR5-100 even though the intent is by default to use AR6. Edits added soon, but will of course not change much. Have been focused on the messaging that FECM and others need to see.

Recall that the current report outline has separate sections for methods and results. Have added "Results" subheaders for what of this text will be in which spot of the report.

1 INTRODUCTION

The goals of the LCA component of this project are twofold. First, to help contextualize how the other results of this study (i.e., NEMS and GCAM models) connect to past studies of US NG and LNG operations. Second, to leverage the results of the other models to quantitatively represent the global GWP consequences from changes in quantities of US exported LNG.

In support of the first goal, the LCA component of this project will:

- Assess whether NEMS results suggest significant changes in domestic supply (and thus, resulting in potential future upstream GWP intensity or emissions changes)
- Assess the level of difference between GCAM's representation of NG sector emissions vs. existing DOE/NETL studies
- Align GCAM and NETL results for consistent representation of the global natural gas supply chain

In support of the second goal, the LCA component of this project will:

- Develop a quantitative "market effect adjustment factor" that represents the consequences of additional export volumes of US LNG, such as how additional available quantities of natural gas led to changes in the energy sectors of countries that purchase the LNG and the country that exports the LNG. These consequential effects will be estimated by tracking differences in global GHG emissions and quantities of LNG exported from the GCAM model scenarios, and will be assessed in addition to the existing quantitative estimates of the upstream natural gas production
- Use speciated GHG emissions estimates from the GCAM model to estimate the social costs of carbon in the seven scenarios using methods developed by the White House and DOE

Past studies done by NETL on NG and LNG have largely been techno-economic analyses focused on expected costs per unit delivered (landed) or attributional life cycle analyses that only estimate the emissions and other impacts associated with units of NG/LNG delivered. These LCA studies are limited in that they 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, 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. In this study, these consequential effects will be estimated by tracking differences in global CO2 emissions and quantities of LNG exported from the GCAM model scenarios.

In this section, we detail 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 assess the differences in the two models at more detailed levels.

1.1 Past NETL Natural Gas Life Cycle Reports

As shown in the top half of Table 1, the NETL Natural Gas model (cite 2020 version here) is separated into five stages that generally align with categories used in other federal efforts such as the US EPA's GHGRP and GHGI products. Results of this model are provided for two scopes: Production through Transmission (e.g., for large scale industrial users, like power plants directly connected to a pipeline), and Production through Distribution (e.g., for residential or smaller industrial users where the gas is delivered through smaller distribution pipelines). Results are provided for various techno-basins of production, regions, and US average production, using a variety of IPCC Assessment Report Global Warming Potential (GWP) values.

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 1. The data for these unit processes are based on peer-reviewed industry data representative of 2017 technology.

Commented [SM1]: Let's also verify year/etc basis of this data (2017?). also can you grab those and paste in below? We can ask Harsh to verify if needed.

Commented [P2R1]: I think its 2020?

Commented [SM3R1]: The year of the study is 2020, but the data is older. Not sure of year.

Table 1. 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 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 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

Commented [SM4]: Pri - can you grab these and paste in?

Commented [PSR4]: Is this what you were referring to in the comment at the first line of this section?

Destination Transmission / Distribution	Similar processes as described above, and not functionally different than as described for the natural gas only part.

Quantitatively, NETL[a] has estimated ranges of greenhouse gas emissions by species, and by stage, for the domestic natural gas supply chain as shown in Figure 1. Given the scope of domestic natural gas production through the transmission stage, the mean US average total CO2-equivalent emissions are about 7.44 g CO2e/MJ (IPCC AR6, 100-year basis), with a confidence interval of the mean of 4.6-11.1 g CO2e/MJ. While not shown here, 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 US average.

[a] (Natural Gas Extraction and Power Generation: U.S. 2020 Emissions Profile[2]) – be sure to cite specific Appendix E file?

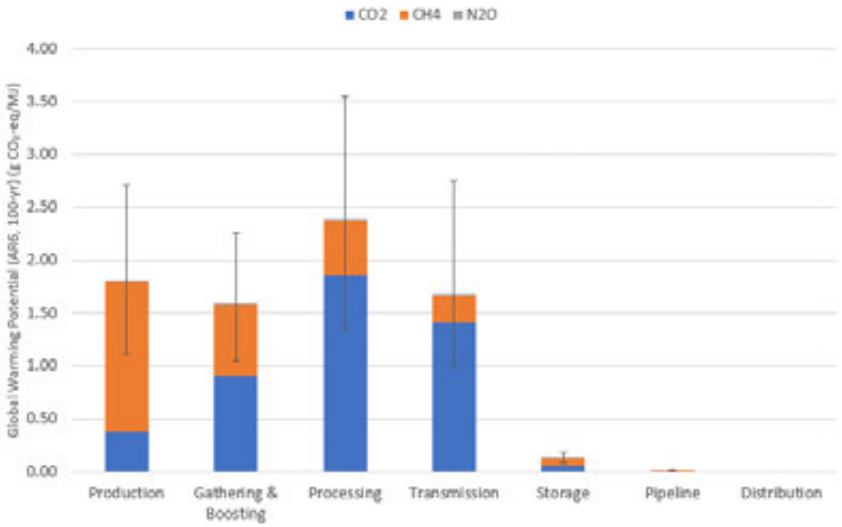


Figure 1. Life cycle GHG emissions from the 2020 U.S. average NG supply chain (Source: NETL 2023)

Past work by NETL has also estimated the greenhouse gas emissions implications of the additional stages to produce and deliver US average LNG around the world. 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 CO2e/MJ delivered (IPCC AR6, 100-year basis). In short, the additional processes and natural gas needed to liquefy, ship, and regasify natural gas to Rotterdam adds about 10 g CO2e/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 CO2e/MJ, given above). The GHG emissions intensity result on a per MJ NG delivered to liquefaction plant basis is 7.44 g CO2e/MJ (AR6, 100-yr) 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 CO2e/MJ NG

(AR6, 100-yr) delivered to power plant. 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.[b]

The NETL natural gas model and the LNG report are attributional studies of the domestic natural gas system. The results seek only to identify and attribute the emissions associated with various unit processes that create them. These methods do not seek to more broadly consider the consequences of what happens when additional volumes of US natural gas is produced and delivered across the world, or, in other words, the market-based effects of producing domestic natural gas and exporting it.

In this project, the NEMS and GCAM models seek to represent economic and environmental changes associated with the defined changes in US LNG exports. The GCAM model explicitly estimates global GHG emissions effects, separated by region. Thus, an initial area of exploration of this study was to compare the upstream natural gas GWP impacts as represented in the GCAM model, which has similar but different data sources (compared to NETL). To maintain consistency with past NETL work used by DOE in support of natural gas and LNG export decisions, GCAM emissions results can be assessed and quantitatively adjusted to rationalize the emissions estimates of the two models.

[b] Results from 2019 LNG report (cite!), Exhibit A-2, adjusted from g CO2e/MWh to g CO2e/MJ using heat rate of 145 kg natural gas/MWh, and higher heating value of 54.3 MJ/kg.

2 MODEL COMPARISONS

2.1 NEMS V/S NETL

The NEMS modeling done in this project focused on domestic changes that would be expected to occur in the seven Scenarios modeled. The NEMS chapter of the report has already detailed its high-level results. Not previously shown, but of interest to the LCA section of the project, was whether the regional extraction mix of natural gas would be expected to change over time. This is relevant since 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 this GHG intensity would be something to consider in the results.

Results

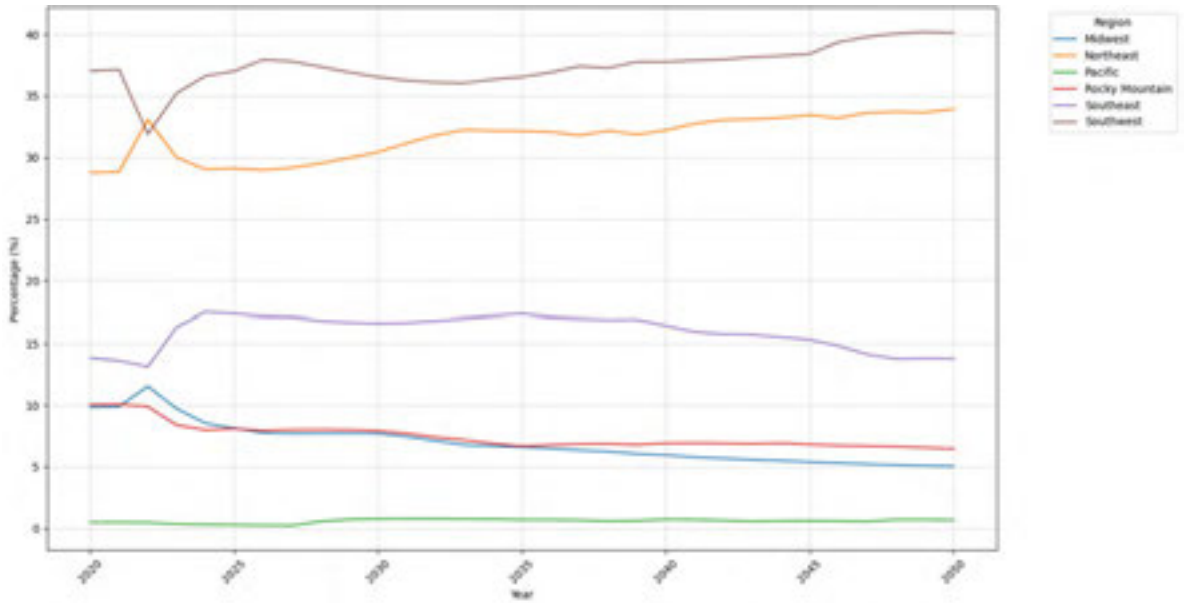


Figure 2. Dry Production percentage time-series for each region

Using data generated by the NEMS modeling results, Figure 2 shows the percent of natural gas dry production for each region of Scenario 1 as compared to total production in a specific year between 2020 to 2050. A state-based natural gas dry production (excluding the extraction losses) rate in a million cubic feet was taken from this data and every state was assigned to one of the six regions (Midwest, Northeast, Pacific, Rocky Mountain, Southeast, Southwest). Further aggregation of the production rates is performed to get values for every unique region. The same process was done for the other Scenarios.

The region-specific production data between 2020 to 2050 is used to calculate the percentage production within a region based on the total production across the US for a given year. Regional GWPs for 2020 from the 2020 NETL model were multiplied with the region-specific yearly production rates to estimate US weighted-average annual GWPs between 2020 through 2050. Figure 3 shows

these values for all Scenarios. A limitation of this analysis is that GWP values by region were only available for the year 2020, as such the results should be interpreted as an index as compared to the estimated 2020 values as opposed to predictions of future GWP.

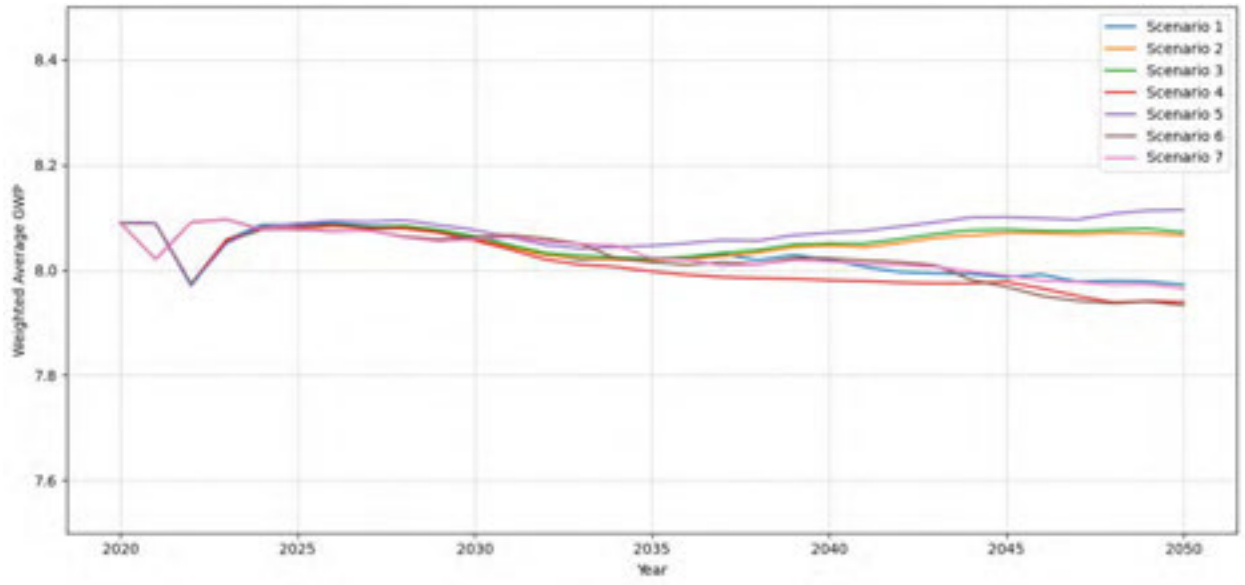


Figure 3. Estimated US Average GWP (Scenarios 1 to 7), Production through Transmission (2020 - 2050)

Overall, Figure 3 suggests that the expected changes in domestic production by region across the seven Scenarios are not expected to have a significant effect on the expected GWP intensity of domestic production (given the 2020 data on GWP by region).

2.2 Comparison of GCAM and NETL estimates of GHG emissions of the natural gas sector

In the GCAM model, economic activity (and its GHG emissions) is 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 are relevant to the scope of this LCA-focused effort (i.e., with a focus on the natural gas sector).

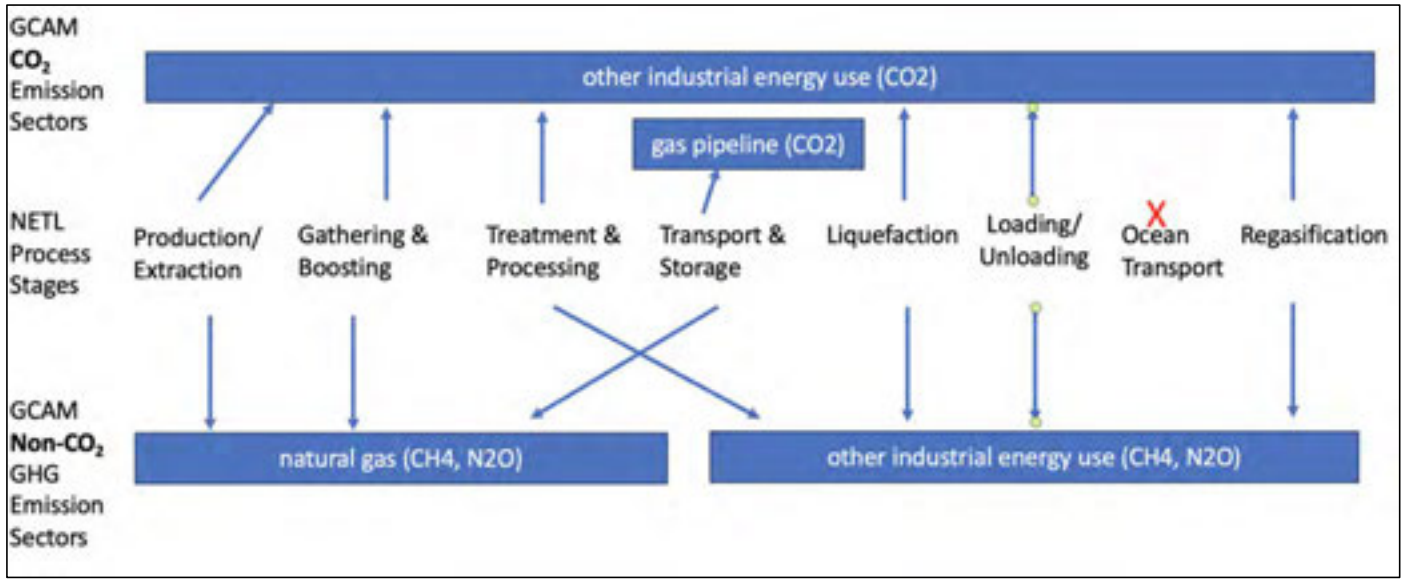
Detailed investigation and discussion with the GCAM team during this project identified that only three sectors in the GCAM model encompass the greenhouse gas emissions of the natural gas sector - *natural gas, gas pipeline*, and *other industrial energy use* (see Appendix for more detail). Using the basis of process stages as represented in the NETL Natural Gas model, Figure 4 shows the relevant GCAM sectors that represent 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 are available.

In short, all stages are explicitly represented in GCAM except for Ocean Transport. These (relatively small, in global terms) emissions should also be contained within GCAM's "other industrial energy use" sector. However, due to data limitations, it was deemed not possible to explicitly extract these emissions from that sector. GCAM results will not explicitly represent LNG transport via ocean, and as such our comparisons will focus on production of natural gas domestically rather than LNG delivered around the world. This is a limitation of this comparative analysis.

Commented [P6]: Is there a specific number of sector-technology pairs?

Commented [SM7R6]: On second thought I dont think we need to specify the NN pairs in the model, we will just worry about the ones we need to.

Figure 4: Mapping of NETL Natural Gas Stages to GCAM Sectors (can discuss a better graphic)



Results

(note, are updating the table below based on various things, but wanted to maintain the values we had been using in past discussions to ensure previous messaging discussions were still valid. Intent though will be to have AR6 values shown)

Table 2 shows the emissions intensities of the various GCAM sectors for the *USA* region for the three natural gas-relevant sectors identified above. Note that the *gas pipeline* and *natural gas* sectors are assumed to wholly incorporate natural gas-relevant emissions, and so total emissions are shown, as 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 GDP of each region, making it relatively difficult to explicitly identify emissions related to natural gas. As further detailed in the Appendix, 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. 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 is excluded from the analysis, consistent with the focus on upstream natural gas effects.

The emissions intensity cells in Table 2 show the underlying equation used to generate values, where the numerator is the total emissions from the GCAM model for the USA region for Scenario 1 for the year 2020 for each of the three greenhouse gases (if available), normalized by the total production of US natural gas from the GCAM model in 2020 (33.13 EJ). 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 2 show comparisons to those of the NETL model.

Table 2: GCAM Emissions Intensities for Sectors (S1, 2020, USA region)

			Estimated GCAM Emissions Intensity (Tg CO_2e / EJ, g CO_2e / MJ) [IPCC AR5 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.	38.2/33.1 = 1.15	-	-

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.	-	171.4/33.1 = 5.17	.016/33.1 = 4.8 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.	81.3/33.1 = 2.46	.04/ 33.1 = .001	xx
other industrial energy use (technology = refined liquids and refined liquids cogen)[a]		For technology = refined liquids or refined liquids cogen, GHG emissions are allocated to the natural gas and crude oil products on an energy (EJ) produced basis from GCAM output data. 2015 crude oil – 24.7 EJ, natural gas 26.2 (50%) 2020 – 22.5, 33.1 (NG is 60%)	16.3/33.1 = 0.5 50% = 0.25 60% = 0.3	.4 / 33.1 = .01	xx
other industrial energy use (electricity)[a]			-	-	-
Total GCAM by gas (including <u>only 50% gas shares of *other ind* above</u>)			**= 1.15 + 2.46 + .5 = 4.23**	**5.17 + .0005 + .005 = 5.18**	4.8 E-4
Total GCAM (including <u>only 50% gas shares of *other ind* above</u>)			**9.41**		

Subtotal from NETL Model, Processing through Transmission boundary	**7.58**

Overall, on an IPCC AR5 100-year basis, the best guess of upstream emissions in the GCAM model are about 9.41 g CO2e/MJ, which are slightly higher than those of the NETL model for the boundary of production through transmission to large end user (7.58 g CO2e/MJ). Given the use of similar data sources throughout the GCAM model, emissions in the natural gas sector should be adjusted by a factor of 9.41/7.58, or 0.8 (a 20% reduction) to maintain consistency with past NETL work, so this alignment factor is used for all regions and for all years in the model. As implemented, this adjustment factor of 0.8 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.

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 associated with only natural gas emissions 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, it avoids the outcome where the 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). For context, in the provided GCAM results for Scenario 1 in Year 2020, total global GHG emissions are approximately 53,000 Tg. The post-processing of the GCAM model results of the *gas pipeline* and *natural gas* sectors reduces emissions by about -30 and -200 Tg CO_2e, respectively, when considering those of Scenario 1 in the Year 2020. Post-processing adjustments of the GCAM model results of the *other industrial energy use* sector reduces emissions by about -100 Tg CO_2e when considering those of Scenario 1 in the Year 2020. Overall, the adjustments for these three sectors have the equivalent effect of reducing emissions in the GCAM model by about 0.6% (in Scenario 1 in the Year 2020).

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

Not finished yet: Effects of future methane mitigation in GCAM and other needed alignment….

2.2.1 Market Adjustment Factors

In order to quantify the broad and global market effects associated with increasing exports of US LNG, a method was proposed to use the adjusted GCAM results to estimate the change in global GHG emissions per unit of LNG exported between various scenarios. This market adjustment factor (MAF) is defined as:

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

and represents a ratio of the change in GHG emissions for a given scenario compared to a base scenario, versus the change in US LNG exports between the same two scenarios. For example, a comparison of Scenario 2 vs. Scenario 1 would have n=2, and compare the differences in GCAM values for these two scenarios. This MAF can be calculated for every model year (2015-2050), and can use linearly interpolated values for the non-model years.

MAFs for Scenarios 2-5 can all be found versus a baseline of Scenario 1, although Scenarios 3-5 represent significantly different global economic outcomes and should be interpret more cautiously. Similarly, the MAF for Scenario 7 was deemed most relevant to be compared against Scenario 6.

Results

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. MAFs were calculated using the post-processed NETL-adjusted GCAM results described previously. A particular Scenario MAF is calculated for every year 2015-2050 (including the linearly interpolated non-model year results), but is summarized by only the aggregate values over the time horizon of the model (i.e., the MAF for S2 versus S1 uses as inputs to the equation 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 period). Results were created for various IPCC GWP values.

Currently included are those for IPCC's 5th Assessment Report, for 100-year time horizons, including the effects of climate carbon feedback (see Appendix for GWP values used). *Only IPCC AR5-100 are shown here at this point (QA'ing and checking the others)*. The Appendix shows the annual summaries of GHG emissions, LNG export volumes, and deltas compared to baselines for each underlying year of GCAM model runs. Given the many different aspects of the global economy modeled in the various project Scenarios, results are carefully distinguishes into separate tables.

Figure 5 shows the market adjustment factors for Scenario 2 (vs. Scenario 1), which vary from -5.9 to XX on a 100-year time horizon and from XX to XX on a 20-year time horizon. Also included is a summary reminder of the differences in the modeled scenarios (e.g., where S1 is the baseline and S2 modestly adds an economic solution for LNG exports, making a direct comparison of the two appropriate).

Figure 5: Market Adjustment Factors for Scenario 2 vs. Scenario 1 Using Various GWP Values from IPCC

	Results (g CO_2e/ MJ)				
MAF Case	**AR5, 100 with ccf**	**AR5, 20**	**AR6-100**	**AR6-20**	**Scenario Difference**
Scenario 2 vs. Scenario 1 (S2-S1)	-5.9	xx	xx	xx	Adds economic solution for LNG exports.

Figure 6 shows the market adjustment factors for Scenarios 3-5 (vs. Scenario 1). Also included is a summary of the differences in the modeled scenarios (where S1 is again the baseline). As noted above, Scenarios 3-5 represent additional and substantial packages of assumptions as compared to S2, and as a result should not be directly compared to the MAF for S2 or S7 (and MAFs for S3 through S5 should be carefully compared to each other). Nonetheless, the results of these three MAFs represent relative bounds on the MAFs across a wide range of economic assumptions such as inexpensive renewable energy and high global population growth.

The MAFs for Scenario 3 vary from 231 to XX on a 100-year time horizon and from XX to XX on a 20-year time horizon. The MAFs for Scenario 4 vary from -0.4 to XX on a 100-year time horizon and from XX to XX on a 20-year time horizon. The MAFs for Scenario 5 vary from -38 to XX on a 100-year time horizon and from XX to XX on a 20-year time horizon.

Figure 6: Market Adjustment Factors for Scenarios 3-5 vs. Scenario 1 Using Various GWP Values from IPCC

	Results (g CO_2e/ MJ)				
MAF Case	**AR5, 100 with ccf**	**AR5, 20**	**AR6-100**	**AR6-20**	**Scenario Difference**
Scenario 3 vs. Scenario 1 (S3-S1)	231	xx	xx	xx	Adds economic solution for LNG exports, also higher assumed population growth outside of the U.S.
Scenario 4 vs. Scenario 1 (S4-S1)	-0.4	xx	xx	xx	Adds economic solution for LNG exports, but constraints on importing and exporting natural gas with a global focus to maximize use of domestic gas.
Scenario 5 vs. Scenario 1 (S5-S1)	-38	xx	xx	xx	Adds economic solution for LNG exports, but lower capital costs for renewable energy technologies.

Figure 7 shows the market adjustment factors for Scenario 7 (vs. Scenario 6), both of which represent significantly different energy and economic investments in support of a low-carbon global economy through climate policies. The Scenario 7 MFAs vary from -3.5 to XX on a 100-year time horizon and from XX to XX on a 20-year time horizon.

Figure 7: Market Adjustment Factors for Scenario 7 vs. Scenario 6 Using Various GWP Values from IPCC

	Results (g CO_2e/ MJ)				
MAF Case	**AR5, 100 with ccf**	**AR5, 20**	**AR6-100**	**AR6-20**	**Scenario Difference**

Scenario 7 vs. Scenario 6 (S7-S6)	-3.5	xx	xx	xx	S6 1.5°C pathway, economic solution for LNG exports

2.2.2 Interpretation of Market Adjustment Factor Results

On an IPCC AR6 100-year basis, for S2-S1, the MAF result is approximately -6 g CO2e/MJ, or put another way, would almost fully compensate for the +7.4 g CO_2e/MJ upstream natural gas production values estimated by the NETL NG model. For S7-S6, the MAF result is slightly lower (about -3.5 g CO_2e/MJ), but would reduce the domestic upstream NG GWP impacts by about 50%.

Considering the broader life cycle perspective of natural gas delivered to other parts of the world as LNG, and considering the 17.9 g CO_2e/MJ for LNG from New Orleans to Rotterdam described earlier, the market adjustment factors for S2-S1 would reduce the GWP impact of that delivered LNG by about one-third. Using the MAF for S7-S6 would reduce the GWP impact by about one-fifth.

Following the broader conclusions already suggested by the GCAM section of the report on the GHG effects of the various scenarios, the market adjustment factors estimated by this project, using the adjusted GCAM simulation results, suggest that the consequences of increasing US LNG exports broadly lead to decarbonization in the global economy.

These results are important as modeled, but also should be presented with various caveats:

- The GCAM simulations represent broad modeling of the global economy, and despite tremendous sectoral detail, can not represent all technologies, or fully encapsulate all activities or market effects
- The results are aggregate in relation to estimated future volumes of exported LNG from the US 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 gas sources would directly lead to lower GHG emissions results when supplied around the world.

2.2.3 Social Cost of Carbon

Following previous DOE and NETL studies, the speciated emissions of CO_2, CH_4, and N_2O from each Scenario were estimated as Social Costs of Carbon (SCC) using the spreadsheet-based DOE NEPA Social Cost Estimating Tool. This tool estimates annual and cumulative social costs of emissions of each gas in future years using discount rates of 2.5, 3, and 5 percent.

Adjusted global GCAM emissions from 2020 (the first year able to be modeled in the tool) through 2050 are used as inputs. Unlike other GHG results shown above which vary based on use of IPCC GWP factors, the tool provides just a single set of social cost estimates. The Appendix shows the underlying annual and cumulative social costs from each scenario. Table X shows the cumulative present values of SCC (in millions of dollars)

Table 3: Summary of Social Cost Estimates for the Adjusted GCAM Scenarios

Scenario	SC-CO2			SC-CH4			SC-N2O			SC-Total		
	5%	3%	2.5%	5%	3%	2.5%	5%	3%	2.5%	5%	3%	2.5%
1	$xx											
2												
3												
4												
5												
6												
7												

Considered together, these social cost estimates show the dramatic reductions in social costs that occur in Scenarios 6 and 7 compared to the other scenarios, given their focus on meeting the 1.5 degree C targets and investments in renewable energy around the world. Scenarios 1-5 have similar and higher social costs as compared to Scenarios 6 and 7.

Do we want line graphs? One for each discount rate for all 7 scenarios?

Scroll down to see Appendix (also still in progress).

Appendix to LCA section (not very well organized yet, mostly stuff pasted here)

NEMS GWP Analysis

The code used for this analysis can be mathematically represented as a series of summations, percentage calculations, and weighted averages.

1. **Filtering Columns:**

$$\boldsymbol{actual_years} = \{\boldsymbol{column} \mid \boldsymbol{column} \notin \{\boldsymbol{Region}', '\boldsymbol{state}', '\boldsymbol{State}'\}\}$$

2. **Calculate the Yearly Totals Across All Regions:**

   Let D be the dataset (or matrix) of all data. For each year y in actual_years:

$$\boldsymbol{yearly_totals}[\boldsymbol{y}] = \sum_{i=1}^{n} D_{i,y}$$

   Where n is the number of regions.

3. **Calculate the Percentage for Each Region Compared to the Yearly Total:**

   For each year y in actual_years and for each region r

$$\boldsymbol{percentage_df_{r,y}} = \left(\frac{\boldsymbol{D_{r,y}}}{\boldsymbol{yearly_totals_{[y]}}}\right) \times \mathbf{100}$$

4. **Transform Data to Long Format:** This step reshapes the dataset, converting it from wide format to long format. It's a structural transformation, not a mathematical operation.

5. **Weighted Average Calculation:** For each year y in $actual_years$:

$$weighted_{averages[y]} = \sum_{i=1}^{n} \left(GWP_{i,2020} \times \frac{percentage_df_{i,y}}{100}\right)$$

Where $GWP_{i,2020}$ is the GWP value for region i in the year 2020.

3 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 are relevant to this analysis (i.e., with a focus on the natural gas sector).

We used R code explicitly developed for this project to process the CSV file results provided by PNNL for the various Scenarios (1-7 and years modeled. Specifically, we were provided data files described in Table 4.

Commented [P8]: Is there a specific number of sector-technology pairs?

Commented [SM9R8]: On second thought I dont think we need to specify the NN pairs in the model, we will just worry about the ones we need to.

Table 4. 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 ($MtCO_2/yr$) for various sectors, energy sources or "technology" for 6 different scenarios across each of 37 regions.
co2_seq_tech_2023.06.22	Provides data showing CO_2 emissions in megatons per year ($MtCO_2/yr$) 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, 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.
luc_em_2023.06.22	contains information about CO2 emissions (in million metric tons per year) for different regions and years.
Columns	**Description**
scenario	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 CO2 emissions values are provided, this ranges from 2015 to 2050.
value	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 CO2 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., HFC125, HFC134a, HFC143a, HFC23, HFC32, SF6, HFC245fa, HFC365mfc, 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).

Amongst many data sources used in GCAM relevant to the natural gas and LNG, two are of importance – IEA data on energy and GHG emissions flows and the Community Emissions Data System (CEDS). We were provided detailed information on how the sectors of the NETL natural gas model may best align with those in the GCAM model, as in the table below.

Table XX

LCA stage	**IEA energy flow**	**GCAM sector – energy & CO_2**	**CEDS sector**	**GCAM sector – nonCO_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

Initially, to aid in identifying supply connections in the model, our team scripted separate R code to perform a "backward trace" of outputs of interest to see the inputs from sector-technology "pairs" and connect them throughout the upstream supply chain. The focus was on exemplar of pairs relevant to this analysis. In producing **Error! Reference source not found.**, a trace was run on the "delivered gas" output – the name of the output of natural gas that is ready to be used by large-scale customers such as power plants. Connected outputs and inputs can be seen in alternating rows (the blue arrow demonstrates the first such connection).

As shown in Table 5, our analysis uncovered the input-output pairs for each sector which is used to generate the emission values by dividing the GCAM output values with the total gCO2 equivalent for each sector. For comparability purposes, this value is further scaled based on scaling factors for both input and output to then generate the "scaled" emissions in gCO2e/MJ of output.

However, subsequent analysis has suggested that the trace algorithm is insufficient in tracking the entire upstream supply chain of activities, as there are various GCAM sectors that support natural gas activity but that are disconnected from the supply chain that is identified using the described algorithm. Nonetheless, the backwards trace example is maintained here to help to explain upstream supply chain connections in GCAM. Additional sectors from GCAM have been added at the bottom of Table 3 to account for these activities.

In the final columns of Table 3 are the global and US-only estimated GCAM emissions associated with natural gas for Scenario 1 for the Year 2020. (Note these are still using the mid-June values but are not expected to significantly differ in the final report).

Table 5. Traced GCAM CO2 and non-CO2 emissions for each sector and corresponding technology (Scenario 1, Year 2020, mid June results)

					Global GHG Emissions		**US GHG Emissions**	
Sector	**Technology**	**Input**	**Output**	**Description**	**CO_2 (Tg)**	**Non-CO2**	**CO_2 (Tg)**	**Non-CO2**

						(Tg)		(Tg)
Pairs from trace of NG sector								
Delivered gas	Delivered gas	Gas pipeline	Delivered gas	Seems to only be a market exchange sector	0	0	0	0
Gas pipeline	Gas pipeline	Gas processing	Gas pipeline	PNNL confirms this to be the expected pair, but IEA data may be spotty	186.2	0	38.2	0
Gas processing	Natural gas	Regional natural gas	Gas processing	We assume this is intended to be comparable to gas processing in NETL model, but e-mail discussions with PNNL have indicated their scope is not as comprehensive as ours.	0	0	0	0
Regional natural gas	Domestic natural gas	Natural gas	Regional natural gas		0	0	0	0
Regional natural gas	Imported LNG	Traded LNG	Regional natural gas		0	0	0	0
Regional natural gas	Imported N American pipeline gas	Traded N. Amer	Regional natural gas		0	0	0	0

Commented [P10]: no more regional gas related sector (within scenario 1)

		pipeline gas						
Additional sectors separately identified as relevant								
Other industrial energy use	gas/gas cogen	N/A		Mentioned by PNNL as sector where emissions from extraction, G&B, processing, liquefaction, regasification would occur	255[c]	2.4	81.3	.03
Other industrial energy use	Refined liquids/refined liquids cogen				39[a]	5.7	16.3	.4
Natural gas	Natural gas			Identified by PNNL team	0	1164.2	0	171.5
Total (GCAM)					**480**	**1172**	**42.4**	**171.5**
Total (GHGI)							**36.5**	**185.3**

In terms of validation, the US values in Table 3 (which sum to 214 Tg CO2e) have been compared to the US EPA Greenhouse Gas Inventory (GHGI) for 2020. GHGI suggests that the total emissions of "Natural Gas Systems" are 36.5 Tg CO2 and 185.3 Tg of methane in CO2e (221.8 Tg CO2e total). Both the CO2 and non-CO2 values are within 10% of the EPA GHGI value. The total values differ only by about 5**%. Note however that the GHGI does not include CO2 emissions other than flaring in those of the "Natural**

[c] The values currently listed here are generated from allocations of energy use from the underlying IEA data – they will be replaced with direct estimates of GHG emissions when provided by PNNL. Total GHG emissions from GCAM in these two sector-technology pairs are 1514 and 731 Tg, respectively **and are NOT separated between oil and gas**. We do not expect significant differences when these are received.

Gas Systems" category – other non-flaring CO2 emissions from natural gas are in the broadly used "Fossil fuel combustion" category and can not easily be disaggregated.

In addition, the GCAM values can be normalized by the modeled final demands of natural gas produced in the US in S1/2020,

For appendix: In terms of comparing GCAM results of the natural gas sector with the NETL model, the emissions from appropriate total production value for a country is given by the output 'natural gas' from the sector-technology pair 'natural gas'. In 2020, the US total production in 'natural gas' is 33.13 EJ.

Old Mapping text

Given the information identified above, Table 4 demonstrates the intended correspondence of categories between the NETL NG model results and the GCAM model results.

Table 6. Potential Mapping of GCAM sector-technology pair with NETL stages

GCAM Sector	NETL LCA Stage	Comments/Potential mapping inaccuracy
delivered gas	NA	No CO2 or non-CO2 emission values for this GCAM sector (possible market exchange sector), therefore the mapping of this sector with the NETL stage isn't feasible.
gas processing	NA	No CO2 or non-CO2 emission values for this GCAM sector therefore the mapping of this sector with the NETL stage isn't feasible.
regional natural gas	NA	No CO2 or non-CO2 emission values for this GCAM sector therefore the mapping of this sector with the NETL stage isn't feasible. Also, "Region" in GCAM model stands for geopolitical region, which for the NETL stage was assumed as consisting

		of all the natural gas production through storage stages, since it considers the case of United States only.
gas pipeline	Transmission (Storage too?)	Have assumed this fully represents the Transmission sector equivalent to the NETL NG model.
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.
other industrial energy use (gas/gas cogen and liquids and liquids cogen)	WHAT HERE	WHAT HERE

Table 6 was the potential GCAM Sector mapping with NETL LCA Stages, prepared in order to analyze the relation between the two methodologies concerning natural gas processing, pipeline and distribution. The mapping is not accurate for reasons such as the geographical and technological context of data coverage and calculations within the two models/methodologies creates varying values (with vastly differing units) with do not perfectly align with one another in order to make a direct comparison, which was attempted in **Error! Reference source not found.**.

GWP Values used in this section (IPCC AR5, 100-yr with ccf)

1	CH4	36
2	CH4_AGR	36
3	CH4_AWB	36
4	N2O	298
5	N2O_AGR	298
6	N2O_AWB	298
7	HFC125	3691
8	HFC134a	1549
9	HFC143a	5508

10	HFC23	13856
11	HFC32	817
12	SF6	26087
13	HFC245fa	1032
14	HFC365mfc	966
15	C2F6	12340
16	CF4	7349
17	HFC43	164
18	HFC152a	167
19	HFC227ea	3860
20	HFC236fa	9810

S2-S1 – Detailed Background Data

	Scenario 1			Scenario 2				
year	global_lng	us_export_lng	global_co2_eq	global_lng_s2	us_export_lng_s2	global_tg_co2_eq	Δ_co2_eq	Δ _us_export_lng
2015	11.858	0.018	52488.031	11.858	0.018	52488.031	0.000	0.000
2016	13.753	0.538	53270.409	13.753	0.538	53270.409	0.000	0.000
2017	15.648	1.058	54052.788	15.648	1.058	54052.788	0.000	0.000
2018	17.543	1.578	54835.166	17.543	1.578	54835.166	0.000	0.000
2019	19.438	2.097	55617.545	19.438	2.097	55617.545	0.000	0.000
2020	21.333	2.617	56399.923	21.333	2.617	56399.923	0.000	0.000
2021	22.180	3.086	55750.013	22.180	3.086	55750.013	0.000	0.000
2022	23.027	3.555	55100.103	23.027	3.555	55100.103	0.000	0.000
2023	23.874	4.023	54450.193	23.874	4.023	54450.193	0.000	0.000
2024	24.722	4.492	53800.283	24.722	4.492	53800.283	0.000	0.000
2025	25.569	4.961	53150.373	25.569	4.961	53150.373	0.000	0.000
2026	26.428	5.372	53501.087	26.428	5.372	53501.087	0.000	0.000
2027	27.287	5.782	53851.802	27.287	5.782	53851.802	0.000	0.000
2028	28.147	6.193	54202.516	28.147	6.193	54202.516	0.000	0.000
2029	29.006	6.603	54553.230	29.006	6.603	54553.230	0.000	0.000
2030	29.865	7.014	54903.945	29.865	7.014	54903.945	0.000	0.000
2031	30.896	7.544	54924.381	30.811	7.462	54924.986	0.605	-0.082
2032	31.928	8.074	54944.818	31.756	7.910	54946.028	1.210	-0.164
2033	32.959	8.605	54965.254	32.702	8.358	54967.069	1.815	-0.246
2034	33.991	9.135	54985.691	33.648	8.806	54988.111	2.420	-0.328
2035	35.022	9.665	55006.127	34.594	9.254	55009.152	3.025	-0.411
2036	35.768	9.766	54910.372	35.911	9.996	54909.429	-0.943	0.230

2037	36.514	9.867	54814.616	37.229	10.738	54809.706	-4.910	0.871
2038	37.260	9.968	54718.861	38.546	11.481	54709.983	-8.877	1.513
2039	38.005	10.069	54623.105	39.864	12.223	54610.260	-12.845	2.154
2040	38.751	10.170	54527.350	41.182	12.965	54510.537	-16.812	2.795
2041	39.631	10.170	54466.246	42.361	13.561	54447.487	-18.760	3.391
2042	40.511	10.170	54405.143	43.540	14.157	54384.436	-20.707	3.987
2043	41.391	10.170	54344.040	44.719	14.753	54321.385	-22.655	4.583
2044	42.271	10.170	54282.937	45.898	15.350	54258.335	-24.602	5.180
2045	43.151	10.170	54221.834	47.077	15.946	54195.284	-26.550	5.776
2046	43.875	10.170	54100.302	47.928	16.271	54067.774	-32.528	6.101
2047	44.600	10.170	53978.770	48.779	16.597	53940.263	-38.507	6.427
2048	45.324	10.170	53857.239	49.629	16.922	53812.753	-44.486	6.752
2049	46.048	10.170	53735.707	50.480	17.248	53685.243	-50.464	7.078
2050	46.773	10.170	53614.176	51.331	17.573	53557.732	-56.443	7.403

S7-S6 – Detailed Background Data

	Scenario 6			Scenario 7				
year	global_lng	us_export_lng	global_co2_eq	global_lng_s2	us_export_lng_s2	global_tg_co2_eq	Δ_co2_eq	Δ _us_export_lng
2015	11.858	0.018	52488.032	11.858	0.018	52488.032	0.000	0.000
2016	13.753	0.538	53270.734	13.753	0.538	53270.734	0.000	0.000
2017	15.648	1.058	54053.436	15.648	1.058	54053.436	0.000	0.000
2018	17.543	1.578	54836.137	17.543	1.578	54836.137	0.000	0.000
2019	19.438	2.097	55618.839	19.438	2.097	55618.839	0.000	0.000
2020	21.333	2.617	56401.540	21.333	2.617	56401.540	0.000	0.000
2021	22.169	3.086	55465.461	22.169	3.086	55465.461	0.000	0.000
2022	23.005	3.555	54529.382	23.005	3.555	54529.382	0.000	0.000

2023	23.841	4.023	53593.303	23.841	4.023	53593.303	0.000	0.000
2024	24.677	4.492	52657.223	24.677	4.492	52657.223	0.000	0.000
2025	25.513	4.961	51721.144	25.513	4.961	51721.144	0.000	0.000
2026	25.931	5.067	51838.068	25.931	5.067	51838.068	0.000	0.000
2027	26.349	5.173	51954.992	26.349	5.173	51954.992	0.000	0.000
2028	26.766	5.278	52071.916	26.766	5.278	52071.916	0.000	0.000
2029	27.184	5.384	52188.840	27.184	5.384	52188.840	0.000	0.000
2030	27.602	5.490	52305.764	27.602	5.490	52305.764	0.000	0.000
2031	28.237	5.782	50941.678	28.237	5.782	50941.679	0.001	0.000
2032	28.871	6.075	49577.593	28.871	6.075	49577.595	0.002	0.000
2033	29.506	6.367	48213.507	29.506	6.367	48213.510	0.003	0.000
2034	30.141	6.659	46849.421	30.141	6.659	46849.425	0.004	0.000
2035	30.776	6.951	45485.335	30.776	6.951	45485.340	0.005	0.000
2036	31.740	7.481	44135.034	31.740	7.481	44135.038	0.004	0.000
2037	32.705	8.010	42784.733	32.705	8.010	42784.736	0.002	0.000
2038	33.669	8.539	41434.433	33.669	8.539	41434.434	0.001	0.000
2039	34.633	9.068	40084.132	34.633	9.068	40084.131	0.000	0.000
2040	35.598	9.597	38733.831	35.598	9.598	38733.829	-0.002	0.000
2041	36.181	9.712	37288.808	36.398	10.012	37287.814	-0.994	0.300
2042	36.764	9.827	35843.786	37.199	10.427	35841.799	-1.987	0.601
2043	37.347	9.941	34398.763	37.999	10.842	34395.784	-2.979	0.901
2044	37.930	10.056	32953.741	38.800	11.257	32949.769	-3.972	1.201
2045	38.513	10.170	31508.718	39.600	11.671	31503.754	-4.964	1.501
2046	38.673	10.170	30133.387	39.817	11.836	30127.643	-5.745	1.666
2047	38.833	10.170	28758.057	40.034	12.001	28751.532	-6.525	1.831
2048	38.992	10.170	27382.726	40.251	12.166	27375.421	-7.305	1.996
2049	39.152	10.170	26007.395	40.468	12.331	25999.310	-8.085	2.161
2050	39.312	10.170	24632.065	40.685	12.496	24623.199	-8.865	2.326

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To: Curry, Thomas; Sweeney, Amy
Cc: Iyer, Gokul; Scott Matthews; Jamieson, Matthew B.; Whitman, Peter C; Skone, Timothy
Subject: [EXTERNAL] RE: LNG Export Report
Attachments: DOE_FECM_LNG_Analysis_Report_FINAL_REVIEW_05Sep23.docx
Importance: High

DRAFT – DELIBERATIVE – PRE-DECISIONAL

Amy and Tom,

The combined team from PNNL, OnLocation, and NETL are pleased to submit the FINAL REVIEW DRAFT of the attached report "ENERGY, ECONOMIC, AND ENVIRONMENTAL ASSESSMENT OF U.S. LNG EXPORTS".

We look forward to successfully completing the FINAL Deliverable soon.

Best, Paco

Francisco De La Chesnaye | **Vice President**
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Subject: RE: LNG Export Report

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Great! Thanks all for your work over the weekend. We very much appreciate it.

Tom

From: Francisco De La Chesnaye <francisco.delachesnaye@onlocationinc.com>
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To: Curry, Thomas <thomas.curry@hq.doe.gov>
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Subject: [EXTERNAL] LNG Export Report

Tom,

We worked over the weekend to address all tenoning comments and complete the report. It is now going through a final technical edit review. We are planning to finish today by COB. I'll give you another status update later today.

Best, Paco

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

FINAL REVIEW DRAFT September 5, 2023

Prepared for:

Office of Resource Sustainability

U.S. DEPARTMENT OF ENERGY | Fossil Energy and Carbon Management

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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, served 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 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 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 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

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. domestic analysis** 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 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 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 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 GtCO2e and U.S. emissions range from 4.3-4.6 GtCO2e 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.

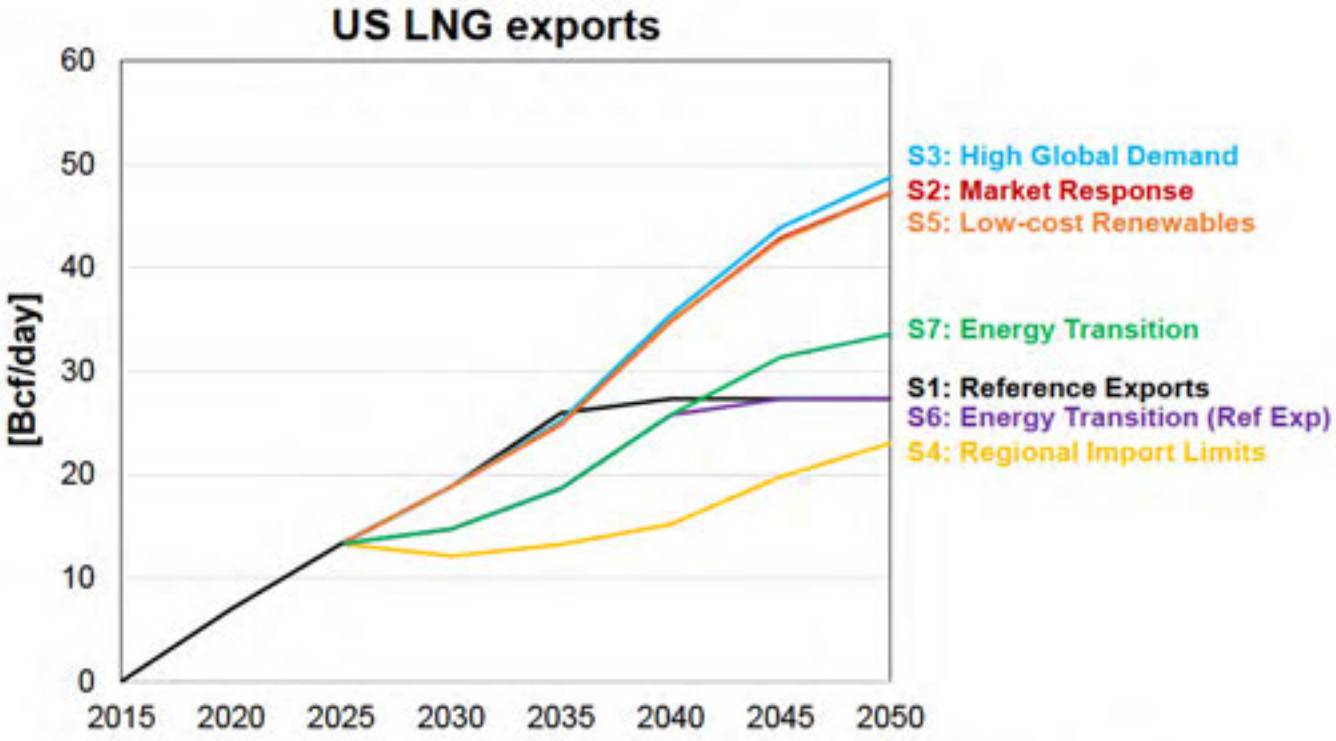


Figure ES-1. U.S. LNG exports across the scenarios explored in this study. Note that the U.S. LNG export outcomes for S2 and S5 were very close to each other.

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.

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
The Macroeconomic Impact of Increasing U.S. LNG Exports[4]	Baker Institute/ Oxford Economics	Baker 2018

[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
[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

Report Name	Organization	Short Name
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-sensitive industries was very small while increased investment raised GDP.

[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 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 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 were found using a global equilibrium model and were then inputted 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.

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

[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).

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 geo-political 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

[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.

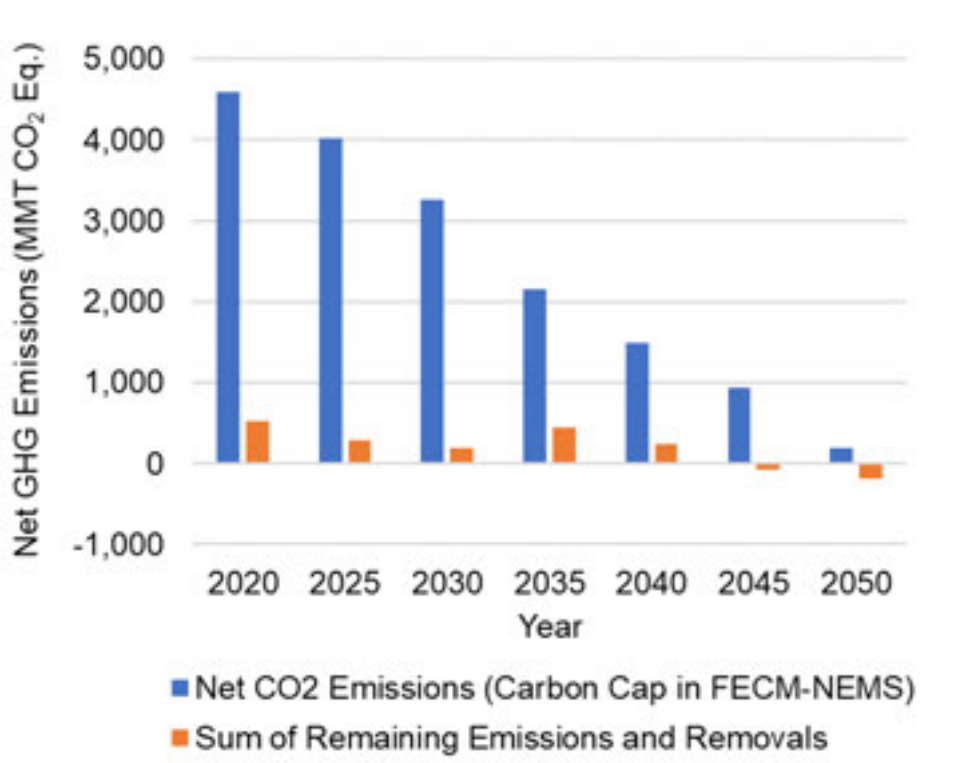


Figure 1. U.S. GHG emissions and removals in the net-zero scenarios

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 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.

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.

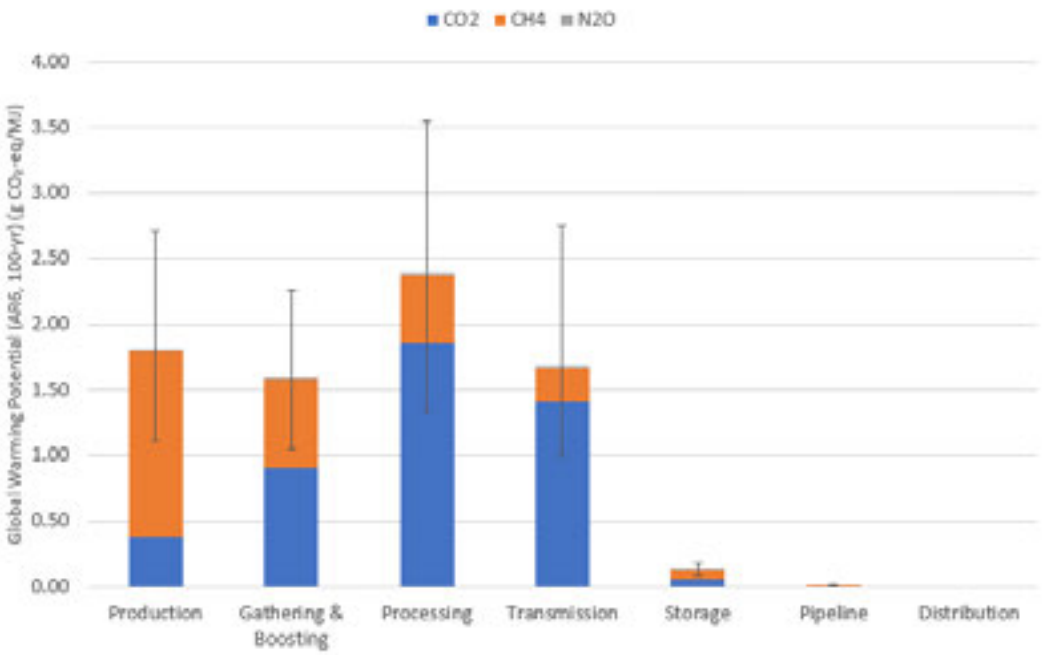


Figure 2. Life cycle GHG emissions from the 2020 U.S. average Natural Gas supply chain, HHV basis (Source: NETL 2023)

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 CO2e/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 CO2e/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 CO2e/MJ, HHV basis, given above). The GHG emissions intensity result on a per MJ NG delivered to liquefaction plant basis is 7.44 g CO2e/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 CO2e/MJ NG delivered 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]

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

[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 CO2e/MWh to g CO2e/MJ using heat rate of 145 kg natural gas/MWh, and higher heating value of 54.3 MJ/kg.

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:

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

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 *S*2 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.

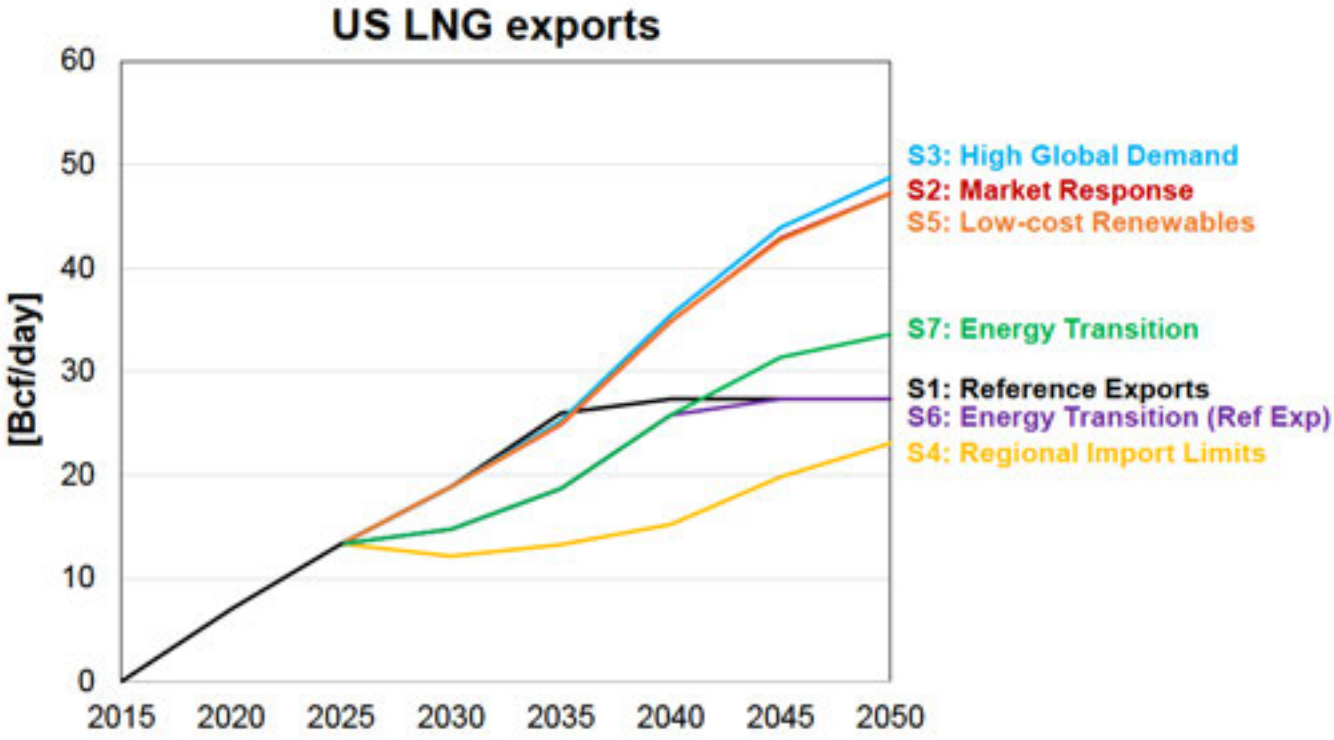


Figure 3. U.S. LNG exports across the scenarios. Note that the U.S. LNG export outcomes for S2 and S5 are very close to each other.

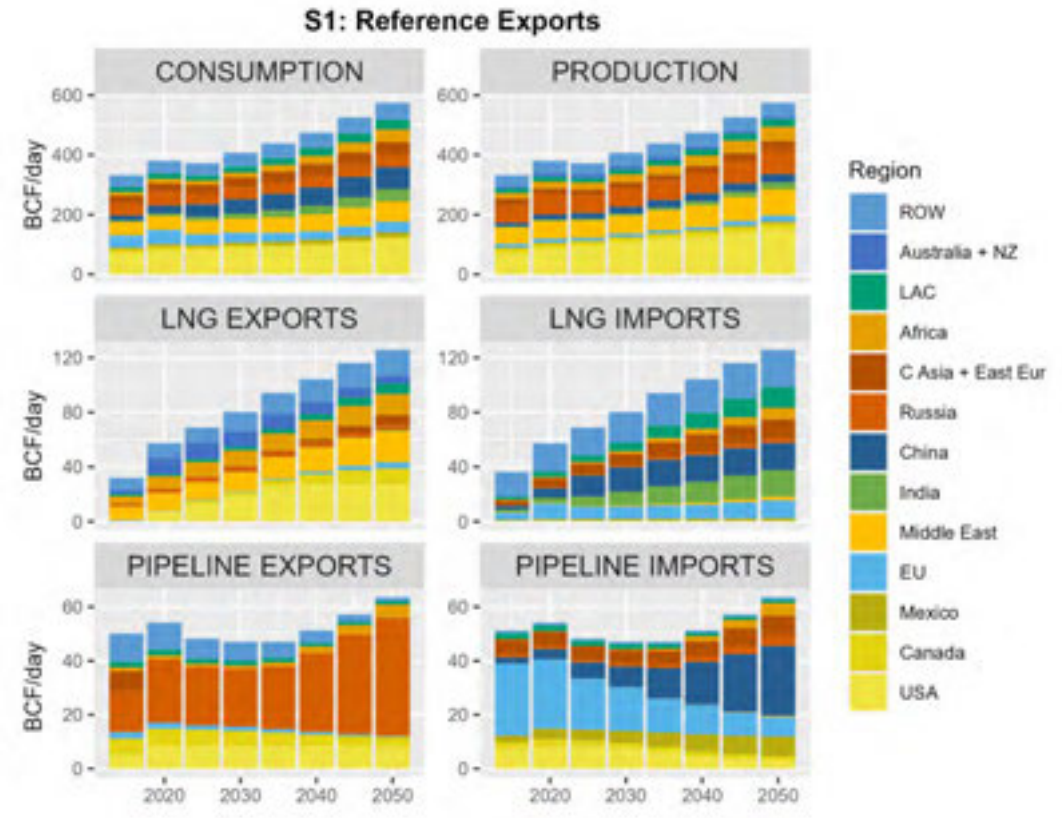
U.S. LNG exports under *S3*, the scenario with increased global population, increased to 49 Bcf/day in 2050, emerging as the upper bound. With higher population assumptions in *S3*, total energy demand – and consequently natural gas demand – outside the U.S. increased compared to *S2*, resulting in an 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).



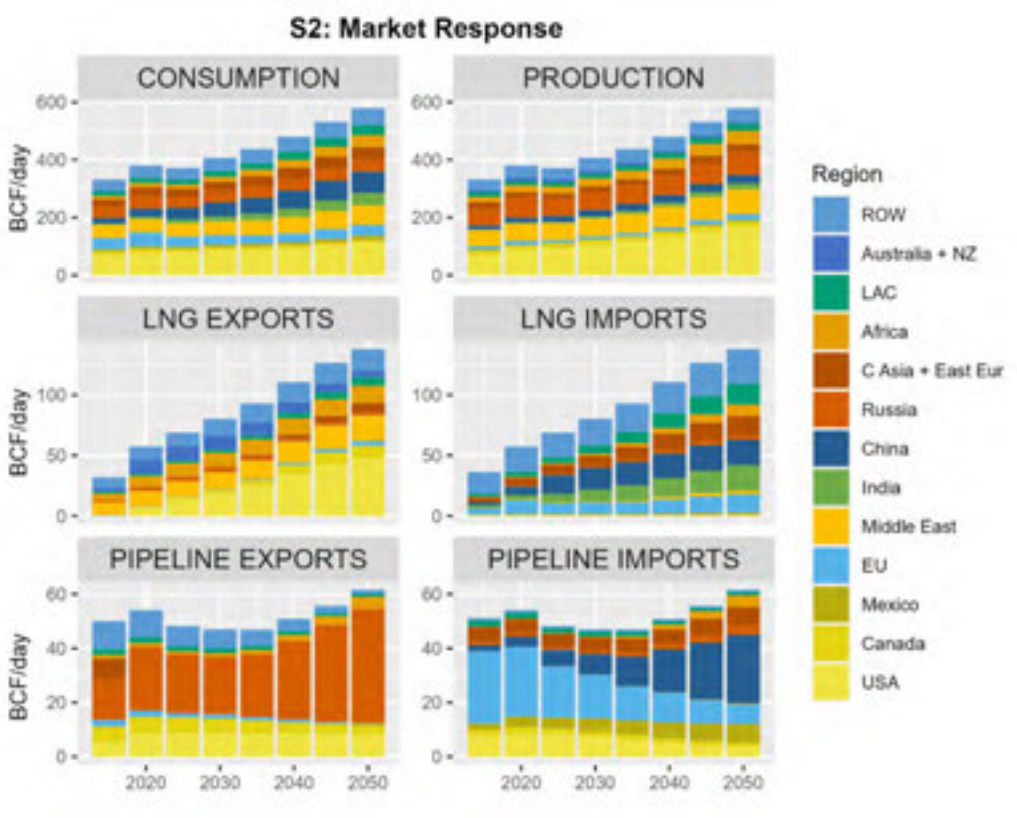


Figure 4 Natural gas consumption, production, and trade by region under S1 (upper) and S2 (lower).

As shown in

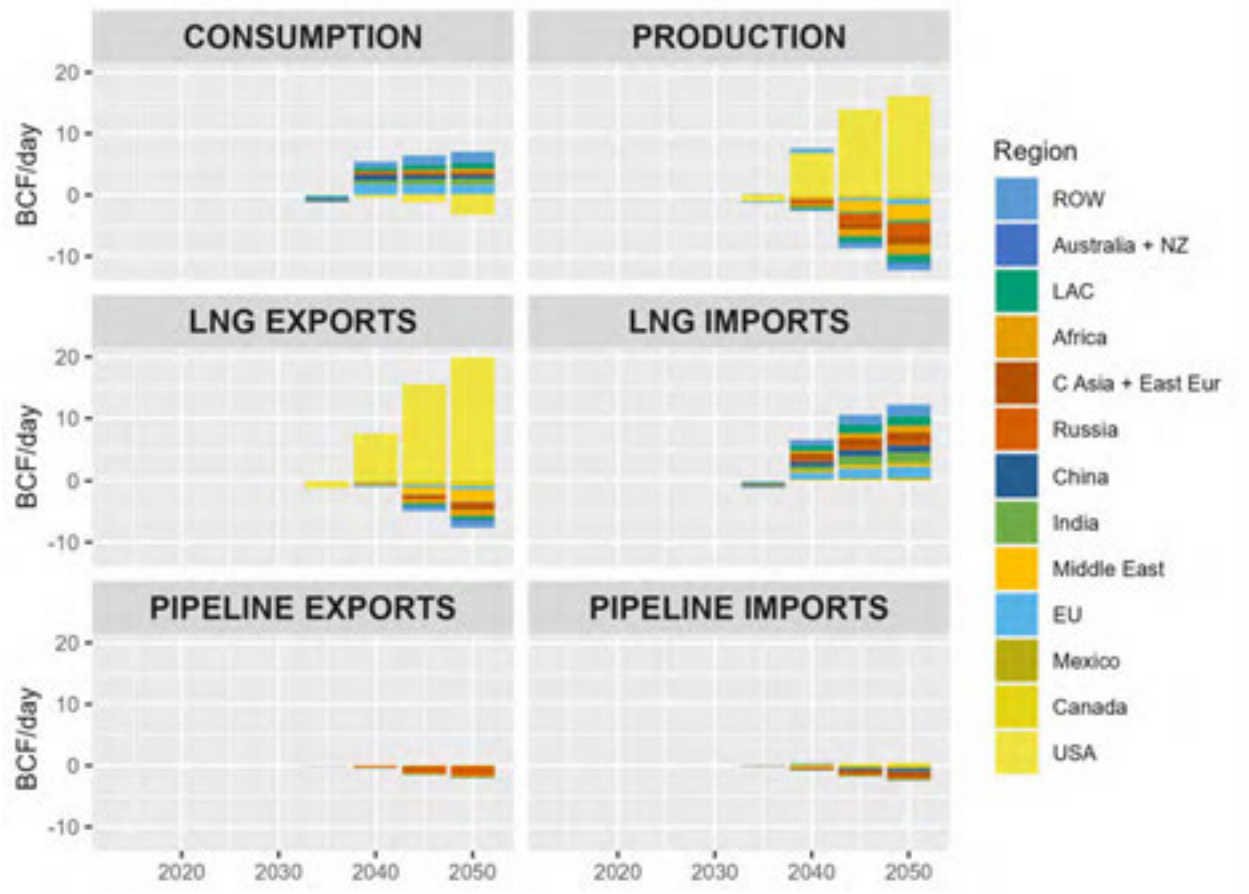


Figure 5, under S2*, in which U.S. LNG exports were determined by market equilibrium, U.S. natural gas production and LNG exports increased compared to* S1 *to satisfy the growing demands of natural gas globally. Under* S2*, U.S. LNG exports grew to ~47 Bcf/day by 2050. In this scenario, the availability 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*

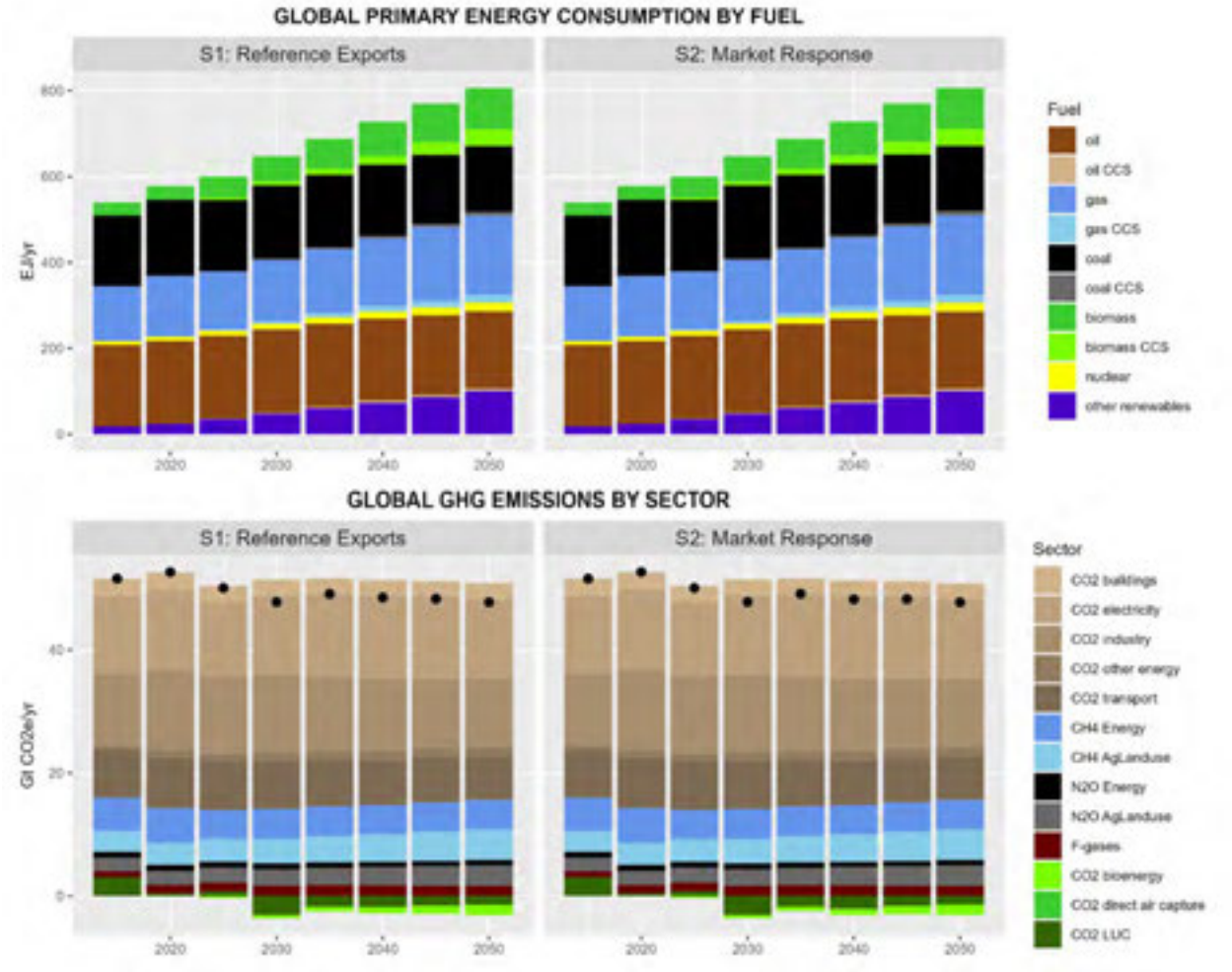


Figure 6.

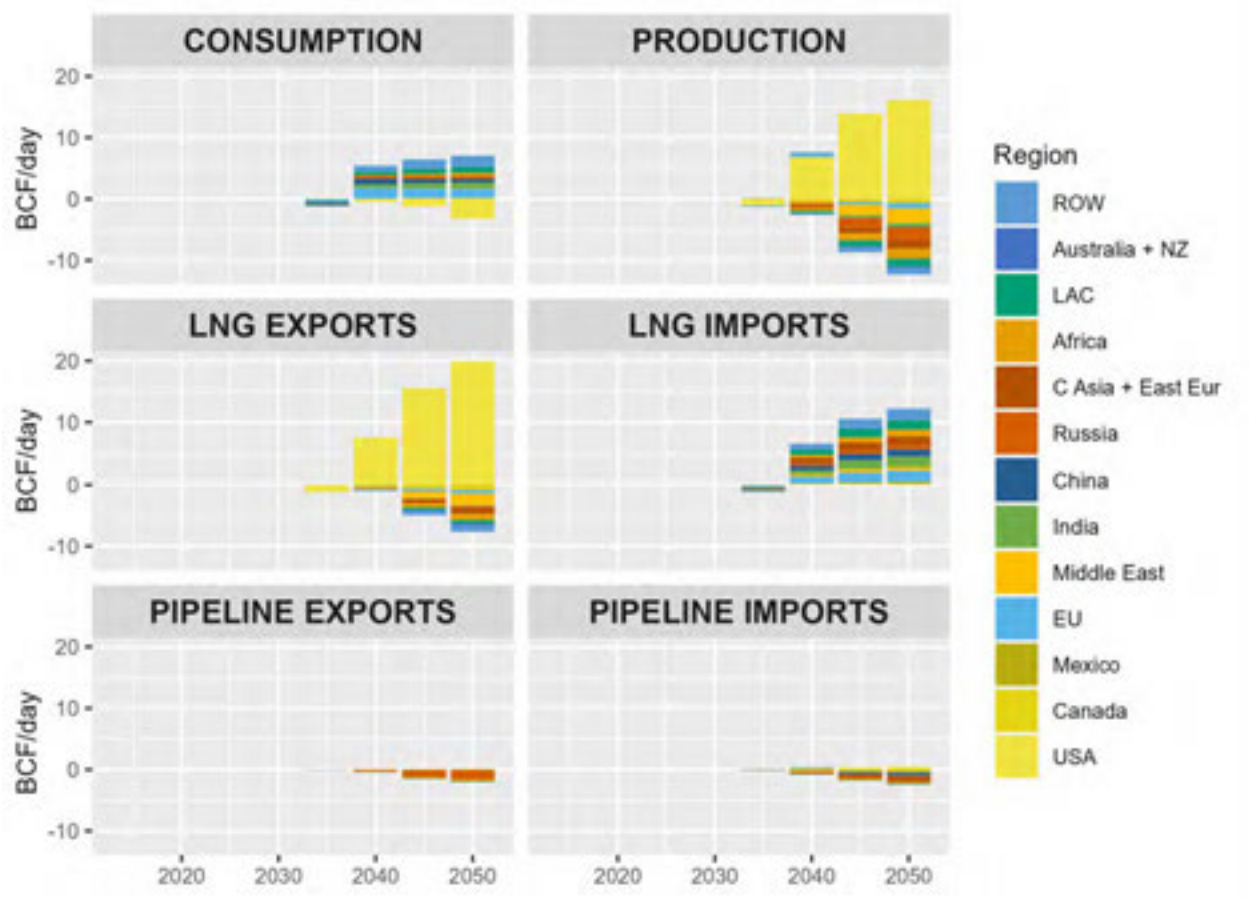


Figure 5. Changes in natural gas consumption, production, and trade by region in S2 vs. S1

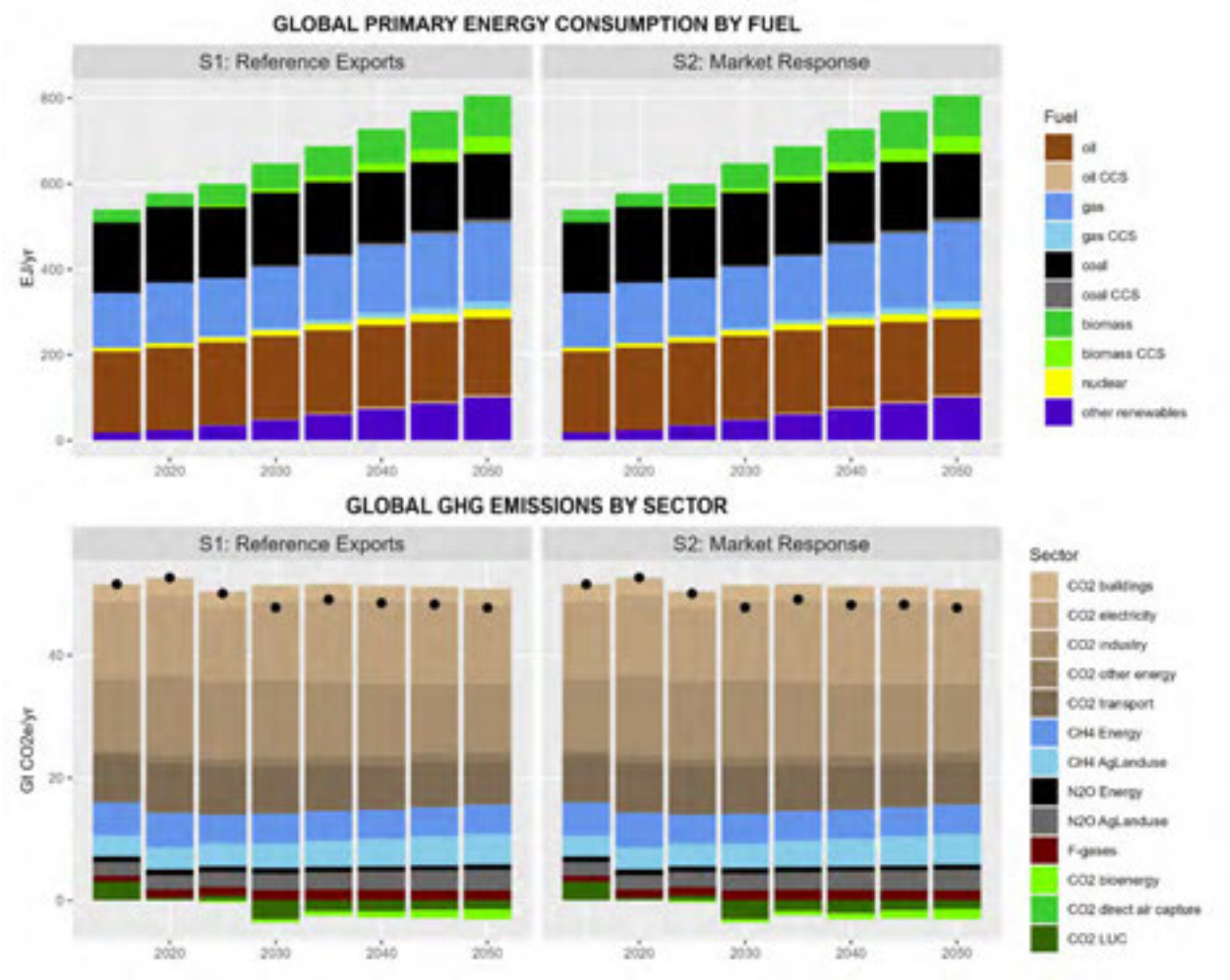


Figure 6. Global primary energy consumption by fuel and GHG emissions by sector under S2 and S1. Net GHG emissions are shown as a dot in each bar.

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 Figures Figure 7 and 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*.

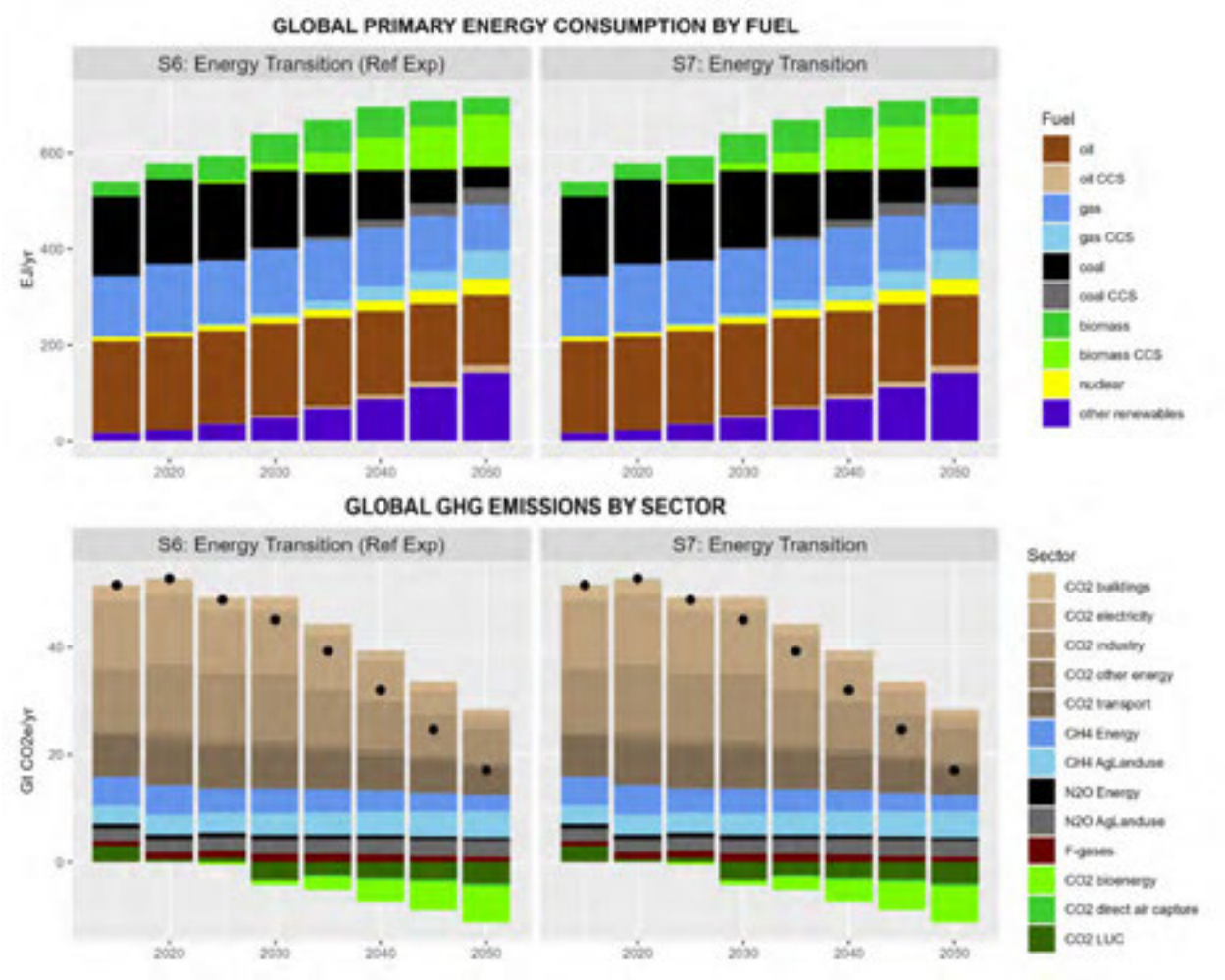


Figure 7. Global primary energy consumption by fuel and GHG emissions by sector under S6 and S7. Net GHG emissions are shown as a dot in each bar.

Notably, the scale and distribution of CDR deployment varied by type and region. By 2050, about 6.8, 4, and 0.4 GtCO2e respectively of BECCS, afforestation, and DAC were deployed globally in S6 and S7, as

shown in

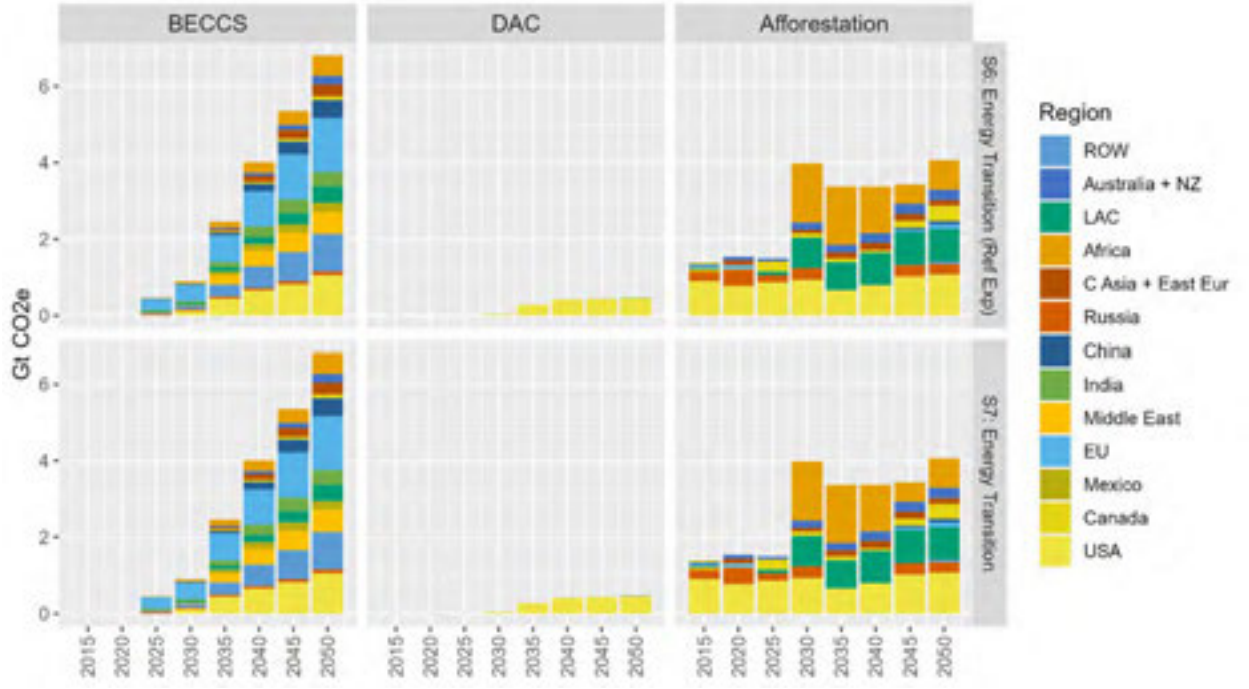


Figure 9. CDR deployment by type and region in S6 and S7

. 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 GtCO2e), 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

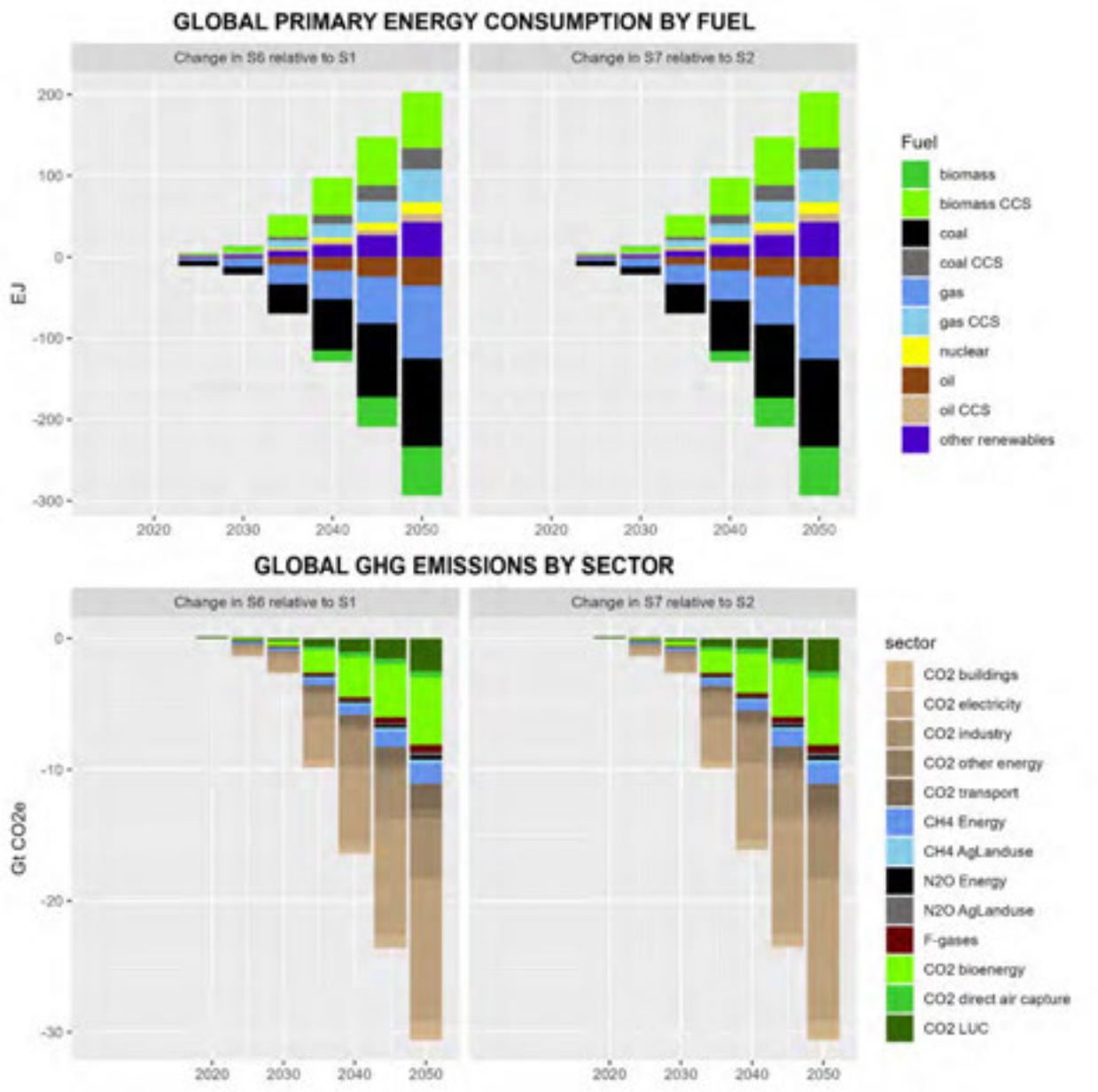


Figure 8. Changes in global primary energy consumption and GHG emissions under S6 and S7 relative to S1 and S2 respectively

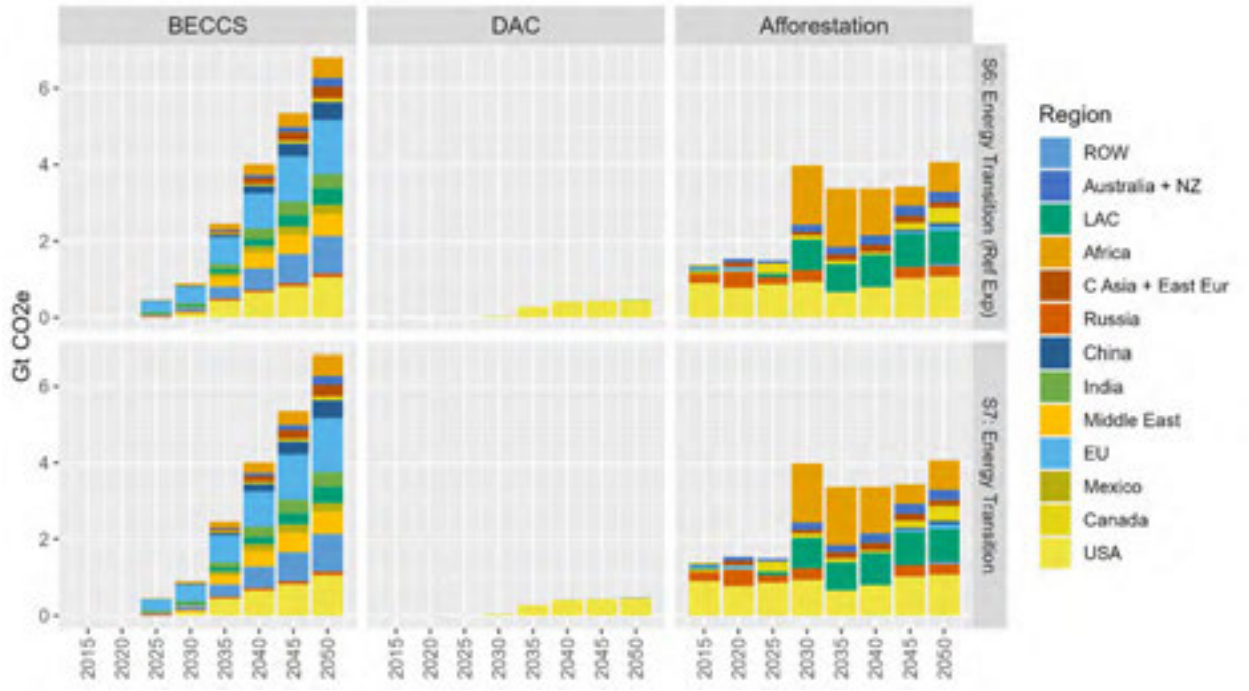


Figure 9. CDR deployment by type and region in S6 and S7

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.

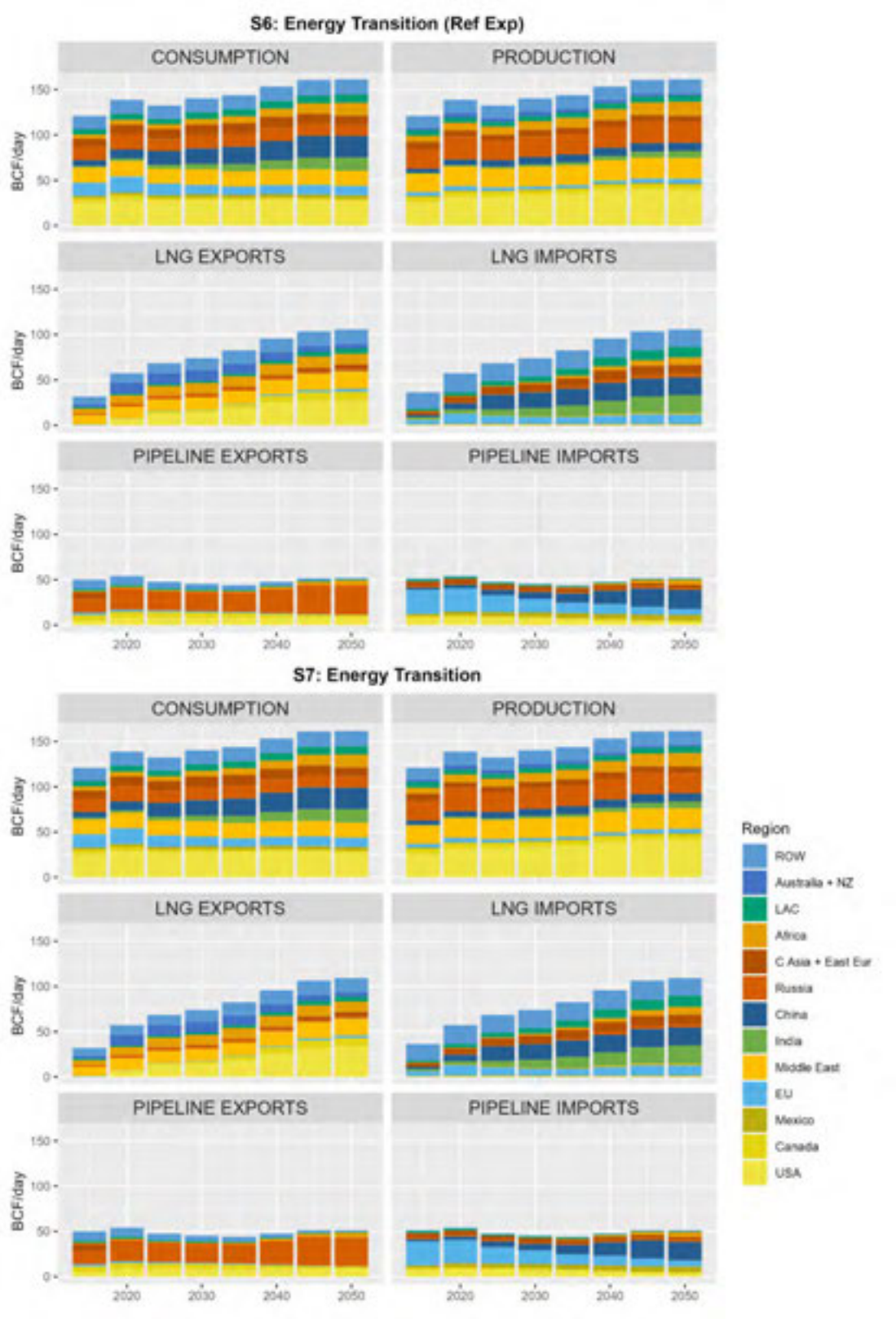


Figure 10. Natural gas consumption, production, consumption, and trade by region under S6 and S7

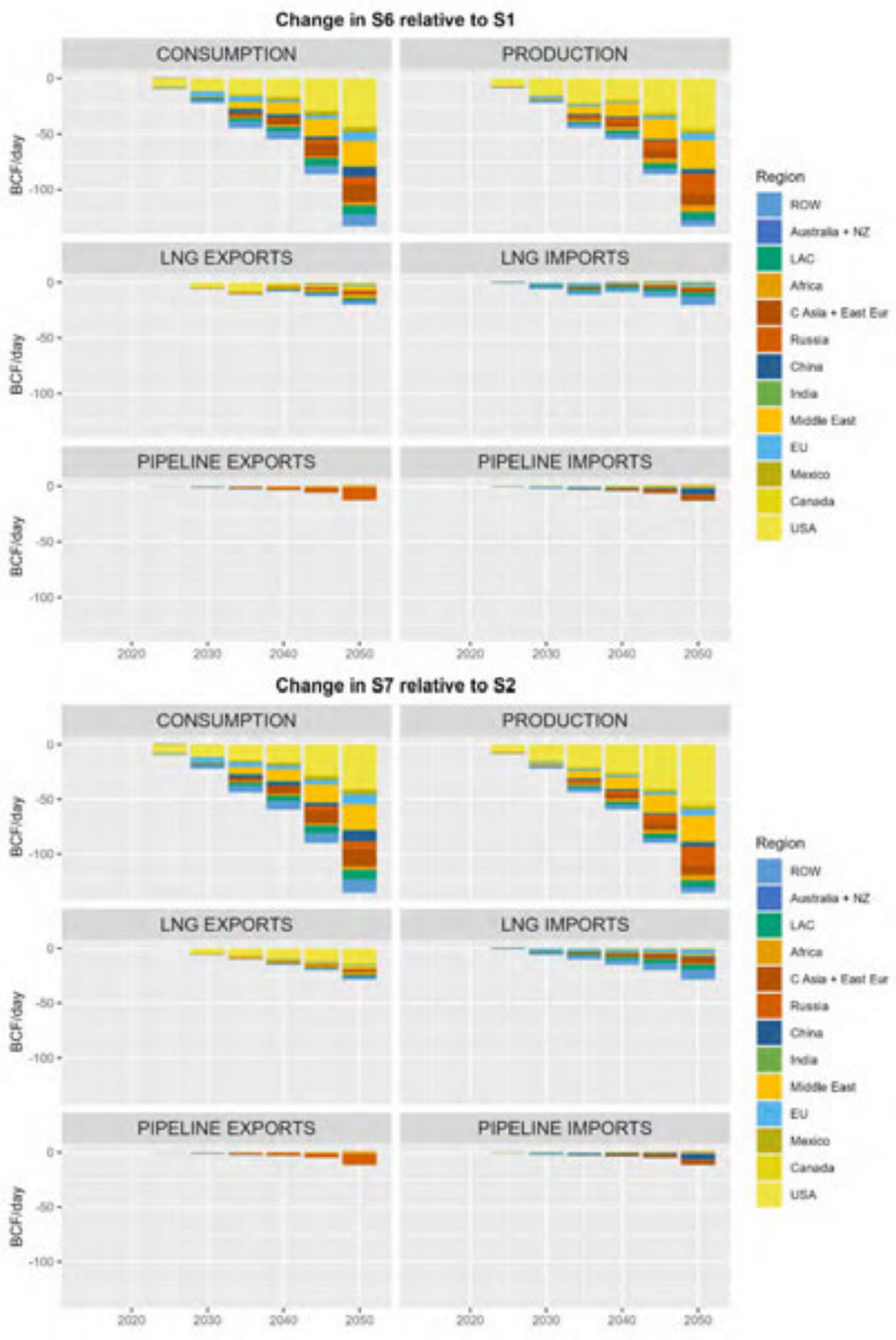


Figure 11. Changes in natural gas consumption, production, and trade by region in S6 vs. S1 and S7 vs. S2.

As shown in

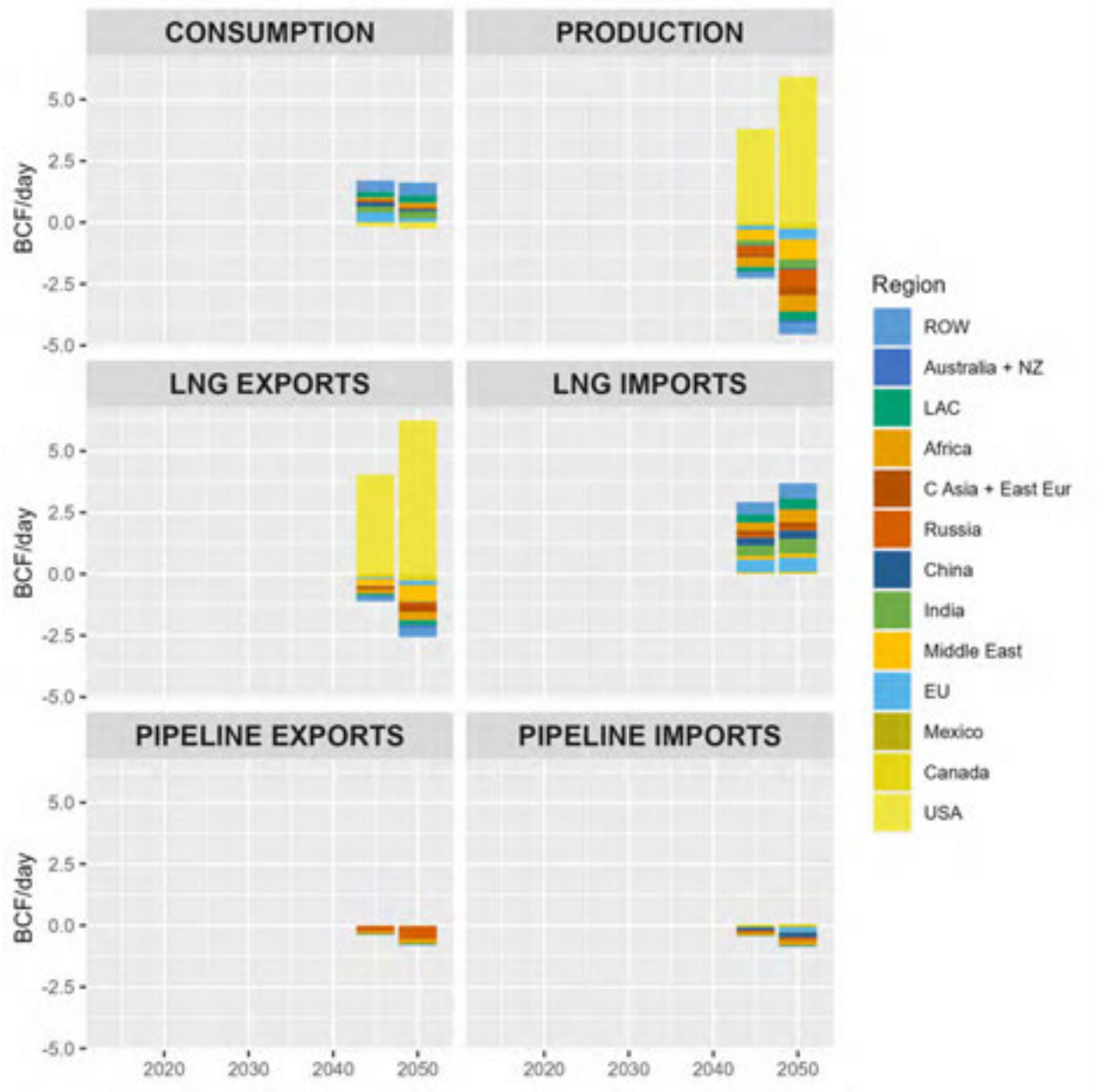


Figure 12, *S6* and *S7* differed in the role of U.S. LNG exports in the global natural gas market. By 2050, U.S. LNG exports in *S6* were not different from *S1* because this scenario assumed the *S1* values (which are based on AEO2023) as an upper bound. Under *S7*, which assumes economically driven 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*.

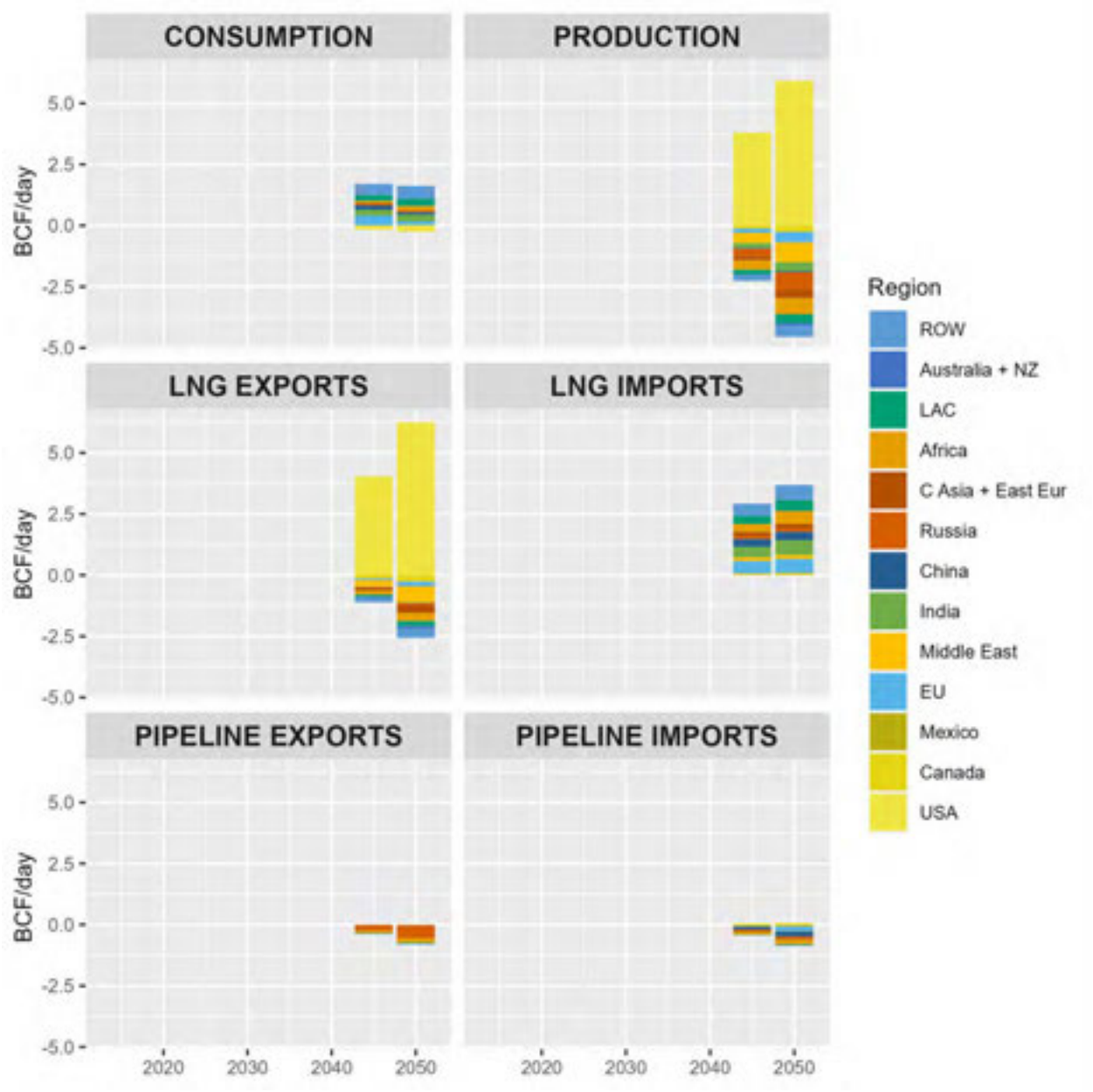


Figure 12. Changes in natural gas markets in S7 vs. S6.

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.

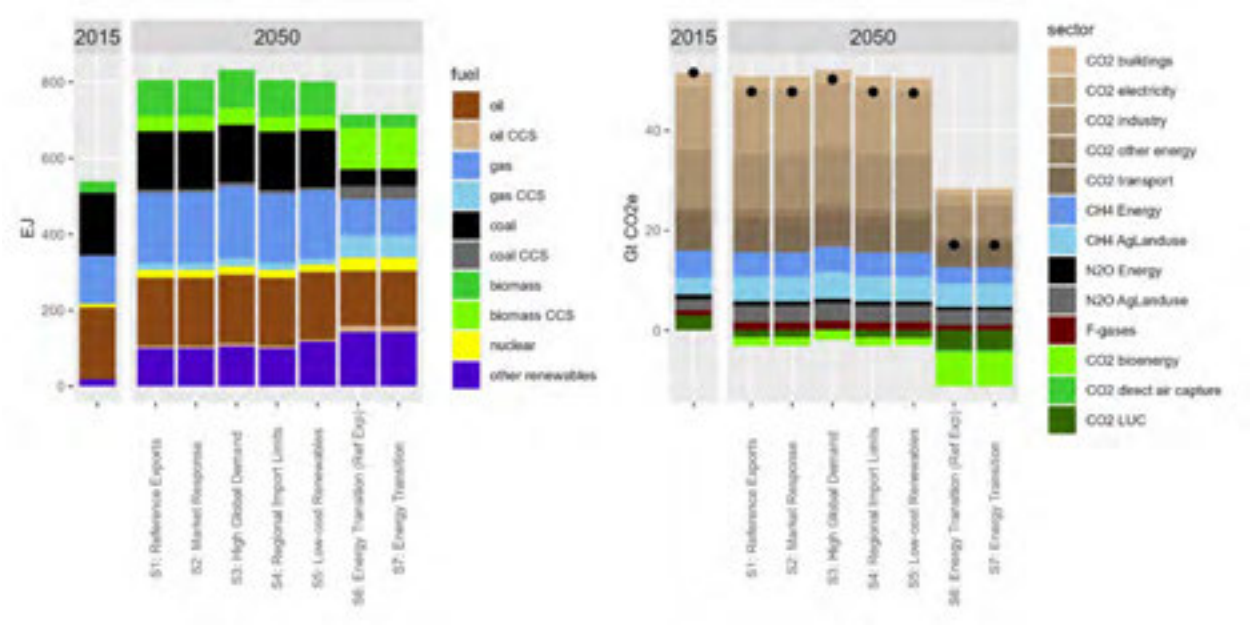


Figure 13. Primary energy consumption by fuel and GHG emissions by sector under all scenarios

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.

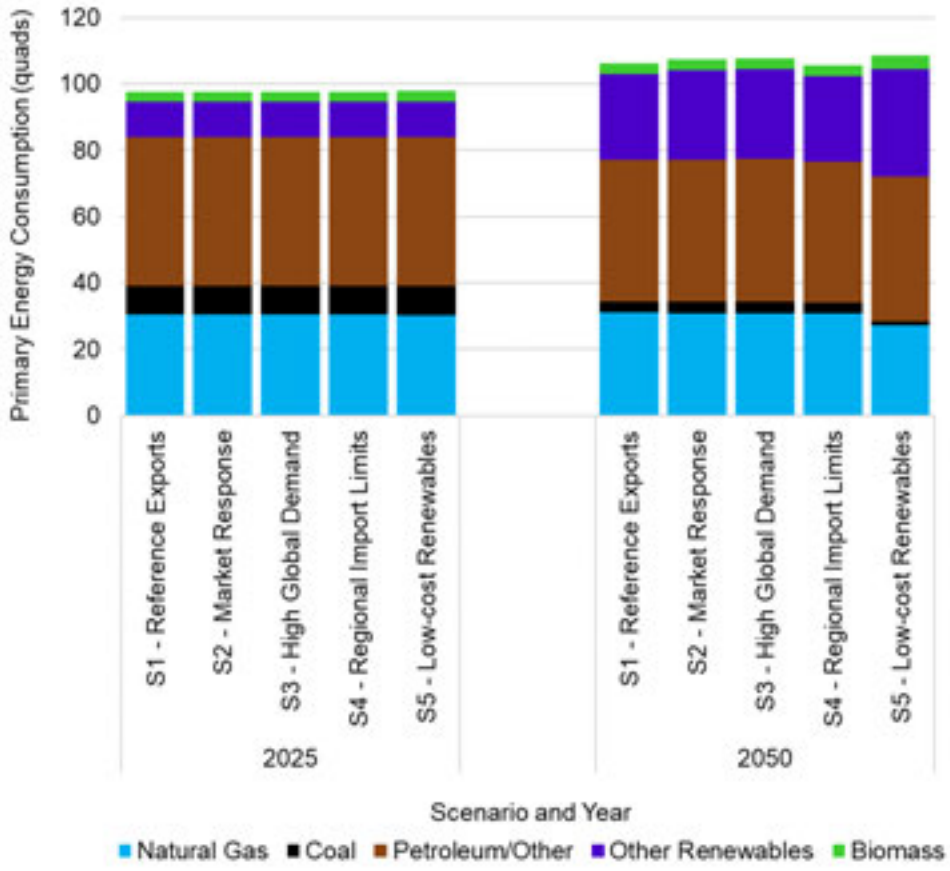


Figure 14. U.S. Primary energy consumption S1 – S5.

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*.

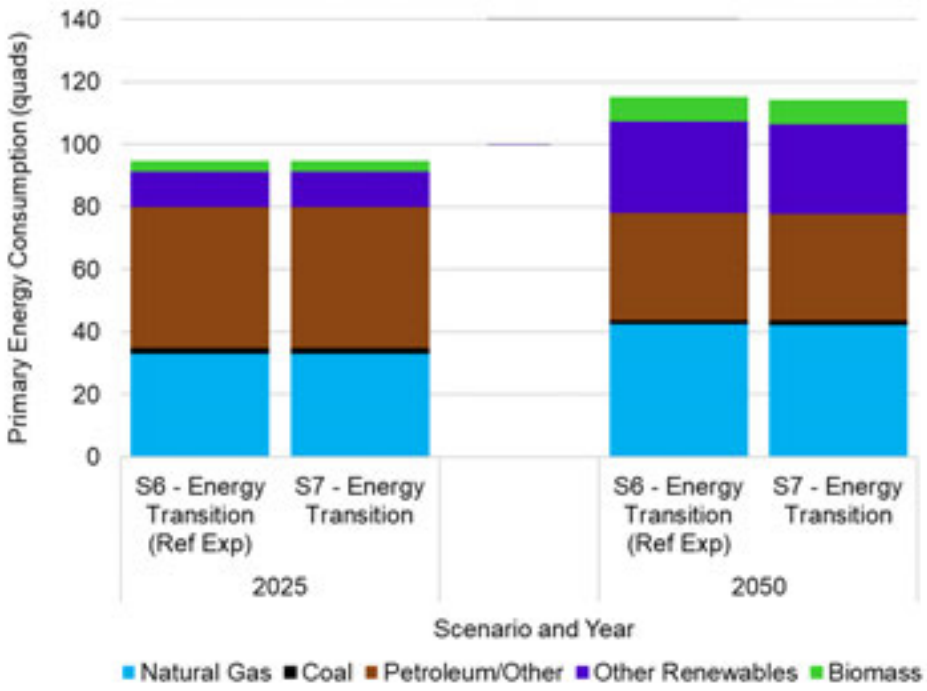


Figure 15. U.S. primary energy consumption S6 and S7.

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.

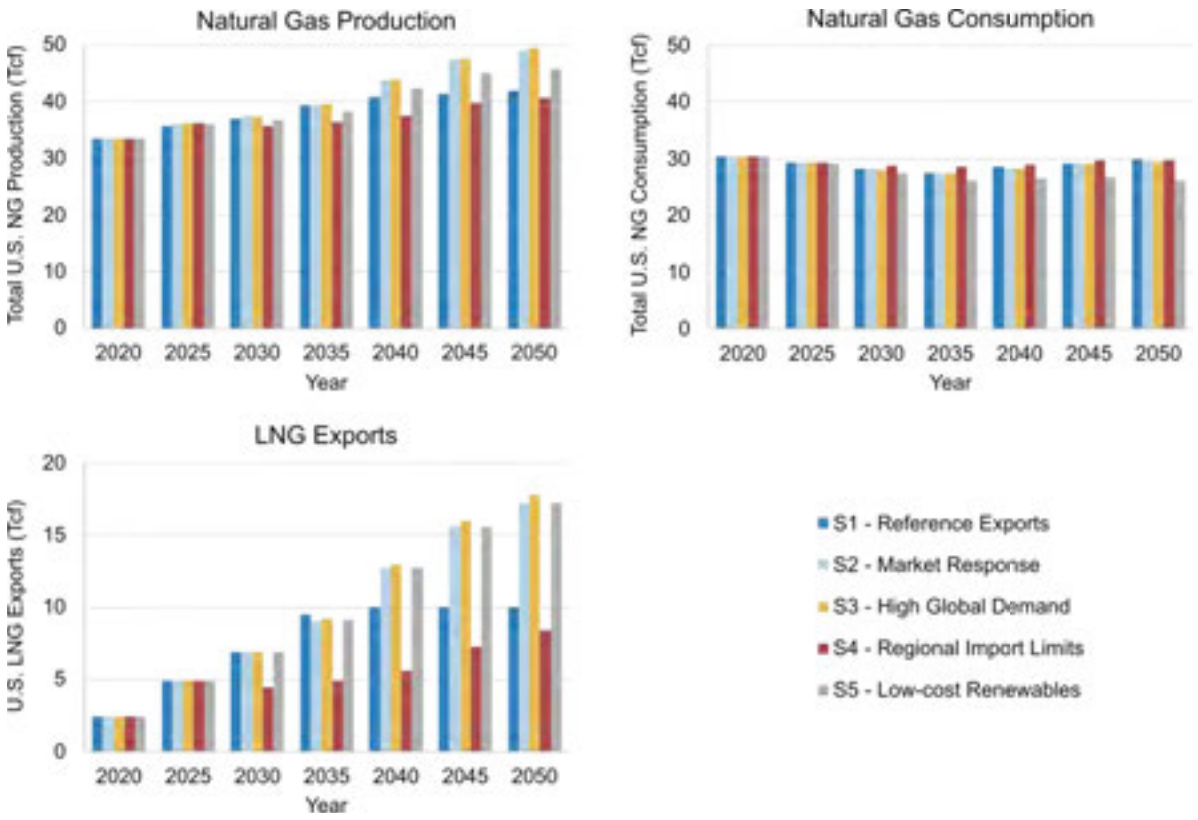


Figure 16. Total U.S. natural gas production, consumption, and export volumes over time, by scenario

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.

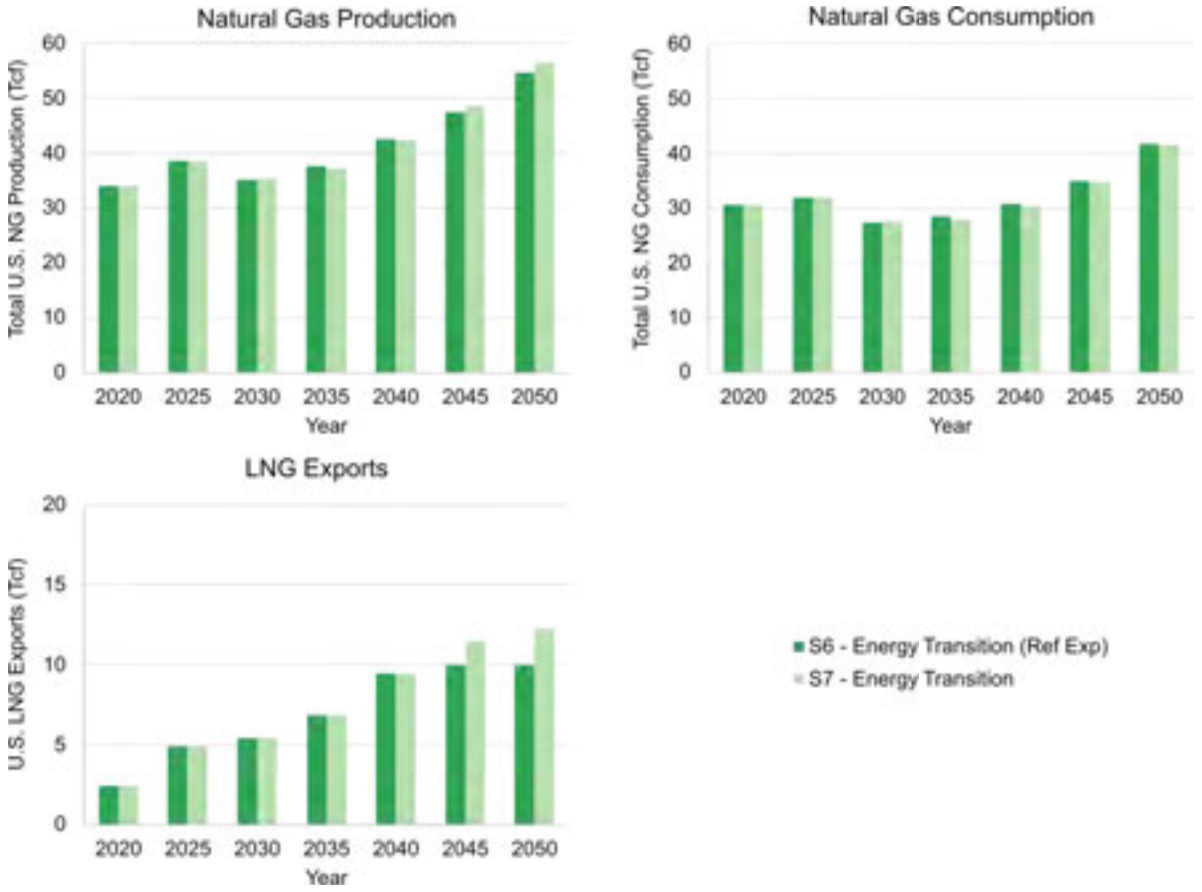


Figure 17. Total U.S. natural gas production, consumption, and export volumes, net-zero scenarios

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.

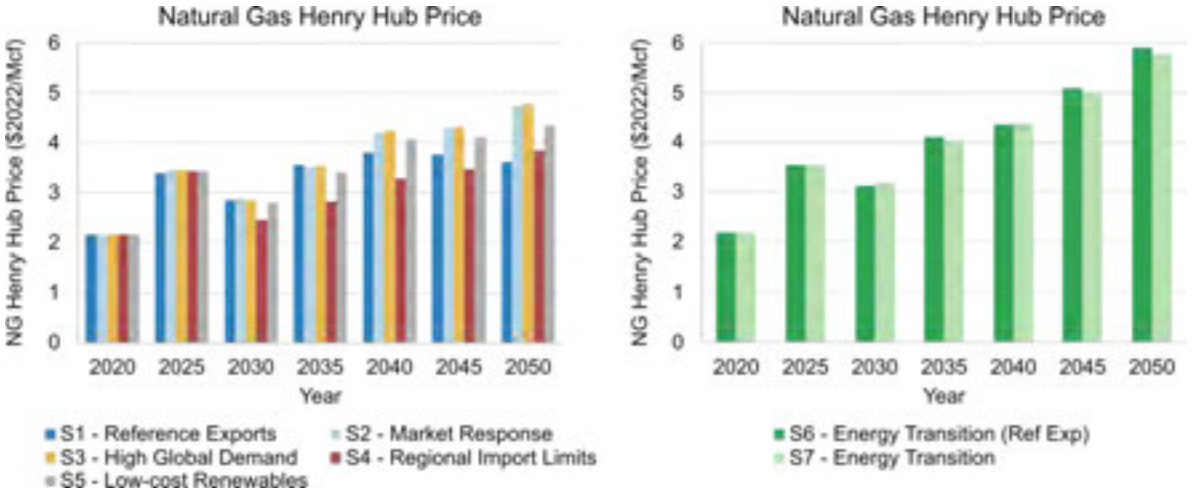


Figure 18. Total U.S. natural gas Henry Hub price by scenario ($2022)

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.

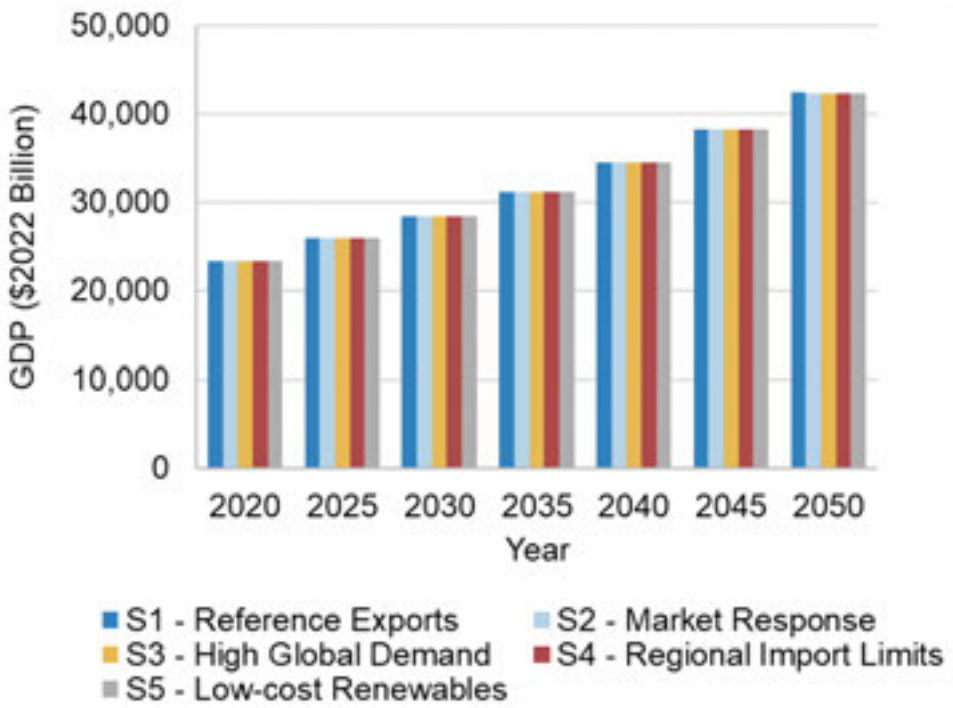


Figure 19. U.S. Real GDP changes

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.

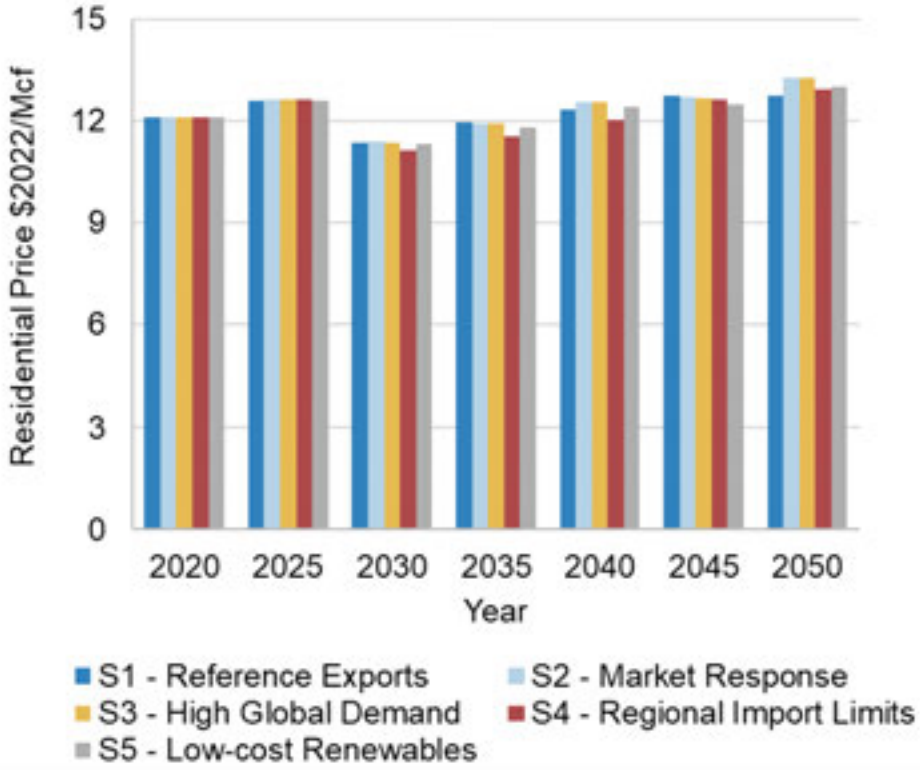


Figure 20. U.S. Residential natural gas prices

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.

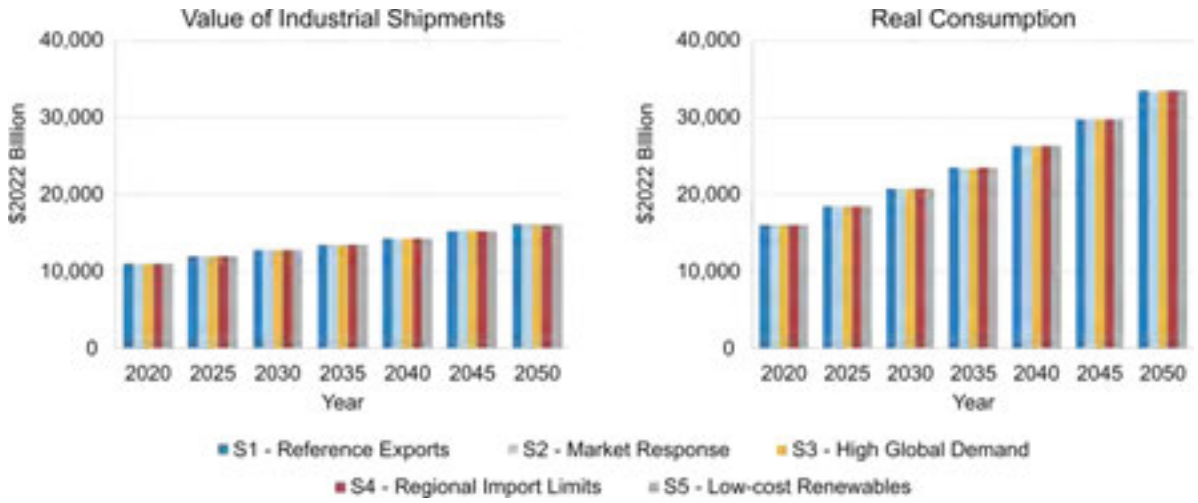


Figure 21. U.S. Value of industrial shipments and real consumption

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%.

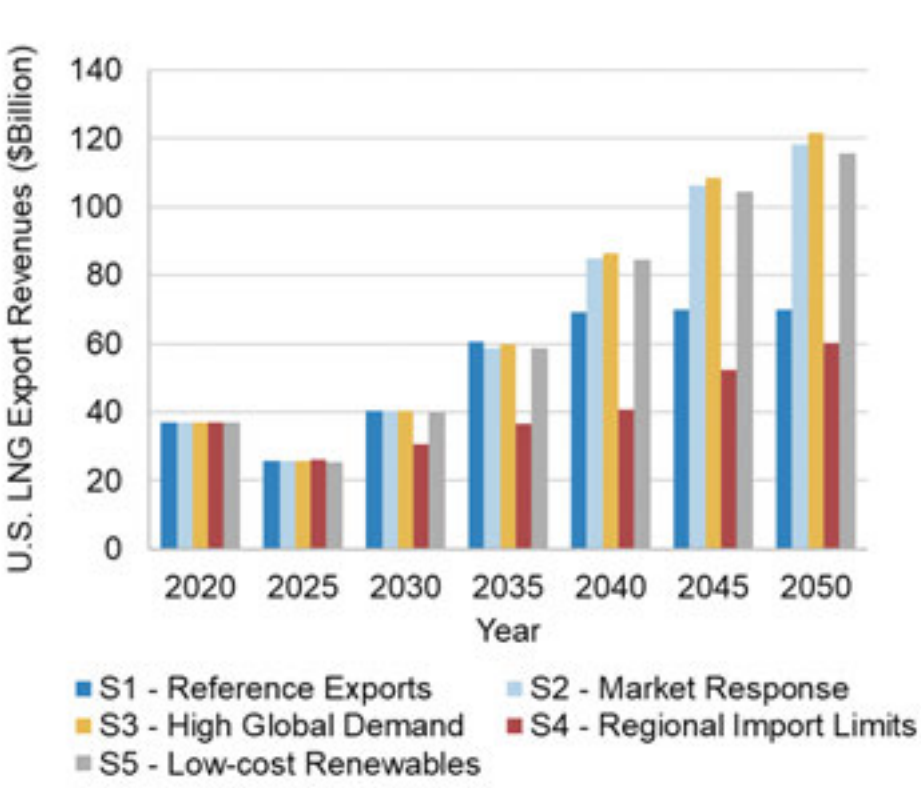


Figure 22. U.S. LNG export revenues

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*.

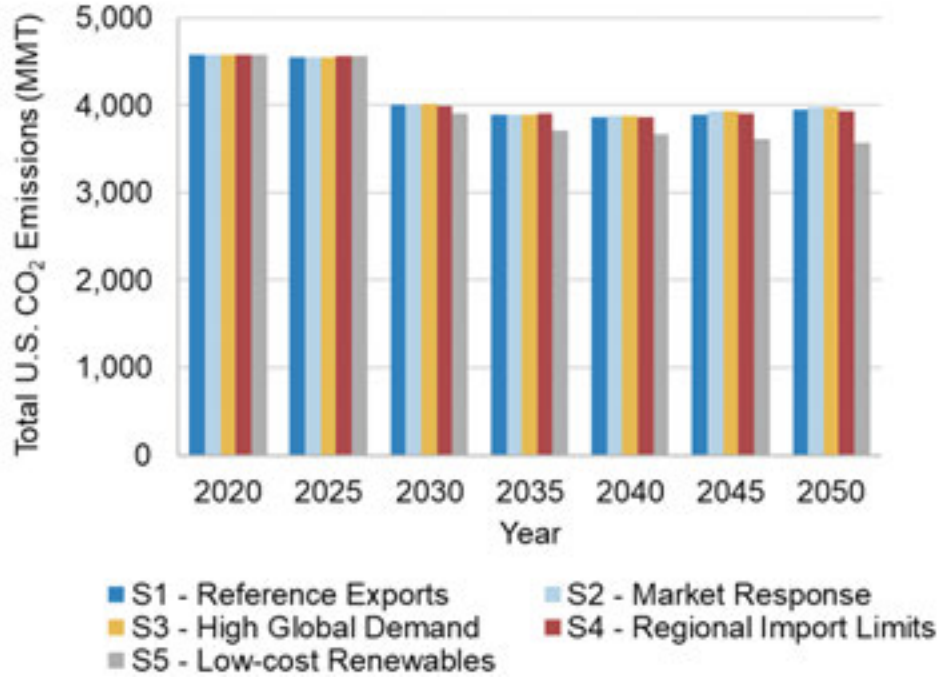


Figure 23. Total U.S. CO_2 emissions from fossil fuel combustion

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.

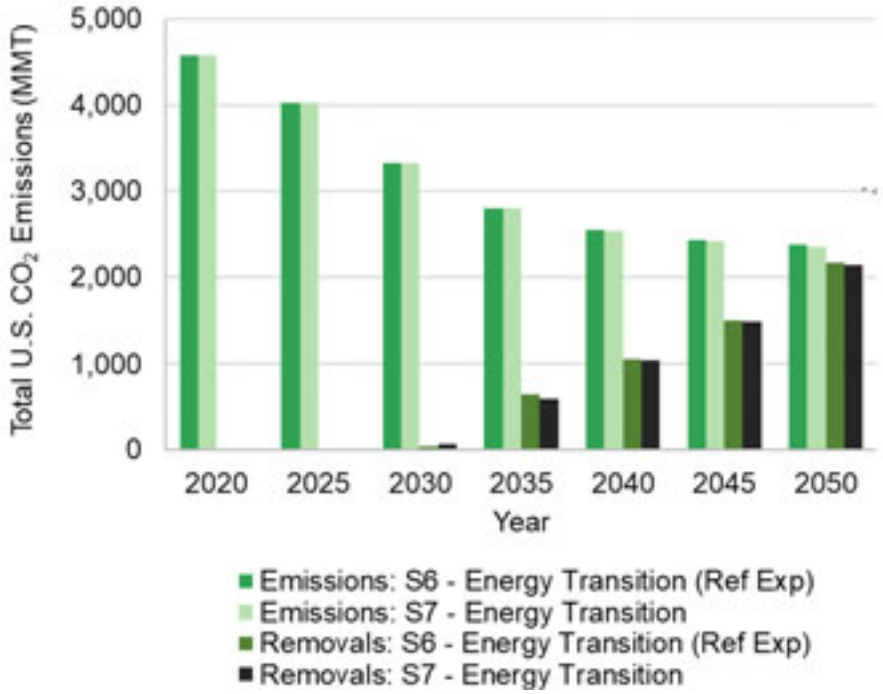


Figure 24. Total U.S. CO_2 emissions from fossil fuel combustion and removals, S6 and S7

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 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 NETL work used by DOE in support of natural gas and LNG export decisions, NETL assessed and aligned the emissions estimates of the two models.

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 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.

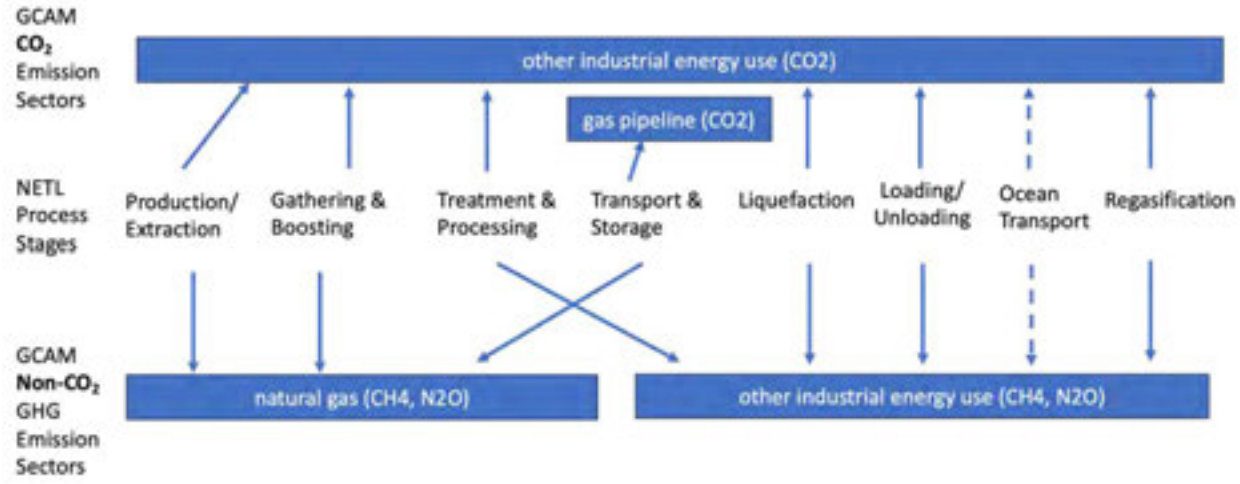


Figure 25. Mapping of NETL natural gas stages to GCAM sectors

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 were about 8.52 g CO2e/MJ (on an IPCC AR6 100-year 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 CO2e/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.

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).

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

Results (g CO_2e/ MJ)			
MAF Case	**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)

Results (g CO_2e/ MJ)			
MAF Case	**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 CO2e/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 7.4 g CO2e/MJ (HHV). The MAF indicated that as U.S. LNG exports increased, the induced global market effects result in an 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 CO2e/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 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 GtCO2e and U.S. emissions range from 4.3-4.6 GtCO2e 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

[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/

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* 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.

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

Scenarios	U.S. LNG Exports (Bcf/d)	U.S. NG Residential Price ($2022/Mcf)	US Net GHG Emissions (GtCO2e)	Global Net GHG Emissions (GtCO2e)
S1	27.3	$12.74	4.5	48
S2-S5	23.1 – 48.7	$12.92 – $13.28	4.3-4.6	47-50
S6-S7	27.3 – 33.6	$34.97 – $35.24	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

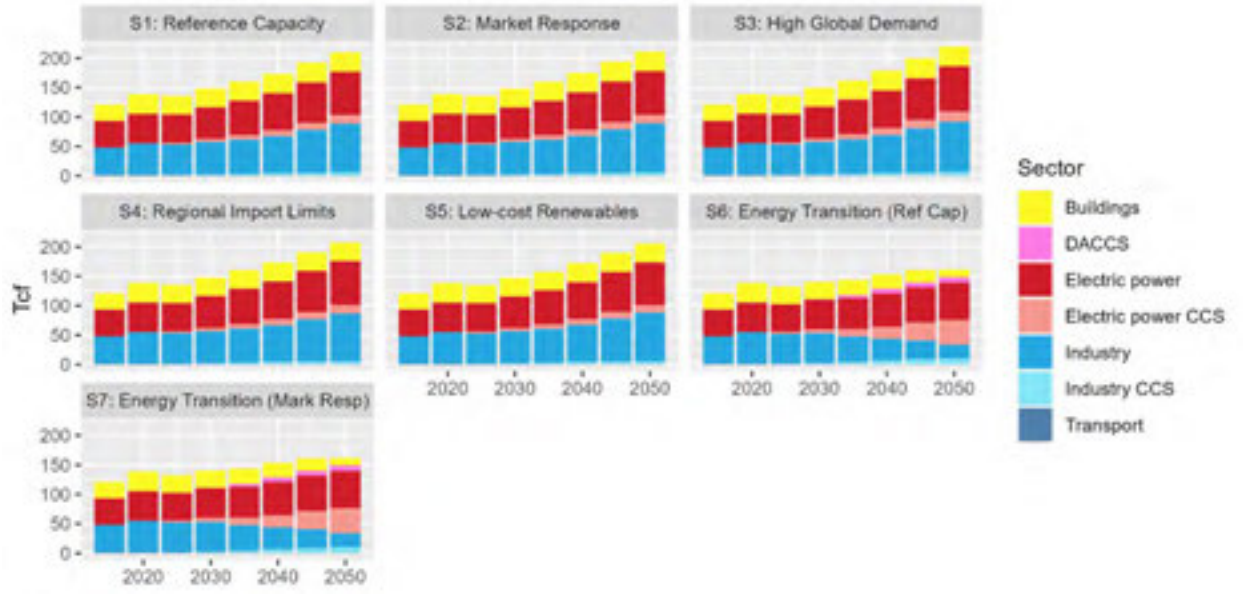


Figure A-1. Global natural gas consumption by sector across all scenarios



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

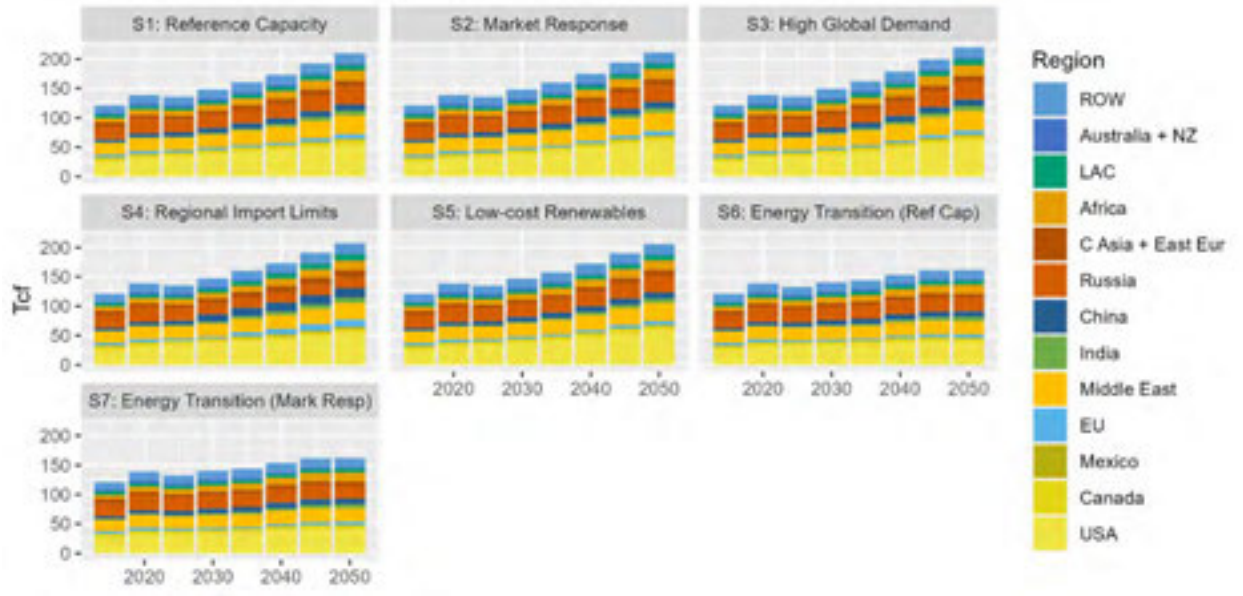


Figure A-3. Global natural gas production by region across all scenarios

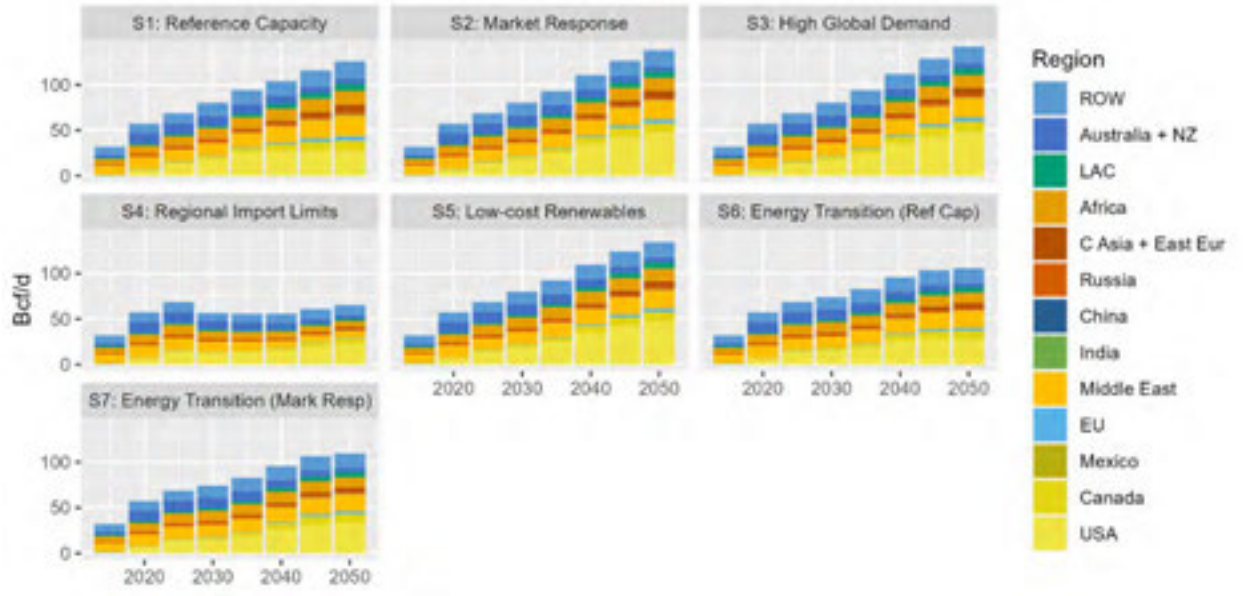


Figure A-4. Global LNG exports by region across all scenarios

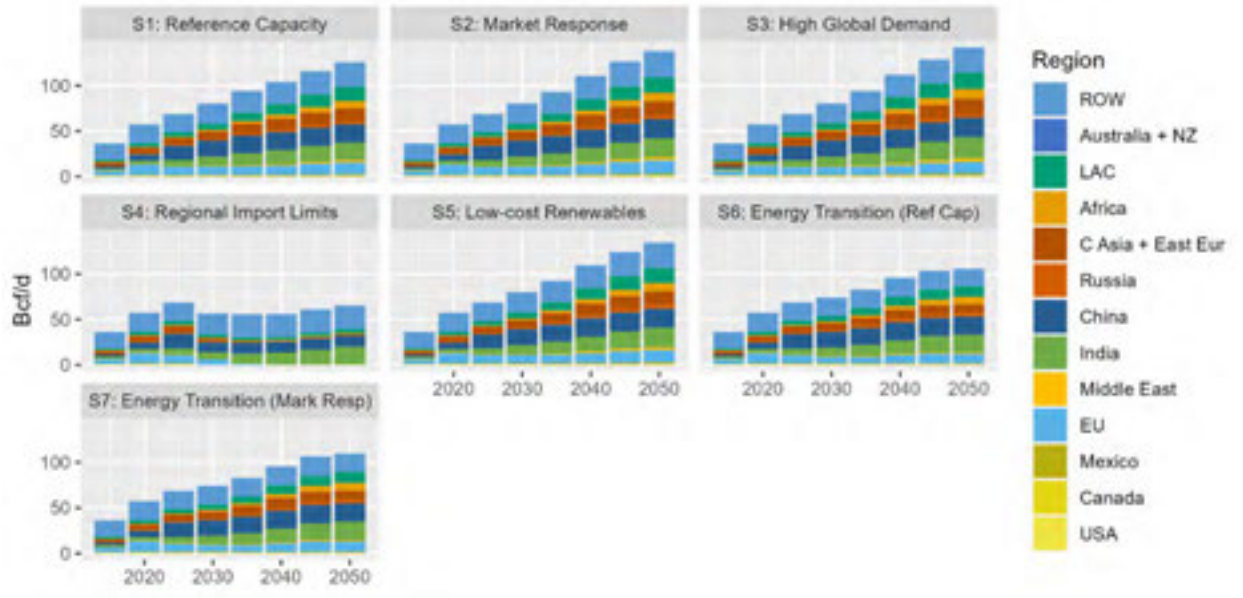


Figure A-5. Global LNG imports by region across all scenarios

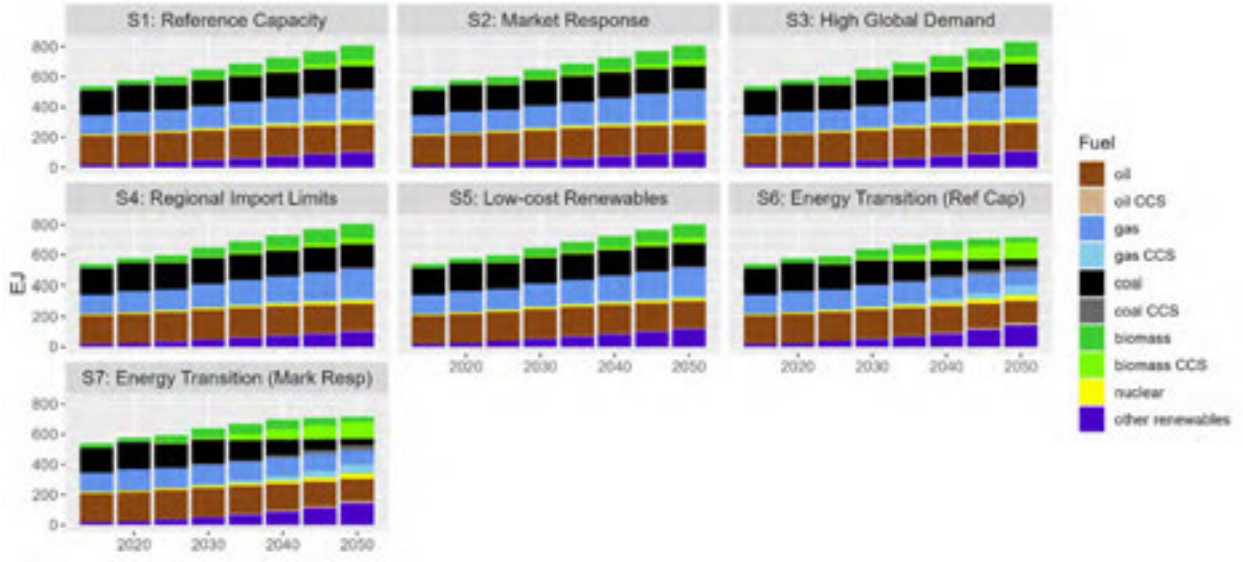


Figure A-6. Global primary energy consumption by fuel across all scenarios

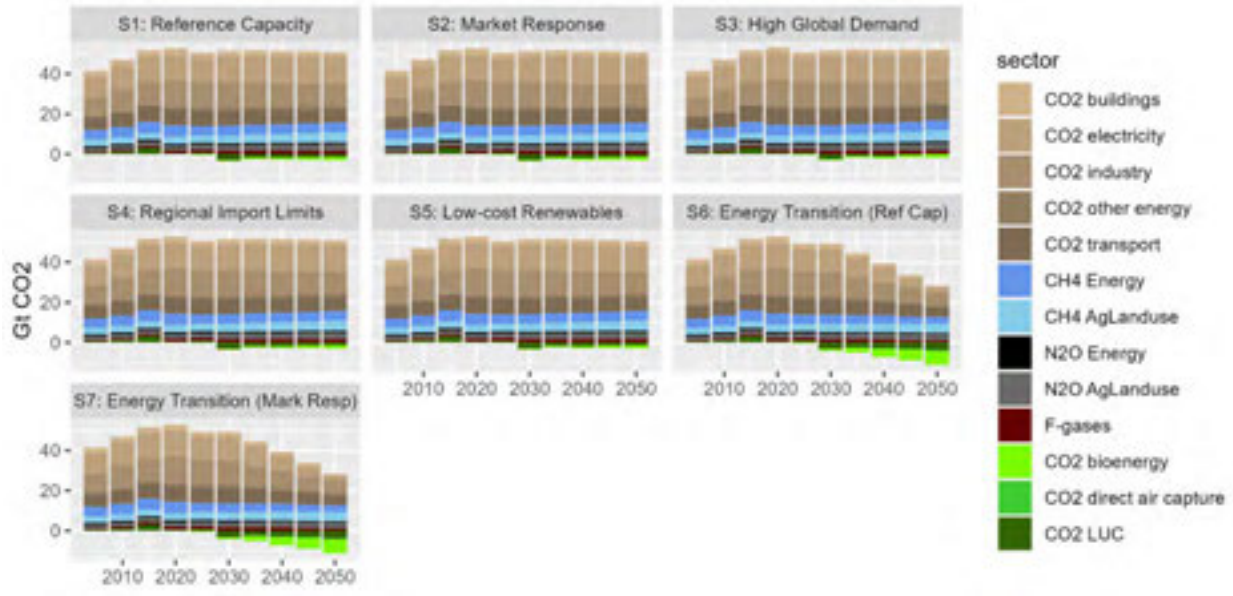


Figure A-7. Global GHG emissions by sector across all scenarios

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.

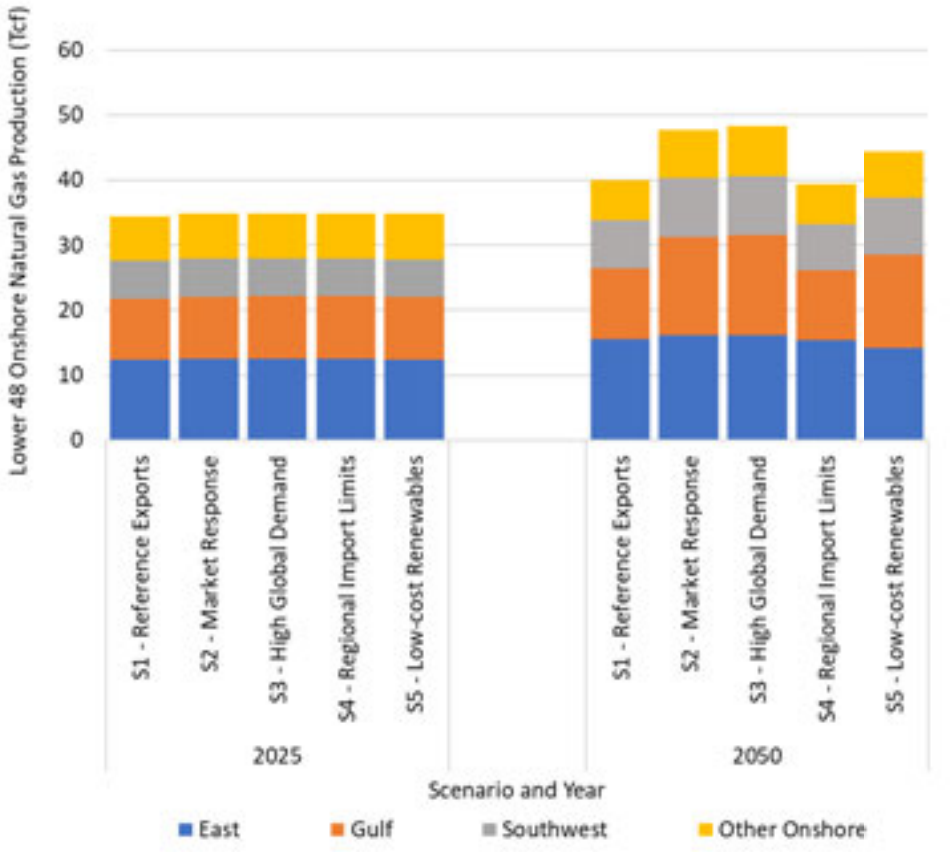


Figure B-1. U.S. Regional Natural gas production, S1 *through* S5

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.

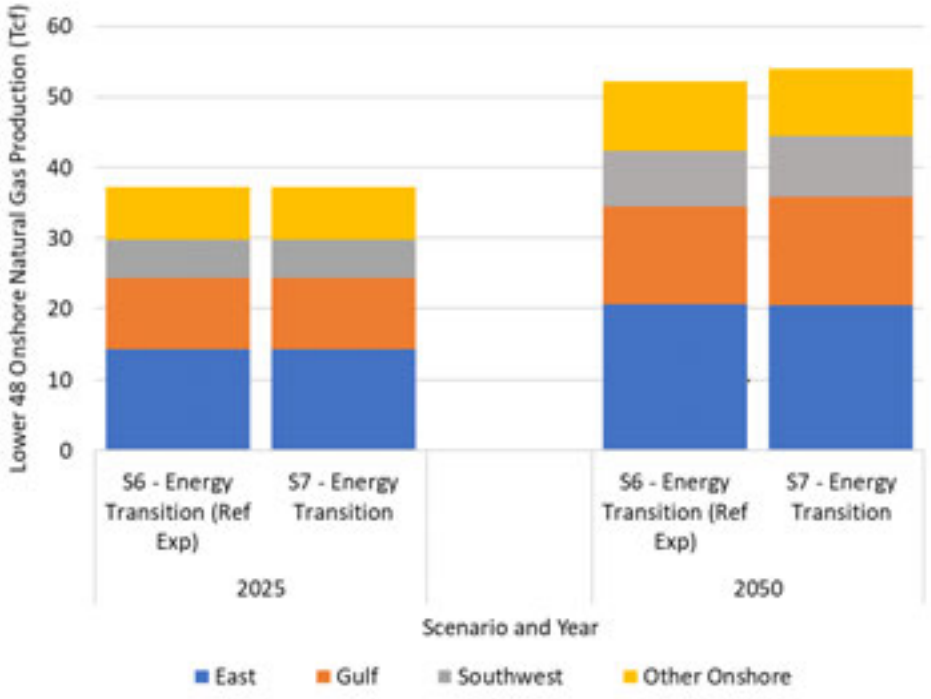


Figure B-2. U.S. regional natural gas production in S6 and S7

Onshore natural gas production grows significantly from 2025 to 2050 for both net-zero scenarios, rising from 37 Tcf in 2025 to 52 Tcf in *S6* and 54 Tcf in *S7*, respectively, by 2050. The large growth in natural gas production is primarily due to demand from DAC facilities, with only a small increase associated with elevated LNG exports in the *S7* scenario. Natural gas production rises in all regions, with the largest absolute increases coming from the East (6.4 Tcf in *S6* and 6.2 Tcf in *S7*) and Gulf (3.8 Tcf in *S6* and 5.3 Tcf in *S7*) regions and the largest increase by percentage coming from the Southwest (47% in *S6* and 58% in *S7*).

2. Natural gas consumption by economic sector

Figure B-3 plots natural gas consumption for electric power, industry, residential use, commercial use, and transportation over time for *S1* through *S5*.

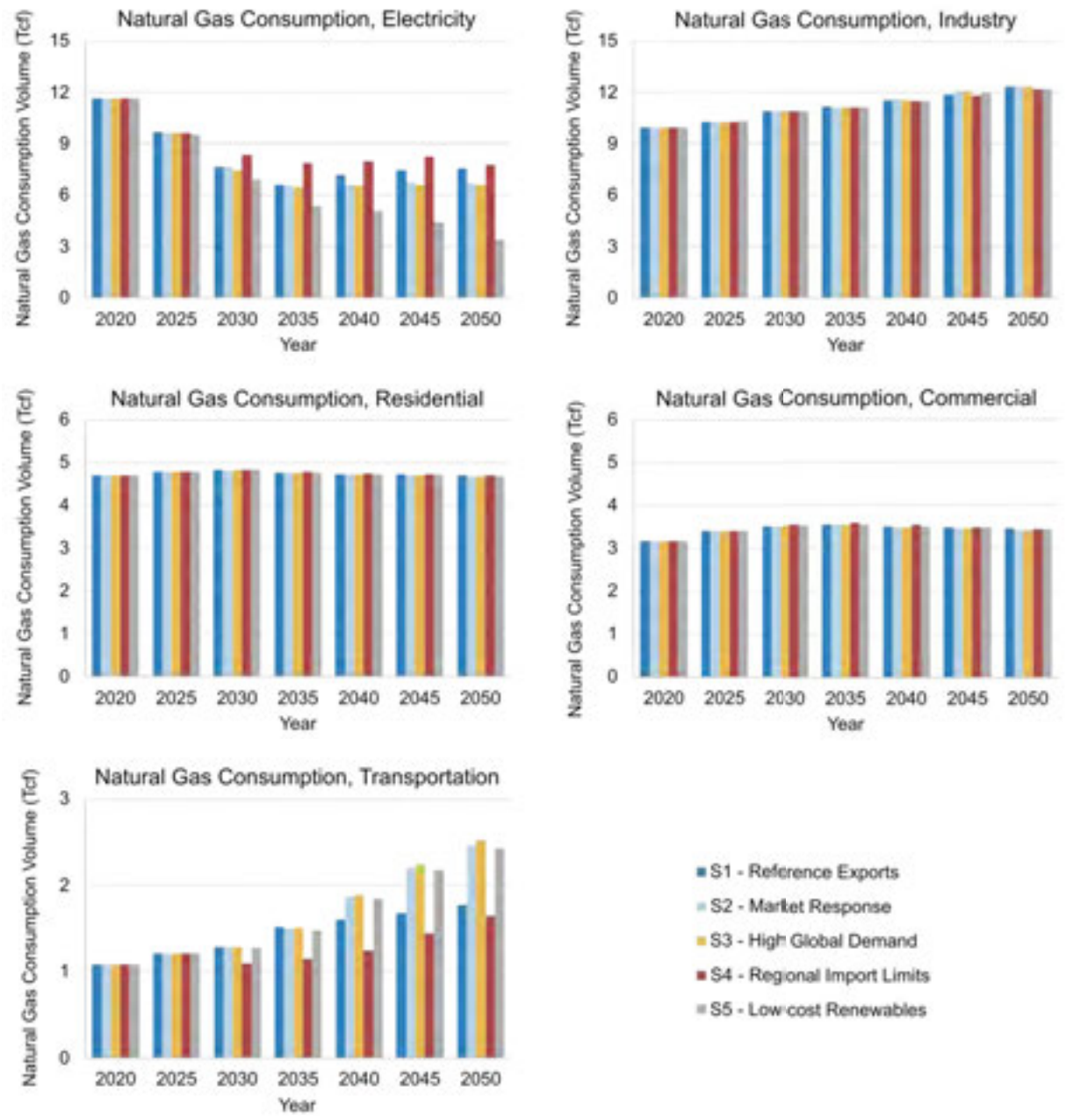


Figure B-3. U.S. natural gas consumption by sector S1 – S5.

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.

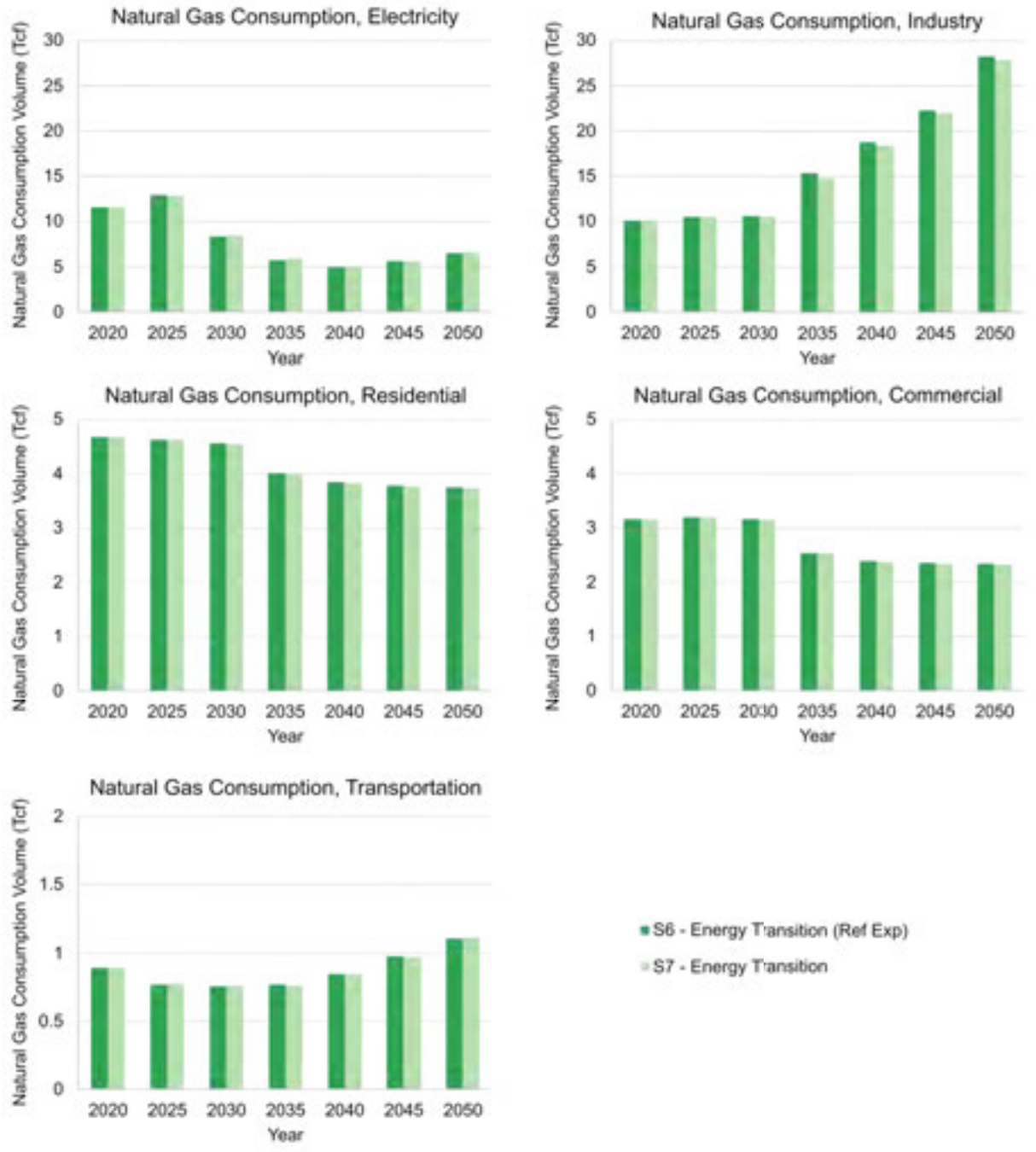


Figure B-4. U.S. natural gas consumption by sector net-zero scenarios

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.

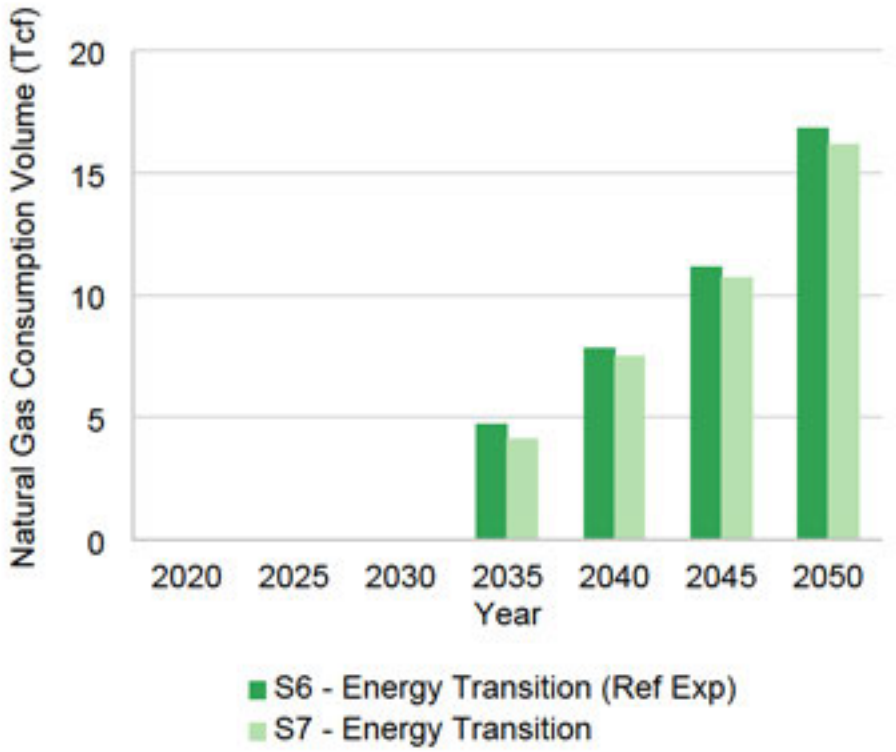


Figure B-5. Natural gas consumed for DAC, net-zero scenarios

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 and pricing 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.

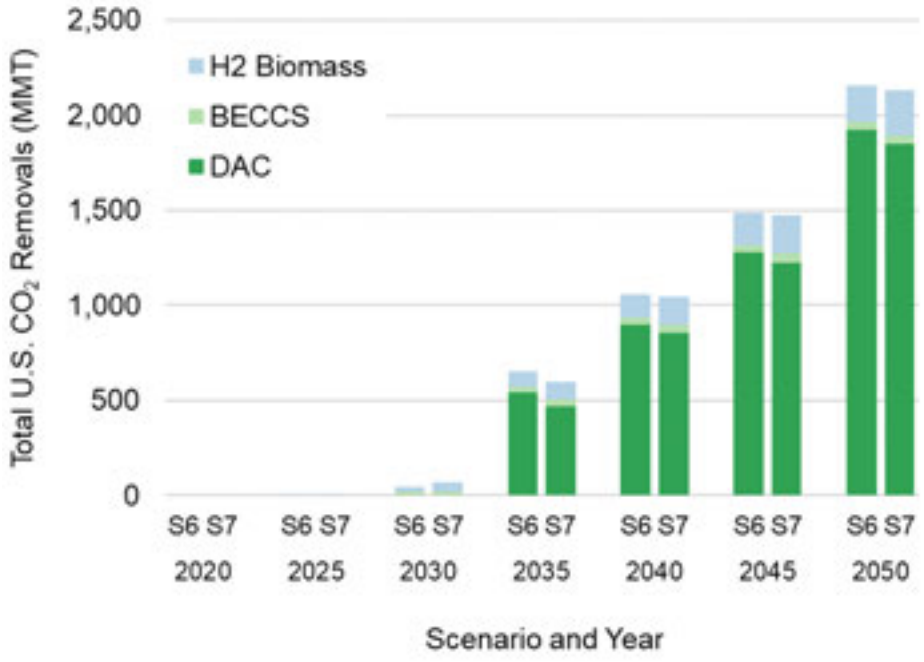


Figure B-6. U.S. CO_2 emissions and removals, net-zero scenarios

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 (

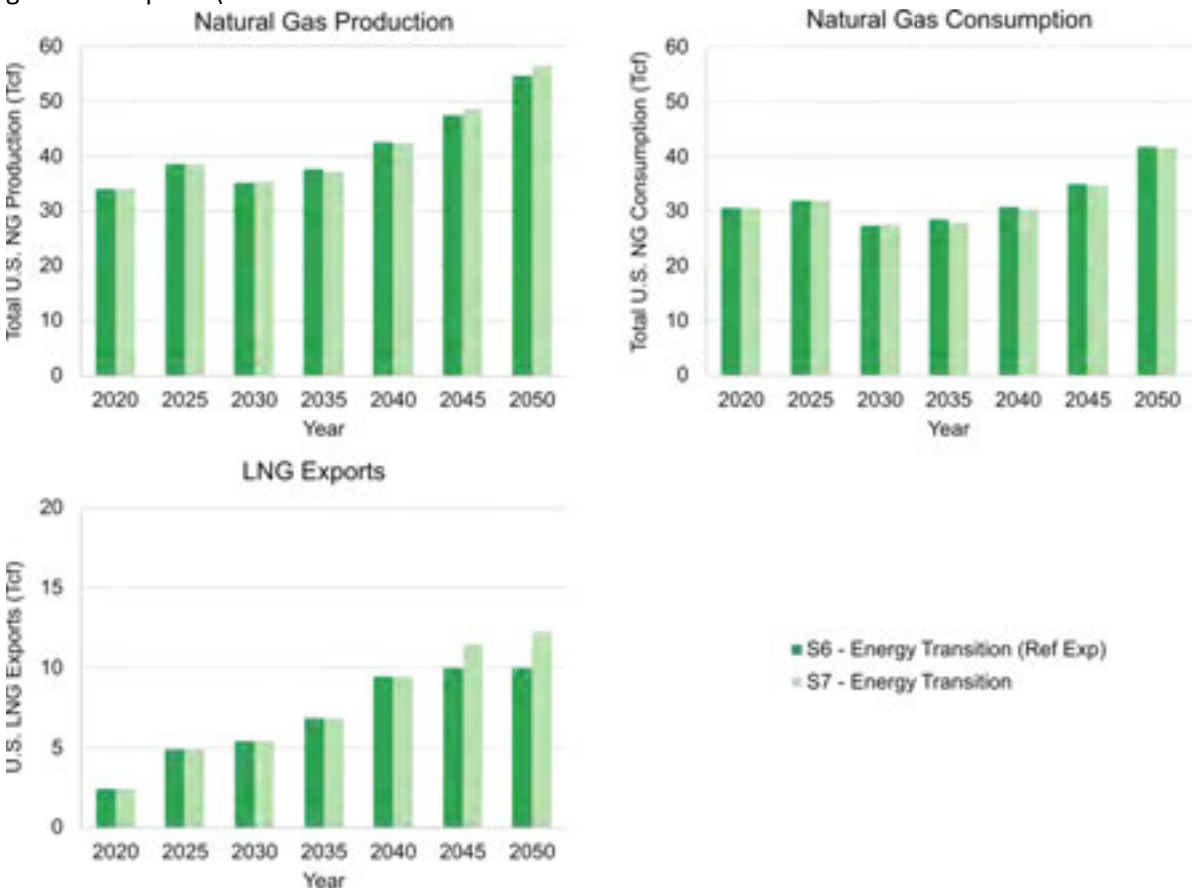


Figure 17. Total U.S. natural gas production, consumption, and export volumes, net-zero scenarios

) 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

[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.

$5.90 2022/Mcf and $5.77 2022/Mcf. Residential prices, reflecting the implied carbon penalty are $34.97 and $35.24/mcf in S6 and S7 respectively in 2050.

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. The CO_2 price is plotted in Figure B-7.

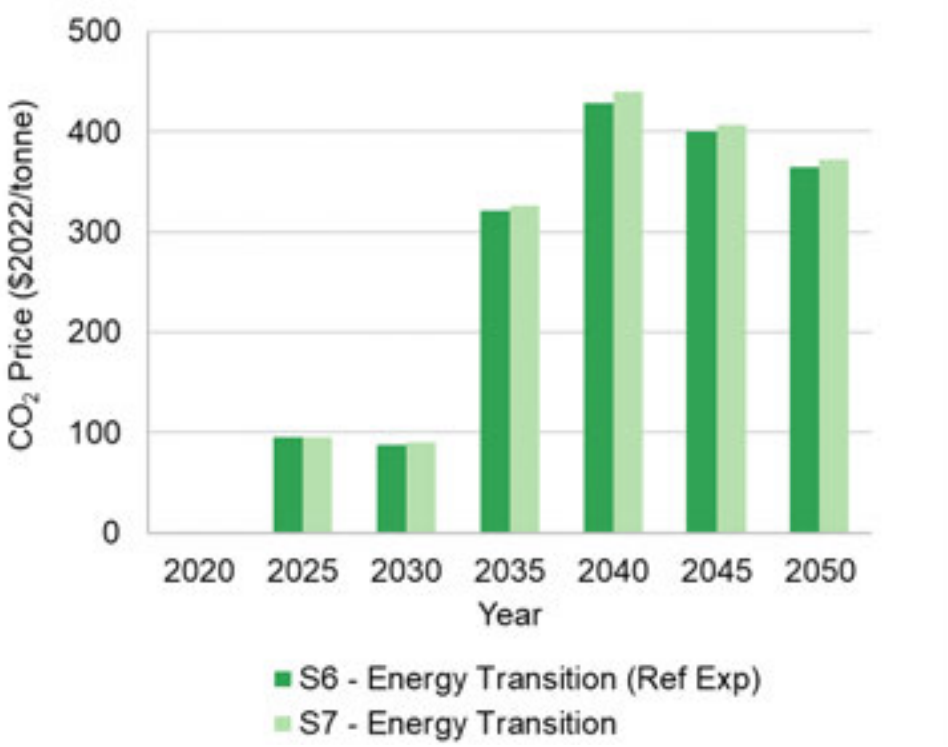


Figure B-7. U.S. CO_2 price, net-zero scenarios

The implied CO_2 price rises to $87-$96/ton CO_2 by 2030. The lower price during the first ten years reflects the cost of electrification and fuel switching from fossil to non-fossil sources throughout the energy system, reducing overall CO_2 emissions and satisfying the carbon cap. While emissions continue to decline after 2030, the rate of decline slows; most of the progress towards meeting the carbon cap after 2030 comes in the form of increased carbon removals. The implied CO_2 price climbs rapidly to $429/ton CO_2 in *S6* and $440/ton CO_2 in *S7* by 2040 as CO_2 removal technologies (primarily DAC) are brought online to satisfy the carbon cap and the subsidies for CO_2 sequestration expire. The rate of emissions reduction slows further from 2040 to 2050, with removals making up a greater portion of the net-decrease in CO_2 emissions. The CO_2 price in these last ten years is therefore dominated by the price of CO_2 removal technologies. It decreases to $364/ton CO_2 in *S6* and $372/ton CO_2 in *S7* by 2040, reflecting technological improvements to the CO_2 removal processes.

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

Production by OGSM District	State	Region
Mississippi, North	Mississippi	Southeast
Mississippi, South	Mississippi	Southeast
Missouri	Missouri	Midwest
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

Production by OGSM District	State	Region
South Atlantic State Offshore	South Carolina	Southeast
Alabama State Offshore	Alabama	Southeast
Louisiana State Offshore	Louisiana	Southeast
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, Scenario 1

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, Scenario 1

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.

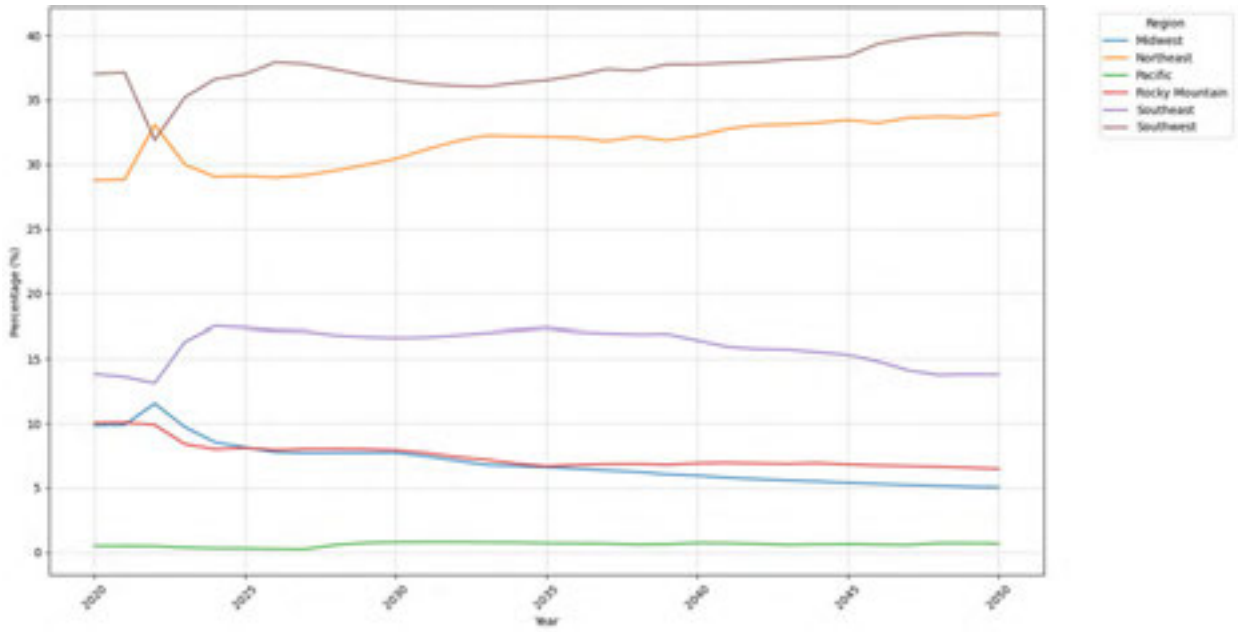


Figure C-1. Dry NG production percentage time-series for each region

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 (gCO2e/MJ) from 2020 NETL Natural Gas Report

Region	GHG (gCO2e/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.

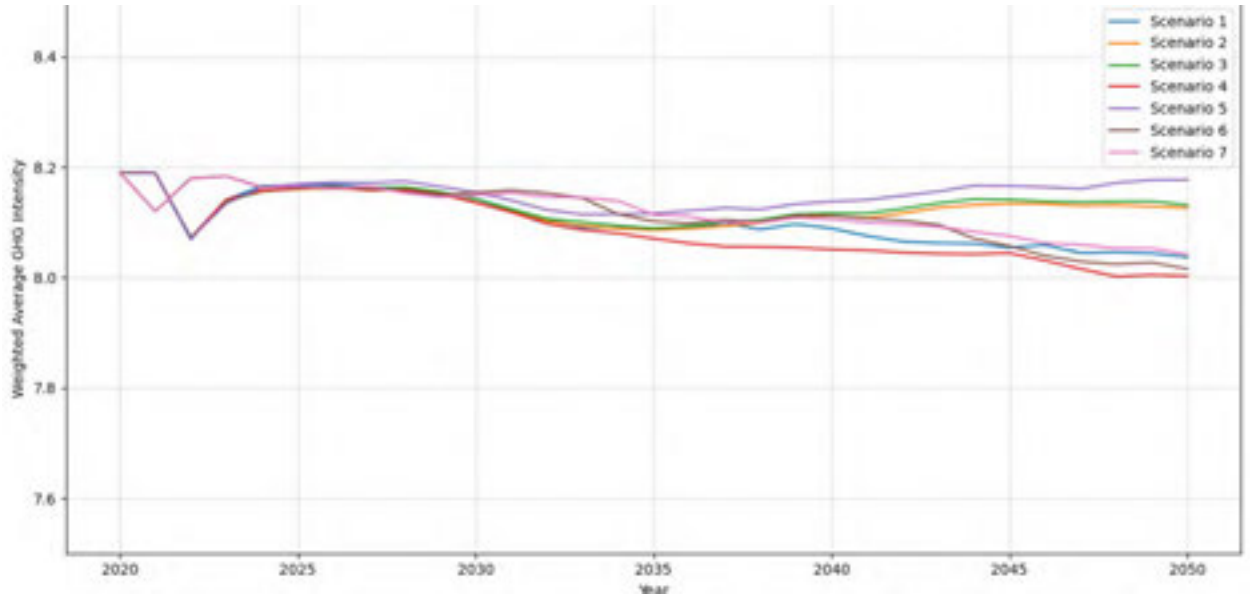


Figure C-2. Estimated U.S. Average GHG Intensity (g CO_2e/MJ) (Scenarios 1 to 7), Production through Transmission (2020 - 2050)

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 ($MtCO_2$/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.
Columns	**Description**
scenario	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 CO2 emissions values are provided, this ranges from 2015 to 2050.
value	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 CO2 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).

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 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 – nonCO_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

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.

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 CO2 equivalent per Exajoule, which conveniently are equal to g CO2e/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.

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	92.9/32.5 = 2.86	-	-
other industrial energy use (technology = refined liquids and			11/(32.5+22.5) = 0.2	-	-

refined liquids cogen)[a]		cogen, GHG emissions are allocated to the natural gas and crude oil products on an energy (EJ) produced basis from GCAM output data.			
other industrial energy use (electricity)[a]			-	-	-
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)

	Estimated GCAM Emissions Intensity (Tg CO_2e / EJ, g CO_2e / MJ) [IPCC AR5 100 yr]		
GCAM Sector	**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)

	Estimated GCAM Emissions Intensity (Tg CO_2e / EJ, g CO_2e / MJ) [IPCC AR5 20 yr]		
GCAM Sector	**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).

Table C-14. Annual Export Volumes of US LNG and Adjusted Global CO2 Emissions (AR6-100 basis)

Scenario	Year	US Export LNG (EJ)	Global CO2e 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
S1	2041	10.170	51339.6

Scenario	Year	US Export LNG (EJ)	Global CO2e Emissions (Tg)
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
S2	2045	15.946	50972.7

Scenario	Year	US Export LNG (EJ)	Global CO2e Emissions (Tg)
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
S3	2049	17.777	51353.0

Scenario	Year	US Export LNG (EJ)	Global CO2e Emissions (Tg)
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
S5	2017	1.058	51161.6

Scenario	Year	US Export LNG (EJ)	Global CO2e Emissions (Tg)
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
S6	2021	3.086	52542.1

Scenario	Year	US Export LNG (EJ)	Global CO2e Emissions (Tg)
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
S7	2025	4.961	48994.3

Scenario	Year	US Export LNG (EJ)	Global CO2e Emissions (Tg)
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

From: Curry, Thomas
Sent: Fri, 28 Jul 2023 18:43:47 +0000
To: Harker-Steele, Amanda J (NETL); Skone, Timothy; Sweeney, Amy; Easley, Kevin
Cc: Robert Wallace; hartesingh@deloitte.com; Adder, Justin (NETL); Francisco De La Chesnaye
Subject: RE: LNG Regulatory Analysis FWP - Task 4 Deliverable
Attachments: Draft_Env.Review_Task4_LNG_LNGRegAnalysisSupport_FWP-DraftPreDecisional_7_28_23.docx

DRAFT – DELIBERATIVE – PRE-DECISIONAL

Hi Amanda and Team,

As Kevin mentioned in an earlier email, the HQ team has reviewed the updated draft and added edits and comments throughout, those are consolidated in the attached file. We appreciate that the team updated resources and we understand that you are adding additional resources based on conversations with Tim and Kevin.

In addition to the detailed comments in the attached, we wanted to provide the overarching comments listed below.

I am going to be on vacation next week, but I know Kevin and Tim have scheduled time to meet with you. Please stay in communication with Kevin and Tim as you are working on this next round of updates.

I hope you have a good weekend.

Tom

Overarching Comments

- Global: Chapters 2-7 should include a brief summary of the findings or key takeaways, this could be at the opening or the end of the chapter but should be consistent in each chapter.
- Chapter 1: The regulatory review should be shortened and kept at a high level.
- Remaining chapters:
    - Remove regulatory sections
    - Include R&D in each section but create a parallel section
- Chapter 7: revamp the current DRAFT as follows:
    - Provide a condensed, succinct explanation of justice concerns in general (perhaps <= 1 page)
    - Lay out a brief treatment of energy justice more specifically (**NOTE**: Kevin / Natenna to discuss)
    - Summarize literature available on potential justice impacts related to unconventional natural gas
        - Any academic type studies of impacts of unconventional natural gas production, and of LNG projects (e.g., pipeline buildout, community impacts – from fenceline to regionally)
        - If that literature is limited or non-existent in an academic context, broaden scope first to any kind of oil and/or gas project, then to other types of energy projects (e.g., power lines)
        - If even that literature is limited or non-existent, the Addendum must clearly state that EJ type literature is currently limited; additionally, in the interest of providing

useful information for decisions makers and the public in general, present EJ summary information from:

- FERC EISs for LNG projects – EJ sections
- State studies or guidelines?
- Revisit the 2022 Ethane Report and its EJ / Stakeholder Engagement content / findings
- Other sources detailing energy development and EJ (except news journals, Op Eds, etc.)

From: Harker Steele, Amanda J. <Amanda.HarkerSteele@netl.doe.gov>
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Subject: LNG Regulatory Analysis FWP - Task 4 Deliverable

Hi Tom, Amy, Tim, and Kevin,

*DRAFT*DELIBERATIVE*PRE-DECISIONAL*

Please find the revised draft of the update to the 2014 Addendum to the Environmental Review attached. We look forward to receiving your feedback and appreciate you allowing us the opportunity to improve the original draft.

I have also attached a .zip folder that contains notes from and slides presented during the meetings we had today.

I will be on travel next week but am reachable by email and in-person if you are in the D.C. area. I will be there for a conference.

I hope you all have a nice weekend!

Sincerely,
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NATIONAL ENERGY TECHNOLOGY LABORATORY

POTENTIAL ENVIRONMENTAL IMPACTS ASSOCIATED WITH UNCONVENTIONAL NATURAL GAS

Commented [TC1]: Global comment: is the EJ chapter consistent with the frame of "environmental impacts"? Should the title and introduction be "environmental and community impacts"? I'd like feedback from Kelli, Natenna, and Odysseus on this.

Commented [ST2R1]: Guidance to NETL: We are interested in your thoughts if the title is still accurate or should be changed to reflect that the addition of EJ and that the natural gas sections discuss both unconventional and conventional gas production.



July 21, 2023

DOE/NETL-2023/4388

DRAFT DELIBERATIVE PRE-DECISIONAL

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All images in this report were created by NETL, unless otherwise noted.

Hartej Singh[2]*: Writing – Original Draft;* ***Michael Marquis***[2]*: Writing – Original Draft;* ***Odysseus Bostick***[2]*: Writing – Original Draft;* ***Robert Wallace***[2]*: Writing – Original Draft;* ***Amanda Harker Steele***[1*]*: Writing – Review & Editing, Supervision*

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Commented [ST3]: Header text needs to fit on one line.

The authors wish to acknowledge the excellent guidance, contributions, and cooperation of the NETL staff, particularly:

Commented [HSAJ4]: Comment for FE/HQ: We will update accordingly for final draft to reflect contributions.

Commented [STSR4]: Understood - thank you.

Suggested Citation:
H. Singh, M. Marquis, O. Bostick, R. Wallace, and A. Harker Steele, "Potential Environmental Impacts Associated with Unconventional Natural Gas," National Energy Technology Laboratory, Pittsburgh, July 21, 2023.

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ACRONYMS AND ABBREVIATIONS

AEO	Annual Energy Outlook
API	American Petroleum Institute
AR5	IPCC Fifth Assessment Report
B	Billion
Bcf	Billion cubic feet
BLM	Bureau of Land Management
BTEX	Benzene, toluene, ethylbenzene, xylenes
Btu	British thermal unit
CBM	Coalbed methane
CH_4	Methane
CMSC	Citizens Marcellus Shale Coalition
CO	Carbon monoxide
CO_2	Carbon dioxide
CO_2e, CO_2-eq	Carbon dioxide equivalent
COGCC	Colorado Oil and Gas Conservation Commission
CRS	Congressional Research Service
d	Day
DOE	Department of Energy
DOI	Department of the Interior
EIA	Energy Information Administration
EDP	Exploration, development, and production
EPA	Environmental Protection Agency
FECM	Office of Fossil Energy and Carbon Management
FERC	Federal Energy Regulatory Commission
FP	Flowback and produced (water)
ft, FT	Foot
g	Gram
G&B	Gathering and boosting
gal	Gallon
GAO	Government Accountability Office
GHG	Greenhouse gas
GHGI	Greenhouse Gas Inventory
GHGRP	Greenhouse Gas Reporting Program
GWP	Global warming potential
H_2S	Hydrogen sulfide
HAP	Hazardous air pollutant
HPh	Horsepower-hour
IPCC	Intergovernmental Panel on Climate Change
kg	Kilogram
kJ	Kilojoule
km	Kilometer
km^2	Square kilometers
kWh	Kilowatt hour
LCA	Life cycle analysis
LNG	Liquefied natural gas
m^2	Square meter
m^3	Cubic meter
Mcf, MCF	Thousand cubic feet
min	Minute
MIT	Massachusetts Institute of Technology
MJ	Megajoule
MM	Million
MWh	Megawatt hour
N_2O	Nitrous oxide
NEIC	National Earthquake Information Center
NETL	National Energy Technology Laboratory
NGL	Natural gas liquid
NOAA	National Oceanic and Atmospheric Administration
NORM	Naturally occurring radioactive material
NOx	Nitrogen oxides
NPS	National Park Service
NSPS	New Source Performance Standards
NYSDEC	New York State Department of Environmental Conservation
O_2	Oxygen
OAC	Ohio Administrative Code
ONE Future	Our Nation's Energy Future
ORC	Ohio Revised Code
OSF	Oral slope factor
PA	Pennsylvania

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PADEP	Pennsylvania Department of Environmental Protection
PM	Particulate matter
PRV	Pressure release valve
REC	Reduced emission completion
RFF	Resources for the Future
RfV	Reference value
RRC	Railroad Commission of Texas
scf	Standard cubic foot
SDWA	Safe Drinking Water Act
SF_6	Sulfur hexafluoride
SO_2	Sulfur dioxide
T	Trillion
T-D, T&D	Transmission and distribution
T&S	Transport and storage
Tcf	Trillion cubic feet
tCO_2	tonnes carbon dioxide
TexNet	Texas' Center for Integrated Seismicity Research
t NG	tonnes natural gas
Tg	Teragram
tonne	Metric ton
U.S.	United States
UIC	Underground Injection Control
USFS	U.S. Forest Service
USGS	U.S. Geological Survey
VOC	Volatile organic compound
WV	West Virginia
yr	Year

1 INTRODUCTION

The United States (U.S.) Department of Energy's (DOE) Natural Gas Regulatory Program is responsible for ~~granting authorizations~~reviewing applications to import and/or export natural gas from and/or to foreign countries. An important dimension ~~of~~ in considering whether to grant such authorizations is how the additional natural gas production and transport activities needed to support proposed actions ~~these exports and/or imports~~ may impact the environment. ~~As such~~Accordingly, ~~these~~ potential impacts are factors affecting the public's interest.[1]

Although fundamental uncertainties exist regarding the exact amount and location of natural gas production or transportation that would occur in response to additional authorizations being granted, it is important that DOE acknowledge and provide the public and decision-makers with access to updated information regarding the potential environmental consequences associated with such activities. Accordingly, DOE has prepared this update to the 2014 Addendum to Environmental Review Documents Concerning Exports of Natural Gas from the United States (hereafter the 2014 Addendum) to provide the public with an improved understanding of the potential environmental impacts associated with such activities (DOE, 2014).

We cannot estimate with certainty where, when, or by what method any additional natural gas would be produced, consumed, or exported in response to the granting of authorizations to import and/or export natural gas. Therefore, DOE cannot meaningfully analyze the specific environmental impacts associated with such activities. ~~As such, similar to~~Therefore, as with the 2014 Addendum, this report provides only a review of ~~the profusion of~~ peer-reviewed, scientific literature ~~produced~~ related to the potential environmental consequences of expanding natural gas production and related activities.

As unconventional natural gas production has represented an ever-growing share of U.S. natural gas production, the environmental impacts reviewed in this report relate primarily to those associated with unconventional production activities. The publications referenced build on a strong body of existing literature that traces the evolution of unconventional natural gas production techniques from their conceptual stages in the 1970s, to the technology advancements that contributed to the shale gas boom of the early 2000s, as well as ~~and~~ further development of additional unconventional resources, including tight gas sands and coalbed methane (CBM) resources to the export of liquefied natural gas (LNG).

This report attempts~~makes every attempt~~ to summarize the published descriptions of the potential environmental impacts of ~~unconventional~~ natural gas ~~upstream~~ operations within the lower 48 states as detailed by government, industry, academia, scientific, non-governmental, and citizen organizations. The sources cited are all publicly available documents. While this

[1] DOE is responsible for considering the environmental impact of its decisions on applications to export natural gas, including liquefied natural gas (LNG), to countries with which the United States has not entered into a free trade agreement (FTA) requiring national treatment for trade in natural gas. (Applications for trade with FTA countries are deemed to be in the public interest by statute.) DOE conducts environmental reviews under the National Environmental Policy Act (NEPA) and as part of its public interest review under the Natural Gas Act (NGA).

Commented [TC6]: @Lavoie, Brian D. should we specify that this is for authorizations to non-FTA countries or is the use of this document broader to include all authorizations?

Commented [LBD7R6]: It's correct that this would only be used for non-FTA applications. (FTA applications are not subject to DOE NEPA review.) I'd suggest maybe just a footnote on this (see my suggestion), so as not to distract the reader at this early point. (Amy/Jen - please jump in if you have a different view.)

Commented [ST8R6]: Guidance to NETL: Add Brian's suggested footnote.

Commented [LBD9]: Suggest consider "may" and similar language that reflects uncertainties about impacts.

Commented [LBD10]: @Easley, Kevin do you suggest in-text treatment of this point vs. the footnote? I think it should be one or the other.

Commented [EK11R10]: I don't have a preference. But my sense is not everyone reading this Addendum will know what exactly goes into / governs a DOE 'public interest determination.' I defer to you and @Sweeney, Amy, @Lavoie, Brian D.

Commented [LBD12]: "such activities" near the end of this passage, at least textually as written, refers to "both conventional and unconventional natural gas markets" earlier in the passage. Suggest clarify to focus on unconventional, which is the topic of this report.

Commented [HSAJ13R12]: Done

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report by no means represents an exhaustive list of the sources that discuss environmental consequences of upstream natural gas activities, the sources cited are ~~assumed~~ believed to be representative, and no significant areas have been excluded from the report. Multiple publications on similar topics are compared based only on their technical and methodological distinctions. Over the past decade, the focus of environmental issues has evolved with some interest in the public literature varying over time. Key research in some areas remains the same with minor to no new additions to the basis of scientific knowledge, in this situation some historical references have been maintained. No opinion on or endorsement of these works is intended or implied.

Commented [LBD14]: Can something be said like that the authors believe this survey is representative and no significant areas have been excluded from this review?

Commented [HSAJ15R14]: Done

This report is divided into chapters, each of which contains a separate section of references so that each type of environmental impact can be explored further. The types of environmental impacts that are documented in this review include the following:

- Greenhouse gas (GHG) emissions and climate change (Chapter 2)
- Air quality (Chapter 3)
- Water use and quality (Chapter 4)
- Induced seismicity (Chapter 5)
- Land use and development (Chapter 6)
- Environmental and social justice (Chapter 7)

In addition to containing information on potential environmental impacts, this report provides some background information on domestic natural gas production.

1.1 Natural Gas Basics

Natural gas is an odorless, gaseous mixture of hydrocarbons, largely made up of methane (CH_4) but also containing small amounts of natural gas liquids (NGLs) and nonhydrocarbon gases (e.g., carbon dioxide [CO_2] and water vapor) (EIA, 2023b). Natural gas is one of the major combustion fuels used throughout the country. It is mainly used to generate industrial and utility electric power, produce industrial process steam and heat, and heat residential and commercial spaces. The average gross heating value of natural gas is approximately 1,020 British thermal units per standard cubic foot (Btu/scf), usually varying from 950 to 1,050 Btu/scf.

Commented [ST16]: The HHV of natural gas used in the LCA work is 1,031 Btu/scf (54.1 MJ/kg) [60 deg F, 1 atm]. You need to specify HHV or LHV and at what standard conditions you are reporting. My understanding is that the oil & gas industry uses 60F / 1atm as the definition of "standard" conditions, while the industrial gas industry prefers 70F / 1atm.

Natural gas is typically classified as being either conventional or unconventional, depending on the permeability of the formation within which it is found, the production technology used to secure it, the current economic environment, and the scale, frequency, and duration of production from the resource (EIA, 2023b; Krieg, 2018).

Generally, conventional natural gas refers to natural gas found in highly permeable reservoirs, typically composed of sandstone or limestone, which allows for extraction to be completed in a relatively straightforward manner via vertical rather than horizontal drilling. Unconventional natural gas refers to natural gas found within low-permeabilityle reservoirs; it is generally trapped within the pores (i.e., small, unconnected spaces) of rocks, which makes extraction

more difficult and necessitates advanced drilling (e.g., directional or horizontal drilling) and well stimulation (e.g., hydraulic fracturing) techniques that are energy intensive (BP, 2017).

Innovations in existing oil and gas exploration and production technologies have revolutionized unconventional natural gas production in the United States. The production of natural gas from ~~U~~unconventional ~~natural gas~~ resources has not only ~~make~~ made up for declining conventional natural gas production but has~~ve~~ also led to new levels of natural gas supply in the United States. This increased supply has contributed to an increase in the use of natural gas for power generation, manufacturing, transportation, and residential and commercial heating, as well as the ~~amount~~ availability of natural gas ~~being exported~~ for export from the United States.

There are three primary types of unconventional natural gas:[b]

- **Shale Gas:** refers to natural gas found within shale rock formations, which consist of fine-grained sedimentary rock that forms when silt and clay-size mineral particles are compacted together (Zendehboudi and Bahadori, 2017). Shale rock formations can be easily broken into thinner, parallel layers of rock. ~~Black shale, a dark-colored type of sedimentary shale rock containing organic-rich material, is also a source rock for unconventional natural gas (Ohkouchi, Kuroda, and Taira, 2015).~~
- **CBM:** refers to natural gas that is both generated and stored in coal beds. Originally extracted from coal mines to reduce the potential for explosions caused by an excess of CH_4 gas within the mine and subsequently disposed of, CBM now serves as an important source of energy. ~~Sequestering~~ Producing CBM from deeper, denser coal formations often requires the use of hydraulic fracturing technology.
- **Tight Sands Gas:** refers to natural gas found in low-permeability, gas-bearing, fine-grained sandstones, or carbonates.

Shale rock formations can contain significant accumulations of natural gas and/or oil. These formations are often referred to as "plays" and can be found in nearly 30 U.S. states. Operators in ~~T~~the Barnett Shale formation, which is located in Texas and is one of the largest onshore natural gas ~~fields~~plays in the United States, haves been producing unconventional natural gas since the early 2000s (RRC, 2023). ~~It is one of the largest onshore natural gas fields in the United States.~~ While operators in the Barnett Shale formation still produces a significant amount of unconventional natural gas, the Marcellus Shale formation—located in the Appalachian Region of the United States and spanning Ohio, Pennsylvania, and West Virginia—is currently the largest ~~producer~~ source of unconventional natural gas from shale (EIA, 2023b).

Primary enabling technologies for accessing unconventional natural gas include hydraulic fracturing and horizontal drilling. Hydraulic fracturing (sometimes referred to as hydrofracking or simply fracking) is the process of pumping water mixed with a small amount of sand and other chemical additives (i.e., fracturing fluid) underground through a wellbore at a pressure

Commented [ST17]: NETL: we added this text for clarity, is it still appropriate to reference BP, 2017? Please confirm.

Commented [LBD18]: Should increasing exports be mentioned here, for completeness?

Commented [HSAJ19R18]: Adjusted

[b] There are other types of unconventional natural gas whose exploitation has not yet reached commercial scale. These include methane hydrate, which is a crystalline solid that consists of a methane molecule surrounded by a cage of interlocking water molecules. Methane hydrate is an "ice" that only occurs naturally in subsurface deposits where temperature and pressure conditions are favorable for its formation.

that is sufficient to cause a target rock formation to break (i.e., fracture) (USGS, 2019).[c] As the rock is fractured, natural gas that would have otherwise remained trapped is able to be released into a wellbore and returned to the surface (USGS, 2019).

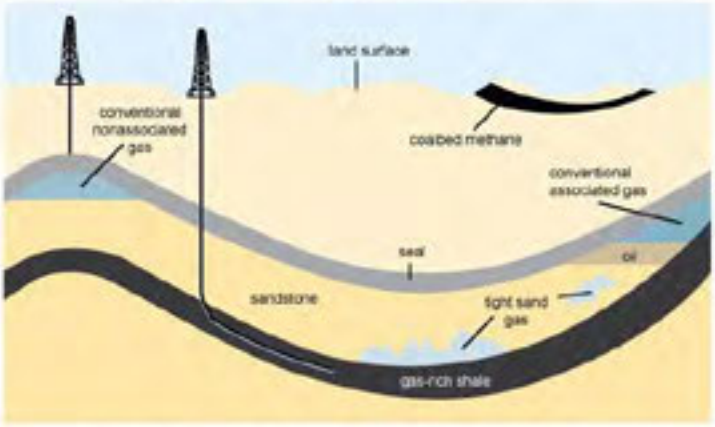
The iInternal pressure caused by the fracturing of the rock formation also releases fluid, which travels to the surface through the wellbore. This fluid is commonly referred to as "flowback" or "produced water" and may contain the injected chemicals in addition to any naturally occurring materials found below the surface (e.g., brines, metals, radionuclides, and hydrocarbons). The fluid is typically stored on site in tanks or pits before it is treated and disposed of or recycled. In many cases, disposing of the fluid involves injecting it underground. In areas where underground injection is not an option, the fluid can either be reused or processed by a wastewater treatment facility and subsequently discharged into surface water.

Hydraulic fracturing has been applied since the late 1940s when Standard Oil of Indiana (later known as Amoco) developed the technique and performed some of the first fracture treatments in the Hugoton Gas Field in Kansas (BP, 2017). While the use of hydraulic fracturing is not limited only to wells that are horizontally drilled, the combination of horizontal drilling and hydraulic fracturing has increased the volume of domestic natural gas considered to be "technically recoverable" (i.e., able to be produced using currently available technology and industry practices regardless of any economic considerations).

The process of horizontal drilling involves first drilling a vertical well. Once a certain depth has been reached with the vertical well, the path of drilling is bent until the well begins to extend horizontally. Horizontal wells are not only longer than vertical wells, but the process is much more complex. As such, aA horizontal well is therefore generally more expensive to drill than a vertical well, but it is expected to produce more natural gas (EIA, 2018). The horizontal section, sometimes referred to as or directionally drilled section, of a well can extend thousands of feet (ft). Exhibit 1-1 provides a schematic of conventional natural gas and the various types of unconventional natural gas resources described previously (EIA, 2023b). Exhibit 1-2 provides a schematic of the hydraulic fracturing process (BP, 2017).

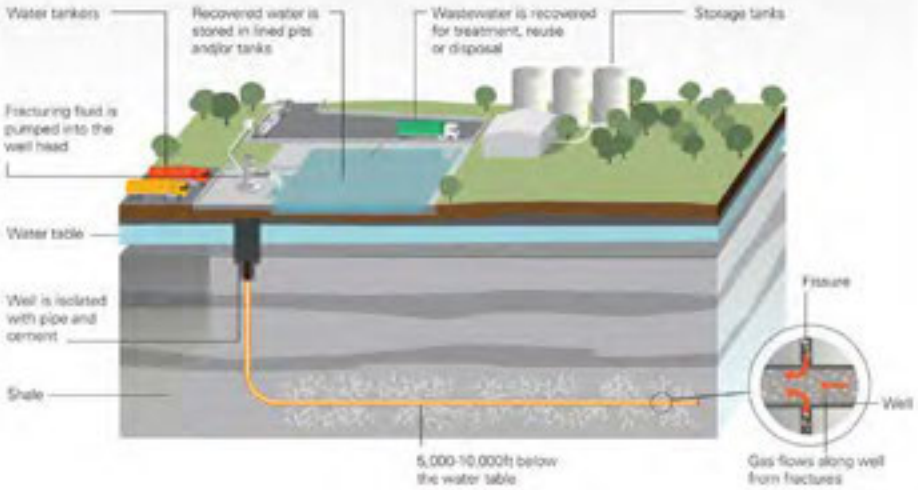
[c] The specific types of chemical additives used, and the proportions of each, depend on the type of rock formation that is being fractured. Additives function as friction reducers, biocides, oxygen (O_2) scavengers, stabilizers, and acids, all of which are necessary to optimize production. The composition of these fluids and the purposes of the additives are described in more detail in Chapter 4 – Water Use and Quality.

Exhibit 1-1. Schematic geology of natural gas resources



Source: Energy Information Administration (EIA 2023b)

Exhibit 1-2. Schematic geology of natural gas resources (3D)



Permission pending from BP (2017)

Commented [TC20]: I assume NETL has requested permission for all the figures, what is the timeline for getting these permissions in place?

Commented [ST21R20]: NETL: please create a graphic permission tracker with the received permissions contained/linked to archive with the project files. Thank you.

1.1.1 Liquefied Natural Gas

Liquefied natural gas (LNG) is natural gas that has been cooled to a liquid state (~~i.e., cooled to about~~approximately –260° Fahrenheit). The volume of natural gas in a liquid state is about 600 times smaller than ~~the volume of natural gas~~ in a gaseous state. Liquification of natural gas makes it possible to transport natural gas to places where pipelines currently do not exist or current pipeline infrastructure is unable to reach as well as for natural gas storage for end-use reliability ~~(e.g., abroad)~~. Liquefying natural gas is one way to allow markets that are far away from production regions to access natural gas. Once in liquid form, natural gas can be shipped to terminals around the world via ocean tankers and in some cases by LNG transport trailers (i.e., trucks). At these terminals, the LNG is returned to its gaseous state and transported by pipeline to distribution companies, industrial consumers, and power plants (DOE, 2021).

1.2 U.S. Natural Gas Resources

Annual U.S. production of dry natural gas was approximately ~~equal to~~ 35.81 trillion cubic feet (Tcf) in 2022 (an average of about 98.11 billion cubic feet [Bcf] per day). Production has mostly increased year over year since 2005 as hydraulic fracturing combined with horizontal drilling of shale, sandstone, carbonate, and other geologic formations has continued. About 70~~.4~~ percent of domestic dry natural gas production in 2021 was supplied by ~~five~~ of the United States's 34 natural gas-producing states. States with a larger percentage share of total U.S. dry natural gas production in 2021 include Texas (24.6 percent), Pennsylvania (21.8 percent), Louisiana (9.9 percent), West Virginia (7.4 percent), and Oklahoma (6.7%) (Exhibit 1-3) (EIA, 2023b).

Exhibit 1-3. U.S. natural gas production by state in 2021



eia Data source: U.S. Energy Information Administration, *Natural Gas Annual*, September 2022

Source: EIA (2023b)

Commented [TC22]: Are there years that it did not increase? I'd rather not use "mostly" unless necessary. Would prefer to say, "With the except of X years, production has increase year over year since 2005..."

Commented [HSAJ23]: Notes/Questions for FE HQ:

1. State-Level production data is not yet available for 2022 from the EIA. Do you prefer we remove this figure?

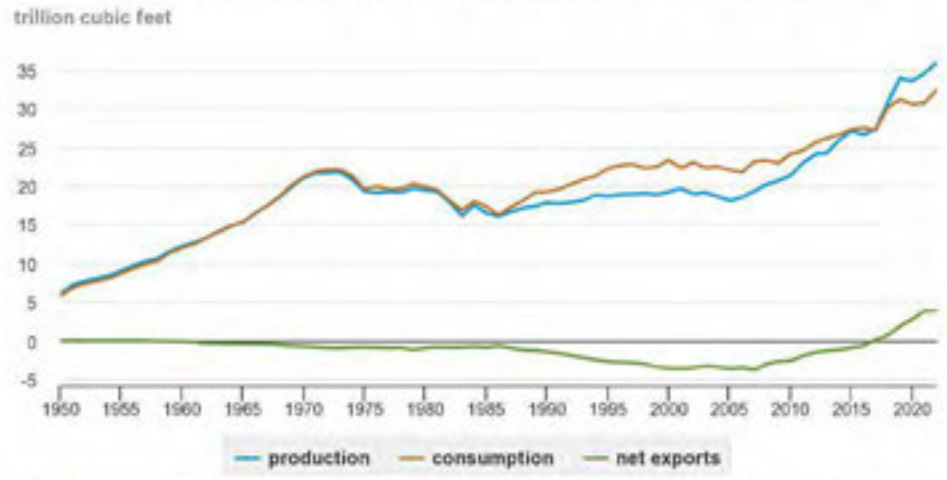
Commented [ST24R23]: NETL: Keep figure BUT add to paragraph above the 2021 US dry gas production total put it in context to the 2022 value and support the 2021 figure. It is okay to state that 2022 state level data was not available at the time of report production in a footnote if you would like.

In 2022, production from coalbeds accounted for about 2 percent of U.S. dry natural gas production, and supplemental gaseous fuels accounted for about 0.2 percent. Supplemental gaseous fuels include biogas (sometimes called renewable natural gas), synthetic natural gas, and other gases. Although most of the natural gas wells operated by the United States are located onshore, some wells are drilled offshore (i.e., into the ocean floor in waters off the coast of the United States). In 2022, offshore dry natural gas production was approximately equal to 0.80 Tcf, accounting for about 2.3 percent of total production. The majority—87.6 percent—of this production occurred in federally managed waters within the Gulf of Mexico (EIA, 2023c).

In addition to being a producer of natural gas, the United States is also a consumer and net exporter of natural gas. In 2022, the United States produced about 10.8 percent more natural gas than it consumed. While there was sufficient domestic production to meet our consumption requirements, the United States did import some natural gas, mostly from Canada. However, on a net basis, the United States was an exporter of natural gas. ~~, not enough, however, to no longer be considered a net exporter.~~ Exhibit 1-4 highlights recent (2022) and historical (1950–2021) U.S. natural gas production, consumption, and net exports (EIA, 2023c).

Commented [ST25]: NETL: we removed all discussion of projections from this document that followed Exhibit 1-4. Projections will be covered by the GCAM/NEMS work. Thanks.

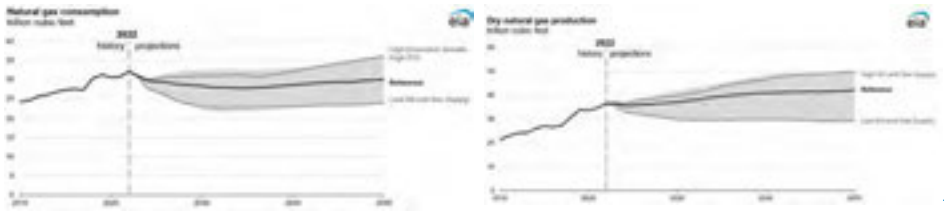
Exhibit 1-4. U.S. natural gas consumption, dry production, and net exports (1950–2022)



Source: EIA (2023c)

~~According to EIA's Annual Energy Outlook 2023 (AEO2023) reference scenario, domestic natural gas consumption is projected to decrease slightly but remain relatively constant out to 2050. Domestic natural gas production is projected to increase slightly and then also remain relatively constant out to 2050; see Exhibit 1-5 (EIA, 2023a).~~

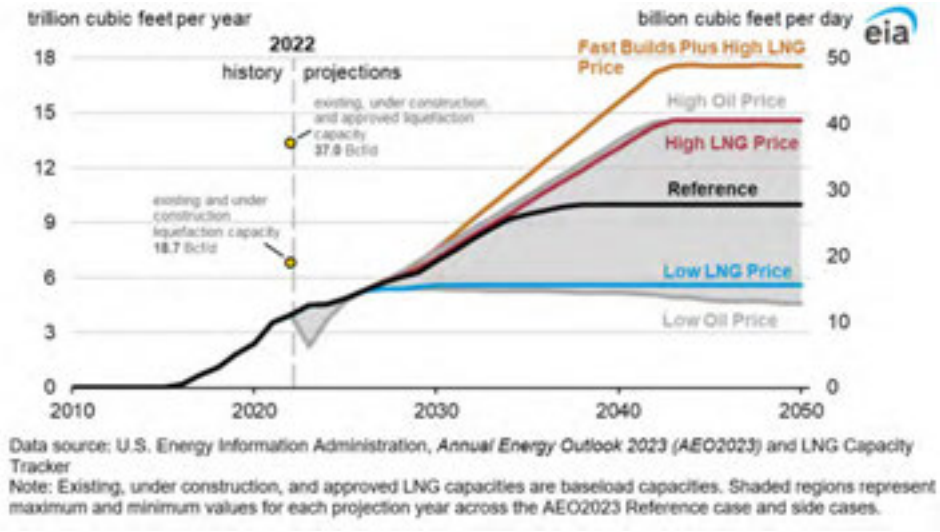
Exhibit 1-5. Natural gas consumption and dry production projections through 2050



Source: EIA (2023a)

The AEO2023 reference scenario also projects that exports of natural gas, primarily LNG, will continue to increase between now and around 2035 (see Exhibit 1-6).

Exhibit 1-6. U.S. LNG export projections through 2050



Data source: U.S. Energy Information Administration, *Annual Energy Outlook 2023 (AEO2023)* and LNG Capacity Tracker
Note: Existing, under construction, and approved LNG capacities are baseload capacities. Shaded regions represent maximum and minimum values for each projection year across the AEO2023 Reference case and side cases.

Source: EIA (2023a)

1.3 U.S. Regulatory Framework and Federal Research and Development Programs

The following sub-sections provide a review of both federal and state regulatory responsibilities related to the production, transportation, use, and export of domestic natural gas resources.

1.3.1 Federal

Multiple federal agencies have authority over the production of unconventional natural gas resources. Three of these agencies—DOE, the Department of the Interior (DOI), and the Environmental Protection Agency (EPA)—play a critical role as they are charged with monitoring, assessing, and reporting on various natural gas environmental impacts [illegible] Exhibit 1-5 describes the roles and responsibilities of these three agencies in more detail in addition to the way these agencies work together to inform policy-relevant science.

Exhibit 1-5. Key U.S. agencies and their roles in natural gas development and production



Source: DOE

EPA is in charge of regulating underground injection and disposing of wastewater resources and other liquids covered under the Safe Drinking Water Act (SDWA). They are also charged with regulating the air emissions covered under the Clean Air Act (CAA).

Federal agencies including EPA, DOI's Bureau of Land Management (BLM), the National Park Service (NPS), the Occupational Safety and Health Administration (OSHA), and the U.S. Forest Service (USFS) are responsible for enforcing regulations for unconventional natural gas wells drilled on public lands. BLM is responsible for ensuring the environment of these lands remains protected and unaffected by natural gas production and other related activities.

USFS and BLM are both responsible for managing natural gas development on federally owned lands. Natural gas production and other related activities that will or do take place within the boundaries of our nation's national parks and other land managed by the ~~are the responsibility of~~ NPS, which establishes regulations to protect park resources and visitor values. Exhibit 1-6

Commented [EK26]: Please add CAA to the Acronyms List.

Commented [EK27]: Please add OSHA to the Acronyms List.

provides some examples of federal statutes that apply to unconventional natural gas development.

Exhibit 1-6. Selected federal regulations that apply to unconventional oil and gas development

Statutes	Applicability
Clean Air Act	Places requirements on air emissions from sources of emissions at well sites; addresses compliance with existing and new air regulations, often delegated to local and state agencies. Generally, there is no distinction made between conventional and unconventional wells under the Clean Air Act.
Comprehensive Environmental Response, Compensation, and Liability Act	Only applies if hazardous substances besides crude oil or natural gas are released in quantities that require reporting. Natural gas releases do not require notification under the Comprehensive Environmental Response, Compensation, and Liability Act, but other hazardous substances may be released in reportable quantities during natural gas production.
Clean Water Act	Limits pollutants on produced water discharge under the National Pollutant Discharge Elimination System; stormwater runoff containing sediment that would cause a water-quality violation requires a permit under Clean Water Act decisions. Beneficial uses of surface waters are protected under Section 303.
Emergency Planning and Community Right-to-Know Act	Requires facilities storing hazardous chemicals above the threshold to report same and provide a Material Safety Data Sheet to officials and fire departments.
Endangered Species Act	Prohibits federal agencies from taking any action that is likely to jeopardize the continued existence of any endangered or threatened species (listed species) or result in the destruction or adverse modification of such species' designated critical habitat (Section 7); prohibits the taking of a listed species (Section 9); allows the Fish and Wildlife Service and National Marine Fisheries Service to issue a permit, accompanied by an approved habitat conservation plan, that allows for the incidental, non-purposeful "take" of a listed species under their jurisdictions (Section 10).
National Environmental Policy Act	Requires analysis of potential environmental impacts of proposed federal actions, such as approvals for exploration and production on federal lands.
Oil Pollution Act	Identifies spill prevention requirements, reporting obligations, and response planning (measures that will be implemented in the case of release of oil or other hazardous substances).
Resource Conservation and Recovery Act	Addresses non-hazardous solid wastes under Subtitle D. The Solid Waste Disposal Act exempts many wastes produced during the development of natural gas resources, including drilling fluids and produced water. EPA has determined that other federal and state regulations are more effective at protecting health and the environment.
Safe Drinking Water Act	Prevents the injection of liquid waste into underground drinking water sources through the Underground Injection Control (UIC) program. Fluids other than diesel fuel do not require a UIC permit. The UIC program gives requirements for siting, construction, operation, closure, and financial responsibility. Forty states control their own UIC programs.

1.3.1.1 Bureau of Land Management

BLM manages the U.S. government's onshore subsurface mineral estate, an area of about 700 million (MM) acres held jointly by BLM, USFS, and other federal agencies and surface owners.

Natural gas produced from the U.S. government's onshore subsurface mineral estate represents a significant portion of our nation's energy mix. In fiscal year 2022[4], sales of oil, gas, and natural gas liquids produced from the U.S. government's onshore subsurface mineral estate accounted for approximately 11 percent of all oil and 9 percent of all natural gas produced in the United States. About 23 MM acres had been leased to natural gas developers by the end of that year, and about 12.4 MM of those acres were producing natural gas in economic quantities (BLM, 2023). BLM published a rule regulating fracking on public lands on March 26, 2015—this rule was rescinded on December 28, 2017 (Fitterman, 2021).

1.3.1.2 Environmental Protection Agency

EPA's New Source Performance Standards (NSPS) under the CAA set the regulations for emissions sources from the oil and natural gas sector. Exhibit 1-7 illustrates the scope of NSPS established to-date and the way regulations have evolved in scope since 2012 (EPA, 2021).

Exhibit 1-7. Natural gas sources covered by EPA's proposed NSPS and Emissions Guidelines, by site

Location and Equipment or Process Covered	Required to or Would be Required to Reduce Emissions under EPA Rules (if finalized as proposed)	Rules that Apply			
		2012 NSPS for VOCs (OOOO)	2016 NSPS for Methane & VOCs (OOOOa)	2021 Proposed NSPS for Methane & VOCs (OOOOb)	2021 Proposed Emissions Guidelines for Methane (OOOOc)
Oil and Natural Gas Well Sites					
Completions of hydraulically fractured wells	✓	•	•	•	
Compressors at centralized tank batteries	✓			•	•
Fugitive emissions	✓		•	•	•
Liquids unloading	✓			•	
Pneumatic controllers	✓	•	•	•	•
Pneumatic pumps	✓		•	•	•
Storage vessels	✓	•	✓[1]	•	•
Sweetening units	✓	✓[1]	✓[1]	✓[1]	✓[1]
Associated gas from oil wells	✓			•	•
Natural Gas Gathering and Boosting Compressor Stations					
Compressors	✓	•	•	•	•
Fugitive emissions	✓		•	•	•
Pneumatic controllers	✓	•	•	•	•
Pneumatic pumps	✓			•	•
Storage vessels	✓	•	✓[1]	•	•
Sweetening units	✓	✓[1]	✓[1]	✓[1]	✓[1]
Natural Gas Processing Segment					
Compressors	✓	•	•	•	•
Fugitive emissions	✓	•		•	•
Pneumatic controllers	✓	•	•	•	•
Pneumatic pumps	✓		•	•	•
Storage vessels	✓	•	✓[1]	•	•
Sweetening units	✓	✓[1]	✓[1]	✓[1]	✓[1]
Transmission and Storage Segment					
Compressors	✓		•	•	•
Fugitive emissions	✓		•	•	•
Pneumatic controllers	✓		•	•	•
Pneumatic pumps	✓			•	•
Storage vessels	✓	•	•	•	•

[1]Covered for SO_2 only; [2]Covered for VOCs only

Source: EPA

EPA's Greenhouse Gas Reporting Program (GHGRP) requires reporting of GHG emissions data and other relevant information ~~to be reported~~ by large sources of emissions, including fuel and industrial gas suppliers and CO_2 injection sites (EPA, 2023). The data reported is available to businesses, stakeholders, and other persons interested in tracking and comparing the GHG emissions of facilities, identifying opportunities to reduce emissions, minimizing wasted energy, and saving money. ~~States, cities, and communities can also use EPA's GHG data to identify high-~~

[4] October 1, 2021 through September 30, 2022

Commented [TC28]: BLM proposed rules to regulate methane releases in federal lands in 2021. Interior Department Takes Action to Reduce Methane Releases on Public and Tribal Lands | Bureau of Land Management (blm.gov)

Commented [ST29R28]: NETL: please add the 2021 rule to the discussion.

Commented [TC30]: I recommend revising this section to generally discuss EPA's role establishing regulations for air, GHG emissions, and water. The specifics on each could then be moved to the appropriate sections in the chapters.

Commented [ST31R30]: NETL: Note global guidance is to consolidate at a high level the regulatory discussion within Chapter 1. Please disregard the following part of the comment form Tom above " The specifics on each could then be moved to the appropriate sections in the chapters."

~~emitting facilities in their areas, compare emissions between similar facilities, and develop common-sense climate policies for constituents.~~ The petroleum and natural gas industry is covered under Subpart W of EPA's GHGRP. Unconventional natural gas production is covered under the provisions for onshore production, natural gas processing, natural gas transmission, and LNG storage and import/export. Annual CO_2, CH_4 and nitrogen oxides (NOx) emissions must be reported separately for each of these segments.

EPA studied the relationship between hydraulic fracturing for oil and natural gas and drinking water resources (EPA, 2022a). The study includes a review of published literature, analysis of existing data, scenario evaluation and modeling, laboratory studies, and case studies. EPA released a progress report in December 2012, a final draft assessment report for peer review and comment in June 2015, and the final report in December 2016. The final EPA report concludes that hydraulic fracturing activities can impact drinking water resources under some circumstances and identifies factors that influence these impacts.

A core element of the SDWA UIC program is setting requirements for proper well siting, construction, and operation to minimize risks to underground sources of drinking water. The Energy Policy Act of 2005 excluded hydraulic fracturing (except when diesel fuels are used) for oil, natural gas, or geothermal production from regulation under the UIC program. This statutory language caused regulators and the regulated community alike to raise questions about the applicability of permitting practices. As a result, EPA developed revised UIC Class II permitting guidance specific to oil and natural gas hydraulic fracturing activities using diesel fuels (EPA, 2022a). Although developed specifically for hydraulic fracturing where diesel fuels are used, many of the guidance's recommended practices are consistent with best practices for hydraulic fracturing in general, including those found in state regulations and model guidelines for hydraulic fracturing developed by industry and stakeholders. Thus, states and tribes responsible for issuing permits and/or updating regulations for hydraulic fracturing will find the recommendations useful in improving the protection of underground sources of drinking water and public health wherever hydraulic fracturing occurs. The guidance outlines for EPA permit writers, where they are the permitting authority, (i) existing Class II requirements for diesel fuels used for hydraulic fracturing of wells, and (ii) technical recommendations for permitting those wells consistently with these requirements (EPA, 2022a).

EPA completed a stakeholder engagement effort in 2020 that sought input on how the agency, states, tribes, and stakeholders regulate and manage wastewater from the oil and gas industry. EPA released a draft report in May 2019 that described what it heard during its engagement for this study (EPA, 2022a). EPA accepted public input on the draft report and, after considering this input, published a final report. In many regions of the United States, underground injection is the most common method of managing fluids or other substances from shale gas extraction operations. Management of flowback and produced water via underground injection is regulated under the SDWA UIC program. The Clean Water Act (CWA) effluent guidelines program sets national standards for industrial wastewater discharge to surface waters and municipal sewage treatment plants based on the performance of treatment and control technologies. Effluent guidelines for onshore oil and natural gas extraction facilities prohibit the discharge of pollutants into surface waters, some permit exception may allow for discharge under unique conditions, ~~except for wastewater that is of good enough quality for use in~~

Commented [LBD32]: Please check timing/dates -- 2020 engagement was reported on in 2019?

Commented [LBD33]: Citation?

Commented [EK34]: Please add CWA to the Acronym List.

agricultural and wildlife propagation for those onshore facilities. On June 28, 2016, EPA promulgated pretreatment standards for the Oil and Gas Extraction Category (40 Code of Federal Regulations Part 435). These regulations prohibit discharge of wastewater pollutants from onshore unconventional oil and natural gas extraction facilities to publicly owned treatment works.*

On December 6, 2022, EPA issued a supplemental proposal to update, strengthen, and expand standards intended to significantly reduce emissions of GHG and other harmful air pollutants from the Crude Oil and Natural Gas source category (EPA, 2022b). First, EPA proposed standards for certain sources that were not previously addressed. Second, EPA proposed revisions that strengthen standards for sources of leaks, provide greater flexibility to use innovative advanced detection methods, and establish a super-emitter response program. Third, EPA proposed to modify and refine certain elements of the proposed standards in response to information submitted in public comments. Finally, EPA proposed details of the timelines and other implementation requirements that apply to states to limit CH_4 pollution from existing designated facilities in the source category under the CAAlean Air Act (EPA, 2022b).

Commented [LBD35]: Is there anything that can be said at the end of the paragraph on current status? Or timeline expected for final rule?

1.3.1.3 Department of Energy

The NGAatural Gas Act requires DOE to make public interest determinations on applications to export LNG to countries where the United States does not have existing free-trade agreements requiring national treatment for trade in natural gas. The Office of Fossil Energy and Carbon Management's (FECM) natural gas import–export regulatory program is implemented by the Division of Regulation in the Office of Regulation, Analysis, and Engagement. Typically, the Federal Energy Regulatory Commission (FERC) has direct regulatory responsibility over the siting, construction, and operation of onshore LNG export facilities in the United States. In these cases, FERC leads the environmental impact assessments of proposed projects consistent with the National Environmental Policy Act (NEPA), and DOE is typically a cooperating agency as part of these reviews (DOE, 2023a). Similarly, for offshore LNG export facilities, the Department of Transportation's (DOT) Maritime Administration (MARAD) is responsible for environmental reviews, in coordination with the U.S. Coast Guard (USCG), guided by requirements in the Deepwater Port Act. Again, DOE is typically a cooperating agency in these reviews. In some limited circumstances, DOE is the lead agency for NEPA reviews related to proposed LNG exports.

Commented [EK36]: Please add NEPA to the Acronym List.

Commented [EK37]: Please add both DOT and MARAD to the Acronym List.

Commented [EK38]: Please add USCG to the Acronym List.

FECM's Point Source Carbon Capture Division's research, development, demonstration, and deployment portfolio facilitates the development of technologies and infrastructure that improve performance, reduce costs, and scale the deployment of technologies to decarbonize the industrial and power sectors and remove CO_2 from the atmosphere. Within the natural gas supply chain, these efforts include research and commercial-scale demonstration of

* "Publicly owned treatment works" is a term used in the United States to designate a sewage treatment plant owned, and usually operated, by a government agency. In the United States, publicly owned treatment works are typically owned by local government agencies and are usually designed to treat domestic sewage and not industrial wastewater.

technologies that advance carbon capture and storage on natural gas-fired power plants and industrial natural gas combustion streams (DOE, 2023a).

FECM is working to support efforts to decarbonize LNG terminals through ~~deployment~~ exploration of technical and economic feasibility of carbon capture on gas separation and combustion streams and the use of electric motor drives supplied by net-zero emissions electricity. Decarbonizing LNG terminals is a key part of the effort to reduce life cycle emissions associated with the export of natural gas to global allies. ~~Additionally, DOE has regulatory responsibilities related to LNG. Companies that want to export LNG must get authorization to do so from FECM.~~

FECM's Methane Mitigation Technologies Division aims to eliminate non-trivial fugitive and vented CH_4 emissions from the natural gas supply chain to reduce the climate impacts from the production and use of natural gas. The division is focused on developing accurate, cost effective, and efficient technology solutions and best practices to identify, measure, monitor, and minimize CH_4 emissions from these sources. DOE has funded several technology investigations through NETL that deal with produced water management and life cycle assessments of the natural gas value chain (DOE, 2023b).

DOE's shale gas research program brings together federal and state agencies, industry, academia, non-governmental organizations (NGOs), and national laboratories to develop technologies that enable safe, environmentally sustainable oil and gas production. DOE's shale gas research program is tasked with calculating the risks of oil and gas exploration and production undertakings. ~~DOE has funded several technology investigations through NETL that deal with produced water management and life cycle assessments of the natural gas value chain (DOE, 2023b).~~

On April 21, 2023, a Request for Information (RFI) Pwas issued by FECM to obtain input to inform DOE's research and development (R&D) Pactivities within the Office of Research and Development's Methane Mitigation Technologies Division and the Office of Carbon Management Technologies' Point Source Carbon Capture Division. In addition, such data and information could help inform the Office of Regulation, Analysis, and Engagement's capabilities to assess natural gas import and/or export applications ~~under the Natural Gas Act of 1938, as amended~~. Through the R~~equest for information~~, DOE ~~is~~ requesteding information on strategies and technologies that natural gas and LNG companies are deploying, or could deploy, to reduce GHG emissions and other air pollutants associated with natural gas delivered to liquefaction facilities, housed at liquefaction facilities, and being loaded, transported, and delivered to regasification facilities (DOE, 2023a).

1.3.2 States

States have the power to implement their own requirements and regulations for unconventional natural gas drilling that are equivalent to or more stringent than established federal practices. ~~with federal oversight.~~ All states that produce natural gas have at least one agency charged with issuing new permits for production wells. While state requirements for permits can differ, any requirements set forth by federal regulations must be met ~~in order~~ for a state-level permit to be issued.

Commented [ST39]: We issued an RFI, but do we have funded work on these paths today?

Commented [ST40R39]: NETL: we softened this language as we have not funded CCS or electric motor conversion to support the verb "deployment".

Commented [ST41]: This sentence is broader than Shale Gas Research and better aligns to the Methane Mitigation paragraph above for the LCA work. Produced water is in a different program line as well.

Commented [EK42]: Please add NGOs to the Acronym List.

Commented [ST43]: This sentence is broader than Shale Gas Research and better aligns to the Methane Mitigation paragraph above for the LCA work. Produced water is in a different program line as well.

Commented [ST44R43]: NETL: We moved the sentence. Please confirm you are okay with the move.

Commented [EK45]: Please add RFI to the Acronym List.

Commented [EK46]: Please add R&D to the Acronym List.

NETL evaluated the state regulatory programs for oil and natural gas production for their applicability and adequacy of protecting water resources (NETL, 2014). NETL also reviewed regulations for permitting, well construction, hydraulic fracturing, temporary abandonment, well plugging, tanks, pits, and waste handling and spills. This evaluation revealed several key messages (NETL, 2014):

1. State oil and gas regulations are adequately designed to directly protect water resources through the application of specific programmatic elements such as permitting, well construction, well plugging, and temporary abandonment requirements.
2. Experience suggests that state oil and gas regulations related to well construction are designed to be protective of groundwater resources relative to the potential effects of hydraulic fracturing. However, development and dissemination of best management practices related to hydraulic fracturing would assist states and operators in ensuring continued safety of the practice, especially as it relates to hydraulic fracturing of zones near groundwater, as determined by the regulatory authority.
3. Many states divide jurisdiction over certain elements of oil and gas regulation between the oil and gas agency and other state water protection agencies. This is particularly evident in the areas of waste handling and spill management.
4. The implementation and advancement of electronic data management systems has enhanced regulatory capacity and focus. However, the inclusion of more environmental data is needed, as well as further work in the areas of paper-to-digital data conversion.

In 2014, EPA compiled a summary of state regulatory programs for oil and natural gas exploration, development, and production (EDP) solid waste management. This review was conducted by EPA personnel in the Office of Resource Conservation and Recovery within the Office of Solid Waste and Emergency Response and ~~The review~~ included relevant regulations for Ohio, Oklahoma, Pennsylvania, Texas, and West Virginia, which are presented below that help to drive sustainable practices within these leading oil and gas producing states (EPA, 2014).

1.3.2.1 Ohio

Regulations concerning technical requirements for waste pits are found in Chapter 1501 of the Ohio Administrative Code (OAC) and Rule 1509 of the Ohio Revised Code (ORC), which contains the statutory authority for the regulations promulgated in the OAC as regulated by the Division of Mineral Resources Management in the Department of Natural Resources. The complete set of applicable regulations can be found in Appendix OH-3. Regulations relevant to this addendum include the following:

- OAC 1501:9-1-02 details the requirements for the permitting of wells, including the plan for disposal of water and other waste substances resulting from oil and gas exploration and production activities.
- OAC 1501:9-3-08 details temporary storage of saltwater and other related waste, including design criteria for storage pits.

Commented [TC47]: States also have authority to regulate air emissions from facilities. I would recommend deleting the detailed summary of the adequacy of protecting water resources and include a high-level discussion of state authorities to regulate oil and gas production and associated impacts.

Commented [EK48]: Should we add language that indicates these state O&G regulatory programs, originally summarized in 2014, remain essentially unchanged and continue to be highly effective? Do we have current or recent information that confirms that state of play nearly a decade later? Just concerned potential gas development opponents will consider state regulatory regimes - if they are essentially unchanged in the past decade might be deemed potentially lacking given the U.S. is now a net natural gas exporter?

Commented [ST49R48]: NETL: we are strongly concerned that a 2014 summary is no longer accurate. Can you confirm your summary is current? If yes, please explain. If not, then we need to pull this back to a higher level discussion of the role that states have in regulating solid waste from NG operations. This comment is in line with HQ's broader comments on accuracy of regulatory sections with respect to representing current landscape.

- OAC 1501:9-9-05 specifies tank location restrictions, including setbacks from public roads, inhabited structures, wells, heaters, and other equipment.
- OAC 1501:9-9-03 requires pits of sufficient size and shape to be constructed adjacent to each drilling well to contain all the drilling muds, cuttings, saltwater, and oil.
- OAC 1501:9-9-05 specifies that where a hazard exists, any production equipment at the wellhead and related storage tanks must be protected by an earthen dike or earthen pit with a capacity to contain any substances produced by operation of the related oil or gas well.
- ORC 1509.072 discusses the obligation to restore the land surfaces after drilling operations have ceased, including removing all equipment, revegetating the affected area, preventing sedimentation and erosion, and authorizing the chief retains in the closure of a well.
- ORC 1509.22 discusses the prohibition of water contamination and covers storage and disposal of brine. This section also discusses the storage of waste fluids and the management allowances for these fluids.

1.3.2.2 Oklahoma

Regulations concerning technical requirements for oil field waste pits in Oklahoma are found primarily in Oklahoma Administrative Code, Title 165, Chapter 10, Subchapters 3 and 7 as regulated by the Oklahoma Corporation Commission Division of Oil and Gas. Regulations relevant to this addendum include the following:

- 165: 10-7-16 details minimum technical design standards for waste pits.
- 165:10-7-5 details operating requirements for pits, specifically operating standards in the event of a discharge, including reporting details and requirements along with record-keeping requirements.
- 165:10-7-16.(d) details operating requirements for oil and gas exploration and production activity pits.
- 165:10-3-16.(e) details closure requirements for pits.
- 165:10-3-17 details further closure requirements, primarily the return of the surface conditions at the site of the pit to their original state, free of trash, debris, and equipment, within 90 days of the completion of well activities.

1.3.2.3 Pennsylvania

Regulations concerning technical requirements for oil field waste pits in Pennsylvania are found primarily in Pennsylvania Code, Title 25 (Environmental Protection), Part 1 (Department of Environmental Protection), Subpart C (Protection of Natural Resources), Article I (Land Resources), Chapter 78 (Oil and Gas Wells) and Chapter 91 (General Provisions). Additional language can be found in Pennsylvania (PA) Act 13 of 2012. Regulations relevant to this addendum include the following:

- PA Act 13 of 2012 §3215 prevents wells from being sited in any floodplain if the well is to employ a pit or impoundment or a tank managing solid wastes from oil and gas exploration and production.
- PA Act 13 of 2012 §3216 requires that a well site be restored following cessation of drilling operations. This includes restoration of the earthwork or soil disturbed, removal of all drilling supplies and equipment within nine months after completion of the drilling well, and compliance with all applicable requirements of the Clean Streams Law. The restoration period is subject to an extension if certain conditions are met.
- PA Act 13 of 2012 §78.56 details requirements for pits and tanks that are used to manage waste temporarily. Some requirements include a minimum of 2 ft of freeboard for pits or impoundments, structural soundness of pits and tanks, minimum liner requirements, and waste separations and prohibitions.
- PA Act 13 of 2012 §78.57 details requirements for management of production fluids, including collection of brine and other fluids from the well operations, requirements for pits, removal and disposal of fluids, and restoration of the waste management units or facilities following the closure or cessation of operations.
- PA Act 13 of 2012 §78.61 details the requirements for disposal of drill cuttings, including criteria to be met to allow for disposal in a pit, criteria to be met to allow for disposal by land application, other methods of disposal of drill cuttings, and compliance requirements for disposal.
- PA Act 13 of 2012 §78.64 details secondary containment criteria to be met for tanks used on drill sites, including required capacity and inspection requirements.
- PA Act 13 of 2012 §78.65 details site restoration requirements following the cessation of operations at a well site.

1.3.2.4 Texas

Regulations concerning technical requirements for solid waste management of oil and gas exploration, production, and development in Texas are found primarily in the Texas Administrative Code, Title 16, Part 1, Chapters 1–20. The Railroad Commission of Texas (RRC) is the primary authority in Texas regarding the regulation of oil and natural gas. Regulations relevant to this addendum include the following:

- Rule §3.3 details that all tanks must be clearly identified by signage at all times.
- Rule §3.5 details that a permit is required, issued by the RRC, in order to drill, deepen, plug back, or reenter any oil, gas, or geothermal resource well. The rule does not include any required specifications for waste management in the permit.
- Rule §3.8 defines the various types and functions of pits that are to be found in the regulations. Additionally, the rule defines oil and gas waste. The rule sets forth~~defines~~ what types of pits are prohibited, including for the storage of oil products, the requirement to obtain a permit for constructing and operating a pit, authorized disposal

methods, liner requirements, minimum freeboard provisions, steps to ensure prevention of run-on from stormwater, and procedures for the draining of pits, and inspection of pit liners. In addition, Tthe Rule details instances in which a pit may be used without a permit, including as a reserve pit, completion pit, or basic sediment pit. The Rule also notes that the pit operator must keep records detailing that the pit liner requirements are met.

- Rule §3.15 details the requirements for the removal of all surface equipment from inactive wells, including the removal of all tanks or tank batteries.
- Rule §3.22 details the requirements of screening or netting of pits to protect wildlife, specifically birds.
- Rule §3.57 details the requirements for reclaiming tank bottoms and disposal of other EDP wastes. This includes the requirement for a permit, the use of a reclamation plant, and other miscellaneous requirements.
- Rule §3.78 details financial assurances and fees required ~~in order~~ to commence drilling activities. These financial assurances include bonding requirements for varying operations and number of wells.
- Rule §4.620 prohibits the disposal of naturally occurring radioactive material (NORM) waste by burying it or applying it with the land surface without obtaining a permit. The section details that the disposal of NORM waste is subject to Rule §3.8.

Commented [EK50]: NETL Team - please edit this awkward phrasing. It seems to suggest NORM may be 'applied' with the land surface. Just not sure what the writer here means precisely.

1.3.2.5 West Virginia

Commented [ST51]: No air regs in WV?

The following are oil and natural gas solid waste regulations for the state of West Virginia (WV):

- WV Code Chapter 22 Art. 6 Section 7, Chapter 22 Art. 11 Section 1–27, and Chapter 22 Art. 6 details permitting requirements and authority.
- WV Code Chapter 22 Article 6 Section 7 details waste pit authority of the general permit.
- WV Code Chapter 22 Series 6A contains the Horizontal Well Control Act.
- WV Code Title 35 Series 8 details horizontal well permits regarding the requirements and handling of waste cuttings.

Additionally, documentation that dictates surface and groundwater pollution prevention requirements for WV include the following:

- General Water Pollution Control Permit
- Erosion and Sediment Control Field Manual
- 35-8 Rules Horizontal Well Development
- 35-1 Water Pollution Control Rule

Below is a summary of some relevant sections of the WV code regarding oil and natural gas solid waste regulations relevant to this Addendum:

- §35-1-7 details requirements for dikes, berms, and retaining walls at oil and gas operations, requirements for secondary containment of tanks or tank systems, and other associated mechanical operational requirements.
- §35-4-16 details design and operation criteria for pits and impoundments.
- §35-4-21 describes design and construction requirements for pits and impoundments with a capacity greater than 5,000 barrels, including inspections.
- §35-2-3 requires that a permit be obtained by the Division of Environmental Protection, Office of Oil and Gas prior to the commencement of ~~any~~ solid waste management efforts ~~facilities~~ at the ~~site of~~ oil and gas exploration and production site.
- §35-4-10 details financial assurance requirements for oil and gas exploration and production activities, including the demonstration of financial responsibility of individual and grouped wells, coincidence with permit application for financial assurance, and the varying forms of financial assurance allowable.
- §35-8-5 details requirements for permits, notice, and review of horizontal wells, including siting restrictions, financial assurance for horizontal wells, and permitting requirements.

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2 GREENHOUSE GAS EMISSIONS AND CLIMATE CHANGE

CH_4 and CO_2 emissions from the LNG life cycle ~~and natural gas end uses~~ vary widely across different regions and supply chains. This section presents a review of contemporary (2014 and after) life cycle analysis (LCA) as it pertains to LNG and natural gas GHG emissions.

2.1 INTRODUCTION

To account for all sources of GHG emissions in the natural gas supply chain, and to evaluate their relative contributions and mitigation opportunities, a systems-level perspective is both necessary and preferred. LCA is one type of systems approach available to account for the different sources of GHG emissions in the natural gas supply chain. LCA specifically considers the material and energy flows of an entire system, "from cradle to grave." ~~W~~where ~~the~~ "cradle" refers to the extraction of resources from the earth, and ~~the~~ "grave" refers to the final use and disposition of all products.

Depending on the type of LCA conducted, different system boundaries can be put in place to more accurately estimate the GHG emissions associated with natural gas. Generally, GHG emissions occur from the beginning of the natural gas supply chain (during exploration) through the end (during utilization). In some cases, an LCA may not consider every step of the natural gas supply chain within its analysis framework. This can happen for a variety of reasons, including lack of emission data for a particular step or set of steps, or simply to focus specifically on the emissions associated with one particular ~~part~~ step. Exhibit 2-1 provides an illustration of the natural gas supply chain with examples of key emissions sources (Balcombe et al, 2016).

Exhibit 2-1. Natural gas supply chain with examples of key emission sources



Permission pending from Balcombe et al. (2016)

Commented [TSS2]: This diagram is missing a few steps.

Gathering and Boosting

Piped Transmission and Storage between "Processing" and "Liquefaction".

Is there a more accurate diagram that better aligns with the NETL or EPA GHGRP or GHGI categories and emission sources?

There are two primary approaches used to conduct natural gas LCA: 1) top-down and 2) bottoms-up (Rutherford et al., 2021; Alvarez et al., 2018; Balcombe et al., 2016). A top-down approach ~~1a~~) measures the atmospheric concentrations of CH_4 as reported by fixed ground monitors, mobile ground monitors, aircraft, and/or satellite monitoring platforms; ~~2b~~) aggregates the results to estimate total CH_4 emissions; and ~~3c~~) allocates a portion of these total emissions to each of the different supply chain activities. A bottoms-up approach measures ~~CH_4~~ GHG emissions directly from each source of emissions, then aggregates and extrapolates these measurements to estimate emissions for an entire region or process. Both approaches have ~~their~~ advantages and disadvantages.

For example, several studies (Rutherford et al., 2021; Alvarez et al., 2018; Balcombe et al., 2016) have noted that top-down approaches may lead to a general upward bias in emissions reporting while bottoms-up approaches may lead to a general downward bias in emissions reporting. There are several factors that may lead to these biases, which can be generally explained as follows:

- Top-down approaches sometimes fail to distinguish between different sectors. For example, aircraft that are used to collect emissions data for a particular area may struggle to distinguish between the CH_4 emissions coming from a natural gas processing facility in the area from those coming from a near-by dairy farm. This can lead to incorrect contributions of total CH_4 emissions to specific natural gas activities.
- Bottoms-up measurements sometimes fail to capture "super emitters"—a small number of facilities (or types of equipment) ~~who~~ that emit disproportionately large quantities of emissions. Because bottoms-up approaches measure emissions from individual sources and because super emitters, by definition, represent only a small proportion of the total number of facilities (or equipment) represented within the natural gas supply chain, it can be challenging to accurately capture the contributions of ~~a~~ super emitter activity to total emissions.

Alvarez et al. (2018) also notes that in many bottoms-up approaches to modeling, operator cooperation is required to obtain site access for accurate emissions measurements. Operators with lower-emitting sites are plausibly more likely to cooperate with ~~the conduct of~~ such studies and workers are plausibly more likely to be careful to avoid errors or fix problems when measurement teams are on site or about to arrive, which could lead to a downward bias in estimates of potential emissions (Rutherford et al., 2021; Alvarez et al., 2018; Balcombe et al., 2016).

Another key difference in LCA methodology or assumptions that can lead to differences in LCA outputs (i.e., estimates of emissions) is tied to ~~the choice of~~ which climate-forcing impacts of CH_4 are is used (Balcombe et al., 2016). CH_4 emissions have a large, short-term and climate-forcing impact[1] compared to CO_2. The instantaneous forcing impact of CH_4 is around 120 times that of CO_2 ~~on a~~ for an equivalent amount of mass ~~basis~~. CH_4, however, only has an average

[1] Climate or radiative forcing, a measure, is defined by the Intergovernmental Panel on Climate Change (IPCC) as the influence a given climatic factor has on the amount of downward-directed radiant energy impinging upon Earth's surface.

Commented [LBD53]: GHG emissions? Not only CH4, correct? In this section generally, sometimes reference is made to CH4 monitoring/detection - suggest some explanation of when only CH4 is measured and when all GHGs are considered.

Commented [TSS4]: This needs to be balanced with the understanding that in the 12 year the radiative forcing is changing. I can not find a reference to support the 120 times? Is this in watts/meter perspective?

Recommend we stay with IPCC 100 yr and 20 year perspective of difference in radiative forcing.

The temporal period of how long the pollutant stays in the atmosphere is critical to understanding its relative radiative forcing when compared to other GHGs, CO2. Remove or provide the complete story.

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lifespan of 12 years in the atmosphere, after which it oxidizes into CO_2. CO_2 emissions remain in the atmosphere for much longer—25 percent of CO_2 emissions ~~still exists~~remain in the ~~atmosphere~~atmosphere ~~after~~ 1,000 years after emission (Balcombe et al., 2016). Consequently, while the climate-forcing impact of CH_4 emissions changes significantly over time, the impact of CO_2 emissions remains ~~much more~~ constant for a longer time.

Typically, studies use global warming potential (GWP) to compare the climate impact of emissions of different GHGs such as CH_4 with CO_2. The GWP is defined as a measure of how much energy the emissions of 1 ton of a gas will absorb over a given period, relative to the emissions of 1 ton of CO_2 (Balcombe et al., 2016). The IPCC progressively raised the GWP for CH_4 to 28 over a 100-year period and 84 over a 20-year period in their Fifth Assessment Report (AR5) published in 2014 (Stern, 2022). IPCC's Sixth Assessment Report (published in 2021) raised the GWP of CH_4 to 29.8 over a 100-year horizon but reduced the 20-year horizon factor to 82 (Stern, 2022). Adding climate feedback mechanisms and oxidation, these figures were increased to 36 and 87.15, respectively in the IPCC's Sixth Assessment Report.

To illustrate, if the GWP of CH_4 for a time horizon of 100 years is 36, this means that a pulse emission of CH_4 absorbs 36 times more energy than CO_2 over 100 years, on average. Note that the GWP of CH_4 for a time horizon of 100 years does not give any information on the climate forcing of CH_4 at the end of the 100 years; it gives only the average impact across the 100 years. ~~Additionally, the use of a single value to compare GHGs does not consider the changing impacts over time.~~ It is important to consider ~~the~~ which GWP is used when analyzing the outputs of an LCA, particularly when comparing the outputs of two or more LCAs (Balcombe et al., 2016).

2.2 FEDERALLY-FUNDED LCA

NETL has used LCA to calculate the environmental impacts of natural gas production and use for the generation of electric power for nearly a decade (NETL, 2023). Their work has been documented in a series of reports produced between 2010 and 2019.[6] Together, these reports provide in-depth assessments of the potential GHG emissions resulting from unconventional natural gas production in the United States. The GHG emissions results recorded in the NETL 2019 report considers five stages of the natural gas supply chain, which are visualized in Exhibit 2-2 (NETL, 2019):

1. **Production:** Sources of emissions include the gas vented from pneumatically controlled devices and fugitive emissions from flanges, connectors, open-ended lines, and valves. When vapor recovery units are feasible, vented gas is captured and flared; otherwise, vented gas is released to the atmosphere. Production operations also include the combustion of natural gas and diesel in compressors and other equipment.
2. **Gathering and Boosting (G&B):** Natural gas G&B networks receive natural gas from multiple wells and transport it to multiple facilities. G&B sites include acid gas removal, dehydration, compressors operations, pneumatic devices, and pumps.

[6] The GHG results in the NETL (2019) report supersede the GHG results in the previous NETL reports.

Commented [TS55]: CO2 also declines over time, not constant. The temporal period is just longer. You confirm my point in the previous sentence.

This paragraph is misleading because it is not telling the complete story. A radiative forcing decay graphic showing a single pulse of emissions at time = zero is needed to tell the complete story.

Alternatively, this paragraph. I would keep the first two sentences and use them as the start of the next paragraph on GWP.

Commented [TS56]: Need to mention the LNG work at the beginning and discuss that the LNG report builds upon the NELT upstream natural gas report by adding liquefaction, ocean transport, regasification, distribution and end use of the gas in a large scale power plant.

This will help create synergies to the Exhibit 2-1 description of the natural gas and LNG system boundary.

For Exhibit 2-1, you may want to create your own graphic.

3. **Processing:** A natural gas processing facility removes impurities from natural gas, which improves its heating value and prepares it for pipeline transmission. Natural gas processing facilities include acid gas removal, dehydration, hydrocarbon liquids removal, and compression operations.
4. **Transmission Stations, Storage Facilities, and Transmission Pipelines:** A natural gas transmission system is a network of large pipelines that transport natural gas from processing facilities to the city gate (the point at which natural gas can be consumed by large-scale consumers or transferred to local distribution companies). Transmission stations are located along natural gas transmission pipelines and use compressors to boost the pressure of the natural gas.
5. **Distribution:** Natural gas distribution networks transport natural gas from the city gate to commercial, residential, and some industrial consumers. This analysis uses the distribution portion of the supply chain only for the upstream functional unit; distribution is not necessary for the functional unit of electricity in which natural gas power plants receive natural gas directly from transmission pipelines.

Exhibit 2-2. Supply chain stages that compose the overall LCA boundary



Commented [TS57]: Need higher quality image and to cite image source.

The flexible, consistent framework of NETL's LCA model allows different natural gas sources to be compared on a common basis (per megajoule [MJ] of delivered natural gas). In the NETL (2019) report, five types of natural gas are considered:

1. **Conventional natural gas** is natural gas extracted via vertical wells in high permeability formations that do not require stimulation technologies for primary production.
2. **CBM** is extracted from coal seams and requires the removal of naturally occurring water from the seam before natural gas wells are productive.
3. **Shale gas** is extracted from low permeability formations and requires hydraulic fracturing and horizontal drilling.
4. **Tight gas** is extracted from non-shale, low permeability formations and requires hydraulic fracturing and directional drilling.
5. **Associated gas** is found with petroleum (either dissolved in oil or in a gas cap in a petroleum formation) and is produced by oil wells.

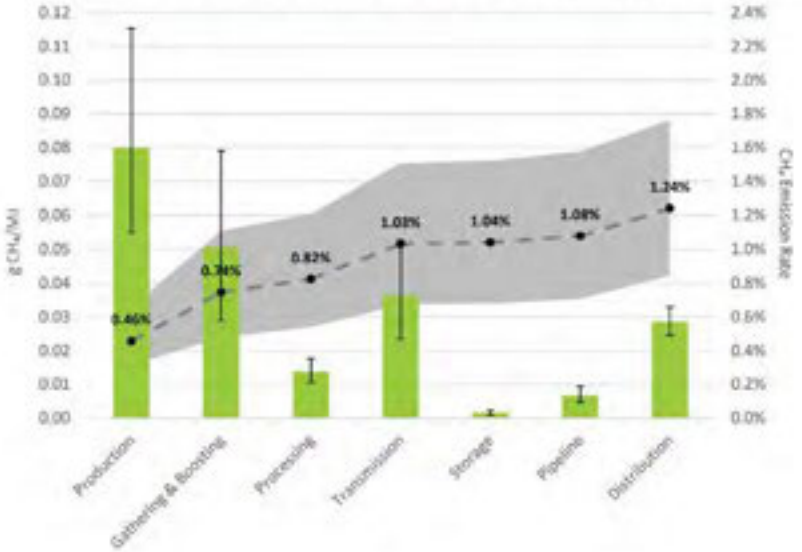
EPA estimates oil and natural gas CH_4 emissions in the annual Greenhouse Gas Inventory (GHGI) it produces. The GHGI uses a bottoms-up approach to estimate national CH_4 emissions.

In its 2019 LCA analysis of the natural gas supply chain, NETL used the GWP reported in the IPCC AR5. Other key input data was sourced from EPA's GHGI, Drilling Info (DI Desktop), and EIA. Results from the 2019 NETL LCA analysis performed suggested the following:

- The life cycle GHG emissions associated with the U.S. natural gas supply chain were 19.9 grams (g) of carbon dioxide equivalents (CO_2e) per MJ of natural gas delivered (with a 95% mean confidence interval of 13.1–28.7 g CO_2e per MJ).
- The top contributors to CO_2 and CH_4 emissions were combustion exhaust and other venting from compressor systems. Compressor systems are prevalent in most stages of the natural gas supply chain and as such were key contributors to the total life cycle emissions estimated.
- Emission rates ~~were~~ are highly variable across the entire supply chain. According to the study (NETL, 2019), the national average CH_4 emissions rate was 1.24 percent, with a 95 percent mean confidence interval ranging 0.84–1.76 percent.

Exhibit 2-3 shows the upstream GHG emissions from the different parts of the natural gas supply chain. In Exhibit 2-4, The blue bars represent CO_2 emissions, the green bars represent CH_4 emissions, and the orange bars represent nitrous oxide (N_2O) emissions. The vertical black lines in Exhibit 2-3 and Exhibit 2-4, respectively, represent the error bars in this analysis, and the shaded grey area represents the 95 percent mean confidence interval.

Exhibit 2-3: Life cycle CH_4 emissions from the U.S. natural gas supply chain



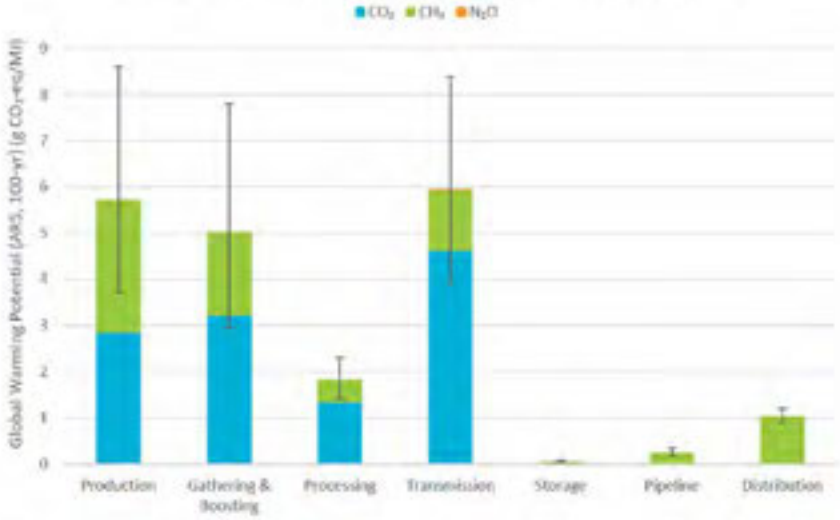
Commented [TS58]: Add citation

Commented [TS59]: Add GHGRP (this is the primary data source, not GHGI)

Commented [LBD60]: Suggest citing somehow that Exhibits 2-3 and 2-4 are from the referenced NETL 2019 report.

Commented [LBD61]: Figure would benefit from a legend or explanation of the different elements.

Exhibit 2-4. Life cycle GHG emissions for the U.S. natural gas supply chain



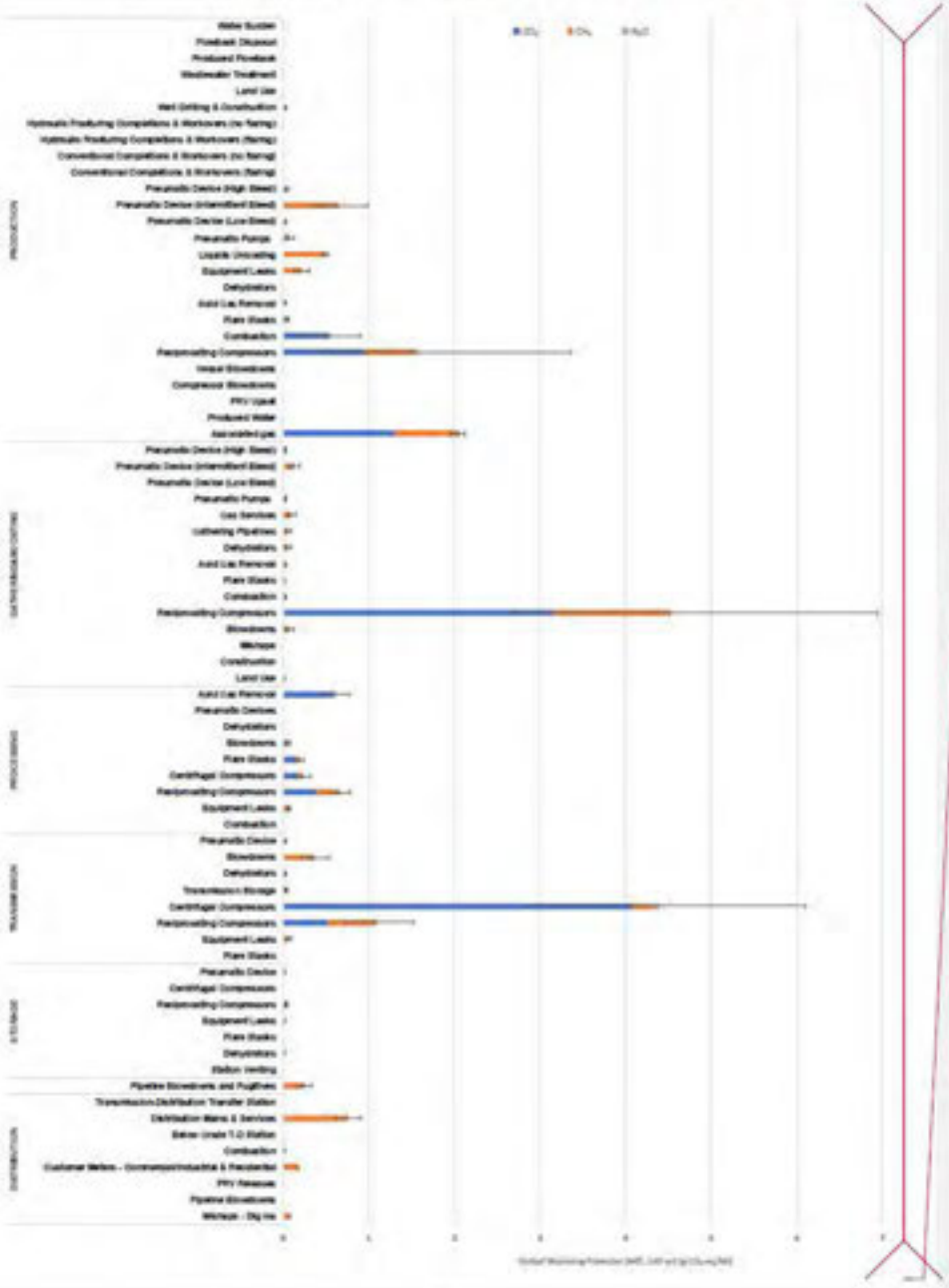
Key drivers of GHG emissions results for the entire natural gas supply chain are illustrated in Exhibit 2-5 (NETL, 2019). Pneumatic devices and compression systems represent a significant portion of the total life cycle GHG emissions associated with the natural gas supply chain (NETL, 2019). Pneumatic devices are used to operate level controllers, valves, and other equipment at natural gas facilities. According to EPA's GHGI, production pneumatics emitted 1,060 kilotons of CH_4 in 2017, accounting for 16 percent of the total CH_4 emissions from the natural gas supply chain. Pneumatic device activity is concentrated at production facilities and there were 833,000 pneumatic devices used by U.S. production facilities in 2019 (NETL, 2019).

Natural gas is compressed for transport from processing facilities to end-consumers. As such, upstream GHG emissions are sensitive to pipeline distances and the number of compressors along these pipelines that the natural gas must pass through. The energy intensity of compression and the fugitive CH_4 emissions from compressors both contribute to upstream GHG emissions (NETL, 2019).

In addition to being a source of CH_4 emissions, compressors are also a source of CO_2 emissions. Most compressors in the U.S. pipeline transmission network are powered by natural gas that is withdrawn from the pipeline itself. Electric motors are not widely used by natural gas pipelines but are installed where local emission regulations limit the use of internal combustion engines or where inexpensive electricity is available. Approximately three percent of compressors used by the natural gas transmission network are electrically driven.

Commented [TS62]: Cite source.

Exhibit 2-5. Detailed GHG emission sources for the U.S. natural gas supply chain



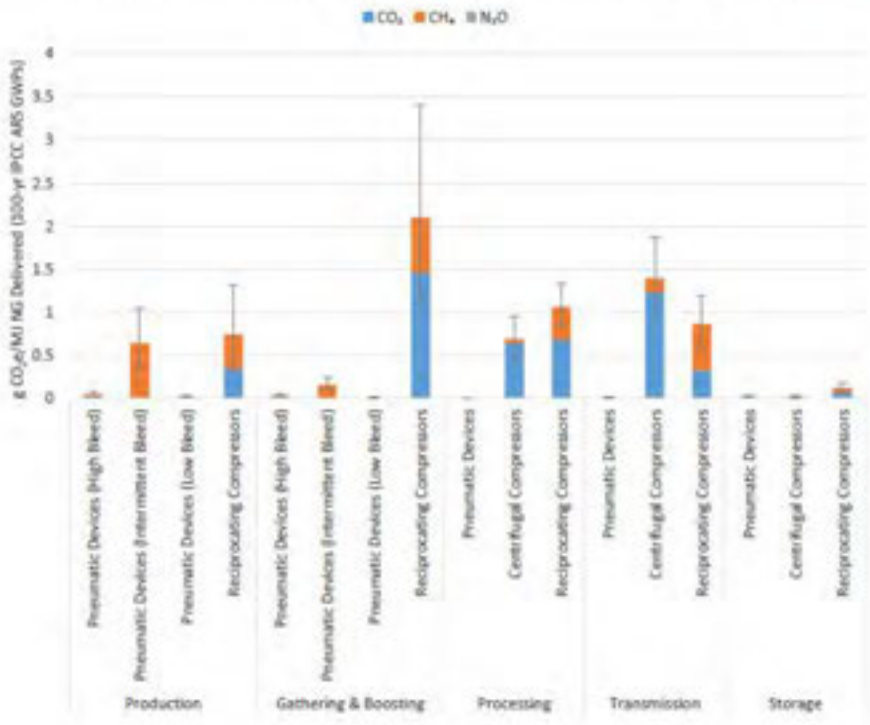
Commented [TS63]: State what year the data represents in the caption and what scope? US average for transmission and distribution combined?

Commented [TS64]: Need higher resolution image.

INTERNAL USE ONLY – NOT APPROVED FOR PUBLIC RELEASE

Two sources of CH_4 emissions from compressor systems include 1) CH_4 that slips through the compressor uncombustedion into the exhaust stream and 2) CH_4 that escapes through compressor seals or packing. Natural gas systems use both centrifugal and reciprocating compressors. Centrifugal compressors are more appropriate for pressure boosting applications in steady-state applications (such as with a transmission pipeline), while reciprocating compressors are more appropriate when gas flow is variable and when large increases in pressure are required. Centrifugal compressors are typically driven by gas-fired turbines but, in some instances, are driven by an electric motor. Reciprocating compressors are driven by gas-fueled engines. Exhibit 2-6 illustrates the emissions associated with pneumatic devices and compressors.

Exhibit 2-6. GHG emissions from pneumatic devices and compressors across the NG supply chain



For all natural gas production types, the GHG emissions results produced by an LCA are sensitive to production rates and episodic emissions (either liquid unloading or workovers).

Commented [LBD65]: "slips through the compressor uncombusted into the exhaust stream"?

Commented [TS66R65]: Yes.

Commented [TS67]: Exhibit 2-5 and 2-6 units, while the same, are described differently. Exhibit 2-5 is the general standard with the exception of carbon dioxide equivalents are ported as CO2e (subscripted 2) and not as CO2-eq in Exhibit 2.5.

Commented [TS68]: The data does not support this statement. Liquids Unloading is 0.5 g CO2e (Exhibit 2-5)per the life cycle total of 19.9 with a mean uncertainty range of 13.1 to 28.7. The variance in liquids unloading is well within the mean uncertainty range and therefore not a sensitive parameter.

Exhibit 6-8 in the NETL 2019 report provides a ranking of GHG emissions uncertainty (not model sensitivity) but does indicate which sources contribute have an influence on the accuracy of the results.

Results are sensitive to:

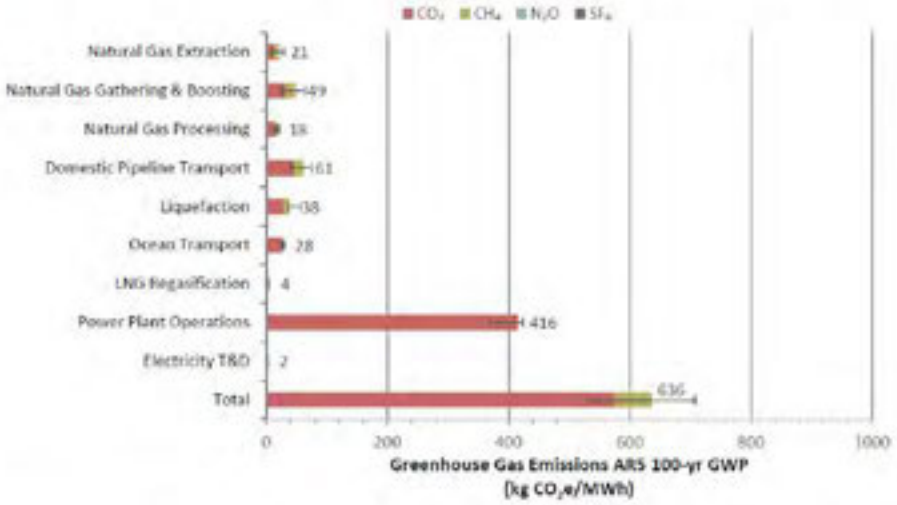
•EUR
•Regional natural gas composition differences (dry versus sour gas).
•Compression energy requirements and type.
•Pneumatic device type, frequency, and number of devices per operation.
•Episodic events that result in higher (than normal operations) methane emissions over a short time frame (not a consistent emission source) originating from maintenance and inspection activities or non-standard operator practices.

The above bullet provides a more generic way of describing episodic emissions. My concern was calling out specifically liquids unloading and workovers.

In addition to its characterization of domestic upstream natural gas, NETL also developed life cycle data for exported LNG, including the GHG emissions from liquefaction, transport, regasification, and ~~the~~ combustion for electricity generation (NETL, 2019).

The NETL (2019) report that analyzed the lifecycle emissions of exporting U.S. LNG to Europe yielded the emissions results (assuming end-use in electricity generation) detailed in Exhibit 2-7.

Exhibit 2-7. GHG emissions from exporting LNG from the United States to Europe



Littlefield, Rai, and Skone (2022) show that geography matters in terms of the GHG emissions estimated for the global natural gas supply chain; – where natural gas is produced and ultimately used plays a tremendous role in the total amount of GHG emissions estimated for the supply chain. ~~As such~~Accordingly, a national average value is not necessarily an adequate representation of an individual (source to sink) natural gas supply chain. Littlefield, Rai, and Skone (2022) provide a detailed life cycle perspective on GHG emissions variability where natural gas is produced and where it is delivered. They disaggregate transmission and distribution infrastructure into six regions, balance natural gas supply and demand locations to infer the likely pathways between production and delivery (estimated via modeling as actual tracking of natural gas from well to customer is not technically feasible), and incorporate new data on distribution meters. They find the average transmission distance for U.S. natural gas is 815 kilometers (km) but ranges 45–3,000 km across estimated production-to-delivery pairings examined (Littlefield, Rai, and Skone, 2022). In terms of total GHG emissions, their results suggest the delivery of 1 MJ of natural gas to the Pacific region has the highest mean life cycle GHG emissions (13.0 g CO_2e/MJ) and the delivery of natural gas to the Northeastern region of the United States has the lowest mean life cycle GHG emissions (8.1 g CO_2e/MJ).

Commented [LBD69]: Is this a separate NETL 2019 report? Or the same one as above? If the same, suggest citing it in full on first mention.

Commented [TS70R69]: Yes a different report.

Commented [LBD71]: Suggest somewhere a comment be made that the supply chain study presented above is "cradle to gate," and excludes end-use, while the LNG study is more truly "cradle to grave," and does include end-use (power generation), meaning extra care should be taken by readers in comparing results and figures.

Commented [TS72]: This report does not discuss global natural gas supply sources?

I think you mean US.

Commented [LBD73]: How does this compare with other analyses we rely on? Do we rely on national averages elsewhere

In 2020, NETL collaborated with industry and published an analysis of Our Nation's Energy Future's (ONE Future) portfolio of assets (Rai et al., 2020). ONE Future is a natural gas industry partnership dedicated to improving the efficiency of the domestic natural gas supply chain. ONE Future represents 1–13 percent of total throughput in the respective segments of the natural gas industry supply chain. The expected life cycle CH_4 emission rate for ONE Future average natural gas is 0.76 percent (with a 95 percent mean confidence interval ranging 0.49–1.08 percent).

The expected life cycle CH_4 emission rate for the U.S. average scenario is 1.06 percent. In terms of IPCC 100-year GWP, the ONE Future and U.S. average scenarios emit 9.7 and 14.1 g CO_2e/MJ of delivered natural gas, respectively.

2.3 Other Natural Gas Analyses

Balcombe et al. (2016) document the wide range of CH_4 emissions estimates across the natural gas supply chain. Estimates of combined CH_4 and CO_2 emissions range 2–42 g CO_2e/MJ. A ~~s~~Significant drivers of this wide range of projections are 1) the emissions associated with upstream natural gas production, and 2) whether the natural gas is ultimately converted to LNG or not. This sub-section explores these different segments of the supply chain.

Commented [LBD74]: Comment applicable to other sections as well – is text being updated with more recent studies? (apologies if updating is ongoing in some sections and I'm not aware of it) Most or all of these studies (aside from NETL's) are >10 years old.

2.3.1 Natural Gas Production Analyses

Commented [LBD75]: Comment applicable to other sections as well – is text being updated with more recent studies? (apologies if updating is ongoing in some sections and I'm not aware of it) Most or all of these studies (aside from NETL's) are >10 years old.

Several studies have found that CH_4 emissions from the natural supply chain are about 1.5–2.5 times the amount reported in EPA's GHGI (Rutherford et al., 2021; Alvarez et al., 2018; Balcombe et al., 2016). Much of the discrepancy can be attributed to differences in the analyses performed for the production segment of the natural gas supply chain where super emitters and emissions-intensive equipment are both prevalent (Rutherford et al., 2021; Alvarez et al., 2018; Balcombe et al., 2016).

To isolate specific sources of disagreement between EPA's GHGI and other studies, Rutherford et al. (2021) reconstruct EPA's GHGI emission factors, beginning with the underlying datasets, and uncover some possible sources of disagreement between inventory methods and top-down studies. The adjusted emissions factors are direct inputs in the Rutherford et al. (2021) study outputs. Rutherford et al. use~~s~~ a bottom~~s~~-up measurement approach, yet the approach differs from the GHGI in that it applies a bootstrap resampling statistical approach to allow for inclusion of infrequent, large emitters, th~~erebyus, robustly~~ addressing the issue of super-emitters in a more robust way.

Rutherford et al. (2021) estimate the mean, production-normalized emissions rate from the production segment as 1.3 percent (1.2–1.4 percent at 95 percent confidence interval, based on gross natural gas production of 32 Tcf and an average CH_4 content of 82 percent), slightly lower than Alvarez et al., 2018) who estimate it at 1.4 percent. Rutherford et al. (2021) estimate mean natural gas production-segment CH_4 emissions as equal to 6.6 teragrams (Tg) per year (6.1–7.1 Tg per year, at 95 percent confidence interval). Both the results of Rutherford et al. (2021) and Alvarez et al. (2018) are approximately two times larger ~~the~~ than estimates of the 2015 EPA

GHGI, which suggests that 3.6 Tg of emissions per year (year 2015 data, excludes offshore systems) come from the natural gas production segment.

Importantly, the difference in U.S. production-segment emissions estimates between the Rutherford et al. (2021) study and EPA's GHGI is approximately the same volume as reflected in the Rutherford et al. (2021) study estimate of the contribution from super-emitters (top 5 percent of emissions events). Given that the Rutherford et al. (2021) results match the Alvarez et al. (2018) site-level results, the former concludes that the divergence between the GHGI and top-down/site-level studies is not likely to be due to any inherent issue with the bottoms-up approach. A results comparison of the Rutherford et al. (2021) study, the Alvarez et al. (2018) study, and 2015 EPA GHGI data can be found illustration in Exhibit 2-8.

Commented [TS76]: This sentence seems to conflict with the 2.5 times difference between Rutherford and EPA?

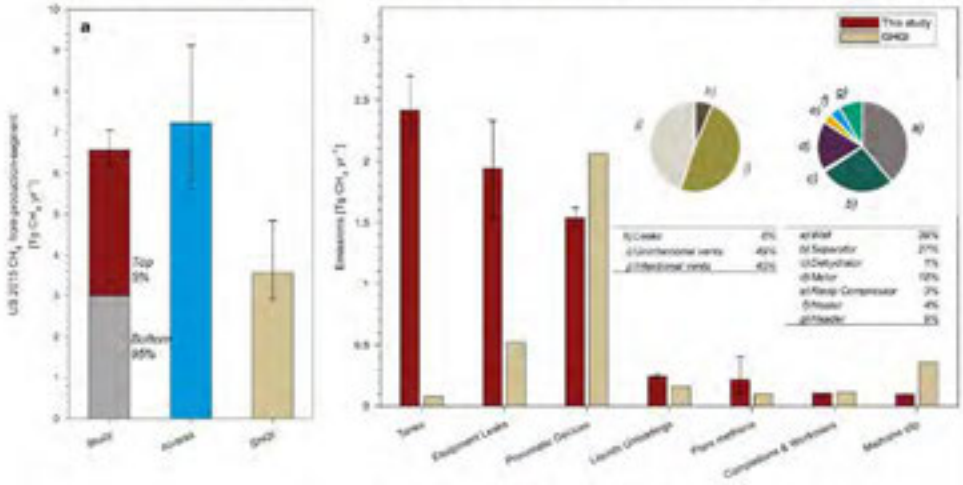
I am not sure I am interpreting your point correctly.

Also, what year does the data represent in the EPA GHGI to Rutherford comparison?

Commented [TS77]: If this is 2015 data, is this still a current perspective of the industry performance?

Does the latest EPA GHGI still result in this conclusion?

Exhibit 2-8. Comparison of GHG Emissions Results from Rutherford et al., Alvarez, et al., and EPA GHGI



Permission pending from Rutherford et al. (2021)

2.3.2 LNG Studies

Commented [LBD78]: Comment applicable to other sections as well – is text being updated with more recent studies? (apologies if updating is ongoing in some sections and I'm not aware of it) Most or all of these studies (aside from NETL's) are >10 years old.

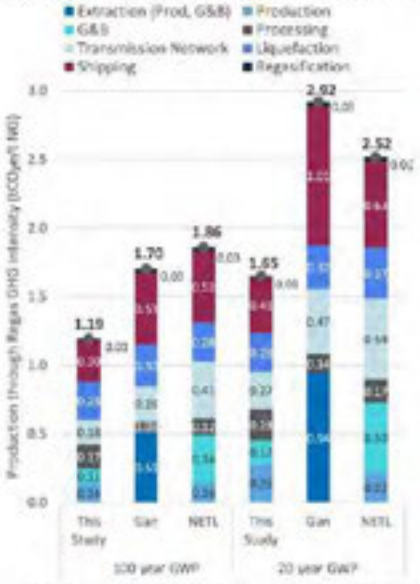
Relative to traditional natural gas supply chains where pipelines are ~~primarily~~ the primary means by which natural gas is transported, LNG supply chains also involve liquefaction, shipping, and regasification stages. Each of ~~which~~ these stages drive even greater variability in emissions profiles in LCA studies. A review of 37 global LNG supply scenarios between the United States and China by Gan et al. (2020) concluded that GHG emissions intensities varied by about 150 percent. Abrahams et al. (2015) note that emissions from the shipping of LNG exports from the United States to ports in Asian and European markets account for only 3.5–5.5 percent of precombustion life cycle emissions; hence, shipping distance is not a major driver of GHGs in the LNG supply chain.

Commented [LBD79]: Does this mean +/- 150%? Or something else?

At the end of 2020, Cheniere Energy was the largest exporter of LNG from the United States in terms of volume. Roman-White et al. (2021) developed an LCA framework to estimate GHG

emissions representative of Cheniere's LNG supply chain, considering both upstream and downstream sources of emissions from Cheniere's Sabine Pass Liquefaction facility, using supplier-specific data collected from wellhead through ocean transport. Roman-White et al. (2021) compare the GHG emissions intensity of Cheniere LNG to two similar assessments of emission intensity from U.S. LNG transported to China (Gan et al., 2020; NETL, 2019). The results of their comparison are illustrated in Exhibit 2-9.

Exhibit 2-9. Comparison of GHG emissions results from Roman-White et al., Gan et al., and NETL



Used with permission from Roman-White et al. (2021)

The NETL (2019) LNG study uses more recent production emission data (2016 data) than Gan et al. (2020). The study is based on natural gas production in Appalachia with relatively low emissions intensity. The NETL analysis differs from the Roman-White et al. study primarily in the intensity of the G&B and transmission stages, which are driven by differences in individual facility performance.

Commented [LBD80]: Which study? Roman-White or NETL?

When modeling transmission compression, the NETL (2019) study assumes a factor of 0.97 horsepower-hour (HPh)/thousand cubic feet (Mcf) to estimate the transmission station throughput (derived from NETL-published parameters). The average ratio of HPh to Mcf of throughput, from Cheniere Energy's known suppliers (used in the Roman-White et al. study) is 0.27 HPh/Mcf, which is based on supplier data collection completed. For modeling gas from other transmission operators, the GHGRP does not publicly provide the throughput of compressor stations. ~~As such, t~~The Roman-White et al. (2021) study assumes 0.29 HPh/Mcf based on data reported by EIA.

The higher factor used by the NETL (2019) study results in increased modeled fuel consumption across the transmission network. The Roman-White et al. liquefaction GHG intensity is 8–13 percent less than the intensity estimated by Gan et al. and is comparable to the NETL (2019) study estimate on a 100-year basis. The Roman-White et al. (2021) study concludes ocean transport stage emission intensity is 42–60 percent less than the transport emission intensity of Gan et al. (2020), and 35–42 percent less than that of the NETL (2019) study.

Jordaan et al. (2022) estimates the global average life cycle GHG emissions from the delivery of gas-fired electricity to be 645 gCO_2e per kilowatt hour (kWh) (334–1,389 gCO_2e per kWh), amounting to 3.6 gCO_2e yr^{-1} in 2017 (10 percent of energy-related emissions). This result is within range of the results obtained by Roman-White et al. (2021), who report life cycle GHG emissions of 524 gCO_2e kWh for electricity in China from LNG supplied by U.S. LNG exporter Cheniere, and 636 gCO_2e per kWh reported by NETL (2019).

Cai et al. (2017) assess GHG emissions of using compressed natural gas and LNG as transportation fuels by three heavy-duty natural gas vehicles types from a wells-to-wheels perspective. In short, the Cai et al. (2017) study concluded that natural gas vehicle wells-to-wheels GHG emissions are largely driven by the vehicle fuel efficiency, as well as CH_4 leakage rates of both the NG supply chain and vehicle end use; the study estimates wells-to-wheels GHG emissions of natural gas vehicles to be slightly higher than those of the diesel counterparts given the estimated wells-to-wheels CH_4 leakage.

2.4 MITIGATION MEASURES

Compressor seals include the wet seals used by the centrifugal compressors and the rod packing used by reciprocating compressors. Wet seals surround the rotating shaft of a centrifugal compressor with oil, which prevents gas leakage from the compressors. The oil used by wet seals must be continuously regenerated, which releases CH_4 into the atmosphere. By replacing wet seals with mechanical dry seals, the CH_4 emissions from centrifugal compressors can be reduced.

Reciprocating compressors prevent CH_4 leakage by encasing each compressor rod with a set of oil-coated, flexible rings. Proper maintenance and routine replacement of these rings prevents unnecessary leakage of CH_4. Storage tanks hold flowback water and liquid hydrocarbons recovered from the production stream. Variable loading levels and temperatures cause the venting of CH_4 and other gases from these tanks. By installing vapor recovery units on storage tanks, producers can more effectively reduce emissions from natural gas production. The captured emissions can be combusted on site to provide process energy, or they can be channeled to the sales stream.

Pneumatic controllers use gas pressure to open and close valves throughout a natural gas production and processing system. Natural gas is commonly used to pressurize pneumatic control systems. The bleeding of natural gas from pneumatic controllers leads to vent ings CH_4 to the atmosphere. The GHG impact of pneumatic control systems can be reduced by installing pneumatic systems that use pressurized air instead of pressurized natural gas.

Commented [LBD81]: This paragraph seems a little bit tacked-on. Consider adding context or possibly deleting.

Commented [LBD82]: Consider adding an introductory sentence or paragraph with an overall statement about types of mitigation measures discussed in this section.

Commented [TS83R82]: Agree to delete this paragraph and replace with a concluding paragraph for Section 2.3. What is the takeaway message from all of these reports and data?

Commented [LD84R82]: Note to reviewers - I think Tim's response here goes with the comment above -- regarding the current last para of section 2.3

Since ~~the~~ regulations focus on reduced emissions completions (RECs), they are more applicable to unconventional wells. RECs employ~~are~~ equipment that allow the capture of gas during flowback, either to be sent to the product line or, if this is not feasible, to be flared. However, ~~the~~ regulations also mandate emission reductions from pneumatically controlled valves and compressor seals, which are two types of emission sources common to conventional and unconventional natural gas technologies. Lastly, ~~f~~flowback emissions are governed by whether RECs are used or not.

The data suggest that the use of this equipment reduces completion emissions by approximately 75–99 percent. For the most established unconventional gas industry, the United States, the use of RECs is compulsory. However, once RECs are employed and CH_4 is flared to some degree, resultant CO_2 emissions from flaring may become significant (Balcombe, 2016).

A~~n~~ NETL (2020) report notes that compressed-air pneumatics are a mature technology that reduces CH_4 emissions from pneumatic systems. The technology replaces existing devices, which are actuated by natural gas, with devices that are actuated with compressed air. This requires the addition of electric-powered air compressors at natural gas facilities but can result in zero CH_4 emissions from pneumatics. A barrier to implementation of compressed-air pneumatics is electricity availability. The United States has an extensive electricity grid, but grid connections are not always near production sites. The same NETL (2020) report notes that proven technologies exist for reducing CH_4 emissions from compression systems (as described below):

- Centrifugal compressors emissions can be reduced by replacing wet seals with dry seals. These seals are used around the rotating shaft of the compressor and prevent high pressure gas from escaping the compressor. Wet seals involve the use of recirculating oil that emits 40–200 standard cubic feet (scf) of natural gas per minute (min). Dry seals use gas to seal the compressor shaft and emit only 6 scf/min. The replacement of wet seals with dry seals reduces centrifugal compressor emissions by 85–97 percent.
- Reciprocating compressor emissions can be reduced by replacement of rod packing. Packing prevents gas from moving around piston rods and escaping the compression cylinder. New packing that is properly installed on a well-maintained compressor will emit about 12 scf/hour. The emission rate for old or poorly installed packing can range 25–67 scf/hour. When compared to the emission rate for new packing, this equates to potential emission reductions of 52–82 percent. Rod packing replacement is a mature technology, but there are new technologies that can also reduce reciprocating engine exhaust slip. These new technologies include advanced materials that increase piston rod service life while reducing rod wear and Teflon-coated rings that reduce friction while maintaining a tight seal. There are no data currently available, however, on the emission reduction potential tied to deployings of these new technologies.
- The majority of the CH_4 emissions from reciprocating compressors are due to the CH_4 slip from engine exhaust. Comparing the exhaust emission factors for rich burn and lean burn engines, respectively, shows that rich burn engines have a combustion effectiveness of 97 percent and lean burn engines have combustion effectiveness of 99

Commented [LBD85]: Which regulations? Suggest explain why they are being mentioned here.

Commented [LBD86]: It may be confusing that this is the name of "equipment." Suggest a little explanation if possible.

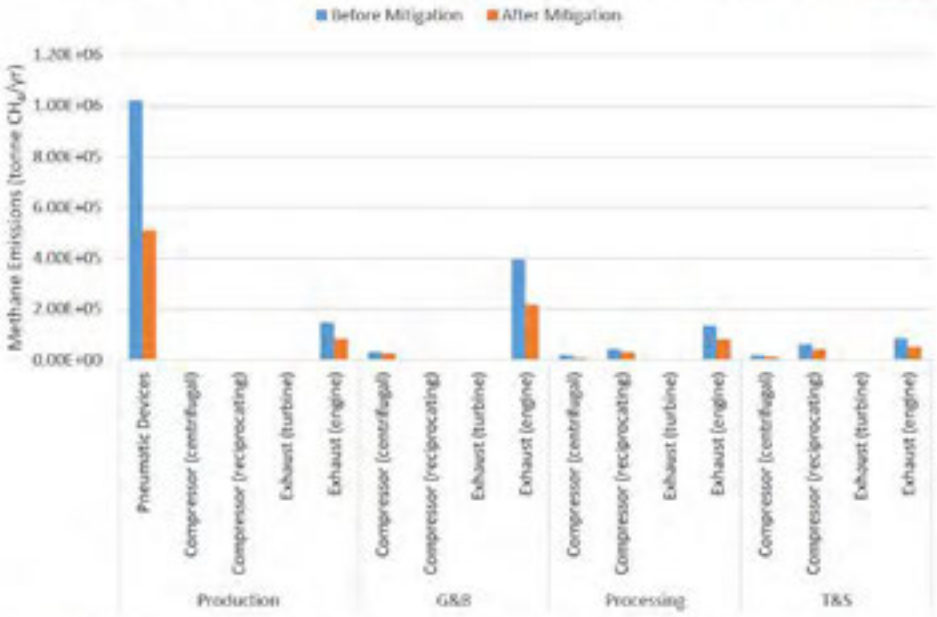
Commented [TS87]: RECs are required by law now this not a current issue for the industry. The point that REC implementation has shifted the emissions from methane to CO2 has occurred and did reduce GHG intensity form a global warming perspective.

Commented [EK88]: NETL Team - with this proposed text correction, is the statement now accurate?

percent. Air-fuel-ratio controls are an option for improving the combustion effectiveness of lean burn engines while keeping NOx emissions low. More research is required to understand the limits of air-fuel-ratio controls but, for this analysis, it is assumed that they can increase the combustion effectiveness of a lean burn engine by 97–99 percent.

Exhibit 2-10 illustrates the impact of these mitigation approaches.

Exhibit 2-10. Illustration of mitigation measure impact for pneumatic devices and compressors



Commented [TS89]: What is the source? If this the ONE Future report, it was limited to the ONE Futures value chain and not the US average.

Balcombe et al. (2018) note that pre-emptive maintenance and a faster response to ~~high~~ detection of high emissions ~~detection~~ are methods for reducing the impact of super emitters. Identifying a cost-effective solution is imperative and much attention is being given to developing lower cost emission monitoring and detection equipment. As Brandt et al. (2016) point out, identifying larger leaks from the highest emitters may be carried out using less sensitive, and consequently cheaper, detectors in areas at the highest risk.

Alvarez et al. (2018) note that key aspects of effective mitigation include pairing well-established technologies and best practices for routine emission sources with economically viable systems to rapidly detect the root causes of high emissions arising from abnormal conditions. The latter could involve combinations of current technologies, such as on-site leak surveys by company personnel using optical gas imaging, deployment of passive sensors at individual facilities or mounted on ground-based work trucks, and in situ remote-sensing approaches using tower networks, aircraft, or satellites. Over time, the development of less

failure-prone systems would be expected through repeated observation of and further research into common causes of abnormal emissions, followed by reengineered design of individual components and processes.

With respect to liquefaction, Mokhatab et al. (2014) note that most of the plant energy consumption and resultant emissions in natural gas liquefaction facilities occur in the compressor drivers, where fuel energy (usually natural gas) is converted to mechanical work (or electricity in case of electrically driven compressors). Due to the energy consumption scale of the LNG plants, any enhancement to the energy efficiency of a plant will result in a significant reduction in gas consumption and consequently CO_2 emissions (Mokhatab et al., 2014).

There are two ways to increase the energy efficiency of LNG plants: 1) liquefaction cycle enhancement and 2) driver cycle enhancement. Liquefaction cycle enhancements reduce ~~the~~ compressor power and consequently the compressor driver's fuel consumption. Driver cycle enhancement reduces the amount of fuel consumption to generate a specific amount of power. Typical fuel sources for natural gas liquefaction cycles include either pure refrigerant in cascade cycles, expansion-based cycles, or mixed refrigerant cycles.

Pure refrigerant cycles have a constant evaporating temperature that is a function of the saturation pressure. Mixed refrigerant cycles do not maintain a constant evaporating temperature at a given pressure. Their evaporating temperature can range and change depending on the pressure and composition. A refrigerant mixture of hydrocarbons and nitrogen is chosen so that it has an evaporation curve that matches the cooling curve of the natural gas with the minimum temperature difference. ~~As such~~Therefore, small temperature differences reduce entropy generation, and, thus, improve thermodynamic efficiency, reduce power consumption, and reduce the emissions associated with liquefaction facilities (Mokhatab et al., 2014).

A study from Pospíšil et al. (2019) notes that a certain part of the energy spent on liquefaction can be recovered by the utilization of the cold stream from LNG. The amount of usable cold is given by thermophysical properties of natural gas and corresponds to 830 kilojoule (kJ)/kg of LNG. This cold energy can be recovered during the regasification process. Regasification is carried out either in port terminals before natural gas is transported via gas lines or directly before the use of natural gas. The exploitation of cold from LNG is quite limited at present. Most of the available cold is wasted during the regasification process when LNG is heated up by water or ambient air. Inefficient use of cold temperature streams reduces the overall efficiency of this primary energy source and leads to greater emissions. Promising ways of utilizing cold from LNG in the regasification process should be explored and implemented (Pospíšil et al., 2019). For LNG that is ultimately combusted for electricity, Jordaan et al. (2022) find that deploying mitigation options can reduce global emissions from gas-fired power by 71 percent with carbon capture and storage (CCS), CH_4 abatement, and efficiency upgrades contributing 43 percent, 12 percent, and 5 percent, respectively— and this suggested mitigation falls within national responsibilities, except with respect to an annual accumulation of 20.5 $MtCO_2e$ of ocean transport emissions generated.

Roman-White et al. (2021) note that for LNG, harmonized data collection and reporting would build confidence in supplier claims about LCA emissions, enabling comparisons between natural

Commented [LBD90]: Suggest explain this term

Commented [LBD91]: Can you add a parenthetical example?

Commented [TS92]: This reads like an NETL statement. When quoting another others recommendations or key conclusions, it would help if the text read

Pspeisel et al. 2019 recommends....

Universal comment to ensure clarity on who's recommendations or findings are being discussed.

Commented [LBD93]: Do you mean aggregate emissions in the world? Or GHG emissions?

Commented [EK94]: Please add CCS to the Acronym List.

Commented [LBD95]: Unclear what this means

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gas supply chains and supporting climate goals for all participants in the supply chain. This could stimulate a virtuous cycle of demand for GHG accounting and reduction and provision of more granular, company-specific emissions estimates.

MacKinnon et al. (2018) demonstrate that natural gas-fired power generation and the natural gas system could play several important roles in supporting sustainable energy strategies over time that can achieve societal GHG reduction goals and help the transition to renewable sources. Natural gas generation can support transitions to renewable resources 1) by use in advanced conversion devices to provide complementary grid services efficiently and with very low emissions to maximize the benefits of intermittent renewable resources (e.g., running a natural gas compression system during peak renewables production), and 2) natural gas generation and the existing natural gas infrastructure can support the use of renewable natural gas with high energy and environmental benefits.

Commented [LBD96]: A term like "natural gas-fired power generation" might be more clear.

According to Stern (2022), three major requirements for creating credible measuring, reporting, and verification of CH_4 emissions are 1) to move measurement and reporting of CH_4 emissions from standard factors—either engineering-based or from EPA data—to empirical (Tier 3) measurements, and to reconcile bottoms-up (ground level) and top-down (satellite/aircraft/drone) observations; 2) to ensure that data measurement and reporting has been verified and certified by accredited bodies; and 3) to require asset-level emissions data to be transparent and publicly available. Failure to do so on grounds of commercial confidentiality risks being interpreted as evidence that the data is not credible.

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3 AIR QUALITY

The natural gas supply chain contributes to air pollution in several ways, including 1) the leaking, venting, and combustion of natural gas during production and 2) the combustion of natural gas and other fossil fuel resources or other emissions during associated operations (e.g., extraction, transportation, downstream combustion). Emissions sources include pad, road, and pipeline construction; well drilling, completion, and flowback activities; and natural gas processing and transmission equipment such as controllers, compressors, dehydrators, pipes, and storage vessels. Pollutants include, most prominently, CH_4 and volatile organic compounds (VOCs)—of which the natural gas industry is one of the highest-emitting industrial sectors in the United States—in addition to nitrogen oxides (NOx), sulfur dioxide (SO_2), and various forms of other hazardous air pollutants (HAPs) (Congressional Research Service [CRS], 2020). Pollutants are described in detail below (CRS, 2020):

- CH_4 is the principal component of natural gas and is a precursor to ground-level ozone formation (i.e., "smog").
- NOx is a ground-level ozone precursor. Significant amounts of NOx are emitted during the combustion of natural gas and other fossil fuels (e.g., diesel). The combustion of natural gas occurs when it is flared during drilling and well completions and when used to drive the various compressors that move products through the system. Combustion also occurs in engines, drills, heaters, boilers, and other production equipment.
- VOCs are a ground-level ozone precursor. The crude oil and natural gas sector is currently one of the largest sources of VOC emissions in the United States, accounting for approximately 20 percent of man-made VOC emissions nationwide (and representing almost 40 percent of VOC emissions released by stationary sources). VOCs—in the form of various hydrocarbons—are emitted throughout a wide range of natural gas operations and equipment. The interaction among VOCs, NOx, and sunlight in the atmosphere contributes to the formation of ozone.
- SO_2 is emitted from crude oil and natural gas production and processing operations that handle and treat sulfur-rich, or "sour," gas.
- HAPs, also known as air toxins, are those pollutants that are known or suspected to cause cancer or contribute to other serious health effects including reproductive issues and birth defects. Of the HAPs emitted from natural gas systems, VOCs are the largest group and typically evaporate easily into the air. The most common HAPs produced from natural gas systems are n-hexane and benzene, toluene, ethylbenzene, and xylenes (BTEX) compounds. Some natural gas reservoirs may also contain high levels of hydrogen sulfide (H_2S). HAPs are found primarily in natural gas itself and are emitted from equipment leaks and during processing, compressing, transmission, distribution, or storage operations. HAPs are also a byproduct of incomplete fuel combustion and may be components in various chemical additives.

Commented [LBD97]: "exploration and production"? Are we including exploration?

Commented [EK98]: Please add Nox to the Acronym list.

Commented [LBD99]: Suggest explain in parens or a footnote what compounds this represents

3.1 Upstream Production and Hydraulic Fracturing

The venting of natural gas during extraction and processing is a key source of VOC emissions. Similar to CH_4, VOCs are a naturally occurring constituent of natural gas and can react with other pollutants to produce ground-level ozone.

Emissions of VOCs and CH_4 are lower for offshore conventional production compared to other types of natural gas types because offshore platforms generally have higher production rates helping to justify capital expenditures on loss reduction technologies, which help to prevent unnecessary venting.[h] Another source of VOC emissions during upstream operations is venting from condensate storage tanks, which occurs in regions with wet gas.[i]

The combustion of natural gas in compressors and gas processing equipment produces NOx and carbon monoxide (CO). Similarly, the combustion of diesel in drilling equipment produces NOx and CO, as well as significant quantities of SO_2 emissions. Beyond VOCs, CH_4, NOx, CO, and SO_2 emissions, upstream processes can also produce aliphatic hydrocarbons, (e.g., C2–C5), alkanes, VOCs (e.g., BTEX), H_2S, n-hexane, and formaldehyde, which can contaminate ambient air (Wollin et al., 2020).

Elliott et al. (2017) estimates that up to 143 air contaminants can be released during hydraulic fracturing. The International Agency for Research on Cancer generates hazard assessments for only 20 percent of these identified contaminants. Twenty of these air contaminants are known carcinogens. Other air contaminants are generated by the peripheral plant components. These include particulate matter, NOx, precursors of ozone and polycyclic aromatic hydrocarbons (Wollin et al., 2020).

The following activities are known to contribute to air contamination at oil or gas drilling sites:

- Preparation of the drilling site including road connections
- Drilling of the well
- Truck traffic for delivery and disposal of materials
- Removal of acid gases and water from gas; separation of natural gas from other hydrocarbons
- Operation of compressor stations to enable the transport of natural gas into transport pipelines
- Preprocessing of crude oil prior to refinery

Exhibit 3-1 illustrates the supply chain for natural gas where each of these activities occurs (Wollin, 2020).

Commented [TC100]: Is the a reference for this finding? I would have thought safety at offshore platforms also would have driven lower emission rates.

If we don't have a reference or more supporting documentation, I think the sentence could be deleted without impacting the narrative.

Commented [LBD101]: Suggest explain wet gas vs. dry gas

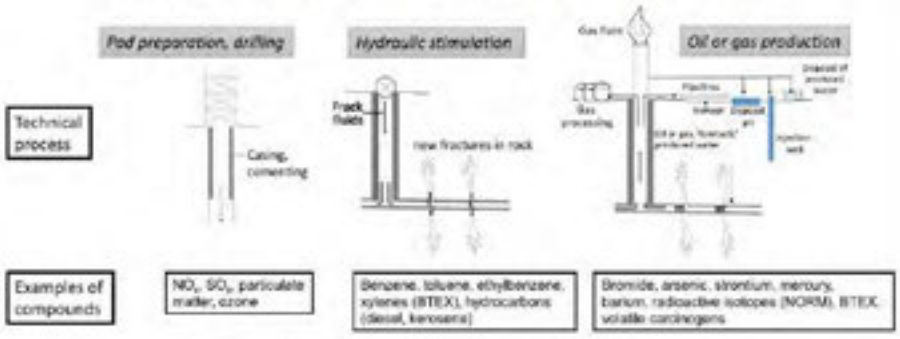
Commented [SW102R101]: I think that would be helpful.

Commented [SH103R101]: Included as footnote.

[h] There are no technological barriers to applying such emission reduction technologies to shale gas or other sources of natural gas.h

[i] When natural gas is retrieved, it can be considered wet or dry. Dry natural gas is at least 85 percent methane, but often more. Wet natural gas contains some methane, but also contains liquids such as ethane, propane or butane. The more methane natural gas contains, the "dryer" it is considered.

Exhibit 3-1. Illustration of supply chain steps where upstream air pollution occurs



Permission pending from Wollin et al. (2020)

NOx and SOx emissions have been reported to be higher during the development of the drilling site compared to during the production phase (Wollin et al., 2020). Similar observations have been made for particulate matter (PM) (e.g., PM2.5 and PM10). Analysis of shale gas production sites in North Texas showed an increase in ozone concentrations by 8 percent at natural gas production sites compared to control sites (Wollin et al., 2020).

Indirect energy consumption can also affect the air quality profile of gas extraction technologies. If the development or operation of a natural gas well uses grid electricity, then the fuel mix of the electricity grid will affect the life cycle performance of the well. The indirect air quality impacts of electricity consumption depend on the fuel mixes and combustion characteristics of power plants that compose a regional electricity grid.

A critical aspect concerning emissions from hydraulic fracturing processes is that several of the organic toxic compounds that are emitted are not regulated. EPA's National Ambient Air Quality Standards only places limits on six Criteria Air Pollutants including CO, ozone near the surface, NOx, PM, SO_2, and lead. Since the N[illegible] do not place limits on nor consider the effects of organic compounds beyond those listed previously, EPA's Integrated Risk Information System is frequently used to identify and characterize the health hazards of other compounds. Unlike [illegible], the Integrated Risk Information System does not place any legal restrictions on the release of the compounds it provides data on. ~~As such~~Therefore, ~~national regulations for the breadth of air emissions released during hydraulic fracturing are insufficient~~. Exhibit 3-2 offers a perspective on non-GHG air pollutant by supply chain step or equipment.

Commented [TC104]: I'm not following the discussion in this paragraph.

Air toxics, or hazardous air pollutants (HAPs), are regulated by EPA under the NESHAP (https://www.epa.gov/stationary-sources-air-pollution/oil-and-natural-gas-production-facilities-national-emission). Would the organic toxic compounds discussed here be regulated under the NESHAP?

Commented [EK105R104]: Agreed. I'm slightly confused as well. After NETL provides clarification, please add NAAQS to the acronym list.

Commented [LBD106]: "Incomplete"?

Commented [TC107]: Does Exhibit 3-2 use EPA's Integrated Risk Information System? I don't understand the connection between the Integrated Risk Information System and the other statements in this paragraph or the Exhibit.

Exhibit 3-2. Perspective of non-GHG air pollutant by supply chain step or equipment

Source	Air pollutant				Data quality
	NO_X	VOC	PM	Other toxic substances	
Well development					
Drilling rigs	•	◦	•	•	Medium
Frac pumps	•	◦	•	•	Medium
Truck traffic	•	◦	•	•	Medium
Completion venting		•		•	Poor
Frac ponds		◦			Poor
Gas production					
Compressor stations	•	•	◦	•	Medium
Wellhead compressors	◦	◦	◦	◦	Medium
Heaters, dehydrators		◦	◦	◦	Medium
Blowdown venting		◦		◦	Poor
Condensate tanks		•		◦	Poor
Fugitives				◦	Poor
Pneumatics		◦		◦	Poor

• Major source, ◦ minor source

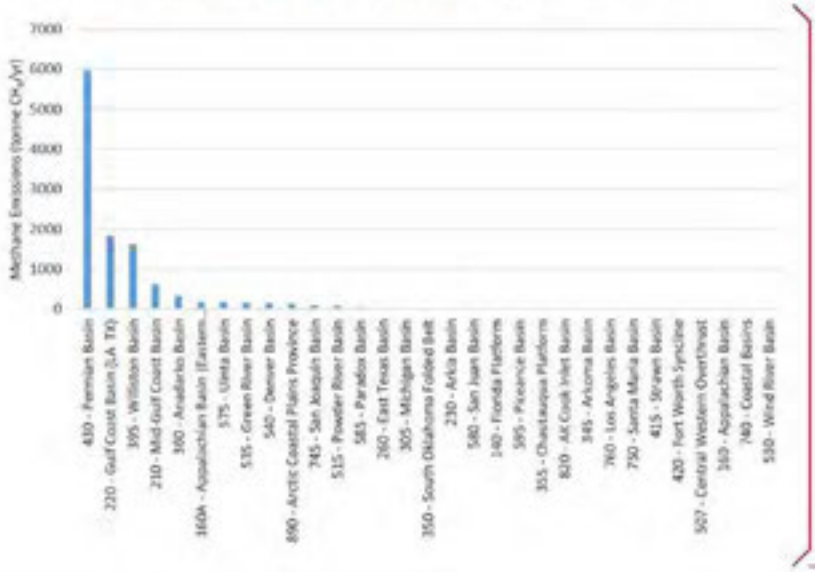
Permission pending from Wollin et al. (2020)

McMullin et al. (2018) analyzed exposure to VOCs emitted during hydraulic fracturing in Colorado. They identified 56 different VOCs that were emitted during hydraulic fracturing using data ~~they~~ compiled from 47 existing air monitoring devices that measured these VOCs at 34 different locations across the region.

Plant et al. (2022) used airborne sampling to measure flare efficiency[i] in three major gas production regions in the United States. They found that both unlit flares and inefficient combustion contribute comparatively to ineffective CH_4 destruction, with flares effectively destroying only 91.1 percent (90.2–91.8 percent; 95 percent confidence interval) of CH_4 emissions. Other emissions from flaring can include carbon particles (soot), unburned hydrocarbons, CO, partially burned and altered hydrocarbons, NOx, and (if sulfur containing material such as H_2S or mercaptans is flared) SO_2. The combustion products of flaring at natural gas production and processing sites specifically include CO_2, CH_4, and N_2O. Exhibit 3-3 illustrates the annual methane emissions from flaring for U.S. production basins (NETL, 2020).

[i] The flare efficiency is a measure of the effectiveness of the combustion process to fully oxidize the fuel. When inefficiencies occur, unburned fuel, CO, and other products of incomplete combustion (e.g., soot, VOCs, etc.) are emitted into the atmosphere.

Exhibit 3-3. Annual CH_4 emissions from flaring for U.S. production basins



Commented [TC108]: Recommend deleting this figure or moving to the GHG chapter.

Commented [EK109R108]: If we retain the figure and move it to the GHG chapter, I still have the following concern: given the enormous flaring outlier data from the Permian Basin reflects, if there is positive movement there (in Texas and / or New Mexico, etc.) in terms of new / proposed flaring regulations, sustainable practices voluntarily advanced by key / several operators, etc., I suggest we add that additional context to the text narrative. The flaring problems in the Permian profiled previously by EDF and others influenced European buyers (e.g., French utility Engie back in 2020) who became increasingly concerned with and began to oppose the importation of 'dirty gas' from that massive play.

Commented [ST110R108]: NETL: Move to GHG section or delete.

3.2 MIDSTREAM TRANSPORT EMISSIONS

Commented [LBD111]: Would it be desireable to provide specific comment on midstream methane emissions, since methane has been cited as an ozone precursor in addition to being a GHG? Possibly it could be a reference to the chapter on GHGs.

While the presence of HAPs in unprocessed, upstream natural gas has been documented, little has been published on their presence in the midstream segments of the natural gas supply chain. Nordgaard et al. (2022) systematically evaluated publicly available, industry-disclosed HAP composition data from natural gas infrastructure applications submitted to FERC between 2017 and 2020. These applications covered 45 percent of the U.S. onshore natural gas transmission system (as measured by pipeline miles). Given that reporting HAP composition data is not required by FERC, only 49 percent of approved projects disclosed their HAP composition data to FERC. Of the applications that did disclose their HAP composition data, HAP concentrations were typically reported as higher for separator flash gas and condensate tank vapor, compared to ~~LNG~~unrefined natural gas and transmission-grade natural gas, with mean benzene concentrations of 1106, 7050, 77, and 37 parts per million, respectively.

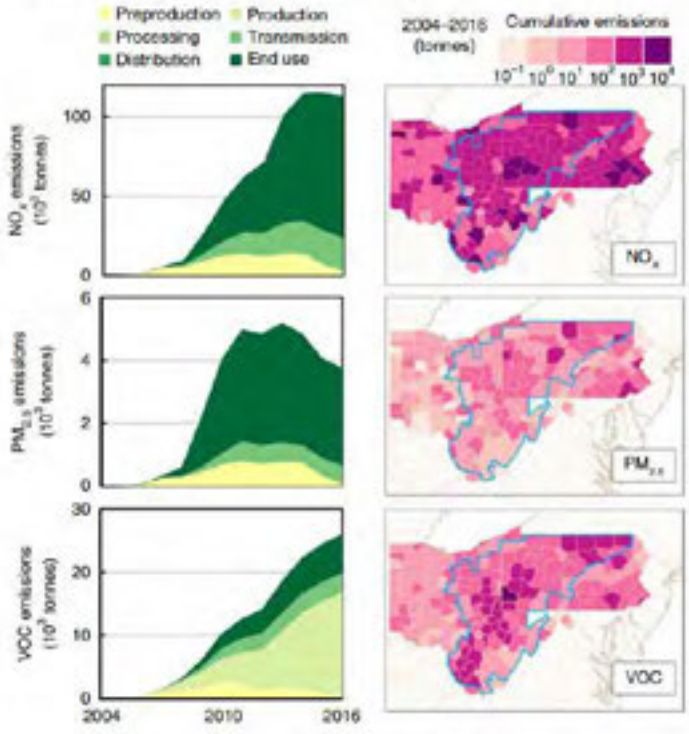
Nordgaard et al. (2022) also identified one pipeline operator that reports real-time HAP concentrations for natural gas at five pipeline interconnection points. Similar to the FERC applications, this operator reported BTEX and H_2S as present in the pipelines used to transport their natural gas. ~~Notably, mercury was also reported as detectable in 14 percent of real-time natural gas measurements but was not reported in any FERC applications.~~ Because current transmission infrastructure releases natural gas during uncontrolled leaks, loss of containment events, and routine operations (e.g., blowouts and compressor station blowdowns), having access to HAP composition data may be ~~critical~~ important for conducting both air quality and health-focused evaluations of natural gas releases.

3.3 END-USE PROCESSES

Commented [TC112]: Please delete this section, end use emissions are out of scope. Some of the information about upstream air emission source might be appropriate to move above.

Mayfield et al. (2019) performed an analysis of the environment impacts associated with the shale gas boom in the Appalachian Basin and found the majority (61 percent) of VOC emissions from the natural gas supply chain can be largely attributed to upstream processes and are spatially concentrated in counties with the highest cumulative production. Upstream processes contribute the most to total NOx (67 percent) and PM2.5 (73 percent) emissions across the natural gas supply chain; NOx and PM2.5 emissions are relatively evenly distributed across counties (Mayfield et al., 2019). Exhibit 3-4 presents annual NOx, PM2.5, and VOC emissions from the natural gas supply chain within Pennsylvania, Ohio, and West Virginia, along with the spatial distribution of cumulative NOx, PM2.5, and VOC emissions by county between 2004 and 2016. It is important to note that the blue lines delineate shale gas-producing counties (Mayfield et al., 2019).

Exhibit 3-4. Annual (left graphs) and cumulative (right graphs) (2004–2016) NOx, PM2.5, and VOC emissions from natural gas supply chain within Pennsylvania, Ohio, and West Virginia



Permission pending from Mayfield et al. (2019)

3.4 REFERENCES

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4 WATER USE AND QUALITY

The literature describes the treatment and management of wastewaters as the central environmental concern regarding natural gas production. Especially in the eastern regions of the United States where—although water is abundant—significant natural gas production has been occurring. In the western part of the United States, persisting dry climates limit the use and availability of freshwater for natural gas production ~~.~~ ~~S~~specifically, freshwater availability for drilling and hydraulic fracturing.

Gallegos et al. (2015) estimate that drilling and hydraulically fracturing a shale gas well can consume 2.6–9.7 MM gallons (gal) of water (Gallegos et al., 2015). From 2015 to 2014, unconventional shale gas in the United States used 187 billion (B) gal of water. From 2012 to 2014, the average use for hydraulic fracturing was 30.6 B gal annually. Additionally, Gallegos et al. (2015)'s integrated data from 6–10 years of operations suggest 212 B gal of combined flowback and produced water are produced from unconventional shale gas and oil formations. While the extensive growth in hydraulic fracturing ~~revolution~~ has increased water use for natural gas production across the United States, the water use and produced water intensity of these well stimulation activities ~~hydraulic fracturing~~ is lower than the water use and produced water intensity of other energy extraction methods and represents only a small fraction of total industrial water use nationwide (Kondash and Vengosh, 2015). However, even the smallest local or seasonal water supply shortages can cause issues.

Commented [LBD113]: Reverse order?

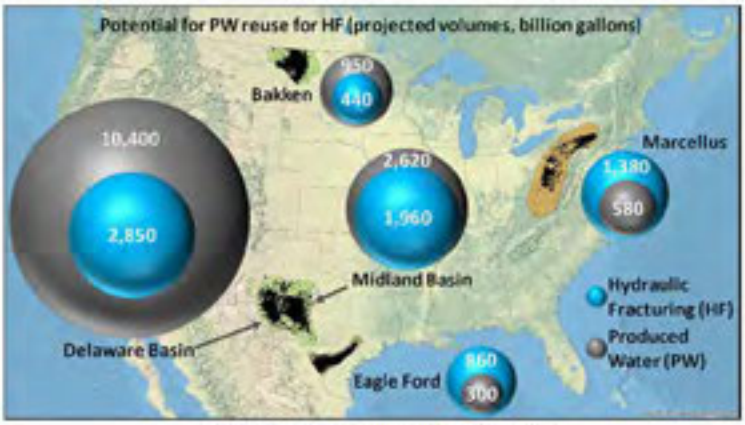
Water quality can also be impacted by natural gas production processes if water is inadequately managed or by the use of fracturing chemicals both on the surface—before injection and after flowback—and in produced water. Subsurface water quality impacts can result from the migration of fracturing fluids, formation waters, and CH_4 along well bores and through rock fracture networks. Management and disposal efforts increasingly include efforts to minimize water use through recycling and re-use of fracturing fluids, in addition to treatment and disposal of wastewater through deep underground injection.

The shale boom has made energy more available and affordable globally, but has also contributed to environmental concerns surrounding the use of water. Scanlon et al. (2020) analyze the water-related sustainability of energy extraction. They focus on meeting the rapidly rising water demand for hydraulic fracturing and managing growing volumes of water co-produced with oil and gas. They also analyze historical (2009–2017) volumes of water in ~73,000 wells and projected future water volumes in major U.S. unconventional oil and gas plays. Their results show a marked increase in fracking water use, depleting groundwater resources in some semiarid regions (Scanlon et al., 2020).

Commented [LBD114]: Volumes of water use?

Water issues related to both fracking water demand and produced water supplies may be partially mitigated through the reuse of produced water ~~to frackfor fracking of~~ new wells. As shown in Exhibit 4-1, projected produced water volumes exceed fracking water demand in semiarid Bakken (2.1×), Permian Midland (1.3×), and Delaware (3.7×) oil plays, with the Delaware oil play accounting for ~50 percent of the projected U.S. oil production (Scanlon et al., 2020). Therefore, water issues could constrain future energy production, particularly in semiarid oil plays.

Exhibit 4-1. Map showing ratio between produced water and fracking water demand for major shale basins



Permission pending from Scanlon et al. (2020)

4.1 Water Use for Unconventional Natural Gas Production

Most of the water used for unconventional natural gas production is used for drilling for hydraulic fracturing. For example, of the total water used by the shale gas industry, hydraulic fracturing is estimated to account for about 89 percent, drilling about 10 percent, and infrastructure the remainder (<1 percent) (Hayes and Severin, 2012). Water is also the main component of the fluids used for hydraulic fracturing, making up approximately 99 percent of the total volume.

Reporting from Gallegos, et al. (2015) suggests hydraulic fracturing uses 2.6–9.7 MM gal of water per well drilled, while the American Petroleum Institute (API) (2023) indicates that the average hydraulically fractured well uses 4 MM gal of water. As water is a scarce resource, it is important to consider the potential environmental impacts of using water from different sources (e.g., ground water, surface water). If available surface water is used to support natural gas production, then the ecosystems that rely on this water could be harmed. Significant groundwater withdrawals can also permanently deplete aquifers.

The process of hydraulic fracturing uses large volumes of water mixed with chemicals and proppant (sand) to fracture low-permeability shale and tight oil rocks, allowing the extraction of hydrocarbons ~~to occur~~. Despite the higher water intensity (the amount of water used to produce a unit of energy; for example, liters per gigajoule~~s~~) compared to drilling conventional vertical oil and gas wells, overall water withdrawals for hydraulic fracturing is negligible compared to other industrial water uses on a national level (Vengosh et al., 2014; Jackson et al., 2014; Kondash, Albright, and Vengosh, 2017; Kondash and Vengosh, 2015). On a local scale, however, water use for hydraulic fracturing can cause conflicts over water availability, especially in arid regions such as the western and southwestern United States, where water supplies are limited (Scanlon, Reedy, and Nicot, 2014; Scanlon et al. 2017; Nicot and Scanlon, 2012; Ikonnikov et al., 2017; Kondash, Lauer, and Vengosh, 2018).

Commented [HSAJ115]: Comment for FE HQ - While this source is older than 2014 it helps to build the context for this section. Please advise if another more recent source is available and we will update accordingly.

Commented [HH116R115]: Hello Amanda,

Thank you for your comment. Please see the references below. Also, please feel free to reference our FOA 2796 (especially in the background section) for updates on the WM program's vision and technical focus areas:

https://www.gwpc.org/wp-content/uploads/2023/05/State-Regulations-Report-2021-Published-May-2023-FINAL.pdf

https://www.gwpc.org/wp-content/uploads/2023/06/2023-Produced-Water-Report-Update-FINAL-REPORT.pdf

https://www.gwpc.org/wp-content/uploads/2021/09/2021_Produced_Water_Volumes.pdf

https://www.energy.gov/fecm/funding-notice-water-research-and-development-oil-and-gas-produced-water-and-coal-combustion

Commented [EK117]: HH: Note about induced seismicity, which has become one of the main reasons for regulatory "Sticks" that are driving technological innovation.

4.1.1 Water Consumption Impacts

Water use for hydraulic fracturing and wastewater production in major shale gas and oil producing regions increased between 2011 and 2016, with water use per well increasing by up to 770 percent—with flowback and produced water volumes generated within the first year of production increasing up to 550 percent. ~~The~~ water-use intensity (that is, normalized to ~~the~~ energy production) increased in all U.S. shale basins, except the Marcellus shale basin, over this period (Kondash, Lauer, and Vengosh, 2018).

Water consumption per shale gas well can vary due to four conditions:

- *Geology*: maturity of the shale and formation depth, thickness, and lateral extent
- *Technology*: horizontal or vertical drilling, water recycling
- *Operations*: operator decisions, availability of nearby freshwater
- *Regulatory*: requirements for use and treatment of water

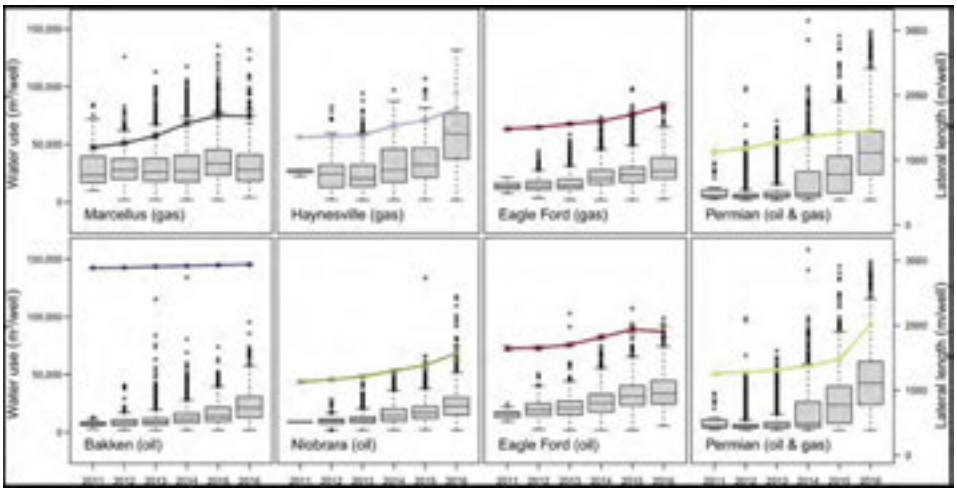
During 2009–2017, ~73,000 wells, or an aggregated total lateral length of ~440 × 10^6 ft (134,000 km), were drilled in the eight studied plays, equivalent to ~3× the Earth's circumference (40,000 km). Dieter et al. (2018) ~~find~~ found that to fracture the rock along that length, a total of ~480 B gal of water was used, equivalent to ~0.1 percent of the U.S. 2015 total water withdrawal, or almost two days of freshwater withdrawal (280 B gal/day). Exhibit 4-2 shows the water consumption for hydraulic fracturing, the amount of produced water used and oil and gas outputs from 9 major plays in the United States (Scanlon et al., 2020). The Eagle Ford play has used 173 B gal of combined hydraulic fracturing and produced water, at nearly a 1.83 ratio of freshwater to produced water and the Marcellus has a freshwater to produced water ratio of 5.83. Other plays use more produced water than freshwater, like Bakken, Delaware, and Barnett, where the ratios of produced water to freshwater are 1.83, 2.21, and 2.11 respectively.

Exhibit 4-2. water use in nine shale plays in the U.S.

Play	Total Length (10^6 ft)	Median Well Length (ft)	Number of Wells	Hydraulic Fracturing Water (10^9 gal)	Produced Water (10^9 gal)	Oil (10^9 gal)	Gas (10^9 gal of oil equivalent)
Bakken	114	9,580	12,036	49	75	100	22
Eagle Ford	95	6,061	17,366	112	61	103	78
Midland	49	8,575	6,461	79	44	30	14
Delaware	36	5,272	7,070	51	113	40	26
Marcellus	51	7,139	9,651	70	12	3	214
Niobrara	21	7,438	3,842	21	5	14	11
Barnett	27	5,241	7,453	35	74	1	111
Haynesville	15	6,270	3,215	30	16	0.03	107
Fayetteville	21	6,386	4,717	24	-	-	55

Exhibit 4-3 from Kondash et al. (2018) indicates that, parallel to the increase in lateral lengths of the horizontal wells and hydrocarbon extraction yields through time, ~~the~~ water use has also increased. The relative increase in lateral length (4–60 percent) was, however, significantly lower than the increase in water use (14–770 percent). When water use per well is normalized to the length of lateral section of the horizontal well, in almost every case among oil producing regions, an increase in water use per length of the horizontal well is observed. This pattern is most evident in the Permian region, where water use increased from 4.4 cubic meter (m^3) per meter in 2011 to 29.3 m^3 per meter in 2016 for gas-producing wells, and from 3.9 m^3 per meter in 2011 to 21.1 m^3 per meter in oil-producing wells. In all cases, with the exception of the Marcellus shale play in 2016, the flowback and produced (FP) water generation ~~was~~ also increased~~ing~~ through time, with particularly higher rates after 2014.

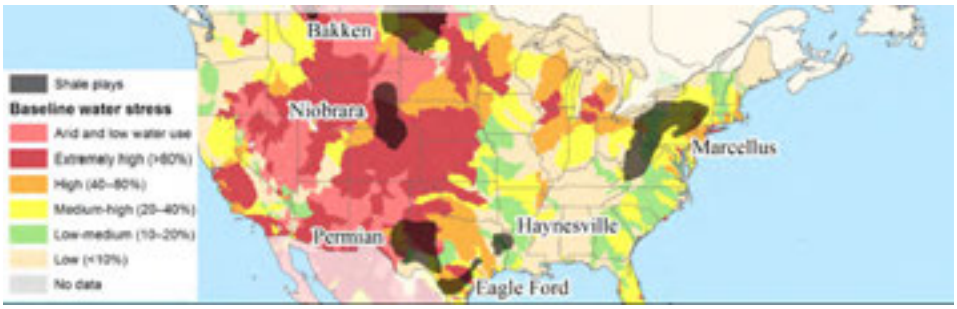
Exhibit 4-3. Water usage and lateral length by shale play



Used with permission from Kondash et al. (2018)

Kondash et al. (2018) also illustrate water conditions where the major plays across the United States are located, see Exhibit 4-4. The Bakken, Niobara, Permian and Eagle Ford plays are all located in arid to extremely dry climates where drought conditions have persisted for many years.

Exhibit 4-4. Baseline water stress and location of shale plays



Permission pending from Kondash et al. (2018)

4.1.2 Water Quality

Concerns have been raised about potential public health effects that may arise if hydraulic fracturing-related chemicals were to impact drinking water supplies. The chronic oral toxicity values—specifically, chronic oral reference values (RfVs) for noncancer effects, and oral slope factors (OSFs) for cancer are available for the list of 1,173 chemicals EPA identified as "associated with hydraulic fracturing." These include 1,076 chemicals used in hydraulic fracturing fluids and 134 chemicals detected in the flowback or produced waters from hydraulically fractured wells.

EPA compiled RfVs and OSFs for these chemicals using six different governmental and intergovernmental data sources. Ninety (8 percent) of the 1,076 chemicals used in hydraulic fracturing fluids and 83 (62 percent) of the 134 chemicals found in flowback/produced water had a chronic oral RfV or OSF reported in at least one or more of the six data sources used. Thirty-six of the chemicals used in hydraulic fracturing fluids have been measured in at least 10 percent of the hydraulically fracted wells drilled nationwide (identified from EPA's analysis of the FracFocus Chemical Disclosure Registry 1.0). Eight of these 36 chemicals (22 percent) had an available chronic oral RfV. The lack of chronic oral RfVs and OSFs for the majority of these chemicals highlights the significant knowledge gap that exists to assess the potential human health hazards associated with hydraulic fracturing (Yost et al., 2016).

Ecological risks to surface waters are present throughout the well life cycle and may manifest themselves differently locally compared to regionally. These risks can also vary temporally, as development activity like surface water withdrawal may only result in a single, brief impact, while the network of roads required for accessing ~~the~~ well pads could increase erosion and sediment runoff for years. Previous work identified the primary risks to surface water quality as sediment runoff from devegetation, leakage and spillage of chemicals into surface waters, unsustainable water withdrawal, landscape fragmentation, and insufficient treatment of oil and gas wastewater prior to discharge (Krupnick, Gordon, and Olmstead, 2013; Slonecker et al., 2012; Drohan et al., 2012; Kiviat, 2013). Unfortunately, few sites exist where baseline environmental monitoring occurred prior to hydraulic fracturing operations commencing (McBroom, Thomas, and Zhang, 2012). This greatly complicates efforts to precisely quantify

impacts of hydraulic fracturing, particularly if these operations are occurring in watersheds with preexisting anthropogenic influence and a host of existing ecological stressors (Mauter et al., 2014).

The surface water risks and impacts associated with unconventional resource development ~~will~~ vary significantly by region (Clements, Hickey, Kidd, 2012). To date, those in the Marcellus region have been examined most extensive~~ly~~ly. This scrutiny has been motivated by the nexus of regionally-specific risk drivers, such as high gradient terrains that could lead to increased erosion, an abundance of small streams, highly variable in-stream flow rates, and the high salinity of produced water in the Marcellus. Moreover, during the early development of the Marcellus shale in ~~PA~~Pennsylvania, the state permitted the disposal of hydraulic fracturing brines in municipal wastewater treatment plants. To reduce the human and environmental impacts associated with this practice, energy and production companies have adopted a moratorium on the disposal of produced water in wastewater treatment plants in ~~PA~~ the state (Wilson and Van Briesen, 2012; Wilson, Wang, and Van Briesen, 2013; Warner et al., 2013; Wilson and Van Briesen, 2013; Renner, 2009).

In the Marcellus and Fayetteville plays, more than 80 percent of the active gas wells are located within 300 meters of drainage areas and recent studies have reported a positive correlation between total suspended solids and the density of upstream gas wells in both the Marcellus and Fayettville.

4.1.3 General Guidelines for Leading Regulatory Practices on Water Sourcing

Increasing demand for water for drilling and hydraulic fracturing in shale gas plays has driven operators to seek supplemental sources of water, and alternatives to local freshwater supplies. Potential alternatives include industrial wastewater, water treatment plant outflows, abandoned mine waters, saline groundwater, and reuse of produced waters.

Ceres (Freyman, 2014) developed a set of guidelines based on gathering the experiences, best practices, and issues throughout the U.S. shale industry. The following is a list developed by Ceres that describes the leading best practices for water sourcing:

- Catalogue the consumptive water use from hydraulic fracturing operations, including sources of water used and the amounts recycled.
- Require information on how operators are planning to manage wastewater streams including final disposal of water.
- Create integrated management structures for joint oversight of ground and surface water (as some are now proposing in British Columbia).
- Realize that higher disclosure requirements alone will not solve water sourcing impacts and risks and must be accompanied by proactive water management plans that include monitoring and enforcement components.
- Ensure that water-sourcing oversight is independent from the department granting oil and gas permits to minimize conflicting mandates and objectives.

Commented [RH118]: It was the State of PA that asked companies to stop doing this, so I would rephrase. According to PSU, "PaDEP asked gas drilling operators to voluntarily stop using these plants for Marcellus wastewater disposal by May 2011 because of mounting water quality concerns downstream of municipal wastewater discharge points." https://extension.psu.edu/water-journey-through-the-shale-gas-processes

Commented [LBD119]: In places like this where literature cited is of this vintage, it might be helpful to add something saying that these are the most recent studies available. [See global comment at beginning of document.]

Commented [LBD120]: Suggest adding a citation or some reference - the reader has just been provided information from 10+ year old sources, so "recent" could seem ambiguous: if this point is based on more recent information, suggest being as specific as possible about that.

Commented [EK121]: HH: Similar to previous comments—would recommend referencing the GWPC PW handbook, which was recently published. Updated guidelines include managing induced seismicity, CM recovery, and identifying safe beneficial reuse opportunities.

- Create systems of incentives and/or mandate requirements to encourage recycling and non-freshwater use.
- Implement measures to prevent invasive species transfers.
- Provide more resources to map and monitor groundwater resources, including remote aquifers and brackish water resources, across North America.
- Reduce reliance on aquifer exemptions and create incentives to minimize use of deep well injection sites.

4.2 REGULATIONS

Although EPA is generally responsible for water quality by regulating underground injection, hydraulic fracturing is exempt from federal regulation under the SDWA (except when diesel fuel is included in the fluid or there is an imminent and substantial danger to the health of persons). As a result, the responsibility to protect drinking water from hydraulic fracturing activity falls primarily on the states (Zirogiannis et al., 2016).

Rapidly growing demand for water for hydraulic fracturing has challenged water resource managers in many regions. Many state and regional water plans have quickly become outdated as demand for water for shale oil and gas development increases and expands into new regions (Collier, 2011).

States ~~or provinces~~ have the primary responsibility for permitting oil and gas development and related water sourcing, but there is currently significant disparity in their approaches to regulating shale water requirements and associated impacts. A recent study by Resources for the Future (RFF) looked at regulations relevant to shale gas energy development and found markedly different water withdrawal policies across 30 of the states they surveyed, including those with major shale energy development (Exhibit 4-5, states with major shale energy development are outlined in yellow). The study found that for most of the 26 states with any water withdrawal permitting requirements, only half require permits for all withdrawals. Several states do not require permits at all, but only disclosure of water use over a certain threshold, as represented by the light purple states (Freyman, 2014).

In addition, some states ~~and provinces~~ exempt the oil and gas operators ~~industry~~ from permitting requirements for water withdrawals, including the following:

- Kentucky, which exempts the industry from both surface and groundwater reporting
- Texas, which requires permits for surface water withdrawals, but generally not for groundwater

Commented [HH122]: The Groundwater Protection Council recently published a report on the state of produced water as well as state regulations.

Please reference the reports to ensure changes, especially state regulations, are represented:

https://www.gwpc.org/wp-content/uploads/2023/05/State-Regulations-Report-2021-Published-May-2023-FINAL.pdf

https://www.gwpc.org/wp-content/uploads/2023/06/2023-Produced-Water-Report-Update-FINAL-REPORT.pdf

https://www.gwpc.org/wp-content/uploads/2021/09/2021_Produced_Water_Volumes.pdf

Commented [TC123]: Please remove this section.

Commented [LBD124]: This verb tense (present perfect) doesn't match well with a source that is 12 years old -- realizing that some editing is ongoing, but just pointing this out.

Exhibit 4-5. Water withdrawal regulations by state



Used with permission from Richardson et al. (2013)

In many cases, states where hydraulic fracturing is taking place have had to set their own regulations. The following is a list of examples of state-based water regulations related to hydraulic fracturing. This list is not exhaustive.

4.2.1 Pennsylvania

Pennsylvania is leading the way in requiring strong disclosure of freshwater and recycled water use during hydraulic fracturing. Within 30 days after completion of a well, the operator must submit a completion report to the Pennsylvania Department of Environmental Protection (PADEP). That report must include a stimulation record, which provides technical details associated with hydraulic fracturing, and list water resources that were used under an approved water management plan, including volume of water used from each source (25 Pa. Code § 78.122(b)(6); 25 Pa. Code § 78.122(b)(6)(vi)). Operators must also disclose the volume of recycled water used during well drilling (25 Pa. Code § 78.122(b)(6)(vii)). The PADEP then reviews individual plans and approves them, provided that water withdrawals:

- Do not adversely affect the quantity or quality of water available to other users of the same water sources.
- Protect and maintain the designated and existing uses of water sources.
- Do not cause adverse impact to water quality in the watershed considered as a whole.
- Are mitigated through a reuse plan for fluids that will be used to hydraulically fracture wells (58 Pa. Cons. Stat § 3211(m)(2)).

Other PA water regulations include the following:

- § 78a.15: If the proposed limit of disturbance of the well site is within 100 ft measured horizontally from any watercourse or any high quality or exceptional value body of water or any wetland 1 acre or greater in size, the applicant shall demonstrate that the well site location will protect those watercourses or bodies of water.
- § 78a.51. Protection of water supplies
    - A well operator who affects a public or private water supply by pollution or diminution shall restore or replace the affected supply with an alternate source of water adequate in quantity and quality for the purposes served by the supply as determined by the Department.
    - A landowner, water purveyor or affected person suffering from pollution or diminution of a water supply ~~as a result of~~due to oil and gas operations may ~~so~~ notify the Department and request that an investigation be conducted. Notice shall be made to the appropriate Department regional office or by calling the Department's Statewide toll-free number at (800) 541-2050. The notice and request must include the following:
- Require operators to demonstrate how they will prevent damage to aquatic life during water withdrawals.[k]

Commented [EK125]: NETL Team - if we don't have the information / text to complete this sentence, I suggest we strike it altogether.

4.2.2 Colorado

The Air Pollution Control Division issued revised versions of Operating and Maintenance Plan Templates for Produced Water Storage Tanks.

In January 2013, the Colorado Oil and Gas Conservation Commission (COGCC) approved the most rigorous statewide mandatory groundwater sampling and monitoring rules in the United States. The purpose of Rule 609, "is to gather baseline water quality data prior to oil and gas development occurring in a particular area, and to gather additional data after drilling and completion operations" (COGCC, 2020).

Wells are constructed with multiple layers of steel casing and cement; COGCC rules require the following specifications for each well:

- In the water-bearing and hydrocarbon zones, the casing is cemented into place, and cement fills the void space between each layer of casing.
- At least two layers of steel casing and cement are in place from the ground surface to the lowest point of the freshwater aquifer.
- In the hydrocarbon formation, several thousand feet below the aquifer in most cases, there is at least one layer of steel and cement, and the hydrocarbons move through the inner-most casing to the surface.

[k] See section C.6 titled "Withdrawal Impacts Analysis," in the PADEP Water Management Plan For Unconventional Gas Well Development Example Format (2013).

Colorado requires disinfection of water suction hoses when water withdrawals occur in cutthroat trout habitats to avoid transfer of invasive or harmful species (Colo. Code Regs. § 404-1:1204, Westlaw 2012.).

4.2.3 Texas

The RRC (the agency that regulates the state's oil and gas industry) recently amended its rules to make it easier to recycle wastewater streams from hydraulic fracturing operations. Operators no longer need permits to recycle water and can even accept water from other areas or companies, as long as the recycling takes place on land leased by the operator so that oversight can be maintained. This new rule also allows operators to turn around and sell the water to other operators (Osborne, 2013).

Commented [EK126]: May want to state the actual year rather than 'recently' - especially if this reference is about a regulatory action that's no longer recent in 2023.

4.2.4 Ohio

Ohio's freshwater and recycled water use rules require operators to identify each proposed source of groundwater and surface water that will be used (Ohio Rev. Code §1509.06(A)(8)(a).). Ohio does not, however, require post-drilling disclosure of actual volumes of freshwater and recycled water used.

4.3 Current Research and Development and Analysis

NETL is performing advanced remediation technology research to better manage effluent water from energy production. The Water ~~Energy Effluent~~ Management Program aims to ensure that American water is affordable, reliable, sustainable, and resilient for energy use, and to reduce the environmental impact of freshwater consumption for energy production related to oil and gas operations (and coal combustion) as well as to reduce the volume of produced water disposal during oil and gas activities by:

- Improving treatment methods for produced water constituents that are ~~both~~ hard~~,~~ ~~and~~ costly~~, and energy intensive~~ to treat.
- Increasing the beneficial use possibilities for treated produced water outside of the oil and gas industry.
- Reducing environmental impacts related to produced water such as freshwater consumption in water scarce regions and induced seismicity.
- Characterizing produced water and energy effluent waters to identify potential resources such as critical minerals that could be harvested for uses within other industries.

To support this vision, the program aspires to reduce the environmental impact of freshwater consumption for energy production related to oil and gas operations and coal combustion as well as to reduce the volume of produced water disposal during oil and gas activities. The research areas include the following:

Commented [EK127]: HH: This is one of the few times we mention coal in this section--should we mention it throughout the section or should we remove reference to coal altogether?

- Treatment technologies – developing effective and cost-effective technologies and treatment trains to treat produced water

- Beneficial use technologies – increasing the likelihood that treated produced water can be utilized in other industries besides oil and gas
- Resource characterization – characterization of produced water constituents for potential harvesting for other industrial uses

A goal of the program is to engineer water composition to improve imbibition into the formation matrix with ionic modification, surfactants, and nanoparticles, which can change the wettability of carbonate rocks toward more water-wet conditions under which water can imbibe into the matrix and displace oil into the fractures. The modified water composition will be injected to improve oil recovery from the carbonate matrix in fractured reservoirs. The result can increase production from the well with no increase in the amount of water, chemicals, proppants, and energy required. This translates to minimized air emissions and other environmental impacts associated with production of a unit volume of oil and gas.

Currently, Water Management Program has existing projects:

- Develop effective management and treatment technologies to treat produced water via energy- and cost-efficient approaches for use within the oil and gas industry (2 projects)
- Develop advanced optimization software, big data tools, and machine learning platform; to automate time-intensive tasks and perform high-computational analysis on produced water and relevant produced water management infrastructure data (2 projects)
- Develop advanced or novel membrane specific technologies for treatment of produced water (1 project)
- Developing methods to for chemical and biological characterization of produced water to and 1) extract rare earth elements or critical minerals from produced and 2) identify safe, beneficial reuse applications for treated produced water uses (2 project)

4.4 REFERENCES

25 Pa. Code § 78.122(b)(6)(vi) and (vii). Well record and completion report.

58 Pa. Cons. Stat § 3211(m)(2). Well permits.

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Commented [EK128]: HH: Would it be possible to provide the names of the projects? We have three additional ones in a university partnership effort, as well as initiatives in the digital space—just to ensure I don't double count.

Commented [ST129R128]: NETL: we need to ensure consistency in the depth and breadth of R&D sections across the chapters. Lets discuss.

Commented [EK130]: HH: Our program pivoted from this some time ago and we are no longer pursuing research in this area.

Commented [EK131R130]: HH: Please reference language about the new program from the NETL article (page 2). Text also copied below:

The Department of Energy (DOE) Office of Fossil Energy and Carbon Management (FECM) is celebrating the integration of the produced water (PW) management research and development (R&D) activities (originally housed within NETL Oil & Gas upstream research) with the Water Management for Power Systems program (operated under NETL's Crosscutting Research Program). These joined programs will be based in the Advanced Remediation Technologies Division (ART). The water-related R&D within FECM will be executed by ART-Water Management (ART-WM), representing one of the first combined programs of its type within DOE.

ART-WM's mission is to deliver societal benefits

Commented [EK132R130]: HH: This does not include the 7-8 FOA awards which will be announced in the coming weeks - yes?

Commented [EK133R130]: @Hadjeres, Hichem - I'm doing my best to integrate your excellent peer review feedback into this Sharepoint version of the Addendum. That said, I'm not exactly sure what you need with this comment RE: the 7-8 FOA

Commented [HH134R130]: @Easley, Kevin we are expecting another 7-8 projects to be added to our portfolio, which will cover new areas (e.g. CM recovery and extraction). The awards are expected to be made in a few weeks. The

Commented [EK135R130]: OK, thanks for the clarification, Hichem. I'll bring this up tomorrow when I meet with @Sweeney, Amy and @Curry, Thomas.

Commented [HH136R130]: @Easley, Kevin Thanks, Kevin!

Commented [HH137]: Please feel free to reword—basically talking about analysis and modeling of produced water samples and the work we do through PARETO to optimize PW management

Colo. Code Regs. § 404-1:1204, Westlaw 2012. Other General Operating Requirements.

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Kondash, A.J., Albright, E., and Vengosh, A. (2017). Quantity of flowback and produced waters from unconventional oil and gas exploration. *Sci. Total Environ*., *574:* 314–321.

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5 INDUCED SEISMICITY

Induced seismicity is ground motion (earthquakes) caused by human activities. Earthquakes have been detected in association with both oil and natural gas production, underground injection of wastewaters (i.e., wastewater disposal), and hydraulic fracturing (Rubinstein and Mahani, 2015). Each of these processes involves injecting large volumes of foreign fluids at various pressures into underground formations.[1] Earthquakes from induced seismicity have happened in multiple countries, including ~~in~~ the United States (Shultz et al., 2020).

5.1 IMPACTS FROM INDUCED SEISMICITY AND ENERGY TECHNOLOGIES

The term seismic activity is generally used to describe vibrations of mechanical energy that pass through the earth, much like sound waves vibrate through the atmosphere. The seismic activity of a region is defined by the frequency, kind, and magnitude of earthquakes experienced in the region during a given period. The National Earthquake Information Center (NEIC) is the entity responsible for determining, as rapidly and as accurately as possible, the location and size of all significant earthquakes that occur worldwide. At present, the NEIC locates and publishes detailed data on the 30,000 "most significant" earthquakes that occur in each year (USGS, 2023).

While millions of earthquakes occur each year, not all are felt at the surface. Earthquakes with magnitudes of 2.0 or less generally cannot be felt at the surface by people, while earthquakes with magnitudes greater than 3.0 tend to produce noticeable shaking. Earthquakes with magnitudes greater than 5.0 are felt at the surface and have the potential to cause structural damage to buildings and property. Most earthquakes that do occur are in response to natural, yet sudden slips and shifts of large masses of rock along geologic faults.

The seismicity rate in the central and eastern United States increased 40-fold within the past decade, predominantly as a result of human activities (Ellsworth, 2013; van der Baan and Calixto, 2017). This recent increase in seismicity rate in the central and eastern United States has largely been attributed to large-volume wastewater disposal wells injecting fluids into deep sedimentary formations (e.g., Keranen et al., 2014; Rubinstein and Mahani, 2015). Other human activities, including hydraulic fracturing (Skoumal, Brudzinski, and Currie, 2015) and carbon sequestration (e.g., Kaven et al., 2015), have induced seismicity to a lesser extent in the central and eastern United States (Skoumal et al., 2020).

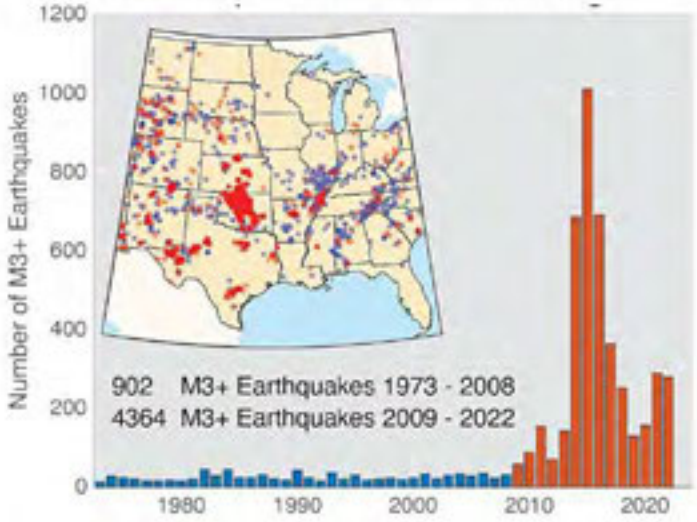
Commented [LBD138]: Suggest update phrasing to more precise years as this reads as 2013-2023 to a current reader.

Exhibit 5-1 presents the annual number of earthquakes (with a magnitude of 3.0 or larger) occurring in central and eastern areas of the United States for 1973–2022. Many of these earthquakes have taken place in areas where hydraulic fracturing has been and is actively occurring (e.g., Oklahoma) (USGS, 2022). Between 1973 and 2008, approximately 25 earthquakes of magnitude three or greater occurred on average annually. Since 2009, at least 58 earthquakes of this same size (magnitude of 3.0 or larger) have occurred annually, and at

[1] Hydraulic fracturing involves injecting large volumes of fluids into the ground to release trapped oil and natural gas. Wastewater from oil and gas production, including shale gas production, is typically disposed of by being injected at relatively low pressures into extensive formations that are specifically targeted for their porosities and permeabilities to accept large volumes of fluid.

least 100 earthquakes of this same size have occurred annually since 2013. The annual number of earthquakes (with a magnitude of 3.0 or larger) peaked in 2015 when 1,010 magnitude 3+ earthquakes were recorded. Given their magnitude, most of these earthquakes are large enough to have been felt by people, yet ~~small~~ not large enough to cause significant damage (USGS, 2022).

Exhibit 5-1. Earthquakes in the Central and Eastern U.S. 1973–2022



The following are examples of induced seismic events in the United States that have occurred in basins where unconventional natural gas production via hydraulic fracturing has occurred.

5.1.1 Utica and Marcellus Shales in the Appalachian Basin

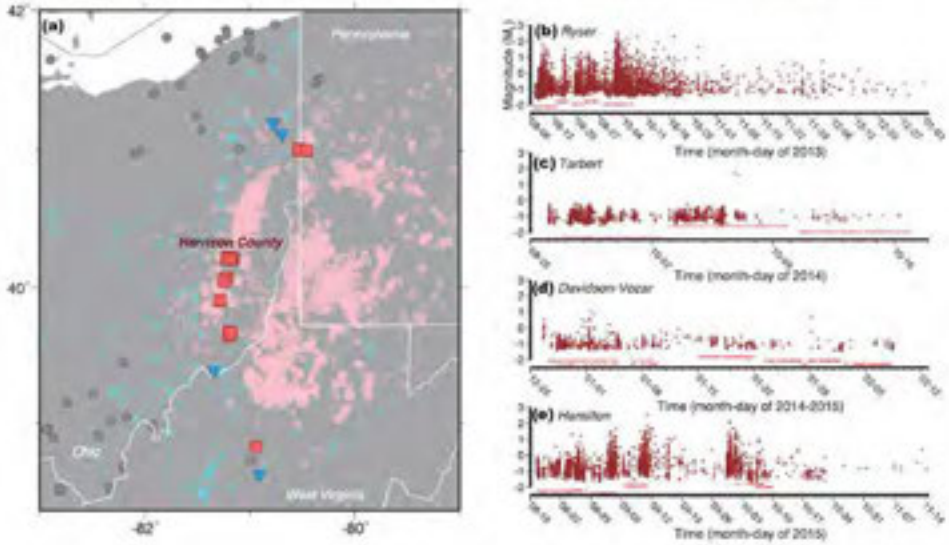
The Appalachian Basin is currently the largest natural gas producing area in the United States. The basin produced over 18 Mcf of natural gas a day (500 m^3/day) in 2019 (EIA, 2019a). The Marcellus and Point Pleasant Utica shale plays are both located in the Appalachian Basin and extend from New York to Kentucky. They each cover prospective areas of 190,000 and 220,000 square kilometers (km^2), with proven reserves of 135 and 24 Tcf of natural gas, and 345 and 210 MM barrels of oil, respectively (EIA, 2019b). Earthquakes detected in the basin during 2013–2015 are presented in Exhibit 5-2.

Commented [EK139]: Is the 2015 induced seismicity information presented here sufficiently 'recent' for the purposes of this Addendum? Is more recent data available from USGS as the graph at the top of the page and supporting text narrative refers to a 2022 data source.

The map on the left provides the location sequences of cataloged (magnitude > 2.0) seismic events in Ohio and neighboring states for 2010–2017. Blue triangles show earthquake sequences induced by wastewater disposal; red squares show earthquake sequences induced by hydraulic fracturing; and pink squares and blue triangles depict the horizontal and wastewater disposal wells that remain in the area. Grey circles represent earthquakes assumed to be occurring from natural causes. The four graphs on the right provide the temporal

distribution of hydraulic fracturing induced seismic events for four wells in Harrison County, Ohio (Schultz, 2020).

Exhibit 5-2. Location and timing of induced and natural seismic events in the Appalachian Basin



Permission pending from Schultz (2020)

5.1.2 Anadarko and Arkoma Basins of Oklahoma

Dramatic increases in seismic activity have been reported for areas in both central and northern Oklahoma, where the Anadarko and Arkoma Basins are located. Historically, an average of one to two ML[m] ≥ 3.0 earthquakes occurred in Oklahoma annually. The number of ML ≥ 3.0 earthquakes occurring in the state, however, rose to over 900 in 2015.

While the seismicity rate began to decline in 2016, the yearly total seismic moment of Oklahoma remained high in response to three Mw[n] ≥ 5.0 earthquakes occurring during the year. Including the Pawnee earthquake, the largest earthquake (5.8 Mw) ever recorded for the state of Oklahoma. The seismicity rate increase has generally been attributed to the disposal of large volumes of produced water into the Arbuckle Group basin (Haffener, Chen, and Murray, 2018).

Exhibit 5-3 shows the location (left) and magnitude (right) of induced seismic events in Oklahoma between 2010 and 2020. In the map on the left, seismic events from natural causes are represented by the blue circles, while induced seismic events are represented by the red (Skoumal et al., 2018) and orange circles (Shemeta, Brooks, and Lord, 2019). The graph on the

Commented [EK140]: NETL Team - 'moment' (as written) or events or some other term? If 'moment,' it's unclear what message / finding the sentence is trying to convey. Also, 'of' Oklahoma' (as written) or 'in' Oklahoma.

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[m] ML refers to the magnitude on the Richter scale, where M stands for magnitude and L stands for local.

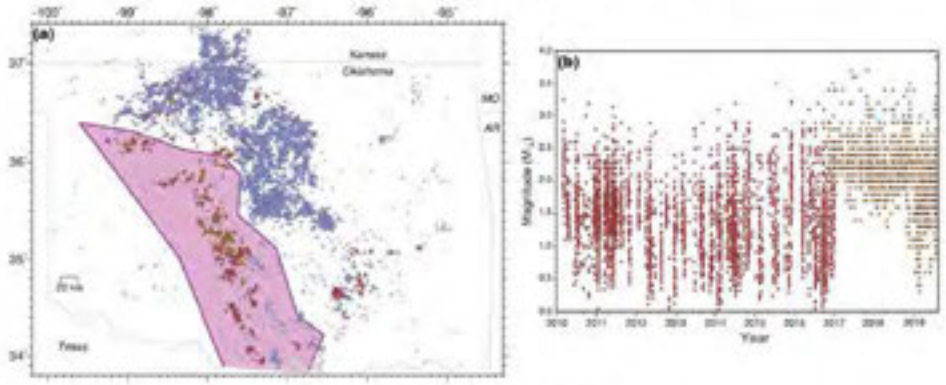
[n] Mw is known as the moment magnitude of an earthquake. For very large earthquakes, moment magnitude gives the most reliable estimate of earthquake size.

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left shows the number and magnitude of the induced seismic events over time (Skoumal et al., 2018; Shemeta, Brooks, and Lord, 2019).

Commented [EK142]: NETL Team - did you mean to type the graphy on the right in Exhibit 5-3 as it's the one that has a 'time series' (2010 - 2019) along the horizontal axis.

Exhibit 5-3. Induced seismicity events in Oklahoma



Permission pending from Schultz (2020)

5.1.3 Fayetteville Formation in the Arkoma Basin of Arkansas

Following the success of the Barnett Shale (Fort Worth Basin, Texas) the Fayetteville Formation in Arkansas became an early target for continued shale gas development in the United States. This unconventional play runs east to west across north central Arkansas, extending across nearly 150 km. By 2005, horizontal well completions in the middle to lower organic rich facies at depths typically 1–2 km were coming online and, by 2009, 0.5 Tcf of gas was being produced per year (Browning et al., 2014).

The Fayetteville Formation has a history of seismicity that dates back to before the region was developed for oil and natural gas extraction. In September 2010, a series of seismic events reaching magnitudes close to 5.0 Mw on the Richter Scale occurred along the Guy-Greenbrier Fault within the basin. Not long after, on February 28, 2011, a 4.7 Mw earthquake—the largest ever recorded—occurred within the basin. This led to concerns that even larger earthquakes could potentially occur in the area, which resulted in an emergency shutdown order for any injections being put in place by the Arkansas Oil and Gas Commission. Analysis of the seismicity, injection patterns, and pore pressure diffusion built a strong case for the activation of the Guy-Greenbrier Fault by wastewater disposal (Horton, 2012; Ogwari, Horton, and Ausbrook, 2016; Ogwari and Horton, 2016; Park et al., 2020). In the neighboring states of Oklahoma and Texas, wastewater disposal by injection is understood to be the primary driver of induced seismicity.

5.1.4 Eagle Ford Shale Play in the Western Gulf Basin of Texas

Texas has a long history of active oil and natural gas production, hydraulic fracturing, wastewater disposal, and general seismicity, some of which occurs within or near areas of

pervasive faulting (see Exhibit 5-4a) (Ewing, 1990; Frohlich et al., 2016). Advancements in horizontal drilling and hydraulic fracturing since 2008 have prompted the Eagle Ford shale play to focus on hydrocarbon production from the Upper Cretaceous Eagle Ford and Austin Chalk Formations (Frohlich and Brunt, 2013; Martin et al., 2011; Pearson, 2012; RRC, 2019).

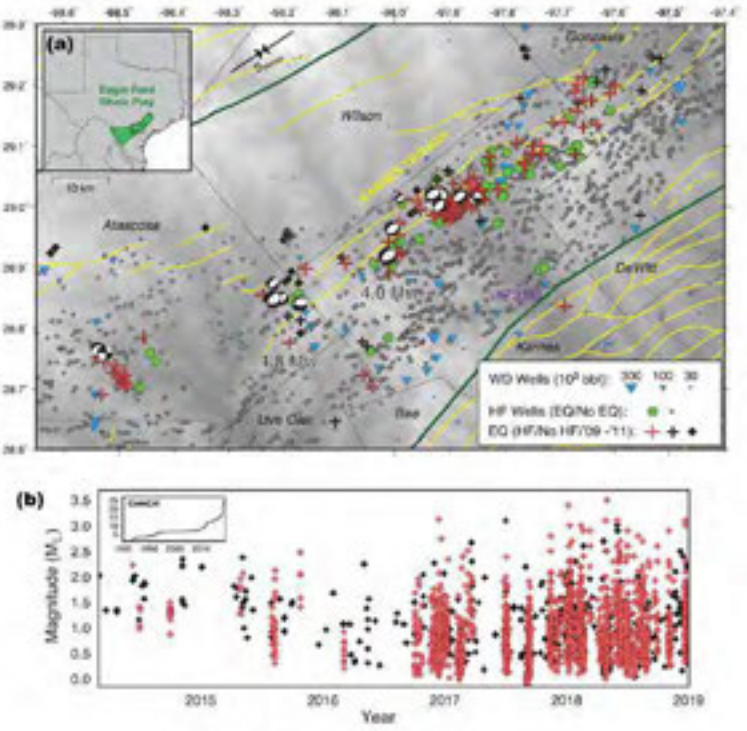
In 2018, the rate at which ML ≥ 3.0 earthquakes occurred in the Eagle Ford shale play was 33 times higher than background levels (3 earthquakes per 10 years during 1980–2010; see Exhibit 5-4b). Fasola et al. (2019) investigated seismicity that has occurred since 2014, in an effort to identify how hydraulic fracturing has contributed to seismicity within the play. Comparing both times and locations of hydraulic fracturing to a catalog of seismic activity, Fasola et al. (2019) suggest more than 85 percent of the seismicity that occurred was spatiotemporally correlated with hydraulic fracturing. More specifically, there were 94 ML ≥ 2.0 earthquakes correlated will 211 hydraulic fracturing well laterals.

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Exhibit 5-4a provides a map from the Texas Seismological Network showcasing earthquakes (crosses) and focal mechanisms (beach balls) that have occurred since 2017. Hydraulic fracturing wells are indicated by black circles in Exhibit 5-4. Correlated earthquakes and hydraulic fracturing wells are displayed as red plus signs and green circles, respectively. Black diamonds show the earthquakes that occurred during 2009–2011 (Frohlich and Brunt, 2013). Purple square shows the seismic station (7358) used for template matching. Wastewater disposal wells are provided as teal triangles sized by median monthly volumes. Arrows show regional orientation (Lund Snee and Zoback, 2016). Faults (Ewing, 1990) are in yellow.

Exhibit 5-4b provides the magnitudes of the various earthquakes both correlated and not correlated with hydraulic fracturing that occurred annually after 2011 within the play (the black and red plus signs shown in Exhibit 5-4a). The inset shows the cumulative number of earthquakes (magnitude ≥ 3.0) occurring in the area, available from the United States Geological Survey (USGS) Comprehensive Catalog.

Exhibit 5-4. Locations and timings of Eagle Ford hydraulic fracturing induced event



Permission pending from Fasola et al. (2019)

5.2 Regulations to Address Induced Seismicity and On-Going Research and Development

State regulators have long been focused on identifying the precise location and magnitude of earthquakes and determining their cause. When earthquakes can be linked to wastewater injection, regulators [illegible] operators to cease or limit either injection rates and/or water volumes in nearby wells (EPA UIC National Technical Workgroup, 2015). Many regulators also require that new injection wells avoid areas near known active faults. In Oklahoma, these techniques have effectively reduced the number of felt earthquakes.

Similar procedures have been applied to hydraulic fracturing operations in some states. That is, when earthquakes are detected, operations are either modified or suspended (AGI, 2017). Oklahoma, Texas, and Ohio have all taken steps to mitigate induced seismicity linked to hydraulic fracturing. In Oklahoma, regulators have instituted the following actions to address induced seismicity (Boak, 2017):

- Governor created the Coordinating Council on Seismicity (2014)

Commented [EK144]: NETL Team - Changed 'If' to 'When' since the Addendum has already cited wastewater injection is one driver of induced seismicity.

- Oklahoma Corporation Commission directives reduce injection (2015)
- Oklahoma Geological Survey position paper published (2015)
- Secretary of Energy fund of an $200,000 worth of seismicity projects (2015)
- Governor's Water for 2060 Produced Water Working Group (2015)
- Research Partnership to Secure Energy for America funded stations that were added to the Oklahoma Geological Survey network (2016)
- Governor's Emergency Fund allocated $1,387,000 to bolster the emergency response capacity of the Oklahoma Corporation Commission , and Oklahoma Geological Survey (2016)
- New Created a tracking system for earthquakes and injection activities for the Oklahoma Corporation Commission to monitor and assess these events and operator practices (2016)

In Texas, the state's Texas' Center for Integrated Seismicity Research (TexNet) is charged with monitoring, locating, and cataloging seismicity across the state. Capable of detecting and locating earthquakes with magnitudes ≥ 2.0, TexNet's backbone network improves investigations of ongoing sequences of seismic activity by deploying temporary seismic monitoring stations and conducting site-specific assessments (Young et al., 2017). TexNet will continue to conduct fundamental and applied research to better understand both naturally and potentially induced seismic events that are occurring across the state of Texas, their associated risks, and potential strategies for communicating with stakeholders and responding to public concerns raised regarding seismicity. (Young et al., 2017)

ComponentAdditional state requirements and activities associated with seismicity include the following (Young et al., 2017):

- Applicants are required to search the USGS seismic database for historical earthquakes within a circular area of 100 square miles around a proposed, new disposal well (~5.6-mile radius)
- Clarifying the Texas Railroad Commission's (RRC)'s authority to modify, suspend or terminate a disposal well permit, or modify operations, if scientific data indicates a disposal well could be contributing to seismic activity
- Increased disclosure of reported volumes and pressures, at RRC's discretion
- RRC may require applicant s to provide additional technical information to demonstrate disposal fluid confinement

Ohio has regulated seismic permits for injection wells for some time; obtaining a permit can require the following tests or evaluations of a proposed brine injection well be completed, in any combination that the chief deems necessary (Dade, 2017):

Commented [EK145]: NETL Team - to your knowledge, is this 2015 funding reference the most recent DOE / S-1 investment into induced seismicity projects?

Commented [LBD146]: Is any update available?

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Commented [EK148R147]: Are we referring to operators in Texas applying for permits of one type or another RE: drilling, disposal, etc.? Please clarify.

Commented [LBD149]: Is any update available?

- Geological investigation of potential faulting within the immediate vicinity of the proposed injection well location, which may include seismic surveys or other methods determined by the chief to assist analysis.
- Permit conditions may include seismic monitoring, pressure fall-off tests, spinner tests, radioactive tracer, geophysical and electrical logs, and downhole pressure monitoring.

Restrictions may be placed on wells drilled near faults or areas of known for seismic activity, in which seismic monitors must be installed for a specified period prior to completion operations (Dade, 2017). Related actions include:

- ML ≥ 1.5 – Direct communication starts between operator and division
- ML = 2.0–2.4 – Work with operator to propose newH or modify existing operation
- ML ≥ 2.5 – Temporary halt of well completions on lateral
- ML = 3.0+ – Well completion on pad suspended until an operator jurisdiction and secured approval of plan to mitigate risks and return to operational statusproposed plan is submitted by operator

The mitigation techniques employed by Ohio include the following:

- Direct communication with the operator is essential
- Discussion of seismic events and stages of the operation need to occur in real-time
- Spatial analysis and time correlation with completion data conducted during the operation

Mitigation techniques when induced seismicity occurs during hydraulic fracturing include the following:

- Change from zipper fracking to stack fracking
- At least 20% reduction in volume and/or pressure
- Skipping stages may be necessary, especially if seismic events indicate a lineament or fault structure near a lateral of the operation
- Switch to smaller sieve sizes for proppant, full effect still unsure

Commented [EK150]: NETL Team - the 'shorthand' in these bullets is confusing, poorly written, and as such I'm uncertain if my proposed text revisions are correctly adjusting the text to make it more understandable. Please feel free to expand upon / revise this section as needed.

Commented [EK151]: NETL Team - please flesh this out as this is very technical terminology many prospective users / readers of the Addendum may not readily recognize / understand.

Commented [EK152]: NETL Team - please add some text to describe why stages may need to be skipped due to seismic events indicating "a lineament or fault structure near a lateral of the operation."

Commented [EK153]: NETL Team - what is meant by / the consequences of this phrase: "full effect still unsure' when switching to smaller sieve sizes for proppant.

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6 LAND USE AND DEVELOPMENT

The growing land use footprint of energy development, termed "energy sprawl," ~~will~~ likely causes significant habitat loss and fragmentation with associated impacts to biodiversity and ecosystem services (McDonald et al., 2009). Land presents a critical yet often overlooked constraint to energy development, including the development of domestic natural gas. Natural gas is set to act as a transition fuel and dominant technology during the grid decarbonization process in the United States, making an understanding of its land use implications critical and necessary consideration (Dai et al. 2023).

Expanding energy development is now the primary source of anthropogenic land cover change in natural ecosystems in North America (Allred et al., 2015; Trainor, McDonald, and Fargione, 2016), including eastern deciduous forests, boreal forests, prairie grasslands, sagebrush-steppe, and deserts (Copeland, Pocewicz, Kiesecker, 2011; McClung and Moran, 2018; Appiah, Opio, Donnelly, 2019). Land use and development issues associated with natural gas production include local surface disturbance; cumulative landscape impacts; habitat fragmentation; and traffic, noise, and light. Vertical wells are typically spaced with 40 acres per well, the drill pads from which each horizontal well originates are typically spaced with 160 acres per well. If wells are drilled conventionally (i.e., vertically) a single square mile of surface area can support 16 pads with one well per pad. If wells are drilled horizontally then the same amount of surface area could support be used to develop 1 pad, from which 6–8 different wells could be drilled (NETL, 2009).

The Citizens Marcellus Shale Coalition (CMSC) (2011) explored two issues related to impacts of shale gas production on public lands and the other industries that rely on these lands. They also explored ~~the~~ impacts on private property rights. CMSC stated that shale gas development must consider the cumulative impacts on state parks and forests and on timber and tourism industries as part of responsible stewardship of public resources. Property rights and environmental degradation are a growing public concern, and eminent domain laws, drill spacing requirements, and grouping of leased lands could help protect these rights.

6.1 SURFACE DISTURBANCE AND LANDSCAPE IMPACTS

The infrastructure ~~to~~ needed to support the supply chain of electricity produced from natural gas involves production sites (production pads and their access roads), transportation facilities (e.g., gathering and transmission pipelines for natural gas), processing facilities, and power plants (end-use) (Dai et al., 2023). Such activities can disturb Earth's surface, the impacts of which can extend over large areas and result in habitat fragmentation that impacts both plant and animal species. Mitigation options include adoption of best-practices for site development and restoration, avoidance of sensitive areas, and minimization of impacts to disturbed areas.

Dai et al. (2023) used machine learning, remote sensing, and geographic information systems to obtain spatially explicit information on the land required to support natural gas production. Their analysis considered land use across five life cycle stages of natural gas produced for electricity production from wells (production stage), natural gas transportation via gathering pipelines (gathering stage), natural gas processing plants (processing stage), natural gas

Commented [HSAJ154]: Comment for FE/HQ - In some cases the best source of information we had for land use impacts predated 2014. Please advise if you would like to see these removed.

Commented [EK155R154]: Amanda - I love that paragraph. Except for the '2011' reference in parentheses. Do we have to 'hang a lanfern' there on how dated that reference is? If what was true then remains true today, I would prefer we remove the "(2011)" reference and continue along. Anyone else have strong feelings on this? @Curry, Thomas @Skone, Timothy @Lavoie, Brian D.

Commented [EK156]: NETL Team - suggest removing 'plants' here as we're focused on the activity itself; if you want to footnote a point RE: land required for all of the processing plants involved in unconventional production here in the U.S., if necessary, that would be fine.

transportation via transmission pipelines (transmission stage), and gas consumption as fuel through combustion in gas-fired power plants (use stage).

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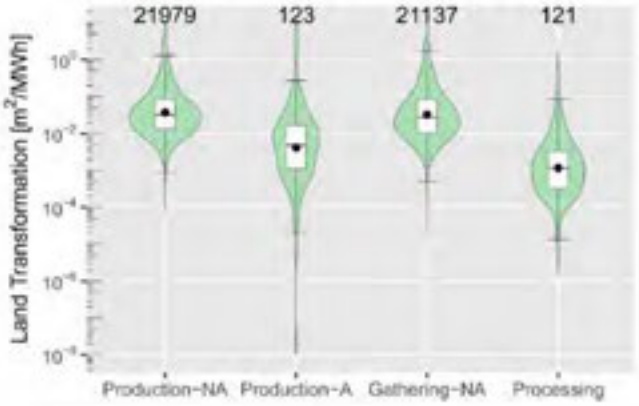
For the production stage, Dai et al. (2023) map land-use for 100,009 wells located at 75,915 different well pads. Among the 100,009 wells examined, 31,716 were co-located. In non-agricultural areas, results suggest vertical wells occupy ~4000 square meters (m^2) less land per site than horizontal-/directional-drilled wells. During the gathering stage in both agricultural and non-agricultural areas, sites with horizontal-/directional-drilled wells, on average require ~230 meters less pipeline in length than sites with vertical-drilled wells, whereas due to the requirement for larger width of right-of-way, the extent of land use is almost doubled for sites with horizontal-/directional-drilled wells. Results from Dai et al. (2023) are summarized in Exhibit 6-1.

Exhibit 6-1. Land use throughout the life cycle of gas-fired electricity

Stage			Unit	Average
Production	Agricultural	Directional	m^2 per site	9,346
		Vertical	m^2 per site	2,100
	Non-agricultural	Directional	m^2 per site	18,170
		Vertical	m^2 per site	14,090
Transportation by gathering	Length	Directional	m^2 per site	597
		Vertical	m^2 per site	818
	Area	Directional	m^2 per site	20,157
		Vertical	m^2 per site	10,128
Processing			m^2 per (MM cubic feet per day)	4,318

Exhibit 6-2 from this study illustrates the land transformation by stage, showing that production in non-agricultural areas utilizes more land than agricultural areas.

Exhibit 6-2. Land transformation in natural gas production



Note: NA = non-agricultural area, A = agricultural area

Used with permission from Dai et al. (2023)

Notably, technological advancements will play a significant role in decreasing the amount of land that will be transformed during the life cycle stages of production, gathering, and consumptionuse of natural gas (Dai et al., 2023).

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6.2 HABITAT FRAGMENTATION

The construction and installation of the infrastructure necessary for development of natural gas development can lead to a habitat being converted from a large contiguous patch of similar environments to several smaller, isolated environments. Long-term effects of shale gas production on habitat disturbance will have to be evaluated as the development of these resources continues. Mitigation measures such as avoidance, best management practices, and prompt reclamation of the drilling site have been put forward as ways to best minimize the possible impacts that shale gas production may have on habitats. Habitat disruption can also result from a lack of surface water availability in response to withdrawals to support natural gas production and quality from erosion and chemical spills. The potential water use implications of natural gas are discussed in Chapter 4 – Water Use and Quality.

There are several impacts associated with the development of gas drilling sites and natural gas production that can disrupt the habitat of both plant and animal species. These impacts can arise from a variety of sources and at various points throughout the extraction and production process. Habitat fragmentation occurs when infrastructure must be installed, or land clearing must take place to allow access to a well location. Habitat fragmentation was given as one of the environmental risk pathways that were identified as a consensus priority risk pathway in a survey of 215 experts in government, industry, academia, and non-governmental organizations (RFF, 2013).

When contiguous core habitats are fragmented into smaller patches, many sensitive species are unable or unwilling to cross non-habitat regions to reach alternative habitat patches. While habitat loss can have an immediate impact on wildlife population, the ecological response to fragmentation is lagged, and affects different species at varying timescales (Makki et al., 2013).

A secondary impact of fragmentation is the creation of edges. Edges are generally defined as the 100 meters between core forest and non-forest habitat (PADEP, 2014; Kargbo, Wilhelm, and Campbell, 2010; Johnson et al., 2010). New edges affect the physical or biological conditions at the ecosystem boundary and within adjacent ecosystems (Fischer and Lindenmayer, 2007). Edge effects are believed to be detrimental by increasing predation, changing lighting and humidity, and increasing the presence of invasive species (Johnson et al., 2010).

Exhibit 6-3 provides a schematic depicting the habitat loss and fragmentation from natural gas production. Exhibit 6-3 progresses from infrastructure development that has quantifiable land impacts leading to temporally extended land changes, impacts which account for habitat loss and fragmentation.

Exhibit 6-3. General procedure for depicting land disturbance from natural gas extraction

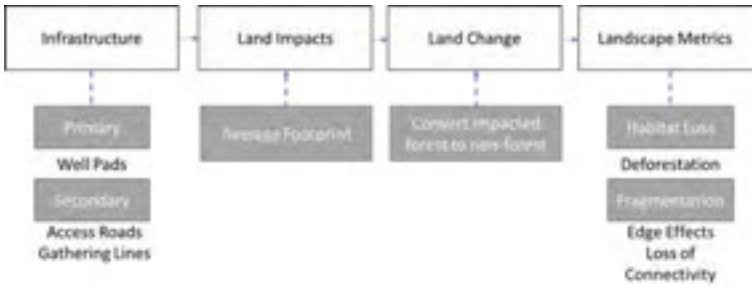
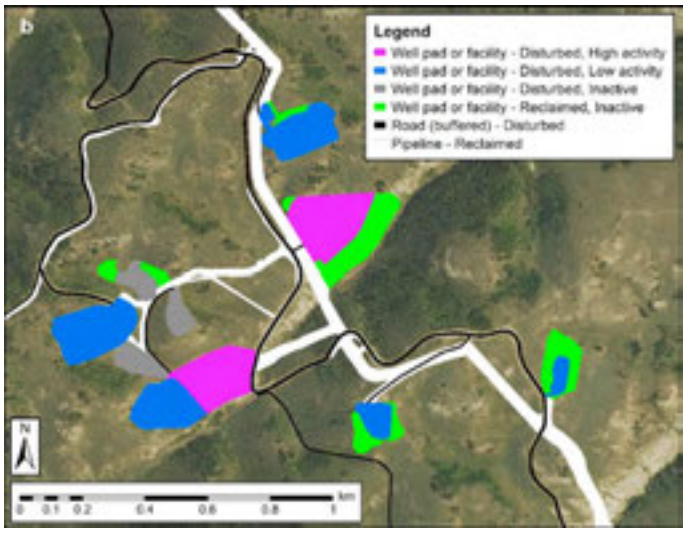


Exhibit 6-4 provides an example of energy infrastructure features digitized from 2013 National Agricultural Inventory Program satellite imagery overlaid with well locations reported in COGCC data. Each mapped feature (or portion thereof) was classified by type (well pad, facility, road, or pipeline) and by surface type (disturbed or reclaimed), and well pads and facilities (or portions thereof) were assigned an activity status (high, low, or inactive) (Walker et al., 2020).

Exhibit 6-4. Footprint of a well pad and surrounding infrastructure



Used with permission from Walker et al. (2020)

Each region where natural gas extraction takes place has unique species and habitat therein~~that inhabit the particular regions~~. Within those species, some are more greatly affected than others, whether it be core habitat fragmentation o~~f~~r edging.

6.3 NOISE, LIGHT, AND TRAFFIC

Natural gas development processes are associated with both noise and light pollution, which can contribute to stress among those living in nearby communities (Down, Armes, Jackson, 2013; Korfmacher et al., 2013; Peduzzi et al., 2013; Witter et al., 2008a; Witter et al., 2008b). Construction, vehicles, drilling, compressors, flaring, and other processing equipment and facilities can all pollute through excessive noise and continuous illumination (Cleary, 2012).

6.3.1 Noise Pollution

~~The~~ A health impact assessment in Colorado identified noise pollution as an area of concern and noted that it occurs during drilling and completion operations, flaring, and ~~as a result of~~ because of vehicular traffic (Witter et al., 2013). Workers can be exposed to noise through many sources on site, including diesel engines, drilling, generators, mechanical brakes, ~~operation of~~ heavy equipment operations, and radiator fans (Witter et al., 2014); therefore, hearing impairment is a noise-related health concern for workers on site.

A biomonitoring study from Texas found residents reporting concerns about odors and noise apparently related to shale gas well and compressor station operations, although this was a separate, independent component from the biomonitoring portion designed ~~in order~~ to address residents' concerns (Texas Department of State Health Services, 2010). While the authors noted that it was difficult to determine if the levels were above acceptable limits that may be harmful to human health, and that noise may affect quality of life, this is speculative because noise levels were not measured to establish decibels of noise in the study area.

Noise standards for a single well pad may be met; however, the cumulative effects of multiple operations in one area might exceed these established decibel levels. In terms of setback distances, some noise regulations distinguish between maximum decibels for day and night, while others distinguish between maximum decibels for certain phases of the operation such as drilling, fracturing, and production; however, there is often variability and, in some areas, it is suggested that distances are set as monitoring points, not necessarily points indicative of being protective of health (Fry, 2013).

6.3.2 Light Pollution

Light pollution has significant implications for the environment and public health, and its effects have become more pronounced over time due to the increasing extent and radiance of artificially lit areas (Kyba, 2017). Substantial economic values have been attached to affected outcomes, such as biodiversity, recreation, and public health. With respect to human health, artificial lights at night are associated with sleep deprivation and mental health (Patel, 2019; Xiao, 2020); sleep deprivation, in turn, has been shown to reduce cognition and labor market productivity, as well as elevate mortality risks associated with dementia, heart attacks, and vehicle accidents (Hafner et al., 2017; Paksarian et al., 2020; Ma et al., 2020; Jin and Ziebarth, 2020; Prats-Uribe, Tobías, and Prieto-Alhambra, 2018.). A study in Australia quantified the financial and non-financial costs of inadequate sleep in 2016–2017 to be $45 B (Hillman et al., 2018) and another study estimates that $680 B is lost due to sleep deprivation across five

Organisation for Economic Co-operation and Development (OECD) countries (Hafner et al., 2017; Boslett, 2021).

Light pollution also has significant consequences for wildlife populations. It affects nighttime behavior and habits of terrestrial (Bennie et al., 2015) and marine (Davies et al., 2014) wildlife populations, particularly for species that use sun or moon light for guidance. It disrupts natural sleep and reproductive cycles, geographical orientation, and predator-prey relationships (Longcore and Rich, 2004). Other effects of light pollution include changes in bird singing behavior (Miller, 2006), estrus patterns in nocturnal primates (LeTallec, Théry, and Perret, 2015), insect pollination (MacGregor, 2015), and fish biological rhythms (Brüning et al., 2015). These impacts have led to ecosystem-wide changes in biodiversity and growing disparities between entire taxonomic groups (Davies et al., 2013).

The impacts of light pollution also extend to human health and well-being. Artificial light disrupts melatonin secretion and circadian rhythm (Haim and Zubidat, 2015) with corresponding changes on mood regulation, depression, and sleeping disorders (Cho et al., 2016). Light pollution-driven changes in circadian rhythms may also have contributed to recent growth in obesity and metabolic dysfunction (Fonken et al., 2010). Growing laboratory and epidemiological evidence also support the long-hypothesized relationship between nighttime light exposure and cancer rates (Kerenyi, Pandula, and Feuer, 1990; Kloog, et al., 2010; Schwimmer et al. 2014; Jones, Pejchar, and Kiesecker, 2015).

While there is some work speculating that light pollution associated with shale development induces psychosocial stress (Fisher et al., 2017), sleep and mental health issues (Casey et al., 2018), and adverse impacts to local ecosystems (Kiviat, 2013), the literature directly connecting the recent resource boom to light pollution is extremely limited. Importantly, no work has documented the causal impact of U.S. shale development on light pollution.

6.3.3 Traffic Pollution

Traffic may increase in any given area ~~as a result~~ because of unconventional natural gas development, but the magnitude of this increase has not been studied in depth. The phases of development that require the most traffic load involve well pad construction, drilling and well completion, and pipeline construction (Witter et al., 2014). It appears that changes in traffic patterns will be dependent upon the area and either the individual project or the cumulative effects of multiple projects in an area. Industrial truck traffic can be detrimental to health-related air quality due to vehicle exhaust, as well as pose an increased risk of motor vehicle crashes.

In the *Revised Draft Supplemental Generic Environmental Impact Statement on The Oil, Gas and Solution Mining Regulatory Program*, the New York State Department of Environmental Conservation (NYSDEC) identified temporary but adverse noise and visual impacts from construction activity and increased truck traffic among the potential land-use environmental impacts associated with natural gas production (Witter et al., 2014). Significant adverse impacts in terms of damage to local and state roads could also result. Among mitigation measures described for environmental impacts, NYSDEC suggests imposing measures to reduce the adverse noise and visual impacts from well construction. A transportation plan could also be

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required that would include proposed truck routes and assess road conditions along the proposed routes. Exhibit 6-5 tabulates the number of truck trips for a typical shale gas well (Massachusetts Institute of Technology [MIT], 2011).

Exhibit 6-5. Truck trips for a typical shale gas well drilling and completion

Activity	1 Rig, 1 Well	2 Rigs, 8 Wells
Pad and Road Construction	10–45	10–45
Drilling Rig	300	60
Drilling Fluid and Materials	25–50	200–400
Drilling Equipment (casing, drill pipe, etc.)	25–50	200–400
Completion Rig	15	30
Completion Fluid and Materials	10–20	80–160
Completion Equipment (pipe, wellhead, etc.)	5	10
Fracturing Equipment (pump trucks, tanks, etc.)	150–200	300–400
Fracture Water	400–600	3,200–4,800
Fracture Sand	20–25	160–200
Flowback Water Disposal	200–300	1,600–2,400
TOTAL	1,160–1,610	5,850–8,905

The large volumes of water involved in hydraulic fracturing operations can create high volumes of road traffic given the majority of the water used for frackingturing is transported by truck. It should be emphasized that the large number of traffic movements shown in the table above are worst-case estimates. In particular, re-use of flowback wastewater significantly reduces the amount of road traffic associated with hauling water, which represents much of the traffic movement. Furthermore, large-scale operators are also using pipelines to transport water to the site, substantially reducing the amount of road traffic (MIT, 2011).

The Eagle Ford Shale Task Force Report for the RRC identified increased traffic and deterioration of roads and bridges among the infrastructure impacts from shale gas development (Porter, 2013). Exhibit 6-6 lists estimates of the number of truck-trips-per-shale-gas-well in the Eagle Ford (Porter, 2013).

Exhibit 6-6. Loaded truck trips per gas well

Activity	Number of Loaded Trucks
Bring well into production	1,184
Maintain production (per year)	Up to 353
Re-fracturing (every 5 years)	997

These impacts are enough of a concern that the task force considered alternative financing methods to help meet the increased demands on roads and bridges (Porter, 2013).

Upadhyay and Bu (2010) surveyed the visual impacts of Marcellus drilling and production sites in ~~PA~~Pennsylvania. They reviewed the drilling process, assessed direct visual impacts, and compared the results to the impacts of other technologies (e.g., windmills and cell towers). They also studied drill-pad density from map and aerial perspectives to examine the likelihood of seeing drill towers across a landscape, and the modeled potential impacts for increased drilling, making the following conclusions:

- Serious impacts from light and noise are a potential problem within a small radius of drilling sites.
- Indirect impacts like increased truck traffic, equipment storage, and temporary structures compose the most salient visual impacts, rather than the drill pads themselves.
- Timelines for site restoration of visual impacts vary significantly.

Upadhyay and Bu (2010) recommended that visual impacts be addressed during the siting and design phase and that nighttime impacts could be avoided by pointing lights downward.

The RFF (2013) report also gave several options in their survey of experts under the category of community disruption. Included in this category, as well as in the habitat fragmentation section, were such risks as light pollution, noise pollution, odor, and road congestion. The industry respondents identified a number of these community disruptions as risk pathways of high priorities, while the other respondent groups identified more conventional (e.g., air pollution, water pollution, etc.) risks.

6.4 Regulations and Strategies to Reduce Land Impacts

While there are very few regulations to reduce the impacts on land, habitat, noise, light, and traffic pollution, best practices have been developed in some cases.

6.4.1 Mitigation Options for Habitat Fragmentation Impacts

The NYSDEC (2011) study proposed that, if the development area included a region of continuous forest over 150 acres in size or a region of grassland over 30 acres, an ecological assessment should be conducted to identify best management practices.

A 2012 study of hydraulic fracturing practices in the Inglewood oil field in California, operated by the Plains Exploration & Production Company, proposed that the best way to mitigate habitat fragmentation impacts is to adopt best management practices, perform wildlife surveys, and implement restrictions during migration and mating seasons (Cardno ENTRIX, 2012). The study also found that ensuring that well pad reclamation occurs is the most productive method to reduce harm to populations (Cardno ENTRIX, 2012).

Avoiding disturbances to sensitive areas such as wetlands, waterways, and wildlife habitats when locating drilling sites could be the best method for mitigating impacts. Reclaiming the land upon completion of drilling activities is the best way to mitigate impacts in those cases when avoiding disturbances is impossible (NETL, 2009). Proceeding with reclamation processes as quickly as possible can minimize the disturbances, but all mitigation measures (including

avoiding disturbances to begin with) are subject to the landscape, plants, and wildlife that are present at a site.

The Western Governors' Association (2006) released a handbook outlining the best management practices for CBM development to be shared among the Association's shareholders. The practices are split into multiple categories, including planning, water, landowner relations, and infrastructure. Several subcategories can be applied to mitigating habitat fragmentation, such as protection of wetland areas, roads and transportation, pipelines and power lines, habitat and species protection, and wells. To protect wetland and riparian areas, facilities such as well pads should be sited outside of such regions as much as possible, and features that cut across the landscape, such as roads and pipelines, should avoid crossing wetlands and riparian areas as much as possible (Western Governors' Association, 2006).

Best practices for mitigating disturbance from roads and transportation include keeping road development to a minimum, using existing access roads as much as possible, using unimproved roads as little as possible during wet weather, following road construction and maintenance standards, avoiding sensitive areas, and attending to safety issues and other problems (Western Governors' Association, 2006). Recommendations of best practices for pipelines and other lines include using existing pathways, installing as many lines as possible in a single location, and using the least invasive construction equipment possible. To protect habitat and sensitive species, lines should be buried rather than installed above ground if possible. Well sites should minimize the amount of surface disturbance that occurs and should be reclaimed as quickly as possible upon completion of development activities (Western Governors' Association, 2006). Again, these best management practices have been developed in areas of CBM production by the Western Governors' Association, but many of these practices are applicable to shale gas development.

Drilling on federal or public lands is subject to oversight by federal agencies, and sections of the Endangered Species Act (ESA) may require that species of plants or animals not be threatened by the permitted drill site (NETL, 2009). Mandatory plans for mitigation and reclamation may be required to ensure that impacts on wildlife and habitat will be as minimal as possible (NETL, 2009).

With approximately 33 units of the National Park System in or near the Marcellus Shale, NPS found it important to be informed and current with development issues. Moss (2012) provides an overview of the geology, technology, current activity, and potential environmental impacts. Among the effects described are widespread development and well spacing, site space needs, water use, aquifer contamination, air quality, and truck transportation. There are then four recommendations to help park units prepare for potential shale gas development on and around NPS lands (Moss, 2012):

1. Check land and mineral ownership – Know if private in-holdings or private or state mineral estate underlie an NPS unit.
2. Be aware of industry interest adjacent to park boundaries – Land speculation, exploration, or drilling could signal increased requests for drilling permits. Contact the state oil and gas agency to express concerns and issues.

Commented [EK162]: NETL Team - my guess is that CBM production BMPs identified by WGA in '06 have indeed been applied to shale gas development sometime in the past 17 years. If we have to show the '06 date of this WGA study, I'm reluctant to include it - unless we can substantiate the BMPs referenced remain unchanged (which, with technology development and continuous improvement efforts I highly doubt). What do others feel? @Curry, Thomas @Skone, Timothy @Sweeney, Amy @Lavoie, Brian D.

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3. Work with state agencies – Meet with the state permitting agency, establish agreements, engage with stakeholders before issuance of permits, and if possible, have protective mitigation measures included directly in the lease.

The NPS Geologic Resources Division assists parks with policy and technical issues and reviews permitting and environmental documents to help mitigate or eliminate adverse impacts (Moss, 2012).

In January 2013, the BLM updated a presentation detailing best management practices for wildlife management that can help to minimize habitat fragmentation. The document offers several practices that can be implemented or planned to lessen impacts on habitat. The well pad itself and the immediate surroundings can be fit to the space available to minimize the disturbed area, rather than constructing a generic rectangular pad (BLM, 2013). There are also multiple examples of reclamation practices, both at the drill site and on access roads, that can be implemented to lessen the impact of the infrastructure. The well pad and supporting infrastructure (roads, pads, storage, and pipes) can be designed to be as efficient and minimally obstructive as possible (BLM, 2013). Wells can be remotely monitored using telemetry, pipelines and other lines can be buried where possible, and any existing corridors for roads and lines should be used whenever possible (BLM, 2013). It is helpful to monitor local wildlife populations to ensure that mitigation and reclamation measures are effective, and final reclamation upon abandonment of the well is critical to the long-term effectiveness of mitigation options (BLM, 2013).

6.4.2 Reducing Light Pollution

Even two decades after the establishment of designated programs by non-government organizationNGOs to recognize and certify the quality of night skies and nighttime darkness resources, the very notion of what a "dark sky" is remains unsettled from a scientific standpoint (Crumey, 2014); while appropriate instrumentation can quantify night sky brightness, it cannot properly account for the human aesthetic experience of natural night. However, various lines of research increasingly suggest that unsafe thresholds of exposure to artificial light at night in terms of intensity, duration, wavelength, and timing likely exist for humans, plants, and animals. In this sense, light-sensing technologies applied in the field could effectively serve as "dosimeters" for monitoring these exposure parameters (Barentine, 2019).

6.5 DOE Research and Development and Analysis

An independent review of the literature suggests there is currently no R&D research and development or analysis with respect to land use, habitat fragmentation, or light, noise, or traffic pollution being conducted by DOE.

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7 SOCIAL JUSTICE AND NATURAL GAS/LIQUEFIED NATURAL GAS MARKET DEVELOPMENT

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7.1 INTRODUCTION

Granting authorizations to import and/or export natural gas into and from the United States could potentially generate and, in some cases, ~~further~~ contribute to perpetuatinge instances of energy, environmental, and social injustice. Conversely, if potential impacts to disadvantaged and frontline communities* are both carefully considered and minimized, then opportunities to advance environmental, energy, and social justice may also be present. Ensuring the advancement of energy, environmental, and social justice across the domestic natural gas market, however, requires meaningfully engaging historically disadvantaged and frontline communities and ensures exposure to harms or burdens for these communities are prevented and minimized.

These types of considerations have driven the implementation of the Biden-Harris Administration's Justice40 initiative that was mandated under Executive Order 14008, and which has an explicit goal that 40 percent of the overall benefits from federal investments should flow to historically disadvantaged and disenfranchised communities and communities burdened by pollution. Specific types of projects include those related to the clean energy transition both in energy production and the advancement ~~for~~ of net-zero emission transportation. Additional categories include affordable housing and "green" workforce development and training, as well as those focused on ~~the~~ remediation of legacy pollution, clean water initiatives, and wastewater projects. Introducing the Justice40 (2023) framework to the ways in which government measures the distribution of investment benefits attempts to right the historical wrongs that have resulted in the unequal outcomes seen today by requiring the success of projects to be measured according to whom the benefits and burdens are distributed.

This chapter seeks to summarize the incorporation of social, environmental, and energy justice concepts found in the broader research literature as they relate to natural gas and LNG market development. The goal is to summarize what already exists and provide guidance as to how future research might be pursued at the nexus of social, energy, and environmental justice and project development. This literature review specifically focuses on the development of large-scale energy infrastructure intended to supplement the energy-transition goals outlined by the current administration and its policies. However, the challenge (and opportunity) researchers face in this space is rooted in the relatively less robust focus that has been spent on applying energy, environmental, and social justice concepts to the development of energy infrastructure projects specifically for natural gas and LNG markets.

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* Per the National Oceanic and Atmospheric Administration (NOAA), frontline communities are "those who are the most vulnerable to and will be the most adversely affected by climate change and inequitable actions because of systemic and historical socioeconomic disparities, environmental injustice or other forms of injustice" (NOAA, 2023).

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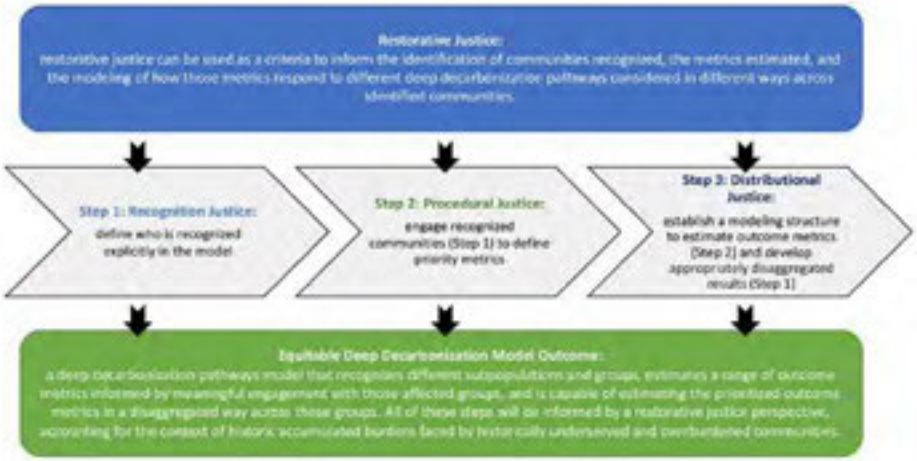
Due to the nascency of research that links social, environmental, and energy justice issues with the development of natural gas and LNG markets, this literature review will cover research that has already connected these issues and weave together the separate literature areas into the discussion. For reference, this review uses the structure presented in Spurlock et al. (2022) that outlines a tractable framework to incorporate energy justice tenets into energy infrastructure planning decisions and deep decarbonization policy implementation strategies.

This discussion is further framed as a struggle to balance energy justice issues rooted in the unequal exposure to pollution and related burdens with the need to resolve where communities do not have equitable access to clean, affordable, and reliable energy. This chapter concludes by underscoring the idea that incorporating energy justice tenets (distributional, procedural, and recognition) must be done from the big-picture view of energy project governance as it is the point where all project planning, development, and implementation is most directly influenced. It is from the point of governance that the effort to ameliorate energy poverty through the implementation of environmental and energy justice can produce a just transition away from a GHG-intensive economy and toward a more sustainable outcome.

7.2 Distributional, Procedural, and Recognition Justice

The three core tenets of energy justice are the assurance of distributional, procedural, and recognition justice, as shown in Exhibit 7-1 (Spurlock, Elmallah, and Reames, 2022). To aid in the understanding of the bigger picture of energy justice, the following subsections provide background on these three tenets.

Exhibit 7-1. Flow of energy justice decisions



Permission pending from (Spurlock et al., 2022)

Commented [RK168]: While the application of a justice framework to this energy context is conceptual - there is a robust literature on socioeconomic and community impacts of UOG development in the last ten years. Will share a separate doc with recommendations.

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7.2.1 Distributional Justice

Distributional justice is focused primarily on the equitable distribution of benefits and dis-benefits across communities (Spurlock et al., 2022). It is a concept focused on the well-being of individuals, which spans the gambit of human outcomes such as psychological well-being, societal well-being, and physiological well-being (Deutsch, 1975). Distributional justice delves into the nuanced context in which equity versus equality versus need may dominate in identifying unjust distributions.

Fairness is a key concept within distributional justice and can be characterized as a problem for geospatial analysis (Bouzarovski and Simcock, 2017). Across the energy supply chain, distributional justice is a problem of implied risk responsibility as well as costs and benefits (Heffron and McCauley, 2014). In addition to inequities created by a historical lack of inclusiveness is the risk that those structural deficits will compound under a changing climate. In other words, unless addressed, the deficits of the past will likely increase as the climate changes much like a revolving line of credit tends to grow faster over time when a balance is carried from one period to the next.

7.2.2 Procedural Justice

Spurlock et al. (2022) present procedural justice as essentially the effort to include all voices. This is the idea that disadvantaged communities are overburdened and underserved and their disenfranchisement can only be corrected when their voices are intentionally included in the start-to-finish process of project and policy development. In other words, stakeholder engagement must be done early and often to ensure the priorities of disadvantaged communities are codified in the priorities of the project or policy.

Procedural justice takes a more holistic view of outcomes from the perspective of group perception. Researchers break the impacts of procedural justice into three areas of effect: voice, dignitary process, and fair process. The voice effect is the positive behavior observed in communities engaged with a decision-making process when the individual feels heard. The effect of dignitary process is best described as respect. When an individual's dignity is preserved, the community buy-in to the procedure grows. Finally, the fair-process effect describes the positive community behaviors that arise when the group perceives the existence of procedural justice. In a sense, the effect of fair process augments the effects of the dignitary process and the power of voice (Lind and Earley, 1992).

7.2.3 Recognition Justice

At its core, recognition justice deals with respect and consideration. Spurlock et al. (2022) present the concept as a demand to recognize that divergent views exist on the best pathways for energy project development and strategies to address issues of climate justice. Those views reflect the unique, diverse backgrounds of these communities who present the perspectives and opinions reflective of their histories. Incorporating those voices in the energy transition is critical to ensuring policymakers implement project development that seeks to serve all.

Equitable outcomes begin with the recognition that disenfranchised communities will require effort to enfranchise and empower their members to ensure their histories and perspectives are heard in a meaningful way.

Recognition justice seeks to provide for fair representation, safety, and the general creation of an environment that is welcome to all. McCauley et al. (2013) identify issues of recognition injustice in terms of how policy might treat those characterized as "energy poor" with the classic example of the behaviors of elderly household energy use. Looking at the overall higher average energy use, United Kingdom policymakers view the issue as an education problem where the assumption was that elderly people do not understand the long run impacts of small behavior changes. The authors reveal that framing choices in way that nudged elderly households toward the intended policymaker outcome required acknowledging that older people need warmer houses for their health and well-being. Strategies for changing behavior are more effective when normative behaviors within the community, culture, or ethnicity are recognized.

7.3 ENERGY JUSTICE

Anchored by the three tenets of distributional, procedural, and recognition justice, energy justice acts as a guiding concept for activism (McCauley et al., 2013). A broad literature review on the topic of energy justice (Qian et al., 2022) shows that the recent growth and focus on energy justice has quickened in pace with the effort to incorporate renewable energy on the electric grid. Debating the definition of energy justice has been a robust area of discussion for researchers, but there exist a few core concepts that underpin most approaches. At its heart, assuring that energy justice deals with the issue of ~~addressing~~ energy poverty and branches out from the broader focus of environmental justice (Iwińska et al., 2021).

While focus on the justice of energy distribution is not new, it has grown in salience as the public increasingly accepts the need to transition from fossil fuels-based systems of energy production and consumption to clean alternatives. Using energy justice as a decision-making framework, Iwińska et al. (2021) outline the focus of this literature as one that seeks to consider how the policy-making framework surrounding the generation and consumption of energy can be fairer. In this sense, energy justice acts as a tool, helping to guide policy design.

On one hand, Iwińska et al. (2021) consider the energy justice concept as a "boundary object" whose conceit is to accelerate the inculcation of these principles in policymaker innovation and across all cultural boundaries—much like a change agent. On the other hand, these authors debate the merits of treating the concept as a standard rather than a boundary object. Standards on energy justice would more easily be incorporated into policy in tractable forms that are quantitative and qualitative, though likely at the loss of a unifying definition (Iwińska et al., 2021).

Digging beyond the core tenets of energy justice, Sovacool and Dworkin (2015) acutely characterize the conceptual metrics by which broader approaches to energy justice may be measured. Those include the need to measure the costs communities face with a special emphasis on the level of inequity across communities relative to the distribution of these costs. Sovacool and Dworkin (2015) also identify the need to distribute benefits to these same

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communities. Though it seems logical to measure the costs *and benefits* to disadvantaged and disenfranchised communities, historical focus has more often been on mitigating or compensating losers for costs rather than on how project design can seek to benefit disenfranchised communities. Their very disenfranchisement may relegate them to an after-the-event consideration (when considered at all), which highlights costs over benefits. The simple statement that benefits should be considered alongside costs may act to nudge the focus back toward before-the-event planning.

Sovacool and Dworkin (2015) list procedure as the critical element that can act to bridge the cost-benefit gap. The process by which energy project development flows can be exclusive by nature; this would naturally prohibit the participation of disenfranchised communities who, again by definition, are not empowered to advocate as robustly as the enfranchised communities.

Iwińska et al. (2021) outline the various foci of energy justice research. The current dominant topic has been renewable energy, as energy transition efforts have driven the growth of interest in energy justice. Summarizing the remainder of the subtopics of energy justice in broad terms, the research falls within the categories of energy poverty, energy policy, law, and governance.

Results from the transition away from fossil fuels are producing differentiated outcomes that vary by community. Energy justice studies reveal that some communities are clearly benefiting from the increased access to renewable energy technology and opportunities while others assume the burdens of change. Those communities that seem to be accruing the adverse health outcomes and increased cost of cleaner technology are the same historically disenfranchised peoples who often fail to reap the job gains and regional economic growth opportunities of change. Beyond this, the transition away from fossil fuel production harms local governments' ability to provide constituent services in cases where fossil fuels are dominant sources of economic activities. Nonprofit organizations tend to lead in the effort to ameliorate these inequitable outcomes (Carley, Engle, and Konisky, 2021).

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Pellegrini-Masini, Pirni, and Maran (2020) make the case that the prevalence of energy justice definitions inhibits the capacity of policymakers to deploy these concepts toward the greater good. They highlight several useful but nuanced approaches with Guruswamy (2010) underscoring the "energy oppressed poor" as those suffering from an inequitable distribution of energy as a resource, which is innately about distributional justice.

7.4 Energy Poverty and Energy Burden

Poverty is a dominant issue that arises often in research focused on energy. As policies are implemented to attenuate the worst effects of climate change, the focus on carbon emissions as a flow and stock[9] necessarily highlights how these costs are going to be born geospatially.

[9] The term "greenhouse gases" refers to those associated with atmospheric warming; however, GHGs are not uniform in how they affect the global warming process as their lifecycles vary. Carbon dioxide is considered a stock gas as it remains in the atmosphere for long periods. As such, it builds up over time like a "stock" of gas. CH_4 is a much shorter-lived GHG. It enters the atmosphere and remains for just about 12 years. As such, it is considered a gas that "flows" through the atmosphere with short-lived warming impacts for any one unit of methane.

Carbon mitigation policies themselves also present societal costs that are unequally burdening communities based on how much of the remaining carbon budget impoverished communities might need. But at its heart, energy justice is an issue of economic opportunity as access to safe, affordable energy is a necessity to meet basic human needs and pursue economic growth opportunities (Piwowar, 2022).

Bouzarovski and Petrova (2015) identify the criteria and conditions that drive energy poverty as the material and/or social deficit in energy services accrued by communities. The authors outline two key issues. First, deficits in domestic energy access and supply are the direct result of ineffective socio-technical mechanisms that fulfill energy demand at the household level of energy services such as heating and lighting. Second, "vulnerability thinking" often drives or exacerbates these outcomes. That is to say, the perceived likelihood of becoming impoverished can drive outcomes, frame processes, and generally lead to the undesired outcome as a result of historical perceptions or perspectives (Hall et al., 2013).

Okushima (2021) attempts to measure the "basic carbon needs" of a community. These are the total GHG emissions an individual community might bare to attain an "adequate level of domestic energy services." Okushima's case study of Japan highlighted that basic carbon needs varied based on differences in several factors within a community including the type of domestic dwelling, community demographics, and variation in climate characteristics across regions. Affluence allows people to shift away from GHG-intensive energy sources and can change basic carbon needs. Moreover, Okushima (2021) found that balancing the ability of all communities to meet their energy needs with decreases in their basic carbon needs is the critical factor for achieving some equitable progress on climate change.

The importance of energy poverty may have increased in recent years as a function of the world's increased attentiveness to climate change risks, but Campbell (1993) points to the 1970*s* oil crises as the flux point at which energy poverty challenges to political stability were revealed. Those latent risks to social cohesion were evident in communities dominated by lower incomes, access to inefficient heating technology, and sub-standard governmental guidelines for housing insulation. However, the sudden rise in oil prices catalyzed those latent risks into active disruptions that were exacerbated as policymakers introduced mechanisms to ration supply.

Campbell (1993) identifies the conceptual term "poverty" as an issue that confounds action on the problem of energy poverty. Poverty is identified as a multi-generational condition that permeates at the community-level without tangible points of action to take. To most, the state of poverty is a state of being. This is a challenge without boundaries—that formlessness tends to overwhelm policymaker action especially when considering the issue as multi-generational. Measuring those impacts on a quantifiable level is, therefore, a distinct challenge.

Energy poverty, on the other hand, is an energy infrastructure problem that capital expenditures can directly cure because household expenditures on fuel are quantifiable; therefore, a threshold exists in theory where energy poverty begins and ends (Campbell, 1993).

Campbell points to Boardman (1987) who posited that 10 percent of one's household income being spent on energy/fuel was the threshold of concern for energy poverty—a metric adopted

by several others (Green et al., 2016; Lloyd, 2006; Lesser, 2015). While a large proportion of research identifies that spending above 10 percent indicated a state of energy poverty whereupon the cost of fuel consumption to meet one's energy service needs was a burden, some researchers have illustrated that threshold is 6 percent (Drehobl et al., 2020).

Follow-on research has expanded on this effort to measure energy poverty by creating a metric of threshold for energy poverty. While some countries have adopted specific metrics for measuring and comparing energy poverty (Faiella and Lavecchia, 2021), there is no clear consensus on best practices. Chapman and Scannell (2005) developed the Affordable Warmth Index based on the calculation of energy ratings to identify sources of energy that need efficiency investments by policymakers and households. Several others have made contributions, for example, Šiksnelyte-Butkiene et al. (2021), Thomson and Snell (2013), Heindl (2013), Miniaci et al. (2014), Okushima (2016), and Brunner, Spitzer, and Christanell, (2012).

Regardless of the methodology for measuring energy poverty, the fundamental issue at hand is that the lack of affordable warmth changes people's basic daily routines. The onerous nature of accommodating these energy deficits tends to drive health and wealth outcomes for households (McCrone, 2015). The lack of affordable energy can bind communities to a lack of economic opportunity as they attempt to accommodate for energy deficits or their high costs, which tend to affect minorities and people of color more intensely.

Commented [DN176]: DOE's Office of Economic Impact & Diversity has come up with a methodology to measure energy poverty/burden

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The myriad impacts of energy poverty on health are too numerous to cover in this document, but Faiella and Lavecchia (2021) outline several. Overall, households with limited incomes are energy poor and suffer from subsequent negative health outcomes (Thomson et al., 2017), for example, excess deaths during wintertime (McAvoy et al., 2007) with the elderly particularly at risk (de'Donato et al., 2013) and increasing seasonal variation due to climate change compounding these risks (Healy, 2003). For healthcare systems, this increased seasonal health risk can reduce economic activity and reduce the integrity of the broader healthcare system (Wells, 2007) with compounding effects to the system over time (Torjesen, 2012).

Negative outcomes tend to accumulate across multiple community contexts, but their effect is not felt in isolation. Rather, these negative community outcomes tend to have cumulative effects that interact and compound each other with the risk of cointegrated impacts higher with LNG project development (Gislason and Andersen, 2016).

7.5 Just Energy Transitions

The current energy transition presents a generational opportunity to make significant progress in ameliorating historical injustices (Wang and Lo, 2021). As technology has evolved and capital has flowed into large-scale energy infrastructure investments, a concerted effort to accrue the economic and social benefits associated with these technologies and investments in disadvantaged communities may prove fruitful in spurring a more just outcome from the energy transition. Equally possible is the ability to start mitigating the systemic injustices that have continued to plague these same communities in response to historical decision-making.

The articulation of energy transition goals varies significantly across the research literature, but it tends to boil down into a handful of broad topics.

These include poverty reduction (Lo and Broto, 2019; Koehn, 2008; Colenbrander et al., 2017), amelioration of historical energy injustices (Jasanoff, 2018; Delina and Sovacool,2018; Carley and Konisky, 2020), and opportunities for economic growth (Yang et al., 2018; Ehresman and Okereke, 2015). Wang and Lo (2021) argue that the energy transition is an apt vehicle for fixing historical wrongs if it can simultaneously account for environmental costs disadvantaged communities already suffer from, the reality that climate change will likely exacerbate these pre-existing environmental costs, and a decision-making process steeped in the tenets of assuring energy justice.

Pellegrini-Masini et al. (2020) attempt to prioritize the approach toward justice and the energy transition across four planes. First, the tradeoff in intergenerational outcomes and opportunities must be a prominent consideration for policymakers. This addresses the core reason that mitigating climate change is essential: subsequent generations should be provided the opportunity for growth and well-being that is at least commensurate with today's generations. Second, building out policy that considers energy vulnerability will help to prevent the transition from being a zero-sum game in which regional, fossil-fuel-reliant economies are left behind. In this sense, energy projects will benefit vulnerable communities. Third, transforming the social self-image of communities whose cultural identity is tied to fossil fuels must be considered to avoid confusing the energy transition with an attack on disadvantaged communities. Finally, the unavoidable damage to local communities must be accounted and compensated.

The ability to move forward into a new energy landscape that is sustainable is a direct function of the ability of policymakers to avoid repeating historical injustices; justice frameworks must be the bedrock of transition planning (Wang and Lo, 2021; Williams and Doyon, 2019). Pai, Harrison, and Zerriffi (2020) provide the framework for researchers to consider strategies for a just transition—one that preserves the well-being of fossil-fuel-reliant communities. Preserving the human capital of these communities is a critical goal for ensuring the energy transition policy provides opportunities for all. Pai, Harrison, and Zerriffi (2020) summarize more than a dozen requirements that would facilitate policymaker efforts to ensure a just transition but underscore one: the requirement of intentional effort for long-term planning with routine efforts to conscientiously engage with affected communities. Historically disenfranchised communities of people must be actively welcomed into the discussion early and often to be re-franchised and ensure their voices are heard (Weller, 2019).

7.6 Fossil Fuel Employment and Revenue

As the United States shifts away from a GHG-intensive economy, the delicate issue of fossil fuel unemployment arises. Specifically, the risk of unemployment rising as a result of the shift away from a GHG-intensive economy is pronounced in regions where fossil fuel and other extractive-based or refining industries have historically dominated available employment opportunities and been the core driver of local economic growth in the region. The loss of those jobs represents a significant loss to local government revenues, long-term declines in the economy, and a potential cycle of population loss under which the region cannot recover.

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The capacity to politicize energy transition debates is high (Healy and Barry, 2017) with GHG-intensive firms in a unique position to rally action against clean-energy projects (Goods, 2022) as a tradeoff between employment and climate policy. There is some merit to this concern from the community perspective as well. Female employment in the solar industry lags far behind male employment (Carley and Konisky, 2020) and disadvantaged or disenfranchised communities tend to bear a larger overall burden of costs even those associated with cleaner energy projects (Brock et al., 2021). To the extent that governance strategies can acknowledge the dignity of historically disadvantaged communities and groups, efforts to engage with those communities and groups in energy transition and governance strategies will be more successful and less divisive (Grossmann and Trubina, 2021).

Unions are viewed as an amenable structure for elevating and empowering the voices of disadvantaged communities in the energy transition (Pai, Harrison, and Zerriffi, 2020; Newell and Mulvaney, 2013). One reason may be in the high unionization rate of fossil-fuel industries (Pai and Carr-Wilson, 2018). Engaging with unions is in many ways a matter of practicality and the pre-existing internal structures built to advocate for their members make unions a strong vehicle for working toward a just transition[q] (Stevis and Felli, 2015). As an expansion of natural gas/LNG U.S. export capacity could limit the loss of employment for communities historically reliant on the fossil fuel industry, there exists an implicit advantage to directly approaching unions as potential enablers of cooperation with communities. Avoiding the mass loss of employment would help these communities from further decline as they tend to be areas in which the negative health and social impacts of fossil fuels are particularly pronounced.

Intentional efforts to diversify local economies would increase the resilience of local economies (Lobao et al., 2016). Notably, increasing the diversity of local economies is a positive regardless of the effort to transition away from fossil fuels. Any local economy highly dependent on one industry—particularly when that industry is as volatile as extractive-based industry—would introduce a greater resilience supportive of regional growth (Freudenburg and Gramling, 1994).

Among the opportunities a just transition presents are the ability to reduce the gender gap in regions dominated by the fossil fuel industry, increase investment into local energy infrastructure, remediate historical environmental damage, retrain the local workforce to "skill up" the region's human capital, and shore up local government revenues through economic diversification (Pai, Harrison, and Zerriffi, 2020).

In the end, just transitions are achieved when local voices are not just heard but amplified during the energy transition process. An unfortunate trend can play out that misses the mark on this issue where well-intentioned decisionmakers attempt to prescriptively advocate on behalf of disadvantaged communities. Often, policymakers advocate for the environmental protection of disadvantaged communities while neglecting to consider the calls for economic development emanating from those communities. A key example of that rests in the Canadian arctic where LNG projects that could act as local development opportunities for increasing local incomes are prevented by national policies that have banned energy projects out of the best intentions (Nicol and Barnes, 2019).

[q] The term "just transitions" originated within community-organizing efforts centered on labor unions (Eisenberg, 2018).

One obvious benefit of large-scale energy project development rests in the rents accrued from the project's completion. Treating these project benefits as a viable source of income that could be distributed to disadvantaged communities was explored in Chandrashekeran (2021), who studied indigenous populations in Australia after land repossession within Aboriginal populations. Chandrashekeran (2021) found that establishing property rights for historically disenfranchised populations is a key step in empowering collective negotiations for revenue sharing to fund reparations.

7.7 Protests and Political Activism

Excluding communities from decisions creates risks not just for disadvantaged populations, but for the completion of large-scale energy project development overall (Temper et al., 2020). The perpetuation of community disenfranchisement leaves people with a sense that the only option available for advocacy is to organize and protest. The way in which narratives are framed matters a great deal with respect to facilitating community buy-in for policy seeking to pivot away from fossil fuels.

Janzwood and Millar (2022) argue that the duality of natural gas—that it simultaneously accelerates the transition as a baseline electricity input and ensures the perpetuation of GHG reliance—creates the conditions for interpretive politics to dominate discourse around the transition. This is especially true for LNG organizations planning large energy infrastructure projects (Korkmaz and Park, 2019) and when regional economies are reliant on fossil fuels or the topic of natural gas as a "bridge fuel" is debated (Cha, 2020).

On the other side, anti-coal and anti-gas advocacy groups proved their own capacity to organize effectively in developed economies (Durand and Keucheyan, 2022). Social movements such as a the "UK Rights to Warmth" in the United Kingdom coalesced around the fight against entrenched energy poverty to some success (Walker and Day, 2012). Successful efforts to stop LNG export projects were found even in fossil fuel-friendly U.S. states such as Texas (Garrett and Sementelli, 2021) with access to social media and the strategic deployment of online networks increasing their efficacy (Correa-Cabrera et al., 2022).

The willingness to protest varies across cultures. Whereas communities within the United States that are at risk of job losses from national policies might tend to view justice as a regional tug of war that *must be* fought, research into Chinese activism shows that the Confucian perspective on justice as a collective outcome (whose goals are harmony between nature and humanity) shifts the perspective of the debate at its core (Wang and Lo, 2022). However, a nation or region's reliance on fossil fuels is not a reliable indicator of attitudes toward natural gas and LNG projects. Case in point, protestors in Canada and Norway have vehemently advocated against the expansion of oil and gas exploration despite their deep reliance on oil and gas production for both economies (Harrison and Bang, 2022). It has also been found that protests can arise in areas where there is a history of oil extraction when unconventional natural gas exploration is proposed (Chailleux et al., 2018).

The politicization of energy infrastructure can result in starkly divided factions, but the common thread of discontent that binds pro-gas and anti-gas contingencies is rooted in process.

Specifically, deficits in procedural and distributional justice tend to increase the likelihood of activism (Evensen, 2018; Temper et al., 2020).

7.8 Energy Governance and Adaptive Management

Governance structures play a vital role in the pursuit of energy project development and the transition away from fossil fuels, but their ability to provide an equitable or just transition is not guaranteed (Moss, 2009). Incorporating the concept of just outcomes begins with the governance structures of energy project development and planning (Newell and Mulvaney, 2013). Those who are in the position of governance are in a position of authority to inculcate more equitable outcomes to benefit disadvantaged populations (Florini and Sovacool, 2009).

As Florini and Sovacool (2009) point out, governance is not simply government. While governance is an activity in which governments participate it exists as a framework for creating and maintaining processes to implement policy. This framework is the conduit for participation that brings together government, intergovernmental organizations, private sector market participants, and communities to collectively manage a process that ideally serves all groups.

Governance is necessary as a result of two issues with which economists often wrestle. One issue is that society is not capable of ensuring equitable access to public goods without some overarching set of rules to facilitate that outcome and a governance structure to provide oversight over implementation. The second issue is that any economic or social activity tends to create what economists call "externalities." That is, there are unintended results that can occur indirectly from the consumption of goods or social interactions. The decommissioning of a coal power plant is a prime example of the need for governance to protect the public's well-being from externalities, as an idle power plant could become the source of negative health outcomes for a community without intentional efforts to prevent such outcomes. Governance structures are necessary to deal with these two conceptual issues because there is no economic incentive to do so (Florini and Sovacool, 2009).

Perspectives can clearly vary within communities and that variation can affect governance structures (Wang and Lo, 2021). In studying international natural gas markets, Norouzi (2022) notes that the heterogeneity of individual members within a collective community implies that international natural gas market outcomes are heavily influenced by individual preferences within any collective. Community engagement is important, but it is not the magic elixir that solves the problem by itself. Ciplet and Harrison (2019) identify three conflicts that emerge in efforts to facilitate an energy transition: 1) between inclusivity and sustainability where inclusive processes that invite community engagement require more time to complete projects; 2) between sustainability and the need to recognize the unique value system for each community, which increases the complexity of sustainability goal pursuits; and 3) between equity and sustainability, meaning that the distribution of costs and benefits can conflict with project performance.

The impact of a region's political economy can also clearly drive outcomes. Inequality is a multi-dimensional concept that varies across countries and individuals (Laurent and Zwickl, 2021). As the communist states of the Eastern Bloc exited the Union of Soviet Socialist Republics, the effort to integrate into energy markets within the European Union revealed that variations in

culture and geography dominated some preferences in energy project outcomes with respect to energy justice (LaBelle, n.d.). On the other hand, a study of sub-Saharan African nations revealed a positive relationship between democracy, energy justice, and growth (Opoku and Acheampong, 2023). Cultural differences aside, income and wealth inequality may drive many of the outcomes. Studies of European Union attitudes toward sustainability policies show that 41 percent country-level variance in negative attitudes is correlated with differences in wealth and income (Pellegrini-Masini et al., 2021).

In short, the lack of consideration for energy justice issues within the global framework of energy governance will likely just perpetuate historical disadvantages within communities (Symons and Friederich, 2022). This is a function of existing power structures within current governance structures. Beyond that, Symons and Friederich (2022) show that the political sovereignty of communities making independent decisions over energy project development will always result in outcomes that serve each group's self-interest and ignore the externality problems. Without intentional adjustments to governance that deal with these structural problems, the current paradigm will continue to create winners and losers and perpetuate the current disenfranchisement of some communities.

Good governance strategies for energy project development require support from the government, reliable capital and operational funding, diversification goals for the economy, and diverse coalitions (Wang and Lo, 2021; Cha, Wander, and Pastor, 2020). Finally, the creation of ownership stake opportunities at the onset of project development for disadvantaged communities is critical to ensuring that the tradeoffs between disenfranchised communities and the regional benefits of energy projects ameliorate losses. Greater rates of acceptance have been found to exist within communities with larger ownership stakes in energy projects (Hogan et al., 2022).

7.9 Sustainable Development

The desire to balance environmental protection and economic development in disadvantaged and frontline communities has led to the championing of a concept called "sustainable development." Summarized broadly, the idea is to balance the needs of current generations without harming the well-being of future generations. Within this movement, the needs of today's impoverished communities are heavily weighted under the theory that gains in wealth and income of today's generation beget gains in tomorrow's generation. In other words, the benefits of economic development compound over generations (Poppel, 2018).

In practical use, the concept of sustainability can be vague (Grossmann et al., 2022). One oft-missing area of focus is the tradeoff between environmental protection advocacy for disadvantaged communities and advocacy with these same communities for energy justice and sustainable development. The concept of embedded sustainable development outlines criteria for energy project development to be measured in terms of how energy justice efforts compare to the energy privilege of communities (Ciplet, 2021).

In 2015, the United Nations outlined a list of 17 Sustainable Development Goals that define the focus of sustainability as a practice (United Nations, 2015). Oriented toward 2030 outcomes, the 17 outcomes broadly fall into Barbier's (1987) canonical "three systems" approach to

process development: environmental, social, and economic. Broadly speaking, the 17 goals break down into the promotion of clean water and sanitation services alongside sustainable cities and sustainable economic growth with full employment as well as the sustainable development of natural resources. They also promote the end to food insecurity and poverty, greater levels of societal health and well-being, lifelong inclusive/equitable educational opportunities, and gender equality, as well as strong judicial and governmental institutions. Finally, the United Nations (2015) advocates for the proactive implementation of climate change policy that results in energy infrastructure resilience where communities have access to reliable and affordable clean energy.

Cherepovitsyn and Evseeva (2020) proffer several criteria to promote sustainable development within the context of LNG project development in the arctic—an area currently receiving a great deal of attention for energy development projects. The authors note the importance of sustainable development in the arctic as it is home to over 20 percent of the world's hydrocarbon resources. To promote sustainable outcomes, they propose seven criteria of sustainable development goals[r]:

- Project development must minimize environmental impacts at the construction and operation site
- Natural resource use should be efficient
- Local community support is paramount as is the effort to preserve indigenous culture and heritage
- Long-run regional economic gains that benefit and reflect stakeholder expectations should be prioritized
- Larger energy infrastructure development goals are achieved
- Innovations to industry technology are achieved
- Strengthening the regional LNG market relative to the global network is achieved

7.10 CONCLUSION

Historical disenfranchisement of communities has often resulted in the creation of winners and losers with respect to policy impacts. To the extent that policy has created the conditions under which disadvantaged communities arise, those policies have likely been rooted in a fundamental lack of inclusivity in the planning and implementation processes of project development. As the United States continues to embark on a transition away from a GHG-intensive economy, the chance to right those historical wrongs presents itself.

DOE deploys the Climate and Economic Justice Screening Tool to identify disadvantaged communities. To do so, the tool pulls in geographic information system data on the universe of communities whose boundaries are defined by the U.S. Census. These communities are identified as disadvantaged if that census tract meets the criteria for disadvantage in one of the

[r] Note that while the framework for measuring outcomes by Cherepovitsyn and Evseeva (2020) focuses on the arctic, this approach may be prudent for any LNG project development strategy. As such, the seven points have been modestly edited to apply more broadly.

categories describing burden or if that community resides within the boundary of a federally-recognize tribe.

The panoply of burdens fall within a framework of several categories. The threshold for being considered disadvantaged under the Climate Change category is that the census tract is at the 90th percentile for agriculture loss, building loss, population loss, or flood and wildfire risk. For Energy, the census tract is at the 90th percentile for energy costs. For Health, the census tract is at the 90th percentile for asthma, diabetes, heart disease, or low life expectancy. For Housing, the census tract is at the 90th percentile for green space deficits, indoor plumbing, or lead paint exposure as well as they have experienced historical disinvestment in housing. For Legacy Pollution, the census tract is at the 90th percentile of exposure to facilities that have dealt with hazardous waste, former defense sites, are proximal to a superfund site or a risk management facility. For Transportation, the census tract is at the 90th percentile for exposure to various environmental particulates, face barriers to transportation access, or barriers due to volume. For Water and Wastewater, the census tract is at the 90th percentile for exposure to storage tanks or releases underground, or the discharge of wastewater. For Workforce Development, the census tract is at the 90th percentile for isolation by their linguistic background, poverty, unemployment, or an overall lower median income.

Currently, the tool identifies roughly 27,251 communities at the census tract level. The deployment of tools like this during the energy transition is key, particularly during the early planning stages, in creating the approach for community outreach, and in the effort to structure governance strategies. Identifying where disadvantaged communities are provides the high-level understanding into where deficits in outreach and inclusion have likely exacerbated the pervasiveness of disadvantage. In doing so, concerted efforts to bring these voices into the development of large-scale energy infrastructure projects related to natural gas/LNG market opportunities is key.

The calls to advocate for energy justice during this transition have grown as the salience of climate change threats grows. Achieving a just transition is largely a functioning of process. The once-in-a-lifetime opportunity to restructure current processes around the core concepts of distributional, procedural, and recognition justice is significant. Re-framing the foundations upon which critical U.S. energy infrastructure is built by bringing diverse voices and stakeholders to the planning table will help to ensure that the best laid plans produce results that facilitate the growth for all, not just some.

To do so, there is a need to accept the existence of frictions innate to energy justice and energy poverty. Providing economic growth opportunities in GHG-intensive regional economies is as paramount as the need for ensuring reliable, affordable, and clean energy for those suffering from a historic lack of energy access. This may require adjusting the method of measuring the benefits and costs of large-scale U.S. energy infrastructure investments. The implementation of the Biden-Harris Administration's Justice40 initiative speaks to this effort.

This chapter provides the framework for pursuing inclusivity goals in its discussion of energy justice and energy poverty. The energy transition is presented as a catalyst for pursuing change with the intended outcome being a just transition for all. In the end, the vehicle for applying

energy justice and energy poverty goals rests in the inclusive design of energy governance structures.

The literature base of energy justice and energy poverty within the space of natural gas and LNG market development is strong and growing. With intentionality, the authors of future research can help to ameliorate those historical disenfranchisements and provide a framework for the kind of shared prosperity that induces strong growth for all.

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From: Curry, Thomas
Sent: Fri, 1 Sep 2023 16:35:52 +0000
To: Harker-Steele, Amanda J (NETL); Easley, Kevin; Sweeney, Amy; Skone, Timothy
Cc: Robert Wallace; Adder, Justin (NETL); Francisco De La Chesnaye
Subject: RE: LNG Regulatory Analysis Support - Task 4 Env. Review Update Ch. 1-6
Attachments: Draft_Env.Review_Task4_LNG_DraftPreDecisional_8_30_23_Ch1-6.docx, NETL 2014 NG Rpt Addendum_CH.7_8_28.docx

DRAFT – DELIBERATIVE – PRE-DECISIONAL

Hi Amanda,

We have reviewed the updated drafts of Chapters 1-6 and Chapter 7. Attached are our comments and suggested revisions. We need to circulate the next draft to the General Counsel's office as early as possible next week. We tried to not include open-ended edits or comments, we think these are straightforward to review and accept with formatting and proofreading being the main tasks, not additional writing or research. With that in mind, would appreciate the return of an updated full draft that incorporates our edits no later than end of day Tuesday (9/5). If you would like to discuss, I'm available before 2:30 this afternoon or can make myself available on Tuesday.

Thank you.
Tom

From: Harker Steele, Amanda J. <Amanda.HarkerSteele@netl.doe.gov>
Sent: Wednesday, August 30, 2023 5:15 PM
To: Easley, Kevin <kevin.easley@hq.doe.gov>; Curry, Thomas <thomas.curry@hq.doe.gov>; Sweeney, Amy <amy.sweeney@hq.doe.gov>; Skone, Timothy <timothy.skone@hq.doe.gov>
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Subject: LNG Regulatory Analysis Support - Task 4 Env. Review Update Ch. 1-6

Hi Tom, Amy, Tim, and Kevin,

*DRAFT*DELIBERATIVE*PRE-DECISIONAL*

Good afternoon! The team has been hard at work updating Ch. 1 - 6 of the report and I am happy to report we are ready to submit today instead of on Friday.

The attached zip folder includes 1) a revised clean version of the report (Ch. 1 - 6) with a few minor comments for your consideration and 2) a comment response log which contains comments from the reviewed version of the report sent to NETL on 8/21 and updated to reflect the parsed down version of Ch. 2 sent by Tom on 8/22.

I hope you all have a good rest of the week! We look forward to getting your feedback. Thanks!

Sincerely,
Amanda J. Harker Steele, Ph.D. (she/her)

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NATIONAL ENERGY TECHNOLOGY LABORATORY

ENVIRONMENTAL IMPACTS AND SOCIAL CONSIDERATIONS ASSOCIATED WITH UNCONVENTIONAL NATURAL GAS

Commented [TC1]: Note revised title.



August 31, 2023

DOE/NETL-2023/4388

DRAFT DELIBERATIVE PRE-DECISIONAL

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All images in this report were created by NETL, unless otherwise noted.

ENVIRONMENTAL IMPACTS AND SOCIAL CONSIDERATIONS ASSOCIATED WITH UNCONVENTIONAL NATURAL GAS

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The authors wish to acknowledge the excellent guidance, contributions, and cooperation of the NETL staff, particularly:

Commented [HSAJ2]: Note for FECM - To be completed at the end.

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ACRONYMS AND ABBREVIATIONS

API	American Petroleum Institute
AR5	IPCC Fifth Assessment Report
B	Billion
Bcf	Billion cubic feet
BLM	Bureau of Land Management
BP	British Petroleum
BTEX	Benzene, toluene, ethylbenzene, xylenes
Btu	British thermal unit
CAA	Clean Air Act
CBM	Coalbed methane
CERCLA	Comprehensive Environmental Response, Compensation, and Liability Act
CH_4	Methane
CMSC	Citizens Marcellus Shale Coalition
CO	Carbon monoxide
CO_2	Carbon dioxide
CO_2e, CO_2-eq	Carbon dioxide equivalent
COGCC	Colorado Oil and Gas Conservation Commission
CRS	Congressional Research Service
CSU	Colorado State University
CWA	Clean Water Act
d	Day
DAC	Disadvantaged community
DOE	Department of Energy
DOI	Department of the Interior
DOT	Department of Transportation
EIA	Energy Information Administration
EIS	Environmental Impact Statement
EPA	Environmental Protection Agency
EPCRA	Emergency Planning and Community Right-to-Know Act
EQ	Earthquakes
ESA	Endangered Species Act
FECM	Office of Fossil Energy and Carbon Management
FERC	Federal Energy Regulatory Commission
ft, FT	Foot
g	Gram
G&B	Gathering and boosting
gal	Gallon
GHG	Greenhouse gas
GHGI	Greenhouse Gas Inventory
GHGRP	Greenhouse Gas Reporting Program
GWP	Global warming potential
GWPC	Groundwater Protection Council
H_2S	Hydrogen sulfide
HAP	Hazardous air pollutant
HF	Hydraulic fracturing
HPh	Horsepower-hour
IOGCC	Interstate Oil and Gas Compact Commission
IPCC	Intergovernmental Panel on Climate Change
ISO	International Organization for Standardization
kg	Kilogram
kJ	Kilojoule
km	Kilometer
km^2	Square kilometers
kWh	Kilowatt hour
LCA	Life cycle analysis
LNG	Liquefied natural gas
m^2	Square meter
m^3	Cubic meter
MARAD	Maritime administration
Mcf, MCF	Thousand cubic feet
min	Minute
MIT	Massachusetts Institute of Technology
mg	Milligram
MJ	Megajoule
ML	Local magnitude
MM	Million
MMT	Million metric tons
Mw	Moment magnitude
MWh	Megawatt hour

NOx	Nitrous oxides
N_2O	Nitrous oxide
NEIC	National Earthquake Information Center
NEPA	National Environmental Policy Act
NETL	National Energy Technology Laboratory
NGA	Natural Gas Act
NGL	Natural gas liquid
NGO	Non-governmental organization
NORM	Naturally occurring radioactive material
NOx	Nitrogen oxides
NPC	National Petroleum Council
NPS	National Park Service
NSPS	New Source Performance Standards
NYSDEC	New York State Department of Environmental Conservation
O_2	Oxygen
OECD	Organisation for Economic Co-operation and Development
OSHA	Occupational Safety and Health Administration
OPA	Oil Pollution Act
OSF	Oral slope factor
PADCNR	Pennsylvania Department of Conservation & Natural Resources
PADEP	Pennsylvania Department of Environmental Protection
PARETO	Produced Water Optimization Initiative
PM	Particulate matter
ppm	Parts per million
PRV	Pressure release valve
POTW	Publicly owned treatment work
R&D	Research and development
RCRA	Resource Conservation and Recovery Act
RD&D	Research, development, and demonstration
REC	Reduced emissions completion
RFF	Resources for the Future
RFI	Request for Information
RfV	Reference value
RPSEA	Research Partnership to Secure Energy for America
RRC	Railroad Commission of Texas
scf	Standard cubic foot
SDWA	Safe Drinking Water Act
SF_6	Sulfur hexafluoride
SO_2	Sulfur dioxide
T-D, T&D	Transmission and distribution
T&S	Transport and storage
Tcf	Trillion cubic feet
tCO_2e equivalent	Tonnes carbon dioxide
TDS	Total dissolved solids
TexNet	Texas' Center for Integrated Seismicity Research
t NG	Tonnes natural gas
Tg	Teragram
tonne	Metric ton
U.S.	United States
UIC	Underground Injection Control
USFS	U.S. Forest Service
USGS	U.S. Geological Survey
VOC	Volatile organic compound
yr	Year

1 INTRODUCTION

The United States (U.S.) Department of Energy's (DOE) Natural Gas Regulatory Program is responsible for reviewing applications to import and/or export natural gas from and/or to foreign countries. An important dimension in considering whether to grant such authorizations is how the additional natural gas production and transport activities needed to support proposed actions may impact the environment.[a] Accordingly, potential impacts are factors affecting public interest during review of applications.

Although uncertainties exist regarding the exact amount and location of natural gas production or transportation that would occur in response to additional authorizations being granted, it is important that DOE provide the public and decision-makers with access to updated information regarding the potential impacts associated with such activities. Accordingly, DOE's National Energy Technology Laboratory (NETL) has prepared this update to the 2014 Addendum to Environmental Review Documents Concerning Exports of Natural Gas from the United States (hereafter the 2014 Addendum) (DOE, 2014).

As with the 2014 Addendum, this report provides a review of peer-reviewed, scientific literature related to the potential environmental consequences of unconventional natural gas production and related activities. As unconventional natural gas production represents the majority and a growing share of total U.S. natural gas production, the environmental impacts reviewed in this report relate primarily those associated with unconventional production activities.

The publications referenced build on a strong body of literature that traces the evolution of unconventional natural gas production techniques from their conceptual stages in the 1970s to the technology advancements that contributed to the shale gas boom of the early 2000s and the further development and recovery of additional unconventional natural gas resources (e.g., tight gas sands, coalbed methane [CBM], and associated gas recovered with shale oil) and to stimulate more production from conventional resources (National Petroleum Council [NPC], 2011 and Commonwealth of Pennsylvania, 2023a).[b,c]

This report summarizes published descriptions of the potential environmental impacts of natural gas operations within the lower 48 states as detailed by government, industry, academia, scientific, non-governmental, and citizen organizations. The sources cited are publicly available documents. While this report by no means represents an exhaustive list of the sources that discuss environmental consequences of natural gas production and related

[a] DOE is responsible for considering the environmental impact of its decisions on applications to export natural gas, including liquefied natural gas, to countries with which the United States has not entered into a free trade agreement requiring national treatment for trade in natural gas. (Applications for trade with free trade agreement countries are deemed to be in the public interest by statute.) DOE conducts environmental reviews under the National Environmental Policy Act and as part of its public interest review under the Natural Gas Act.

[b] In Pennsylvania, hydraulic fracturing, which is primarily used to produce natural gas from unconventional resources, has also been used to help stimulate production from conventional natural gas formations where reservoir characteristics do not otherwise permit sufficient production (Commonwealth of Pennsylvania, 2023a).

[c] A 2011 report by the NPC suggested hydraulic fracturing was responsible for the reversal of long-term declines from onshore conventional production of natural gas in the United States (NPC, 2011).

activities, NETL has determined the sources cited are representative of the literature, and no significant areas have been excluded.

In addition to providing a review of potential environmental impacts, this report also provides the public and decision-makers with information regarding how the ~~justice implications~~social cietal ~~impacts of~~ impacts from natural gas production and related activities, and how they can be ~~evaluated, as well as how justice social considerations can be advanced and promoted in future decisions regarding these activities. The information provided is a result of NETL's review of DOE's~~considered. ~~Justice40 initiative and other publicly available information.~~

Over the past decade, the focus on environmental issues has evolved with some interest in the public literature varying over time. Key research in some areas remains the same with minor to no new additions to the basis of scientific knowledge; in this situation, some historical references have been maintained. No opinion on nor endorsement of these works is intended or implied.

This report is divided into chapters, each of which contains a separate section of references so that each identified focus area can be explored further:

- Greenhouse gas (GHG) emissions and climate change (Chapter 2)
- Air quality (Chapter 3)
- Water use and quality (Chapter 4)
- Induced seismicity (Chapter 5)
- Land use and development (Chapter 6)
- ~~Justice~~Social considerations for natural gas development (Chapter 7)

This report begins with the presentation of background information on domestic natural gas production and federal and state regulatory processes related to managing environmental impacts.

Commented [HSAJ3]: Note for FECM - Ch. 7 still exists as a separate document. However, we have made an attempt to incorporate some content into Ch. 1 that outlines what is contained in Chapter 7. Our hope is by doing this now, we can reach a decision sooner on the title and also help to pull Ch. 106 and Ch. 7 together.

1.1 Natural Gas Basics

Natural gas is an odorless, gaseous mixture of hydrocarbons, largely made up of methane (CH_4) but also containing small amounts of natural gas liquids (NGLs) and nonhydrocarbon gases (e.g., carbon dioxide [CO_2] and water vapor) (Energy Information Administration [EIA], 2023b). Natural gas is one of the major combustion fuels used throughout the country. It is mainly used to generate industrial and utility electric power, produce industrial process steam and heat, and heat residential and commercial spaces. The average gross heating value of natural gas is approximately 1,031 British thermal units per standard cubic foot (Btu/scf), typically varying from 950 to 1,050 Btu/scf.[d]

Natural gas is typically classified as being either conventional or unconventional, depending on the permeability of the formation (reservoir) within which it is found, the production

[d] The 1,031 Btu/scf average, also equivalent to 54.1 megajoule (MJ)/kilogram (kg), is calculated using the high heating value of natural gas at standard conditions of 60 °F and 1 atm.

technology used to secure it, the current economic environment, and the scale, frequency, and duration of production from the reservoir (EIA, 2023b; Krieg, 2018). Generally, conventional natural gas refers to natural gas found in highly permeable reservoirs, typically composed of sandstone or limestone, which allows for extraction to be completed in a relatively straightforward manner via the use of vertical rather than horizontal drilling. Unconventional natural gas refers to natural gas found within low-permeability reservoirs; generally trapped within the pores (i.e., small, unconnected spaces) of rocks, which makes extraction more difficult and necessitates the use of advanced drilling (e.g., directional, or horizontal drilling) and well stimulation (e.g., hydraulic fracturing) techniques that can be energy intensive (British Petroleum [BP], 2017).

Unconventional natural gas production has not only made up for declining conventional natural gas production but has also led to new levels of natural gas supply in the United States. This increased supply has contributed to an increase in the use of natural gas for power generation, manufacturing, transportation, and residential and commercial heating, as well as the availability of natural gas for export from the United States.

There are three primary types of unconventional natural gas:[e]

- **Shale Gas:** refers to natural gas found within shale rock formations, which consist of fine-grained sedimentary rock that forms when silt and clay-size mineral particles are compacted together (Zendehboudi and Bahadori, 2016). Shale rock formations can be easily broken into thinner, parallel layers of rock.
- **CBM:** refers to natural gas that is both generated and stored in coal beds. Originally extracted from coal mines to reduce the potential for explosions caused by an excess of CH_4 gas within the mine and subsequently disposed of, CBM now serves as an important source of energy. Producing CBM from deeper, denser coal formations often requires the use of hydraulic fracturing technology.
- **Tight Sands Gas:** refers to natural gas found in low-permeability, gas-bearing, fine-grained sandstones, or carbonates.

Today, the majority the natural gas produced domestically is unconventional and is found in shale rock formations. These formations are often referred to as “plays” and can be found in nearly 30 different U.S. states. Operators in the Barnett Shale formation, which is located in Texas and is one of the largest onshore natural gas plays in the United States, have been producing unconventional natural gas since the early 2000s (Railroad Commission of Texas [RRC], 2023).

While operators in the Barnett Shale formation still produce a significant amount of our nation’s unconventional natural gas, the Marcellus Shale formation—located in the Appalachian Region of the United States and spanning across areas in Ohio, Pennsylvania, and West

[e] There are other types of unconventional natural gas whose exploitation has not yet reached commercial scale. These include methane hydrate, which is a crystalline solid that consists of a CH_4 molecule surrounded by a cage of interlocking water molecules. Methane hydrate is an "ice" that only occurs naturally in subsurface deposits where temperature and pressure conditions are favorable for its formation.

Virginia—is currently the largest source of domestic unconventional natural gas from shale rock (EIA, 2023b).

Primary enabling technologies for accessing unconventional natural gas include hydraulic fracturing and horizontal drilling. Hydraulic fracturing (sometimes referred to as hydrofracking or simply fracking) is the process of pumping water mixed with a small amount of sand and other chemical additives (i.e., fracturing fluid) underground through a wellbore at a pressure that is sufficient to cause a target rock formation to break (i.e., fracture) (U.S. Geological Survey [USGS], 2019).[f,g] As the rock is fractured, natural gas that would have otherwise remained trapped is able to be released into a wellbore and returned to the surface (USGS, 2019).

The internal pressure caused by the fracturing of the rock formation also releases fluid, which travels to the surface through the wellbore. This fluid is commonly referred to as "flowback" or "produced water" and may contain the injected chemicals in addition to any naturally occurring materials found below the surface (e.g., brines, metals, radionuclides, and hydrocarbons). The fluid is oftentimes stored on site at the well-pad in tanks or pits before it is treated and disposed of or recycled. In many cases, disposing of the fluid involves injecting it underground. In areas where underground injection is not an option, the fluid can either be reused or processed by a wastewater treatment facility and subsequently discharged into surface water.

Hydraulic fracturing has been applied since the late 1940s when Standard Oil of Indiana (later known as Amoco) developed the technique and performed some of the first fracture treatments in the Hugoton Gas Field in Kansas (BP, 2017). While the use of hydraulic fracturing is not limited to wells that are horizontally drilled, the combination of horizontal drilling and hydraulic fracturing has increased the volume of domestic natural gas considered to be "technically recoverable" (i.e., able to be produced using currently available technology and industry practices regardless of any economic considerations).

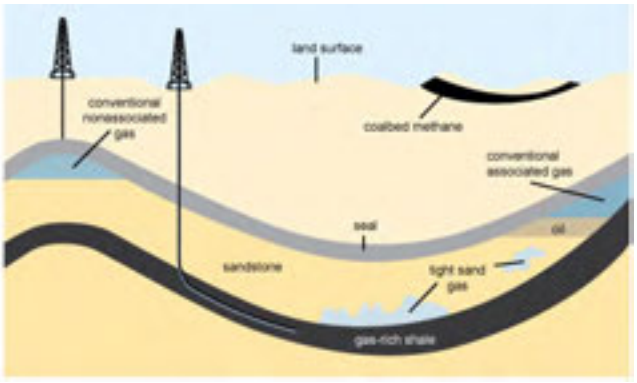
The process of horizontal drilling involves first drilling a vertical well. Once a specified depth has been reached with the vertical well, the path of drilling is bent until the well begins to extend horizontally. Horizontal wells are not only longer than vertical wells, but the process is much more complex. A horizontal well is, therefore, generally more expensive to drill than a vertical well, but it is expected to produce more natural gas (EIA, 2018). The horizontal section of a well, sometimes referred to as the directionally drilled section, can extend thousands of feet (ft).

Exhibit 1-1 provides a schematic of conventional natural gas and the various types of unconventional natural gas resources described previously (EIA, 2023b). Exhibit 1-2 provides a schematic of the combined processes of horizontal drilling and hydraulic fracturing (BP, 2017).

[f] The specific types of chemical additives used, and the proportions of each, depend on the type of rock formation that is being fractured. Additives function as friction reducers, biocides, oxygen (O_2) scavengers, stabilizers, and acids, all of which are necessary to optimize production. The composition of these fluids and the purposes of the additives are described in more detail in Chapter 4 – Water Use and Quality.

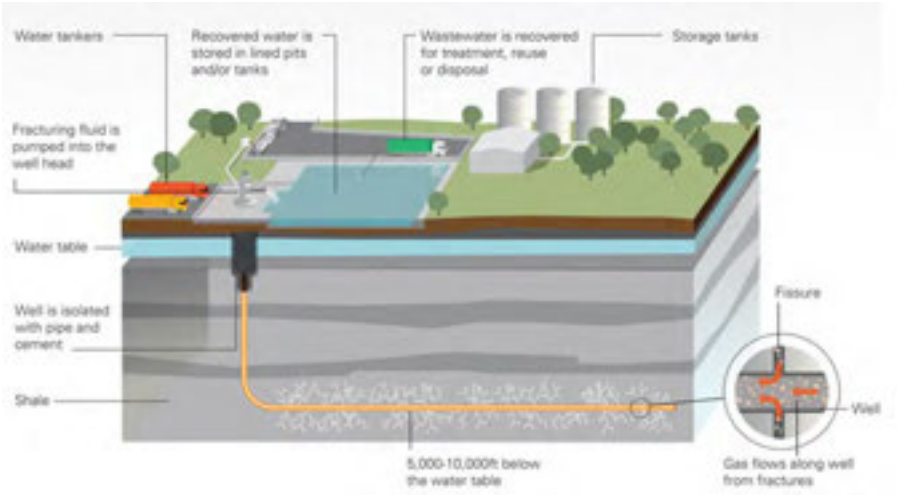
[g] In addition to enabling recovery of natural gas from unconventional resources, hydraulic fracturing techniques have also been used to produce shale oil and both natural gas and oil from conventional resources (NPC, 2011).

Exhibit 1-1. Schematic geology of natural gas resources



Source: EIA (2023b)

Exhibit 1-2. Schematic geology of natural gas resources (3D)



Permission pending from BP (2017)

1.1.1 Liquefied Natural Gas

Liquefied natural gas is natural gas that has been cooled to a liquid state (approximately -260° F or -162° C). The volume of natural gas in a liquid state is about 600 times smaller than in a gaseous state (Molnar, 2022). Liquefying natural gas is one way to allow markets that are far away from production regions, or where pipeline capacity and delivery is constrained or unavailable (e.g., New England) to access natural gas. Once in liquid form, natural gas can be shipped to terminals around the world via ocean tankers. At these terminals, the liquefied

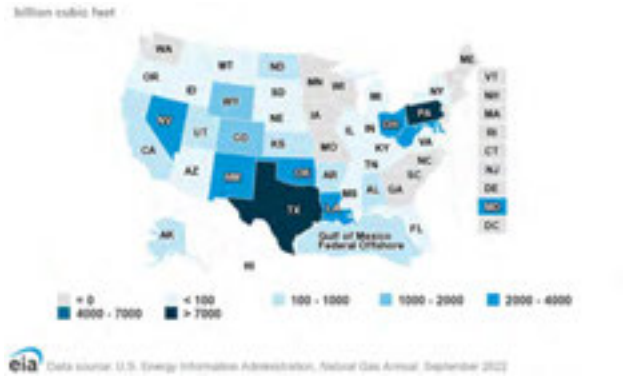
natural gas (LNG) is returned to its gaseous state and transported by pipeline to distribution companies, industrial consumers, and power plants. In some cases (over shorter distances), LNG can also be shipped by transport trailers (i.e., trucks), often to end-use facilities, where it is regasified (DOE, 2021). Liquification of natural gas not only allows for a more flexible way of transporting natural gas, but also makes it more economic to transport natural gas on a per-unit basis but only if there is a need to move the natural gas over a long distance (e.g., export natural gas to overseas markets) (Molnar 2022). Transportation typically accounts for more than half of the total costs that occur throughout the natural gas supply chain regardless of the state of the natural gas. Both pipeline and LNG transportation systems require large upfront investment costs. [h]

1.2 U.S. Natural Gas Resources

Annual U.S. production of dry natural gas was approximately 35.81 trillion cubic feet (Tcf) in 2022 (an average of about 98.11 billion cubic feet [Bcf] per day). Between 2021 and 2022, annual production of dry natural gas increased by about 4 percent from approximately 34.52 Tcf (an average of about 94.57 Bcf per day). With the exception of 2015–2016 and 2019–2020, annual domestic production of dry natural gas has increased year-over-year since 2005 as hydraulic fracturing combined with horizontal drilling has continued.

About 70 percent of the domestic dry natural gas production in 2021 was supplied by five of the United States' 34 natural gas-producing states.[i] States with a larger percentage share of total U.S. dry natural gas production in 2021 include Texas (24.6 percent), Pennsylvania (21.8 percent), Louisiana (9.9 percent), West Virginia (7.4 percent), and Oklahoma (6.7 percent) (Exhibit 1-3) (EIA, 2023b).

Exhibit 1-3. U.S. natural gas production by state in 2021



Source: EIA (2023b)

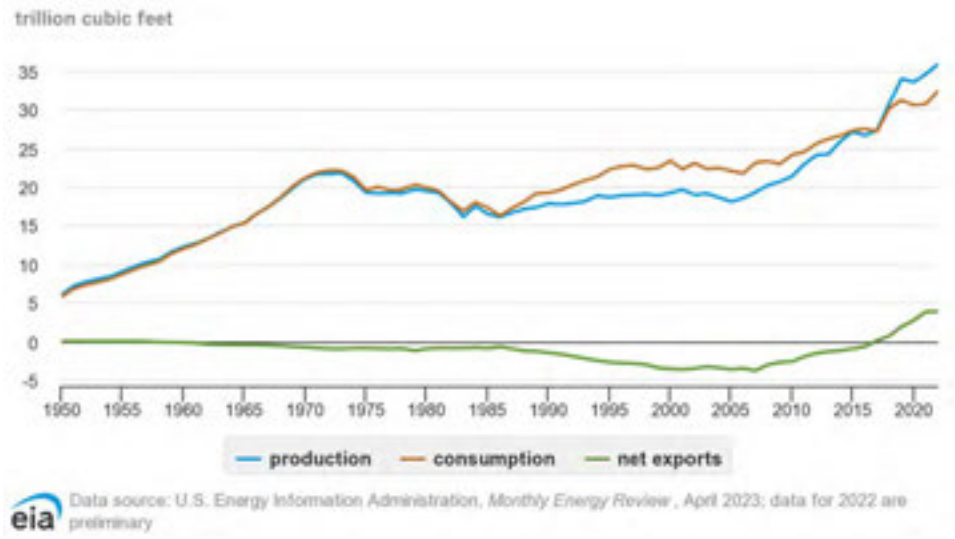
[h] LNG becomes cost-competitive with pipeline transportation once the distance the natural gas needs to travel exceeds 1,000 kilometers (km).

[i] 2022 state-level data was not available at the time this report was written. As such, 2021 state-level data is used above.

In 2022, tight sands natural gas and natural gas from shale collectively accounted for 31.62 Tcf of dry natural gas produced onshore in the lower-48 states. In the same year, 3.43 Tcf of the dry-natural gas produced on-shore was supplied by CBM (EIA, 2023b). Although most of the natural gas wells operated by the United States are located onshore, some wells are drilled offshore (i.e., into the ocean floor in waters off the coast of the United States). In 2022, offshore dry natural gas production was approximately equal to 0.80 Tcf, accounting for about 2.3 percent of total production. The majority—87.6 percent—of this production occurred in federally managed waters within the Gulf of Mexico (EIA, 2023b).

In addition to being a producer of natural gas, the United States is also a consumer and net exporter of natural gas. In 2022, the United States produced about 10.8 percent more natural gas than it consumed—on a net basis, the United States was a net exporter of natural gas. Exhibit 1-4 highlights recent (2022) and historical (1950–2021) U.S. natural gas production, consumption, and net exports (EIA, 2023a).

Exhibit 1-4. U.S. natural gas consumption, dry production, and net exports (1950–2022)



Source: EIA (2023a)

1.3 U.S. Regulatory Framework

The following sub-sections provide a review of both federal and state regulatory responsibilities related to the production, transportation, use, and export of domestic natural gas resources.

1.3.1 Federal

Multiple federal agencies have authority over the production of natural gas resources. Three of these agencies—DOE, the Department of the Interior (DOI), and the Environmental Protection

Agency (EPA)—play a uniquely critical role as they are charged with monitoring, assessing, and reporting on various natural gas environmental impacts, such as those described in this report. Exhibit 1-5 describes the roles and responsibilities of these three agencies at a high-level in addition to the way they work together to inform policy-relevant science.

Exhibit 1-5. Key U.S. agencies and their roles in natural gas development and production



Source: DOE

The following subsections detail some of the specific roles and responsibilities of these agencies and, where applicable, their specific bureaus and offices. Exhibit 1-6 provides examples of the federal statutes applicable to unconventional natural gas development helping to guide the roles and responsibilities described.

Exhibit 1-6. Selected federal regulations that apply to unconventional oil and gas development

Statutes	Applicability
Clean Air Act (CAA)	Places requirements on air emissions from sources of emissions at well sites; addresses compliance with existing and new air regulations, often delegated to local and state agencies. Generally, there is no distinction made between conventional and unconventional wells under the CAA.
Comprehensive Environmental Response, Compensation, and Liability Act (CERCLA)	Only applies if hazardous substances besides crude oil or natural gas are released in quantities that require reporting. Natural gas releases do not require notification under the Comprehensive Environmental Response, Compensation, and Liability Act, but other hazardous substances may be released in reportable quantities during natural gas production.
Clean Water Act (CWA)	Limits pollutants on produced water discharge under the National Pollutant Discharge Elimination System; stormwater runoff containing sediment that would cause a water-quality violation requires a permit under CWA decisions. Beneficial uses of surface waters are protected under Section 303.
Emergency Planning and Community Right-to-Know Act (EPCRA)	Requires facilities storing hazardous chemicals above the threshold to report same and provide a Material Safety Data Sheet to officials and fire departments.
Endangered Species Act (ESA)	Prohibits federal agencies from taking any action that is likely to jeopardize the continued existence of any endangered or threatened species (listed species) or result in the destruction or adverse modification of such species' designated critical habitat (Section 7); prohibits the taking of a listed species (Section 9); allows the Fish and Wildlife Service and National Marine Fisheries Service to issue a permit, accompanied by an approved habitat conservation plan, that allows for the incidental, non-purposeful "take" of a listed species under their jurisdictions (Section 10).
National Environmental Policy Act (NEPA)	Requires analysis of potential environmental impacts of proposed federal actions, such as approvals for exploration and production on federal lands.
Oil Pollution Act (OPA)	Identifies spill prevention requirements, reporting obligations, and response planning (measures that will be implemented in the case of release of oil or other hazardous substances).
Resource Conservation and Recovery Act (RCRA)	Addresses non-hazardous solid wastes under Subtitle D. The Solid Waste Disposal Act exempts many wastes produced during the development of natural gas resources, including drilling fluids and produced water. EPA determined that other federal and state regulations are more effective at protecting health and the environment.
Safe Drinking Water Act (SDWA)	Prevents the injection of liquid waste into underground drinking water sources through the Underground Injection Control (UIC) program. Fluids other than diesel fuel do not require a UIC permit. The UIC program gives requirements for siting, construction, operation, closure, and financial responsibility. Forty states control their own UIC programs.

1.3.1.1 Department of Interior

The DOI is a cabinet-level agency that manages America's vast natural and cultural resources through the operations of 11 technical bureaus. Of the DOI's bureaus, the Bureau of Land

Management (BLM), the National Park Service (NPS), and the U.S. Forest Service (USFS) each have responsibilities related to the enforcement of regulations for natural gas and oil wells drilled on public lands.

1.3.1.1.1 Bureau of Land Management

The BLM manages the U.S. government's onshore subsurface mineral estate—an area of about 700 million (MM) acres—from which sales of oil, gas, and natural gas liquids accounted for approximately 11 percent of all oil and 9 percent of all natural gas produced in the United States during fiscal year 2022.[j,k] About 23 of these 700 MM acres were leased to natural gas developers by the end of that year, and about 12.4 MM of those acres were producing natural gas in economic quantities (BLM, 2023).

From regulatory perspective, the BLM is responsible for 1) ensuring the environment of public lands remains protected and unaffected by natural gas production and other related activities and 2) managing natural gas development on federally owned lands. BLM published a rule regulating natural gas fracking on public lands on March 26, 2015—this rule was rescinded on December 28, 2017 (Fitterman, 2021).

On November 30, 2022, BLM proposed new regulations to reduce the waste of natural gas from venting, flaring, and leaks during oil and gas production activities on Federal and Indian leases (BLM, 2022). Key elements of the proposed rule include the following:

- Technology Upgrades: The rule would require the use of "low-bleed" pneumatic equipment as well as vapor recovery for oil storage tanks, where economically feasible. These requirements would reduce losses of natural gas from pneumatic equipment and storage tanks on federal and Indian leases.
- Leak Detection Plans: The rule would require operators to maintain a Leak Detection and Repair program for their operations on federal and Indian leases.
- Waste Minimization Plans: Requires the development of waste minimization plans demonstrating the capacity of available pipeline infrastructure to take the anticipated associated gas production. The BLM may delay action on, or ultimately deny, a permit to drill to avoid excessive flaring of associated gas.
- Monthly Limits on Flaring: Places time and volume limits on royalty-free flaring. Importantly, this includes a monthly volume limit on royalty-free flaring due to pipeline capacity constraints—the primary cause of flaring from Federal and Indian leases.

Drilling on federal or public lands is subject to oversight by federal agencies, and sections of the ESA may require that species of plants or animals not be threatened by the permitted drill site. Mandatory plans for mitigation and reclamation may be required to ensure that impacts on wildlife and habitat will be as minimal as possible.

[j] This area is held jointly by the BLM, USFS, and other federal agencies and surface owners.

[k] October 1, 2021, through September 30, 2022.

1.3.1.1.2 U.S. Forest Service

The USFS is responsible for managing access to, and the development of, federal oil and natural gas resources on approximately one-third of the over 150 national forests and grasslands. The Federal Onshore Oil and Gas Leasing Reform Act of 1987 grants the USFS authority to decide if the lands reserved from the public's domain can be leased for oil and gas development.[l] The USFS manages oil and gas activity according to the regulations at 36 CFR 228 Subpart E (USFS, 2023a). The purpose of these specific regulations is to set forth rules and procedures through which use of the federal surface lands in connection with operations authorized by the United States mining laws shall be conducted so as to minimize adverse environmental impacts.

1.3.1.1.3 National Park Service

Natural gas production and other related activities that will or do take place within the boundaries of America's national parks are managed by the NPS. Charged with protecting park resources and visitor values, the NPS helps to manage oil and gas operations following the 9B regulations. This set of regulations governs non-federal oil and gas activities and producing a final Environmental Impact Statement (EIS) for units of the national park system where oil and gas production occurs, or is likely to occur, in the foreseeable future (NPS, 2023).

1.3.1.2 Environmental Protection Agency

EPA is charged with regulating the air emissions covered under the CAA. EPA regulates several types of emissions relevant to the natural gas supply chain, including CH_4 emissions, criteria air pollutant emissions, and water and soil pollutants. EPA's New Source Performance Standards (NSPS) under the CAA set the regulations for emissions sources from the oil and natural gas sector. Exhibit 1-7 illustrates the scope of NSPS established or proposed to-date and the way regulations have evolved in scope since 2012 (EPA, 2021).

[l] Lands reserved from the public's domain include lands that have been withdrawn or reserved for use as part of the National Forests or National Grasslands or received in exchange for the same status of land (USFS, 2023b).

Exhibit 1-7. Natural gas sources covered by EPA's proposed NSPS and emissions guidelines, by site



[1]Covered for sulfur dioxide only; [2]Covered for volatile organic compounds only

Source: EPA (2021)

Following an initial proposal in November 2021, on December 6, 2022, EPA issued a supplemental proposal to update, strengthen, and expand standards intended to significantly reduce emissions of GHG and other harmful air pollutants from the Crude Oil and Natural Gas source category (EPA, 2022a). First, EPA proposed standards for certain sources that were not previously addressed. Second, EPA proposed revisions that strengthen standards for sources of leaks, provide greater flexibility to use innovative advanced detection methods, and establish a super-emitter response program. Third, EPA proposed to modify and refine certain elements of the proposed standards in response to information submitted in public comments. Finally, EPA proposed details of the timelines and other implementation requirements that apply to states to limit CH_4 pollution from existing designated facilities in the source category under the CAA (EPA, 2022a). Evaluation of this proposed rule is still in progress.

EPA's Greenhouse Gas Reporting Program (GHGRP) requires reporting of GHG emissions data and other relevant information by large sources of emissions, including fuel and industrial gas suppliers and CO_2 injection sites (EPA, 2023). The data reported is available to businesses, stakeholders, and others interested in tracking and comparing the GHG emissions of facilities, identifying opportunities to reduce emissions, minimizing wasted energy, and saving money. The petroleum and natural gas industry is covered under Subpart W of EPA's GHGRP. Unconventional natural gas production is covered under the provisions for onshore production, natural gas processing, natural gas transmission, and LNG storage and import/export. Annual CO_2, CH_4, and nitrogen oxides (NOx) emissions must be reported separately for each of these segments.

EPA studied the relationship between hydraulic fracturing for oil and natural gas and drinking water resources (EPA, 2022b). The study includes a review of published literature, analysis of existing data, scenario evaluation and modeling, laboratory studies, and case studies. EPA released a progress report in December 2012, a final draft assessment report for peer review and comment in June 2015, and the final report in December 2016. The final EPA report concludes that hydraulic fracturing activities can impact drinking water resources under some circumstances and identifies factors that influence these impacts.

Under the SDWA, EPA is charged with developing the minimum federal requirements for injection well practices to protect the public's health and prevent the contamination of underground sources of drinking water. A core element of the SDWA UIC program is setting requirements for proper well siting, construction, and operation to minimize risks to underground sources of drinking water. The Energy Policy Act of 2005 excluded hydraulic fracturing (except when diesel fuels are used) for oil, natural gas, or geothermal production from regulation under the UIC program. This statutory language caused regulators and the regulated community alike to raise questions about the applicability of permitting practices. As a result, EPA developed revised UIC Class II permitting guidance specific to oil and natural gas hydraulic fracturing activities using diesel fuels (EPA, 2022b). Although developed specifically for hydraulic fracturing where diesel fuels are used, many of the guidance's recommended practices are consistent with best practices for hydraulic fracturing in general, including those found in state regulations and model guidelines for hydraulic fracturing developed by industry and stakeholders. Thus, states and tribes responsible for issuing permits and/or updating regulations for hydraulic fracturing will find the recommendations useful in improving the protection of underground sources of drinking water and public health in general wherever hydraulic fracturing occurs. The guidance outlines for EPA permit writers, where they are the permitting authority, 1) existing Class II requirements for diesel fuels used for hydraulic fracturing of wells, and 2) technical recommendations for permitting those wells consistently with these requirements (EPA, 2022b).

EPA completed a stakeholder engagement effort in 2019 that sought input on how the agency, states, tribes, and stakeholders regulate and manage wastewater from the oil and gas industry. EPA released a draft report in May 2019 that described what it heard during its engagement for this study (EPA, 2022b). EPA accepted public input on the draft report and, after considering this input, published a final report in May 2020 (EPA, 2020). In many regions of the United States, underground injection is the most common method of managing fluids or other substances from shale gas extraction operations. Management of flowback and produced water via underground injection is regulated under the SDWA UIC program. The CWA effluent guidelines program sets national standards for industrial wastewater discharge to surface waters and municipal sewage treatment plants based on the performance of treatment and control technologies. Effluent guidelines for onshore oil and natural gas extraction facilities prohibit the discharge of pollutants into surface waters, although some permit exceptions may allow for discharge under unique conditions. On June 28, 2016, EPA promulgated pretreatment standards for the Oil and Gas Extraction Category (40 CFR Part 435). These regulations prohibit

discharge of wastewater pollutants from onshore unconventional oil and natural gas extraction facilities to publicly owned treatment works (POTWs).[m]

1.3.1.3 Department of Energy

The Natural Gas Act (NGA) requires DOE to make public interest determinations on applications to export LNG to countries where the United States does not have existing free trade agreements requiring national treatment for trade in natural gas. The Office of Fossil Energy and Carbon Management's (FECM) natural gas import–export regulatory program is implemented by the Division of Regulation in the Office of Regulation, Analysis, and Engagement. Typically, the Federal Energy Regulatory Commission (FERC) has direct regulatory responsibility over the siting, construction, and operation of onshore LNG export facilities in the United States. In these cases, FERC leads the environmental impact assessments of proposed projects consistent with NEPA, and DOE is typically a cooperating agency as part of these reviews (DOE, 2023a). Similarly, for offshore LNG export facilities, the Department of Transportation's (DOT) Maritime Administration (MARAD) is responsible for environmental reviews, in coordination with the U.S. Coast Guard, guided by requirements in the Deepwater Port Act. Again, DOE is typically a cooperating agency in these reviews. In some limited circumstances, DOE is the lead agency for NEPA reviews related to proposed LNG exports.

FECM's Point Source Carbon Capture Division's research, development, demonstration, and deployment portfolio facilitates the development of technologies and infrastructure that improve performance, reduce costs, and scale the deployment of technologies to decarbonize the industrial and power sectors and remove CO_2 from the atmosphere. Within the natural gas supply chain, these efforts include research and commercial-scale demonstration of technologies that advance carbon capture and storage on natural gas-fired power plants and industrial natural gas combustion streams (DOE, 2023a).

FECM is working to support efforts to decarbonize LNG terminals through exploration of technical and economic feasibility of carbon capture on gas separation and combustion streams and the use of electric motor drives supplied by net-zero emissions electricity. Decarbonizing LNG terminals is a key part of the effort to reduce life cycle emissions associated with the export of natural gas to global allies.

FECM's Methane Mitigation Technologies Division aims to eliminate non-trivial fugitive and vented CH_4 emissions from the natural gas supply chain to reduce the climate impacts from the production and use of natural gas. The division is focused on developing accurate, cost effective, and efficient technology solutions and best practices to identify, measure, monitor, and minimize CH_4 emissions from these sources. DOE funded several technology investigations through NETL that deal with produced water management and life cycle assessments of the natural gas value chain (DOE, 2023b). NETL's Natural Gas Infrastructure Field Work Proposal aims to strengthen natural gas pipeline reliability and reduce emissions on two fronts: quantifying GHG emissions and developing material and sensor technologies that will help to

[m] "Publicly owned treatment works" is a term used in the United States to designate a sewage treatment plant owned, and usually operated, by a government agency. In the United States, POTWs are typically owned by local government agencies and are usually designed to treat domestic sewage and not industrial wastewater.

mitigate these emissions. Research in this Field Work Proposal will also help address the reliability, public safety, operational efficiency, and flexibility of the America's aging natural gas infrastructure.

~~DOE's shale gas research program brings together federal and state agencies, industry, academia, non-governmental organizations (NGOs), and national laboratories to develop technologies that enable safe, environmentally sustainable oil and gas production. DOE's shale gas research program is tasked with calculating the risks of oil and gas exploration and production undertakings.~~

On April 21, 2023, a Request for Information (RFI) was issued by FECM to obtain input to inform DOE's research and development (R&D) activities within the Office of Research and Development's Methane Mitigation Technologies Division and the Office of Carbon Management Technologies' Point Source Carbon Capture Division. In addition, such data and information could help inform the Office of Regulation, Analysis, and Engagement's capabilities to assess natural gas import and/or export applications. Through the RFI, DOE requested information on strategies and technologies that natural gas and LNG companies are deploying, or could deploy, to reduce GHG emissions and other air pollutants associated with natural gas delivered to liquefaction facilities, housed at liquefaction facilities, and being loaded, transported, and delivered to regasification facilities (DOE, 2023a).

1.3.1.4 Occupational Safety and Health

The Occupational Safety and Health Administration (OSHA) establishes standards, directives (instruction to OSHA staff), letters of interpretation, and national consensus standards that pertain to employee safety within the oil and gas extraction industry (OSHA, 2023). OSHA standards are in place to limit employee exposures to hazards present during oil and gas well drilling, servicing, and storage. Regulations and standards related to site preparation activities, which include leveling the site, trenching, and excavation, are covered under 29 CFR 1926, while all other aspects drilling and servicing operations are covered by 29 CFR 1910 (OSHA, 2023).

1.3.1.5 Pipeline and Hazardous Materials Safety Administration

The Department of Transportation's Pipeline and Hazardous Materials Safety Administration (PHMSA) Office of Pipeline Safety is responsible for carrying out a national program to ensure the safe, reliable, and environmentally-sound operation of the nation's natural gas and hazardous liquid pipeline transportation system. PHMSA develops, proposes, and implements regulatory policy initiatives and regulations governing the safe operation of the nation's hazardous liquid and natural gas pipeline transportation system. The office also directs education and outreach efforts to promote the adoption and increased use of safety programs and activities by state and local governments, pipeline operators, and the general public in their efforts to enhance safety.

Commented [TC4]: Source: Office of Pipeline Safety | PHMSA (dot.gov)

1.3.2 States

States have the power to implement their own requirements and regulations for natural gas drilling that are equivalent to or more stringent than established federal practices.[n] All states that produce natural gas have at least one agency charged with issuing new permits for production wells. While state requirements for permits can differ, any requirements set forth by federal regulations must be met for a state-level permit to be issued. Beyond issuing new permits for production, states can also issue regulatory requirements for managing the potential environmental impacts of natural gas activities.

Although regulations, rules, and restrictions vary by state, in some cases, the actions taken by one or a subset of states have helped to both inform similar regulations imposed by other states and further refine some federal rules. A number of states, including Colorado, New Mexico, and Pennsylvania have adopted regulations to help manage GHG emissions including CH_4 and other air pollutants (e.g., volatile organic compounds) from oil and natural gas operations (Commonwealth of Pennsylvania, 2023b). Colorado, in particular, is ~~also~~ in the process of developing a rule focused on verifying GHG emissions intensity reporting (Colorado Department of Public Health & Environment, 2023).

In Oklahoma, using existing regulatory authorities, state regulators are expanding their technical guidance to inform operator efforts to sustainably manage produced water while reducing incidences of induced seismicity. For example, Oklahoma authorities have systemically identified areas of seismic concern and are 1) focusing resources where induced seismicity has previously occurred due to underground fluid injection activities, and 2) implementing new protocols for hydraulic fracturing, well completion, and wastewater disposal underground (Skinner 2018). As for land use and development considerations, there are permissible noise levels embodied in regulations that gas operators across Colorado must adhere to. For example, drilling, well stimulation and completion, as well as workovers, are now held to maximum permissible noise level standards for industrial zones.

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[n] Zirogiannis et al. (2016) developed a framework for comparing states based on how intensely they regulate unconventional gas development.

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2 GREENHOUSE GAS EMISSIONS

The primary GHG emissions associated with the natural gas supply chain steps of production through transport are emissions of CO_2 and CH_4. CO_2 emissions are primarily the result of fossil fuel combustion which is done to power equipment and operations. CH_4 emissions are the result of intentional and unintentional releases of natural gas as it moves through the supply chain. CH_4 is the primary component of natural gas. CO_2 and CH_4 emissions vary significantly across different regions and supply chains depending on the composition of the natural gas that is being produced, the type of equipment being used to process and transport the natural gas, and the number and size of intentional and unintentional releases of the natural gas.

2.1 OVERVIEW OF GHG EMISSIONS

The U.S. natural gas system encompasses hundreds of thousands of wells, hundreds of processing facilities, and over 1 MM miles of transmission and distribution pipelines. The EPA develops an annual report - the "Inventory of U.S. Greenhouse Gas Emissions and Sinks" – which tracks domestic GHG emissions and sinks by source and economic sector going back to 1990 (EPA, 2023a). The inventory (report) was last released in April 2023 and provided annual estimates up to the year 2021 (EPA, 2023a). Contained within the EPA's GHG Emissions Inventory (hereafter, GHGI) are annual estimates of the GHG emissions including CH_4, associated with natural gas systems.

EPA's April 2023 release of the GHGI ~~suggested~~ estimated that total GHG emissions (including CH_4, CO_2, and nitrous oxide [N_2O]) from natural gas systems in 2021 were 217.5 MM metric tons (MMT) of carbon dioxide equivalent (CO_2e), a decrease of 12 percent from 1990 and a decrease of 2 percent from 2020, both primarily due to decreases in CH_4 emissions. From 2010, emissions decreased by 3 percent, primarily due to decreases in estimated CH_4 emissions. Of the overall GHG emissions from natural gas systems (217.5 MMT CO_2e), 83 percent are CH_4 emissions (181.4 MMT CO_2e), 17 percent are CO_2 emissions (36.2 MMT CO_2e), and less than 0.01 percent are N_2O emissions (0.01 MMT CO_2e). Note that the GHGI reports emissions from engines and turbines used to power natural gas operations as part of its fossil fuel combustion estimate, those emissions are not included in these estimates. Exhibit 2-1 shows estimates of one GHG emission - CH_4 - by segment of the natural gas system (exploration through distribution) as reported by the GHGI.

Exhibit 2-1. EPA GHGI CH_4 emissions from natural gas systems (kiloton)

Segment	1990	2005	2017	2018	2019	2020	2021
Exploration	119	358	49	94	75	9	7
Production	2,311	3,495	3,697	3,823	3,739	3,475	3,360
Onshore Production	1,403	2,464	2,139	2,246	2,122	1,923	1,787
Gathering and Boosting	739	958	1,533	1,547	1,591	1,520	1,548
Offshore Production	170	73	26	30	25	32	24
Processing	853	463	460	483	506	495	510
Transmission and Storage	2,288	1,580	1,460	1,538	1,583	1,625	1,590

Commented [SM5]: This GHGI is an annual effort by EPA, this was just the latest version (31st version, so to speak). Also, GHGRP (mentioned in Chapter 1) plays a key role in the results represented.

SORRY, I see a few sentences later it says its annual - might want to move that up here before the April 2023 refeerence..

Commented [SM6R5]: One small note - they update the method for GHGI (and esp NG systems) alot. I am unsure whether they "redo past estimates" from newer methods. Point is, the raw GHG totals for the NG system may or may not be a good reference. Second point, the intensity is really what matters - if we believe EPA values, the intensity (emissions/MJ) are WAYYY lower than 1990.

Commented [HSAJ7R5]: Note for FECM/HQ - We've addressed Scott's first comment here but I want to leave this in just in case you'd like us to footnote the observation in his second comment, as it seems pretty important and determines whether we can compare estimates from year to year, and also to gather your thoughts on intensity estimates.

Commented [TC8]: Thanks for leaving the comment. I understand the point but don't want to get into calculating intensities here.

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Distribution	1,819	1,018	561	557	554	553	548
Post-Meter	290	344	424	445	457	463	463
Total	**7,680**	**7,260**	**6,652**	**6,939**	**6,914**	**6,619**	**6,478**

Note: To enable results comparison across exhibits, it is important to note the following conversion: 1,000 kiloton of CH_4 is equal to 1 Tg of CH_4.

The global warming potential (GWP) metric was developed to allow comparisons of the global warming impacts of different GHG emissions (e.g., CH_4, CO_2, and N_2O). Specifically, it is a measure of how much energy the emissions of 1 ton of a specific GHG will absorb over a given period, relative to the emissions of 1 ton of CO_2. The larger the GWP, the more that a given gas warms the Earth compared to CO_2 over that period. The period usually used for GWPs is 100 years. GWPs provide a common unit of measure, which allows analysts to add up emissions estimates of different gases (e.g., to compile a national GHG inventory), and allows policymakers to compare emissions reduction opportunities across sectors and gases (EPA, 2023b):

- CO_2, by definition, has a GWP of 1 regardless of the period used, because it is the gas being used as the reference. CO_2 remains in the climate system for a very long time: CO_2 emissions cause increases in atmospheric concentrations of CO_2 that will last thousands of years.
- CH_4 is estimated to have a GWP of 27–30 over 100 years. CH_4 emitted today lasts about a decade on average, which is much less time than CO_2. But CH_4 also absorbs much more energy than CO_2. The net effect of the shorter lifetime and higher energy absorption is reflected in the GWP. The CH_4 GWP also accounts for some indirect effects, such as the fact that CH_4 is a precursor to ozone, and ozone is itself a GHG.
- N_2O has a GWP 273 times that of CO_2 for a 100-year timescale. N_2O emitted today remains in the atmosphere for more than 100 years, on average.
- Chlorofluorocarbons, hydrofluorocarbons, hydrochlorofluorocarbons, perfluorocarbons, and sulfur hexafluoride are sometimes called high-GWP gases because, for a given amount of mass, they trap substantially more heat than CO_2. (The GWPs for these gases can be in the thousands or tens of thousands.)

Based on a review of the science of climate change, the Intergovernmental Panel on Climate Change (IPCC) estimated the GWP for CH_4 to be 36 over a 100-year period and 87 over a 20-year period in their Fifth Assessment Report (AR5) published in 2014 (IPCC, 2014). In the IPCC's Sixth Assessment Report (published in 2021), the IPCC revised the GWP estimates of CH_4 to be 29.8 over a 100-year horizon and 82.5 over a 20-year time horizon (IPCC, 2021). It is important to consider which GWP is used when reviewing the outputs of an analysis of GHG emissions, particularly when comparing the outputs of two or more analyses.

2.2 Sources of GHG Emissions

To account for all sources of GHG emissions in the natural gas supply chain, and to evaluate their relative contributions and mitigation opportunities, a systems-level perspective is both

necessary and preferred. Life cycle analysis (LCA) is one type of systems-level approach available to account for the different sources of GHG emissions in the natural gas supply chain. LCA specifically considers the material and energy flows of an entire system "from cradle to grave"—where "cradle" refers to the extraction of resources from the earth, and "grave" refers to the final use and disposition of all products. The two relevant standards for LCA are International Organization for Standardization (ISO) 14040 and ISO 14044. ISO 14040 describes the principles and framework for LCA, and ISO 14044 specifies requirements and provides guidelines for LCA.

Depending on the type of LCA conducted, different system boundaries can be put in place to more accurately estimate the GHG emissions associated with natural gas. Generally, GHG emissions occur from the beginning of the natural gas supply chain (during exploration) through the end (during utilization). In some cases, an LCA may not be able to consider every step of the natural gas supply chain within its analysis framework. This can happen for a variety of reasons, including lack of emissions data for a particular step or set of steps, or to focus specifically on the emissions associated with one particular step. Exhibit 2-2 provides an illustration of the natural gas supply chain with examples of key emissions sources.

NETL has used LCA to calculate the environmental impacts of natural gas production and use for the generation of electric power for nearly a decade (NETL, 2023). NETL's work was documented in a series of reports produced between 2010 and 2019.[9] Together, these reports provide in-depth assessments of the potential GHG emissions resulting from upstream unconventional natural gas production in the United States (NETL, 2019a). In addition to characterizing domestic upstream natural gas, NETL also developed life cycle data for exported LNG, including the GHG emissions from liquefaction, loading/unloading, ocean transport, regasification, and combustion for electricity generation (NETL, 2019b).

Commented [TC9]: I'm confused - are we referencing the forthcoming publication or the previous one? I appreciate Scott's offer to update. We need to see what is available when we get a publication date for this report.

Commented [SM10]: Just noting that we are finalizing (2023 pub date) an updated analysis for the year 2020, and are using it in the LNG Analysis side (Task 3) of the project.

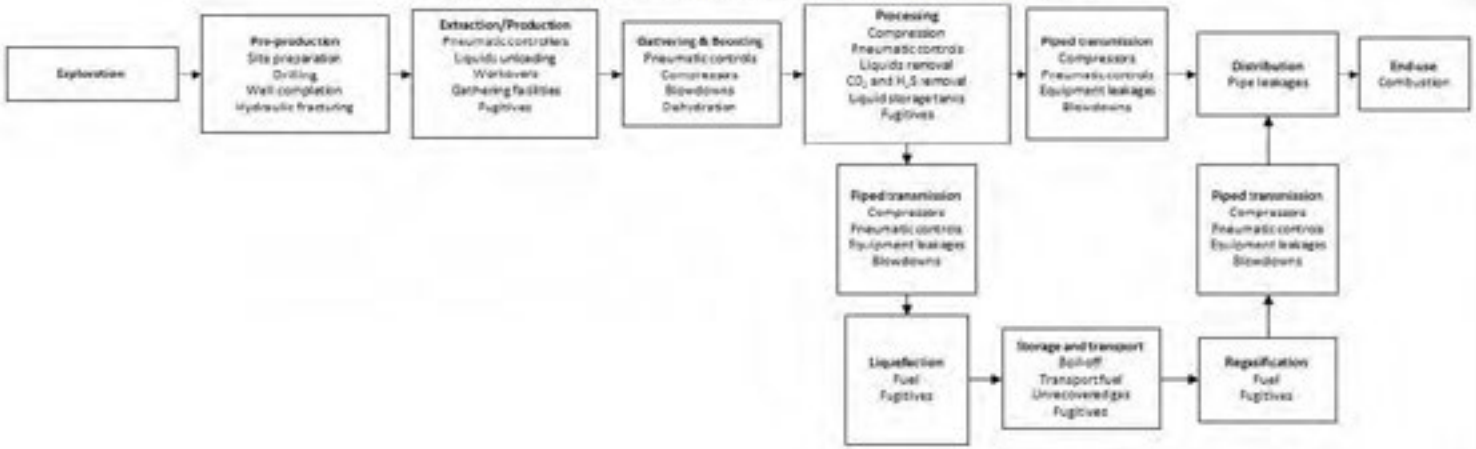
Commented [SM11R10]: Should there be a move to update this chapter based on it. It would be pretty easy. Numbers are in same places and format as in the 2019 report. Main differences are like the key emissions sources, etc..

Commented [SM12R10]: Regardless we could easily help.

Commented [HSAJ13R10]: Note for FECM- HQ: Also leaving this here for your consideration.

[9] The GHG results in the NETL (2019a) report supersede the GHG results in the previous NETL reports.

Exhibit 2-2. Natural gas supply chain with examples of key emissions sources



The GHG emissions results reported in past NETL natural gas LCAs consider five stages of the natural gas supply chain, which are visualized in Exhibit 2-3 (NETL, 2019a):

1. **Production:** Sources of emissions include the gas vented from pneumatically controlled devices and fugitive emissions from flanges, connectors, open-ended lines, and valves. When vapor recovery units are feasible, vented gas is captured and flared; otherwise, vented gas is released to the atmosphere. Production operations also include the combustion of natural gas and diesel in compressors and other equipment.
2. **Gathering and Boosting (G&B):** Natural gas G&B networks receive natural gas from multiple wells and transport it to multiple facilities. G&B sites include acid gas removal, dehydration, compressors operations, pneumatic devices, and pumps.
3. **Processing:** A natural gas processing facility removes impurities from natural gas, which improves its heating value and prepares it for pipeline transmission. Natural gas processing facilities include acid gas removal, dehydration, hydrocarbon liquids removal, and compression operations.
4. **Transmission Stations, Storage Facilities, and Transmission Pipelines:** A natural gas transmission system is a network of large pipelines that transport natural gas from processing facilities to the city gate (the point at which natural gas can be consumed by large-scale consumers or transferred to local distribution companies). Transmission stations are located along natural gas transmission pipelines and use compressors to boost the pressure of the natural gas. Large industrial users typically access natural gas directly from transmission pipelines.
5. **Distribution:** Natural gas distribution networks transport natural gas from the city gate to commercial, residential, and some industrial consumers. This analysis uses the distribution portion of the supply chain only for the upstream functional unit; distribution is not necessary for the functional unit of electricity in which natural gas power plants receive natural gas directly from transmission pipelines.

Exhibit 2-3. Supply chain stages that compose the overall LCA boundary



The flexible, consistent framework of NETL's LCA model allows different natural gas sources to be compared on a common basis (per MJ of delivered natural gas). In the NETL (2019a) report, five types of natural gas are considered:

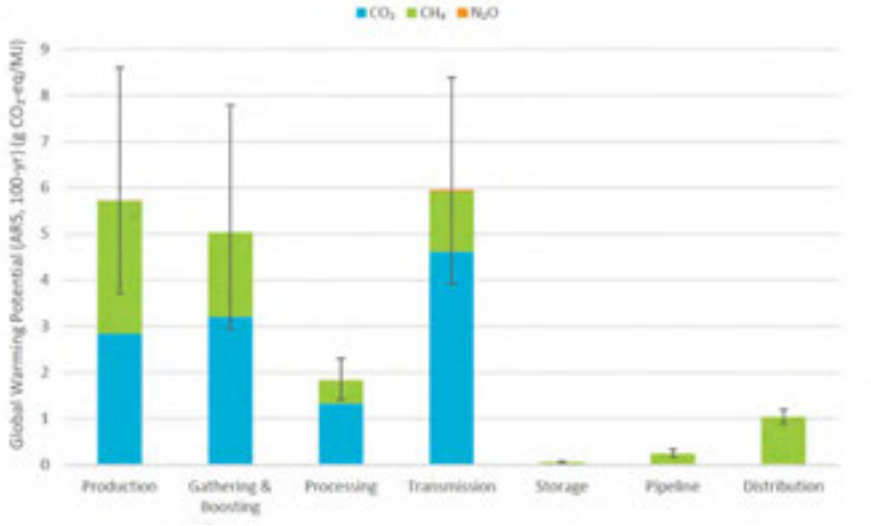
1. **Conventional natural gas** is natural gas extracted via vertical wells in high permeability formations that generally do not require, but can in some cases benefit from, stimulation technologies (e.g., hydraulic fracturing) for primary production.
2. **CBM** is extracted from coal seams and requires the removal of naturally occurring water from the seam before natural gas wells are productive.
3. **Shale gas** is extracted from low permeability formations and requires hydraulic fracturing and horizontal drilling.
4. **Tight gas** is extracted from non-shale, low permeability formations and requires hydraulic fracturing and directional drilling.
5. **Associated gas** is found with petroleum (either dissolved in oil or in a gas cap in a petroleum formation) and is produced by oil wells.

In the 2019 LCA analysis of the natural gas supply chain, NETL used the GWP reported in the IPCC AR5 (NETL, 2019a). Results from the 2019 NETL LCA analysis performed suggested the following (NETL, 2019a):

- The life cycle GHG emissions associated with the U.S. natural gas supply chain were 19.9 grams (g) of CO_2e per MJ of natural gas delivered (with a 95 percent mean confidence interval of 13.1–28.7 g CO_2e per MJ). The boundary used in this study was natural gas production through transmission to large end-users.
- The top contributors to CO_2 and CH_4 emissions were combustion exhaust and other venting from compressor systems. Compressor systems are prevalent in most stages of the natural gas supply chain and as such were key contributors to the total life cycle emissions estimated.
- Emissions rates are highly variable across the entire supply chain. According to the study, the national average CH_4 emissions rate was 1.24 percent, with a 95 percent mean confidence interval ranging 0.84–1.76 percent.

Exhibit 2-4 shows the GHG emissions from the different parts of the natural gas supply chain (NETL, 2019a).

Exhibit 2-4. Life cycle GHG emissions for the U.S. natural gas supply chain



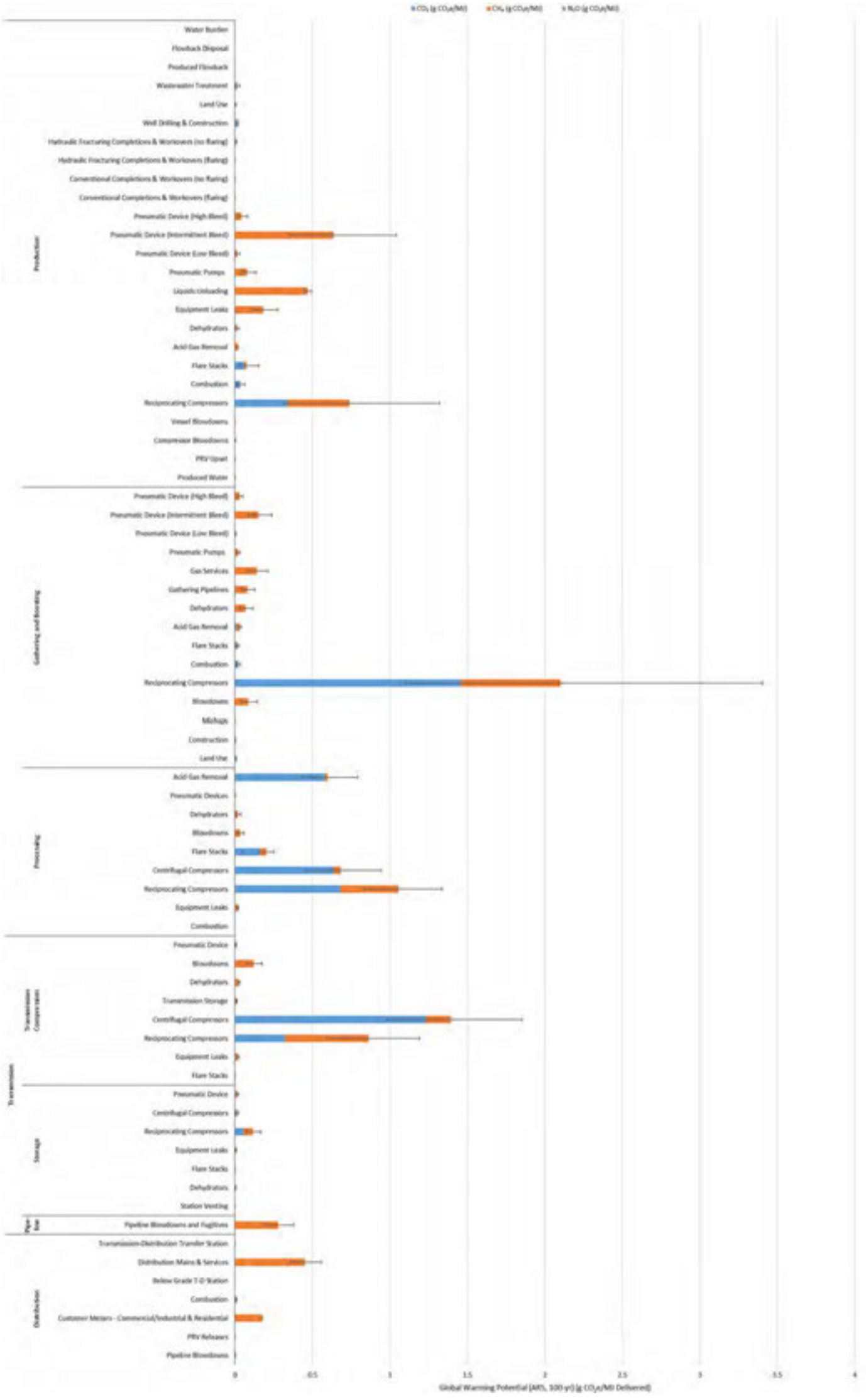
Key drivers of GHG emissions results for the entire U.S. gas supply chain in 2017 are illustrated in Exhibit 2-5 (Littlefield et al., 2020). Pneumatic devices and compression systems represent a significant portion of the total life cycle GHG emissions associated with the natural gas supply chain (NETL, 2019a).

Pneumatic devices are used to operate level controllers, valves, and other equipment at natural gas facilities. According to EPA's GHGI, pneumatics in the production segment emitted 1,060 kilotons of CH_4 in 2017, accounting for 16 percent of the total CH_4 emissions from the natural gas supply chain. Pneumatic device activity is concentrated at production facilities and there were 833,000 pneumatic devices used by U.S. production facilities in 2019 (Littlefield et al., 2020).

Natural gas is compressed for transport from processing facilities to end-consumers. As such, upstream GHG emissions are sensitive to pipeline distances and the number of compressors along these pipelines that the natural gas must pass through. The energy intensity of compression and the fugitive CH_4 emissions from compressors both contribute to upstream GHG emissions (NETL, 2019a).

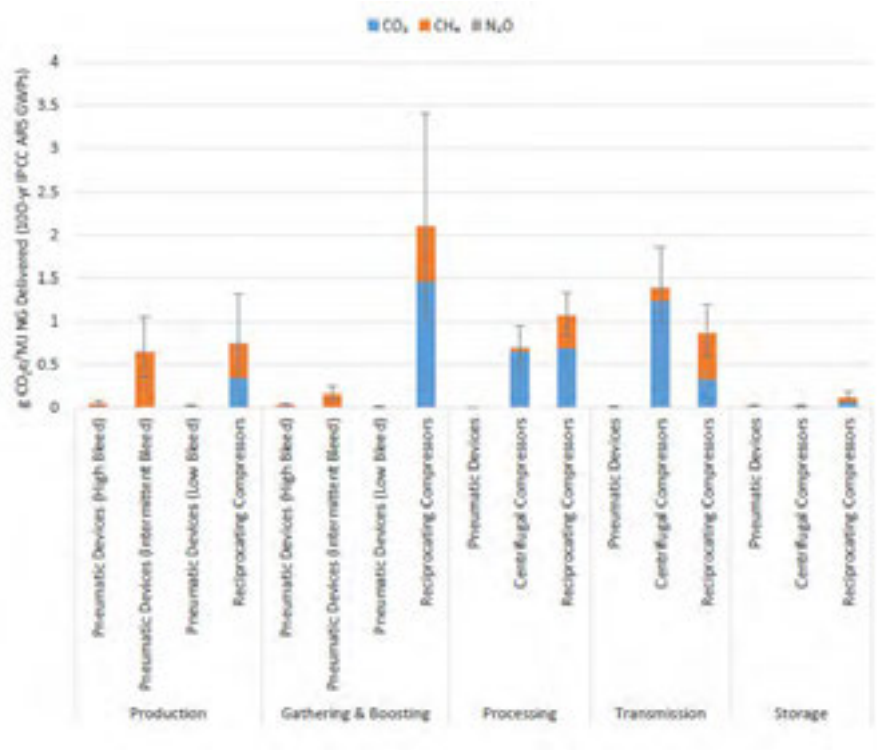
In addition to being a source of CH_4 emissions, compressors are also a source of CO_2 emissions. Most compressors in the U.S. pipeline transmission network are powered by natural gas that is withdrawn from the pipeline itself. Electric motors are not widely used by natural gas pipelines but are installed where local emissions regulations limit the use of internal combustion engines or where inexpensive electricity is available. Nationwide in 2017, 6 percent of compressor stations were powered by electricity, 77 percent were powered by natural gas, and 17 percent were dual gas and electric (Littlefield et al., 2020).

Exhibit 2-5. U.S. average for 2017—detailed GHG emissions sources for the U.S. natural gas supply chain (gCO_2e/MJ)



Two sources of CH_4 emissions from compressor systems include 1) uncombusted CH_4 that slips through the compressor exhaust stream and 2) CH_4 that escapes through compressor seals or packing. Natural gas systems use both centrifugal and reciprocating compressors. Centrifugal compressors are more appropriate for pressure boosting applications in steady-state applications (such as with a transmission pipeline), while reciprocating compressors are more appropriate when gas flow is variable and when large increases in pressure are required. Centrifugal compressors are typically driven by gas-fired turbines but, in some instances, are driven by an electric motor. Reciprocating compressors are driven by gas-fueled engines. Exhibit 2-6 illustrates the emissions associated with pneumatic devices and compressors (Littlefield et al., 2020).

Exhibit 2-6. GHG emissions from pneumatic devices and compressors across the natural gas supply chain (gCO_2e/MJ)



For all natural gas production types, the GHG emissions results produced by an LCA are sensitive to the following factors:

- Estimated ultimate recovery

- Regional natural gas composition differences (dry versus sour gas)
- Compression energy requirements and type
- Pneumatic device type, frequency, and number of devices per operation

In the same NETL (2019a) report, NETL analyzed the N_2O emissions at each stage of the natural gas supply chain. The analysis found a total of 0.14 milligrams (mg) of N_2O were emitted per MJ of natural gas delivered (Exhibit 2-7). The largest contributor (86 percent) to this total number was N_2O emissions that occur during the transmission stage.

Commented [SH14]: Since N2O is more relevant in the discussion of GHGs, I have moved this up from Chapter 3.

Commented [SH15R14]: Open to removal if DOE HQ team feels this is not worth a specific call-out

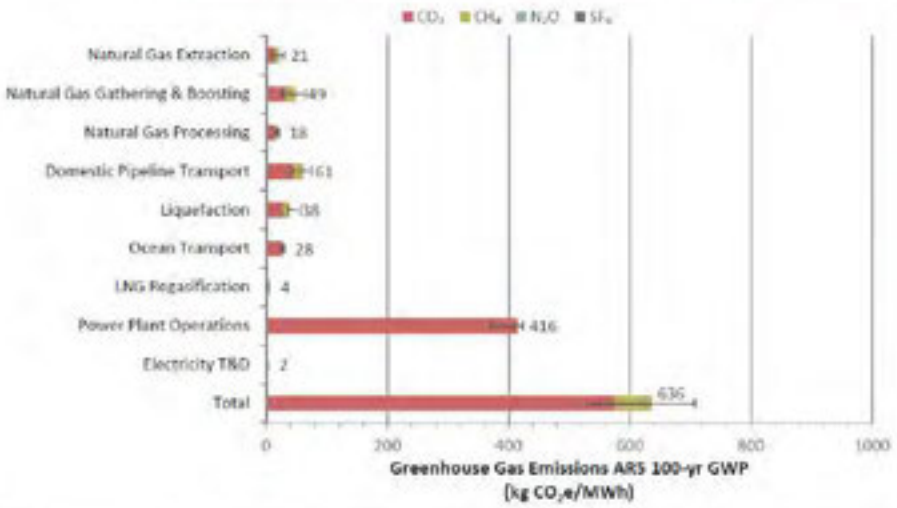
Commented [TC16]: This is fine to keep.

Exhibit 2-7. N_2O emissions across the natural gas supply chain

Stage of Natural Gas Supply Chain	N_2O Emissions (mg/MJ)
Production	0.016
G&B	< 0.0001
Processing	0.0047
Transmission	0.12
Storage	< 0.0001
Pipeline	< 0.0001
Distribution	< 0.0001
Total	*0.14*

~~In addition to its characterization of domestic upstream natural gas, NETL also developed life cycle data for exported LNG, including the GHG emissions from liquefaction, transport, regasification, and combustion for electricity generation (NETL, 2019b). The NETL (2019b) report that analyzed the lifecycle emissions of exporting U.S. LNG to Europe yielded the emissions results (assuming end-use in electricity generation) detailed in Exhibit 2-8.~~

~~Exhibit 2-8. GHG emissions from exporting LNG from the United States to Europe~~



Commented [TC17]: I don't think this is necessary and might be confusing since the graphic includes power generation using the gas. If we need this information, we can refer to the 2019 LNG study directly as it is part of the docket for the regulatory program.

2.3 METHANE EMISSIONS STUDIES

There are two primary approaches used to estimate CH_4 emissions as part of an LCA: 1) top-down and 2) bottom-up (Rutherford et al., 2021; Alvarez et al., 2018; Balcombe et al., 2016). A top-down approach a) measures the atmospheric concentrations of CH_4 as reported by fixed ground monitors, mobile ground monitors, aircraft, and/or satellite monitoring platforms; b) aggregates the results to estimate total CH_4 emissions; and c) allocates a portion of these total emissions to each of the different supply chain activities. A bottom-up approach measures GHG emissions directly from each source of emissions, then aggregates and extrapolates these measurements to estimate emissions for an entire region or process. Both approaches have advantages and disadvantages.

Top-down approaches (see Rutherford et al., 2021; Alvarez et al., 2018; Balcombe et al., 2016) tend to report higher emissions from natural gas systems as compared to bottom-up approaches. There are several factors that may lead to these results, which can be generally explained as follows:

- Top-down approaches capture more emissions sources by covering an entire area. However, depending on the methodology, these approaches sometimes fail to distinguish between different sectors. For example, aircraft that are used to collect emissions data for a particular area may struggle to distinguish between the CH_4 emissions coming from a natural gas processing facility in the area from those coming from a nearby dairy farm. This can lead to incorrect contributions of total CH_4 emissions to specific natural gas activities.

- Bottom-up approaches sometimes fail to capture infrequent high emitting events such as malfunctioning or improperly operated equipment. Because bottom-up approaches measure emissions from individual sources, it can be challenging to accurately capture the contributions of infrequent events to total emissions.

Considerable recent and ongoing research has been devoted to understanding and reconciling the differences between top-down and bottom-up approaches to estimating CH_4 emissions. Example studies include the following:

- The Colorado State University (CSU) Energy Institute's Basin Methane Reconciliation Study—commissioned by NETL, through the Research Partnership to Secure Energy for America (RPSEA) program—was designed to understand, and potentially reconcile, the persistent gap between top-down and bottom-up CH_4 emissions estimates for production regions (CSU, 2018; Vaughn et al., 2018). To minimize the potential shortcomings of prior studies, the Basin Methane Reconciliation Study was designed as a first of its kind to conduct contemporaneous measurements at the device, facility, and regional scales, with site access and activity and emissions data input from local natural gas operators. The study was a multi-agency research project that drew from the scientific expertise of CSU, Colorado School of Mines, University of Colorado-Boulder, the National Oceanic and Atmospheric Administration, and the National Renewable Energy Laboratory. The University of Wyoming, AECOM, Aerodyne, and GHD Engineering also participated in the study.
- In 2019, Environmental Defense Fund launched the Permian Methane Analysis Project (PermianMAP), a first-ever, near real-time CH_4 monitoring initiative in the world's largest oil field (Environmental Defense Fund, 2021; Lyon et al., 2021). Researchers first began collecting aerial CH_4 data in late fall of 2019 and conducted more than 100 flights across the Basin throughout 2020 and 2021. Some flights encompassed the full perimeter of the 10,000 square kilometers (km^2) study area. Others zeroed in on a cluster of randomly selected wells. Carbon Mapper researchers partnered with the PermianMAP project in the summer and fall of 2021, detecting nearly 1,700 plumes over 26 flight days. Leak Surveys Inc., a veteran leak detection company, used a helicopter equipped with an infrared camera to conduct surveys of more than 3,000 flares across the entire Permian Basin to determine their contribution to the region's CH_4 emissions.

Alvarez et al. (2018) note that in many bottom-up approaches to modeling, operator cooperation is required to obtain site access for accurate emissions measurements. Operators with lower-emitting sites are plausibly more likely to cooperate with such studies and workers are plausibly more likely to be careful to avoid errors or fix problems when measurement teams are on site or about to arrive, which could lead to a downward bias in estimates of potential emissions (Rutherford et al., 2021; Alvarez et al., 2018; Balcombe et al., 2016).

Balcombe et al. (2016) document the wide range of CH_4 emissions estimates across the natural gas supply chain. Significant drivers of this wide range of projections are 1) the emissions associated with natural gas production, and 2) whether the natural gas is ultimately converted to LNG. The following sub-sections explore these different segments of the supply chain.

2.3.1 Natural Gas Production Analyses

Commented [TC18]: The studies here are not only production studies - I don't think the subheader is needed. the information connects to the previous section.

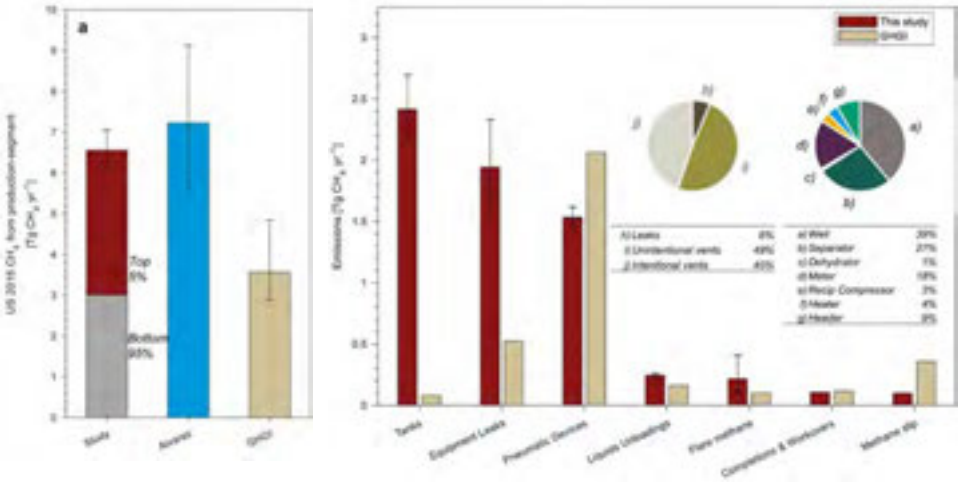
EPA estimates oil and natural gas CH_4 emissions in the annual GHGI it produces. The GHGI uses a bottom-up approach to estimate national CH_4 emissions. Several studies have found that CH_4 emissions from the natural supply chain are about 1.5–2.5 times the amount reported in EPA's GHGI (Rutherford et al., 2021; Alvarez et al., 2018; Balcombe et al., 2016). Much of the discrepancy can be attributed to differences in the analyses performed for the production segment of the natural gas supply chain where infrequent, high emissions events, or "super emitters," and emissions-intensive equipment are prevalent (Rutherford et al., 2021; Alvarez et al., 2018; Balcombe et al., 2016).

To isolate specific sources of disagreement between EPA's GHGI and other studies, Rutherford et al. (2021) reconstructed EPA's GHGI emissions factors, beginning with the underlying datasets, and identified possible sources of disagreement between inventory methods and top-down studies. The adjusted emissions factors are direct inputs in the Rutherford et al. (2021) study outputs. Rutherford et al. use a bottom-up measurement approach, yet the approach differs from the GHGI in that it applies a bootstrap resampling statistical approach to allow for inclusion of infrequent, large emitters, thereby incorporating data on super emitters in a more robust way.

Rutherford et al. (2021) estimate the mean, production-normalized emissions rate from the production segment as 1.3 percent (1.2–1.4 percent at 95 percent confidence interval, based on gross natural gas production of 32 Tcf and an average CH_4 content of 82 percent), slightly lower than Alvarez et al., 2018) who estimate it at 1.4 percent. Rutherford et al. (2021) estimate mean natural gas production-segment CH_4 emissions as equal to 6.6 teragrams (Tg) per year (6.1–7.1 Tg per year, at 95 percent confidence interval). Both the results of Rutherford et al. (2021) and Alvarez et al. (2018) are approximately two times larger than estimates of the 2015 EPA GHGI, which suggests that 3.6 Tg of emissions per year (year 2015 data, excludes offshore systems) come from the natural gas production segment.

Given that the Rutherford et al. (2021) results match Alvarez et al.'s (2018) site-level results, the former concludes that the divergence between the GHGI and top-down/site-level studies is not likely to be due to any inherent issue with the bottoms-up approach. A results comparison of the Rutherford et al. (2021) study, the Alvarez et al. (2018) study, and 2015 EPA GHGI data can be found in Exhibit 2-8.

Exhibit 2-8. Comparison of GHG emissions results from Rutherford et al., Alvarez, et al., and EPA GHGI



Note: "This study" and "Study" labels on the x-axis refer to Rutherford et al. (2021)

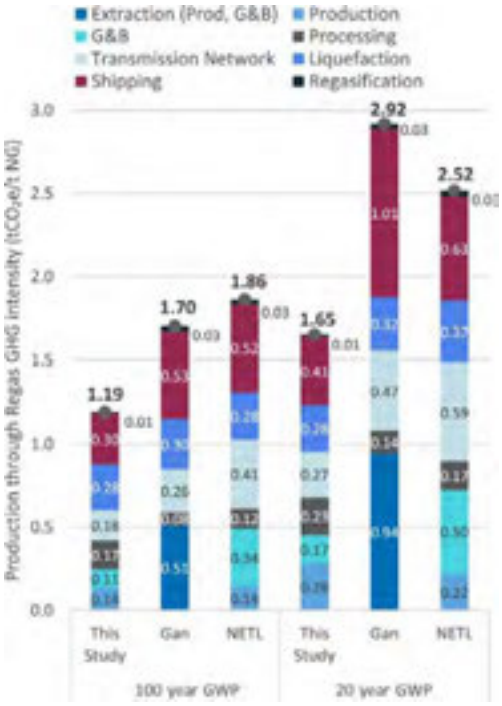
Used with permission from Rutherford et al. (2021)

Littlefield, Rai, and Skone (2022) provide a detailed life cycle perspective on GHG emissions variability where natural gas is produced and where it is delivered (via pipeline). They disaggregate transmission and distribution infrastructure into six regions, balance natural gas supply and demand locations to infer the likely pathways between production and delivery (estimated via modeling as actual tracking of natural gas from well to customer is not technically feasible), and incorporate new data on distribution meters. They find the average transmission distance for U.S. natural gas is 815 kilometers (km) but ranges 45–3,000 km across estimated production-to-delivery pairings examined (Littlefield, Rai, and Skone, 2022). In terms of total GHG emissions, their results suggest the delivery of 1 MJ of natural gas to the Pacific region has the highest mean life cycle GHG emissions (13.0 gCO_2e/MJ) and the delivery of natural gas to the Northeastern region of the United States has the lowest mean life cycle GHG emissions (8.1 gCO_2e/MJ).

~~2.3.2~~2.3.1 LNG Studies

At the end of 2020, Cheniere Energy was the largest exporter of LNG from the United States in terms of volume. Roman-White et al. (2021) developed an LCA framework to estimate GHG emissions representative of Cheniere's LNG supply chain, considering both upstream and downstream sources of emissions from Cheniere's Sabine Pass Liquefaction facility, using supplier-specific data collected from wellhead through ocean transport. Roman-White et al. (2021) compare the GHG emissions intensity of Cheniere LNG to two similar assessments of emissions intensity from U.S. LNG transported to China (Gan et al., 2020; NETL, 2019b). The results of their comparison are illustrated in Exhibit 2-9.

Exhibit 2-9. Comparison of GHG emissions results from Roman-White et al., Gan et al., and NETL



Used with permission from Roman-White et al. (2021)

Note: "This study" labels on the x-axis refer to Roman-White et al. (2021)

The NETL (2019b) LNG study uses more recent production emissions data (2016 data) than Gan et al. (2020). The NETL (2019b) study is based on natural gas production in Appalachia with relatively low emissions intensity. The NETL analysis differs from the Roman-White et al. (2021) study primarily in the intensity of the G&B and transmission stages, which are driven by differences in individual facility performance.

When modeling transmission compression, the NETL (2019b) study assumes a factor of 0.97 horsepower-hour (HPh)/thousand cubic feet (Mcf) to estimate the transmission station throughput (derived from NETL-published parameters). The average ratio of HPh to Mcf of throughput, from Cheniere Energy's known suppliers (used in the Roman-White et al. study) is 0.27 HPh/Mcf, which is based on supplier data collection completed. For modeling gas from other transmission operators, the GHGRP does not publicly provide the throughput of compressor stations. The Roman-White et al. (2021) study assumes 0.29 HPh/Mcf based on data reported by EIA.

The higher factor used by the NETL (2019b) study results in increased modeled fuel consumption across the transmission network. The Roman-White et al. liquefaction GHG

intensity is 8–13 percent less than the intensity estimated by Gan et al. and is comparable to the NETL (2019) study estimate on a 100-year basis. The Roman-White et al. (2021) study concludes ocean transport stage emissions intensity is 42–60 percent less than the transport emissions intensity of Gan et al. (2020), and 35–42 percent less than that of the NETL (2019b) study. A separate study from Abrahams et al. (2015) notes that emissions from the shipping of LNG exports from the United States to ports in Asian and European markets account for only 3.5−5.5 percent of precombustion life cycle emissions; hence, Abrahams et al. (2015) concludes that shipping distance is not a major driver of GHGs in the LNG supply chain.

Jordaan et al. (2022) estimate global average life cycle GHG emissions from the delivery of gas-fired electricity to be 645 gCO_2e per kilowatt hour (kWh) (334–1,389 gCO_2e per kWh), amounting to 3.6 gigatonne CO_2e per year in 2017 (10 percent of energy-related emissions). This result is comparable to the results obtained by Roman-White et al. (2021), who report life cycle GHG emissions of 524 gCO_2e kWh for electricity produced in China using LNG supplied by U.S. LNG exporter Cheniere Energy, and 636 gCO_2e per kWh reported by NETL (2019b). Exhibit 2-10 summarizes these results.

Exhibit 2-10. LCA results comparison of LNG-derived electricity

LNG LCA Study	Mean gCO_2e per kWh
NETL (2019b)	636
Roman-White et al. (2021)	524
Jordaan et al. (2022)	645

Across these studies, the primary difference in the GHG results comes from assumptions about emissions associated with natural gas extraction and G&B portions of the natural gas supply chain.

2.4 Methane Emissions Research and Development

DOE's Methane Mitigation Technologies program aims to eliminate non-trivial CH_4 emissions from the oil and gas supply chain by 2030. These non-trivial CH_4 emissions include CH_4 production, processing, transportation, and use.

The Methane Mitigation Technologies program is focused on developing accurate, cost-effective, and efficient technology solutions and best practices to identify, measure, monitor and eliminate CH_4 emissions from these sources. Methane mitigation R&D efforts include advanced materials of pipeline construction, monitoring sensors, data management systems, and more efficient and flexible compressor stations. Research efforts for CH_4 emissions quantification focus on developing technologies to detect, locate, and measure emissions. This includes the development and validation of measurement sensor technologies for the collection, dissemination, and analysis of emissions data, which will inform efforts, such as the GHGI and orphan well remediation programs of EPA and DOI, respectively. The following three areas comprise DOE's current research, development, and demonstration (RD&D) efforts to identify, address, and reduce oil and natural gas sector emissions.

- Methane Emissions Quantification — activities focus on direct and remote measurement sensor technologies, data acquisition, research, and advanced analytics that quantify CH_4 emissions from point sources along the upstream and midstream portion of the natural gas value chain.
- Methane Emissions Mitigation — project investments and activities aim to develop advanced materials, data management tools, inspection and repair technologies, and advanced compressor technologies for eliminating fugitive CH_4 emissions across the natural gas value chain.
- Undocumented Orphaned Wells — cooperative RD&D efforts involving the Interstate Oil and Gas Compact Commission (IOGCC) are designed and implemented to assist the Federal land management agencies, States, and Indian Tribes in identifying and characterizing undocumented orphaned wells, primarily by developing and testing innovative technologies and approaches that locate and characterize orphaned wells to enable well plugging efforts being administered under DOI's Orphaned Well Plugging Program.

There are several mitigation measures available to address the GHG emissions from the natural gas supply chain, including equipment upgrades and process optimization.[p] Additionally, advancing technologies to detect and measure fugitive and vented CH_4 emissions can help to identify leaks and super emitters.

2.4.1 Detection and Measurement

Alvarez et al. (2018) note that key aspects of effective mitigation include pairing well-established technologies and best practices for routine emissions sources with economically viable systems to rapidly detect the root causes of high emissions arising from abnormal conditions. The latter could involve combinations of current technologies, such as on-site leak surveys by company personnel using optical gas imaging, deployment of passive sensors at individual facilities or mounted on ground-based work trucks, and in situ remote-sensing approaches using tower networks, aircraft, or satellites. Over time, the development of less failure-prone systems would be expected through repeated observation of, and further research into, common causes of abnormal emissions, followed by reengineered design of individual components and processes.

Roman-White et al. (2021) note that for LNG, harmonized data collection and reporting would build confidence in supplier claims about LCA emissions, enabling comparisons between natural gas supply chains and supporting climate goals for all participants in the supply chain. This could stimulate a virtuous cycle of demand for GHG accounting and reduction and provision of more granular, company-specific emissions estimates.

According to Stern (2022), three major requirements for creating credible measuring, reporting, and verification of CH_4 emissions are 1) to move measurement and reporting of CH_4 emissions from standard factors—either engineering-based or from EPA data—to empirical (Tier 3)

[p] Examples of equipment upgrades in this context include compressor seals, reciprocating compressors, and pneumatic controls.

measurements, and to reconcile bottoms-up (ground level) and top-down (satellite/aircraft/drone) observations; 2) to ensure that data measurement and reporting has been verified and certified by accredited bodies; and 3) to require asset-level emissions data to be transparent and publicly available. Failure to do so on grounds of commercial confidentiality risks being interpreted as evidence that the data is not credible.

2.4.2 Equipment Upgrades and Process Optimization

Compressor seals include wet seals used by centrifugal compressors and rod packing used by reciprocating compressors. Wet seals surround the rotating shaft of a centrifugal compressor with oil, which prevents gas leakage from the compressors. The oil used by wet seals must be continuously regenerated, which releases CH_4 into the atmosphere. By replacing wet seals with mechanical dry seals, the CH_4 emissions from centrifugal compressors can be reduced.

Reciprocating compressors prevent CH_4 leakage by encasing each compressor rod with a set of oil-coated, flexible rings. Proper maintenance and routine replacement of these rings prevents unnecessary leakage of CH_4. Storage tanks hold flowback water and liquid hydrocarbons recovered from the production stream. Variable loading levels and temperatures cause the venting of CH_4 and other gases from these tanks. By installing vapor recovery units on storage tanks, producers can more effectively reduce emissions from natural gas production. The captured emissions can be combusted on site to provide process energy, or they can be channeled to the sales stream.

Pneumatic controllers use gas pressure to open and close valves throughout a natural gas production and processing system. Natural gas is commonly used to pressurize pneumatic control systems. The bleeding of natural gas from pneumatic controllers leads to venting CH_4 to the atmosphere. The GHG impact of pneumatic control systems can be reduced by installing pneumatic systems that use pressurized air instead of pressurized natural gas.

Regulations mandate emissions reductions from pneumatically controlled valves and compressor seals. The data suggest that the use of this equipment reduces completion emissions by approximately 75–99 percent.

The practice of reduced emissions completions (RECs) utilizes equipment that allows the capture of gas during flowback, either to be sent to the product line or, if this is not feasible, to be flared. In the United States, the use of RECs is compulsory by law. REC implementation has shifted the emissions from CH_4 to CO_2; there is evidence it has reduced the GHG intensity of completions (Balcombe et al., 2016; Balcombe, Brandon, and Hawkes, 2018).

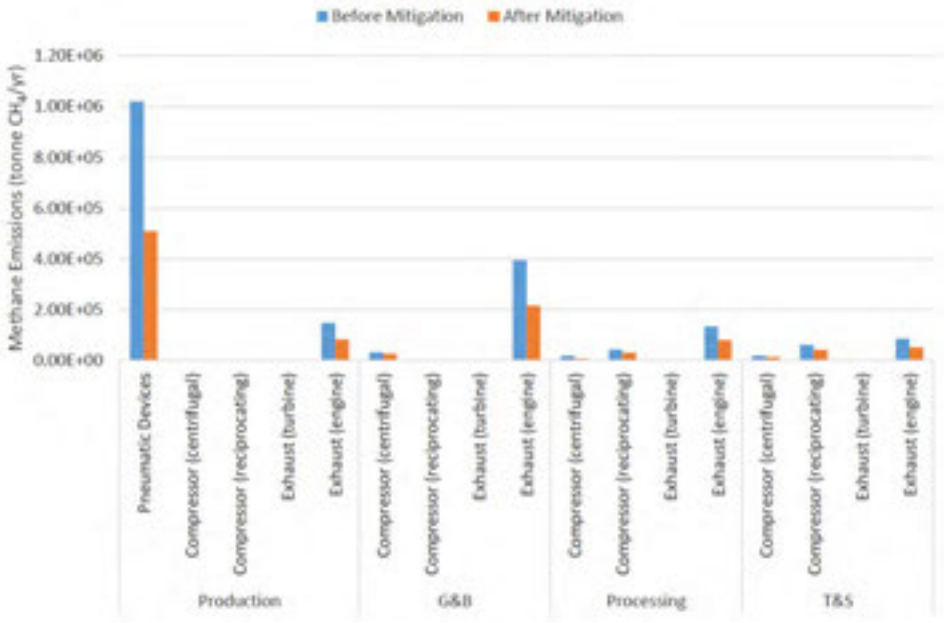
A 2020 report produced by NETL—Littlefield et al. (2020)—notes that compressed-air pneumatics are a mature technology that can reduce CH_4 emissions from pneumatic systems. The technology replaces existing devices, which are actuated by natural gas, with devices that are actuated with compressed air. This requires the addition of electric-powered air compressors at natural gas facilities but can result in zero CH_4 emissions from pneumatics. The same report notes that proven technologies exist for reducing CH_4 emissions from compression systems (as described below):

- Centrifugal compressors emissions can be reduced by replacing wet seals with dry seals. These seals are used around the rotating shaft of the compressor and prevent high pressure gas from escaping the compressor. Wet seals involve the use of recirculating oil that emits 40–200 standard cubic feet (scf) of natural gas per minute (min). Dry seals use gas to seal the compressor shaft and emit only 6 scf/min. The replacement of wet seals with dry seals reduces centrifugal compressor emissions by 85–97 percent.
- Reciprocating compressor emissions can be reduced by replacement of rod packing. Packing prevents gas from moving around piston rods and escaping the compression cylinder. New packing that is properly installed on a well-maintained compressor will emit about 12 scf/hour. The emissions rate for old or poorly installed packing can range 25–67 scf/hour. When compared to the emissions rate for new packing, this equates to potential emissions reductions of 52–82 percent. Rod packing replacement is a mature technology, but there are new technologies that can also reduce reciprocating engine exhaust slip. These new technologies include advanced materials that increase piston rod service life while reducing rod wear and Teflon-coated rings that reduce friction while maintaining a tight seal. There are no data currently available, however, on the emissions reduction potential tied to deploying these new technologies.
- The majority of the CH_4 emissions from reciprocating compressors are due to the CH_4 slip from engine exhaust. Comparing the exhaust emissions factors for rich burn and lean burn engines,[q] respectively, shows that rich burn engines have a combustion effectiveness of 97 percent and lean burn engines have combustion effectiveness of 99 percent. Air-fuel-ratio controls are an option for improving the combustion effectiveness of lean burn engines while keeping NOx emissions low. More research is required to understand the limits of air-fuel-ratio controls but, for this analysis, it is assumed that they can increase the combustion effectiveness of a lean burn engine by 97–99 percent.

Exhibit 2-11 illustrates the potential impact of these mitigation approaches (Littlefield et. al 2020).

[q] The terms rich-burn and lean-burn simply refer to the way in which the engine burns fuel—the air-to-fuel ratio. A rich-burn engine is characterized by excess fuel in the combustion chamber during combustion; a lean-burn engine is characterized by excess air in the combustion chamber during combustion.

Exhibit 2-11. Illustration of mitigation measure impact for pneumatic devices and compressors



Balcombe, Brandon, and Hawkes (2018) note that pre-emptive maintenance and a faster response to detection of high emissions are methods for reducing the impact of super emitters. Identifying a cost-effective solution is imperative, and much attention is being given to developing lower cost emissions monitoring and detection equipment. As Brandt, Heath, and Cooley (2016) point out, identifying larger leaks from the highest emitters may be carried out using less sensitive, and consequently cheaper, detectors in areas representing the highest risk.

2.4.3 Liquefaction Emissions Mitigation Measures

With respect to liquefaction, Mokhatab (2014) note that most of the plant energy consumption and resultant emissions in natural gas liquefaction facilities occur in the compressor drivers, where fuel energy (usually natural gas) is converted to mechanical work (or electricity in case of electrically driven compressors). Due to the energy consumption scale of the LNG plants, any enhancement to the energy efficiency of a plant will result in a significant reduction in gas consumption and consequently CO_2 emissions (Mokhatab, 2014).

There are two ways to increase the energy efficiency of LNG plants: 1) liquefaction cycle enhancement and 2) driver cycle enhancement. Liquefaction cycle enhancements reduce compressor power and consequently the compressor driver's fuel consumption. Driver cycle enhancement reduces the amount of fuel consumption to generate a specific amount of power.

Typical fuel sources for natural gas liquefaction cycles include either pure refrigerant in cascade cycles, expansion-based cycles, or mixed refrigerant cycles.

Pure refrigerant cycles have a constant evaporating temperature that is a function of the saturation pressure. Mixed refrigerant cycles do not maintain a constant evaporating temperature at a given pressure. Their evaporating temperature can range and change depending on the pressure and composition. A refrigerant mixture of hydrocarbons and nitrogen is chosen so that it has an evaporation curve that matches the cooling curve of the natural gas with the minimum temperature difference. Therefore, small temperature differences reduce entropy generation and, thus, improve thermodynamic efficiency, reduce power consumption, and reduce the emissions associated with liquefaction facilities (Mokhatab 2014).

A study from Pospíšil et al. (2019) notes that a certain part of the energy spent on liquefaction can be recovered by the utilization of the cold stream from LNG. The amount of usable cold is given by thermophysical properties of natural gas and corresponds to 830 kilojoule (kJ)/kg of LNG. This cold energy can be recovered during the regasification process.[r] Regasification is carried out either in port terminals before natural gas is transported via gas lines or directly before the use of natural gas. The exploitation of cold from LNG is quite limited at present. Most of the available cold is wasted during the regasification process when LNG is heated up by water or ambient air. Inefficient use of cold temperature streams reduces the overall efficiency of this primary energy source and leads to greater emissions. Pospíšil et al. (2019) recommends that promising ways of utilizing cold from LNG in the regasification process should be explored and implemented (Pospíšil et al., 2019).

As noted in the introduction, in April 2023, FECM issued an RFI to obtain input to inform DOE's R&D activities related to information on strategies and technologies that natural gas and LNG companies are deploying, or could deploy, to reduce GHG emissions and other air pollutants associated with natural gas delivered to liquefaction facilities, housed at liquefaction facilities, and being loaded, transported, and delivered to regasification facilities (DOE, 2023a). Information from that RFI is currently being reviewed and could add to the information summarized here.

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[r] LNG is kept in liquid form through maintaining a storage and transport temperature of approximately -160 °C. When LNG is regasified, there are hot and cold "streams" in the process. Through heat-integration (using heat exchangers, for example), one can utilize a hot or cold stream of a thermochemical process to supply or remove heat from another part of the process.

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3 AIR QUALITY

There are two primary air emissions pathways from sources in the natural gas supply chain 1) the leaking, venting, transport, and combustion of natural gas; and 2) the combustion of natural gas and other fossil fuel resources or other emissions during associated operations (e.g., extraction, transportation, downstream combustion). Emissions sources include pad, road, and pipeline construction; well drilling, completion, and flowback activities; and natural gas processing and transmission equipment such as controllers, compressors, dehydrators, pipes, and storage vessels. Pollutants include, most prominently, CH_4 and volatile organic compounds (VOCs)—of which the natural gas industry is one of the highest-emitting industrial sectors in the United States—in addition to NOx, sulfur dioxide (SO_2), and various forms of other hazardous air pollutants (HAPs) (Congressional Research Service [CRS], 2020). Pollutants are described in detail below (CRS, 2020):

- CH_4 is the principal component of natural gas and is a precursor to ground-level ozone formation (i.e., "smog").
- NOx is a ground-level ozone precursor.[s] Significant amounts of NOx are emitted during the combustion of natural gas and other fossil fuels (e.g., diesel). The combustion of natural gas occurs when it is flared during drilling and well completions and when used to drive the various compressors that move products through the system. Combustion also occurs in engines, drills, heaters, boilers, and other production equipment.
- VOCs are a ground-level ozone precursor. The crude oil and natural gas sector is currently one of the largest sources of VOC emissions in the United States, accounting for approximately 20 percent of man-made VOC emissions nationwide (and representing almost 40 percent of VOC emissions released by stationary sources).[t] VOCs—in the form of various hydrocarbons—are emitted throughout a wide range of natural gas operations and equipment. The interaction among VOCs, NOx, and sunlight in the atmosphere contributes to the formation of ozone.
- SO_2 is emitted from crude oil and natural gas production and processing operations that handle and treat sulfur-rich, or "sour," gas.
- HAPs[u], also known as air toxins, are those pollutants that are known or suspected to cause cancer or contribute to other serious health effects including reproductive issues and birth defects. The most common HAPs produced from natural gas systems are n-hexane and benzene, toluene, ethylbenzene, and xylenes (BTEX) compounds. Some natural gas reservoirs may also contain high levels of hydrogen sulfide (H_2S). HAPs are

[s] NOx is the collective term for the nitrogen oxides nitrogen monoxide and nitrogen dioxide.

[t] EPA's 2014 National Emissions Inventory estimated VOC emissions from "oil and gas" stationary sources to be 3.23 MM tons, from all stationary sources to be 8.26 MM tons, and from all anthropogenic sources to be 16.48 MM tons. Data for VOCs, as well as the other criteria pollutants and HAPs, are derived from EPA's National Emissions Inventory, available at https://www.epa.gov/sites/production/files/2017-04/documents/2014neiv1_profile_final_april182017.pdf.

[u] The EPA has a list of over 180 chemicals that they have determined are toxic air pollutants, or HAPs. Some VOCs are included on that list, so the two concepts (HAPs and VOCs) are not mutually exclusive.

found primarily in natural gas itself and are emitted from equipment leaks and during processing, compressing, transmission, distribution, or storage operations. HAPs are also a byproduct of incomplete fuel combustion and may be components in various chemical additives.

3.1 Upstream Production and Hydraulic Fracturing

The venting of natural gas during extraction and processing is a key source of VOC emissions. Similar to CH_4, VOCs are a naturally occurring constituent of natural gas and can react with other pollutants to produce ground-level ozone. Another source of VOC emissions during upstream operations is venting from condensate storage tanks, which occurs in regions with wet gas.[v]

The combustion of natural gas in compressors and gas processing equipment produces NOx and carbon monoxide (CO). Similarly, the combustion of diesel in drilling equipment produces NOx and CO, as well as significant quantities of SO_2 emissions. Beyond VOCs, CH_4, NOx, CO, and SO_2 emissions, upstream processes can also produce aliphatic hydrocarbons, (e.g., C2–C5), alkanes, VOCs (e.g., BTEX), H_2S, n-hexane, and formaldehyde, which can contaminate ambient air (Wollin et al., 2020).

Elliott et al. (2017) estimates that up to 143 air contaminants can be released during hydraulic fracturing. The International Agency for Research on Cancer generates hazard assessments for only 20 percent of these identified contaminants. Twenty of these air contaminants are known carcinogens. Other air contaminants are generated by the peripheral plant components. These include particulate matter, NOx, precursors of ozone and polycyclic aromatic hydrocarbons (Wollin et al., 2020).

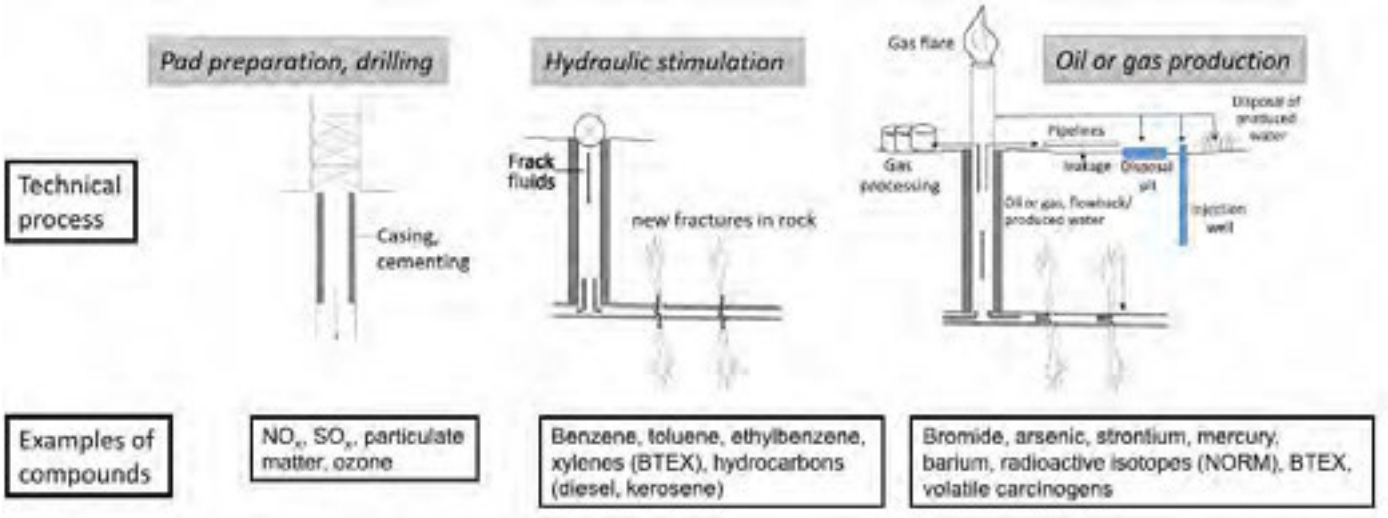
The following activities are known to contribute to air contamination at oil or gas drilling sites:

- Preparation of the drilling site including road connections
- Drilling of the well
- Truck traffic for delivery and disposal of materials
- Removal of acid gases and water from gas; separation of natural gas from other hydrocarbons
- Operation of compressor stations to enable the transport of natural gas into transport pipelines
- Preprocessing of crude oil prior to refinery

Exhibit 3-1 illustrates the supply chain for natural gas where each of these activities occurs (Wollin, 2020).

[v] When natural gas is retrieved, it can be considered wet or dry. Dry natural gas is at least 85 percent CH_4, but often more. Wet natural gas contains some CH_4, but also contains liquids such as ethane, propane, or butane. The more CH_4 natural gas contains, the "dryer" it is considered.

Exhibit 3-1. Illustration of supply chain steps where upstream air pollution occurs



Used with permission from Wollin et al. (2020)

NOx and SOx emissions have been reported to be higher during the development of the drilling site compared to during the production phase (Wollin et al., 2020). Similar observations have been made for particulate matter (PM) (e.g., PM2.5 and PM10). Analysis of shale gas production sites in North Texas showed an 8 percent increase in ozone concentrations at natural gas production sites compared to control sites (Wollin et al., 2020).

Indirect energy consumption can also affect the air quality profile of gas extraction technologies. If the development or operation of a natural gas well uses grid electricity, then the fuel mix of the electricity grid will affect the life cycle performance of the well. The indirect air quality impacts of electricity consumption depend on the fuel mixes and combustion characteristics of power plants that collectively compose a regional electricity grid. Exhibit 3-2 offers a perspective on sources of non-GHG air pollutants by supply chain step or equipment.

Exhibit 3-2. Perspective of non-GHG air pollutant by supply chain step or equipment

Source	Air pollutant				Data quality
	NO_X	VOC	PM	Other toxic substances	
Well development					
Drilling rigs	•	◦	•	•	Medium
Frac pumps	•	◦	•	•	Medium
Truck traffic	•	◦	•	•	Medium
Completion venting		•		•	Poor
Frac ponds		◦			Poor
Gas production					
Compressor stations	•	•	◦	•	Medium
Wellhead compressors	◦	◦	◦	◦	Medium
Heaters, dehydrators		◦	◦	◦	Medium
Blowdown venting		◦		◦	Poor
Condensate tanks		•		◦	Poor
Fugitives				◦	Poor
Pneumatics		◦		◦	Poor

• Major source, ◦ minor source

Used with permission from Wollin et al. (2020)

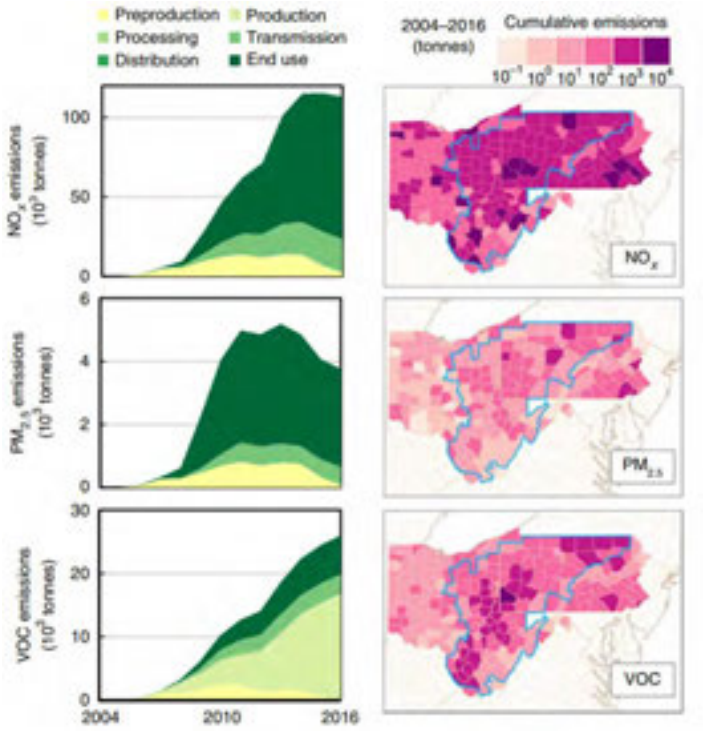
McMullin et al. (2018) analyzed exposure to VOCs emitted during hydraulic fracturing in Colorado. They identified 56 different VOCs that were emitted during hydraulic fracturing using data compiled from 47 existing air monitoring devices that measured these VOCs at 34 different locations across the region.

Plant et al. (2022) used airborne sampling to measure flare efficiency[w] in three major gas production regions in the United States. They found that both unlit flares and inefficient combustion contribute comparatively to ineffective CH_4 destruction, with flares effectively destroying only 91.1 percent (90.2–91.8 percent; 95 percent confidence interval) of CH_4 emissions. Other emissions from flaring can include carbon particles (soot), unburned hydrocarbons, CO, partially burned and altered hydrocarbons, NOx, and (if sulfur containing material such as H_2S or mercaptans is flared) SO_2. The combustion products of flaring at natural gas production and processing sites specifically include CO_2, CH_4, and N_2O.

Mayfield et al. (2019) performed an analysis of the environment impacts associated with the shale gas boom in the Appalachian Basin and found the majority (61 percent) of VOC emissions from the natural gas supply chain can be largely attributed to upstream processes and are spatially concentrated in counties with the highest cumulative production. Upstream processes contribute the most to total NOx (67 percent) and PM2.5 (73 percent) emissions across the natural gas supply chain; NOx and PM2.5 emissions are relatively evenly distributed across counties (Mayfield et al., 2019). Exhibit 3-3 presents annual NOx, PM2.5, and VOC emissions from the natural gas supply chain within Pennsylvania, Ohio, and West Virginia, along with the spatial distribution of cumulative NOx, PM2.5, and VOC emissions by county between 2004 and 2016. It is important to note that the blue lines delineate shale gas-producing counties (Mayfield et al., 2019).

[w] The flare efficiency is a measure of the effectiveness of the combustion process to fully oxidize the fuel. When inefficiencies occur, unburned fuel, CO, and other products of incomplete combustion (e.g., soot, VOCs, etc.) are emitted into the atmosphere.

Exhibit 3-3. Annual (left graphs) and cumulative (right graphs) (2004–2016) NOx, PM2.5, and VOC emissions from natural gas supply chain within Pennsylvania, Ohio, and West Virginia



Permission pending from Mayfield et al. (2019)

3.2 MIDSTREAM TRANSPORT EMISSIONS

CH_4 leakage in the transmission and distribution systems is documented in Chapter 2 – Greenhouse Gas Emissions. This mid-stream segment leakage has important air pollutant considerations, since CH_4 can be a precursor to ground-level ozone formation.

While the presence of HAPs in unprocessed, upstream natural gas has been documented, little has been published on their presence in the midstream segments of the natural gas supply chain. Nordgaard et al. (2022) systematically evaluated publicly available, industry-disclosed HAP composition data from natural gas infrastructure applications submitted to FERC between 2017 and 2020. These applications covered 45 percent of the U.S. onshore natural gas transmission system (as measured by pipeline miles). Given that reporting HAP composition data is not required by FERC, only 49 percent of approved projects disclosed their HAP composition data to FERC. Of the applications that did disclose their HAP composition data, HAP concentrations were typically reported as higher for separator flash gas and condensate

tank vapor, compared to LNG and transmission-grade natural gas, with mean benzene concentrations of 1,106, 7050, 77, and 37 parts per million (ppm), respectively.

Nordgaard et al. (2022) also identified one pipeline operator that reports real-time HAP concentrations for natural gas at five pipeline interconnection points. Similar to the FERC applications, this operator reported BTEX and H_2S as present in the pipelines used to transport their natural gas. Because current transmission infrastructure releases natural gas during uncontrolled leaks, loss of containment events, and routine operations (e.g., blowouts and compressor station blowdowns), having access to HAP composition data may be important for conducting both air quality and health-focused evaluations of natural gas releases.

3.3 Air Emissions Research and Development

Many of the strategies to reduce air emissions from oil and natural gas operations are similar to those identified to reduce GHG emissions. For example, improved flaring efficiency can reduce air emissions and measures to reduce methane emissions will also reduce VOCs and other hazardous pollutants that are emitted with methane.

~~3.3~~3.4 References

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4 WATER USE AND QUALITY

The literature describes the treatment and management of wastewaters as a central environmental concern regarding natural gas production. Especially in the eastern regions of the United States where—although water resources are abundant—significant natural gas production has been occurring and is expanding. In the western parts of the United States, persistent dry climates limit the use and availability of freshwater for natural gas production—specifically, freshwater availability for drilling and hydraulic fracturing.

Gallegos et al. (2015) estimate that drilling and hydraulically fracturing a shale gas well can consume 2.6–9.7 MM gallons (gal) of water. From 2014 to 2015, unconventional shale gas in the United States used 187 billion (B) gal of water. From 2012 to 2014, the average use of water for hydraulic fracturing was 30.6 B gal annually. Additionally, Gallegos et al.'s (2015) integrated data from 6–10 years of operations suggests 212 B gal of produced water[x] are generated from unconventional shale gas and oil formations.

While extensive growth in hydraulic fracturing has increased water use for natural gas production across the United States, the water use and produced water intensity of these well-stimulation activities is lower than the water use and produced water intensity of other energy extraction methods and represents only a small fraction of total industrial water use nationwide (Kondash and Vengosh, 2015). However, given the amount of water required for natural gas production, local or seasonal water supply shortages can cause issues.

Water quality can also be impacted by natural gas production processes if water is inadequately managed or by the use of fracturing chemicals both on the surface (e.g., if chemicals are inadvertently spilled and not contained)—before injection and after flowback—and in produced water. Subsurface water quality impacts can result from the migration of fracturing fluids, formation waters, and CH_4 along well bores and through rock fracture networks. Management and disposal efforts increasingly include efforts to minimize water use through recycling and re-use of fracturing fluids, in addition to treatment and disposal of wastewater through deep underground injection.

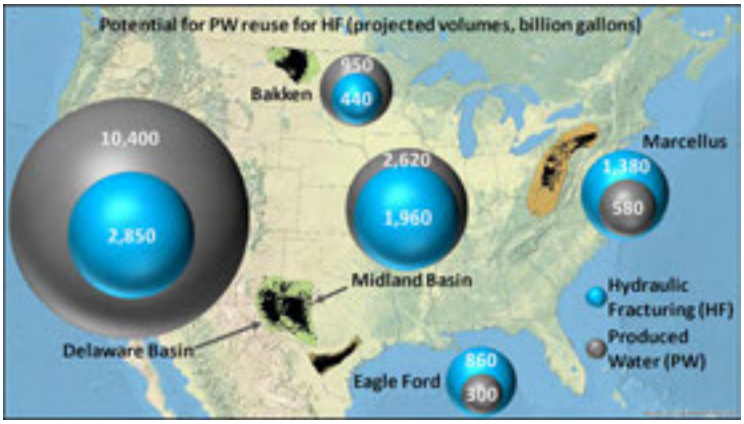
Scanlon et al. (2020a) analyze the water-related sustainability of energy extraction. They focus on meeting the rising water demand for hydraulic fracturing and managing growing volumes of water co-produced with oil and gas. They also analyze historical (2009–2017) volumes of water in ~73,000 wells and project future volumes of water use in major U.S. unconventional oil and gas plays. Their results show a marked increase in water use for fracking, depleting groundwater resources in some semi-arid regions (Scanlon et al., 2020a).

Water issues related to both fracking water demand and produced water supplies may be partially mitigated through the reuse of produced water to frack new wells. As shown in Exhibit 4-1, projected produced water volumes exceed fracking water demand in semi-arid Bakken (2.1×), Permian Midland (1.3×), and Delaware (3.7×) oil plays, with the Delaware oil play

[x] Produced water is defined as the water that is withdrawn through oil and gas extraction. Produced water can begin as ground water within the hydrocarbon bearing formations; however, as the extraction matures, or in the case of shale or tight formations where hydraulic fracturing is necessary to liberate the hydrocarbons, produced water can also contain fluids that were previously injected.

accounting for ~50 percent of the projected U.S. oil production (Scanlon et al., 2020a). Therefore, water issues could impact future energy production, particularly in semi-arid oil plays.

Exhibit 4-1. Map showing ratio between produced water and fracking water demand for major shale basins



Used with permission from Scanlon et al. (2020a)

4.1 Water Use for Unconventional Natural Gas Production

The process of hydraulic fracturing uses large volumes of water mixed with chemicals and proppant (sand) to fracture low-permeability shale and tight oil rocks, allowing the extraction of hydrocarbons. Despite the higher water intensity (the amount of water used to produce a unit of energy; for example, liters per gigajoule) compared to drilling conventional vertical oil and gas wells, overall water withdrawals for hydraulic fracturing is negligible compared to other industrial water uses on a national level (Vengosh et al., 2014; Jackson et al., 2014; Kondash, Albright, and Vengosh, 2017; Kondash and Vengosh, 2015). On a local level, however, water use for hydraulic fracturing can cause conflicts over water availability, especially in arid regions such as the western and southwestern United States where water supplies are already limited (Scanlon, Reedy, and Nicot, 2014; Ikonnikova et al. 2017; Nicot and Scanlon, 2012; Kondash, Lauer, and Vengosh, 2018).

Most of the water used for unconventional natural gas production is used as part of the hydraulic fracturing process. For example, of the total water used by the shale gas industry, hydraulic fracturing is estimated to account for about 89 percent, drilling about 10 percent, and infrastructure 1 percent (Hayes and Severin, 2012). Water is the main component of the fluids used for hydraulic fracturing, making up approximately 99 percent of the total volume.

Reporting from Gallegos, et al. (2015) suggests hydraulic fracturing uses 2.6–9.7 MM gal of water per well drilled, while the American Petroleum Institute (API) (API, 2023) suggests the average hydraulically fractured well uses 4 MM gal of water. It is important to consider the potential environmental impacts of using water from different sources (e.g., ground water,

surface water). If available surface water is used to support natural gas production, then the ecosystems that rely on this water could be impacted. Significant groundwater withdrawals can permanently deplete aquifers.

4.1.1 Water Use Impacts

Water use for hydraulic fracturing and wastewater production in major shale gas and oil producing regions increased between 2011 and 2016, with water use per well increasing by up to 770 percent—and with flowback and produced water volumes generated within the first year of production increasing up to 550 percent. Water-use intensity (that is, normalized to energy production) increased in all U.S. shale basins, except the Marcellus shale basin, over this period (Kondash, Lauer, and Vengosh, 2018).

Water consumption per shale gas well can vary due to four primary factors:

- Geology: maturity of the shale and formation depth, thickness, and lateral extent
- Technology: horizontal or vertical drilling, water recycling
- Operations: operator decisions, availability of nearby freshwater
- Regulatory: requirements for use and treatment of water

During 2009−2017, ∼73,000 wells, or an aggregated total lateral length of $\sim 440 \times 10^6$ ft (134,000 km) equivalent to ∼3× the Earth's circumference (40,000 km), was drilled in eight plays studied by (Dieter et al., 2018). Dieter et al. (2018) found that to fracture the rock along that length, ∼480 B gal of water are required, equivalent to ∼0.1 percent of the U.S. 2015 total water withdrawal, or almost two days of freshwater withdrawal (280 B gal/day).

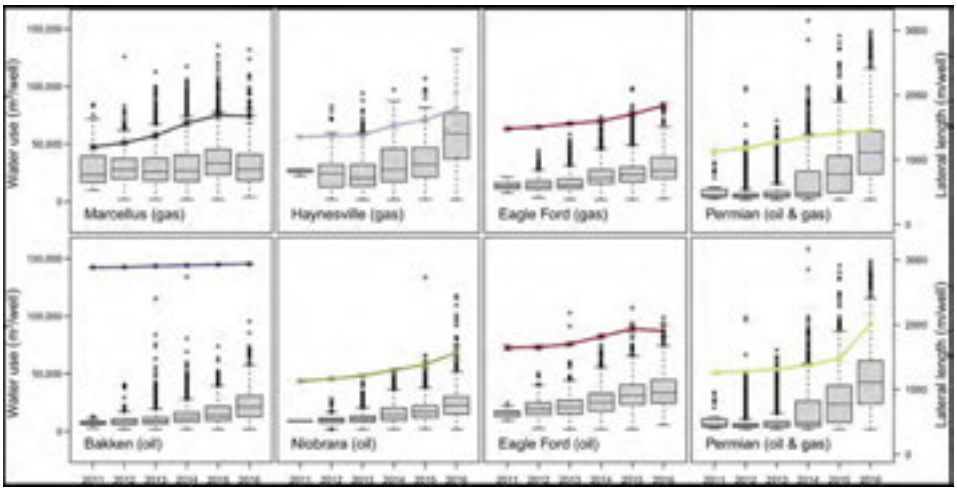
Exhibit 4-2 shows the water use for hydraulic fracturing, the amount of produced water used and oil and gas outputs from nine major plays in the United States from 2009 to 2017 (Scanlon et al., 2020a). The Eagle Ford play has used 173 B gal of combined hydraulic fracturing and produced water, at nearly a 1.83 ratio of freshwater to produced water and the Marcellus has a freshwater to produced water ratio of 5.83. Other plays use more produced water than freshwater, like Bakken, Delaware, and Barnett, where the ratios of produced water to freshwater are 1.83, 2.21, and 2.11, respectively.

Exhibit 4-2. water use in nine shale plays in the U.S.

Play	Total Length (10^4 ft)	Median Well Length (ft)	Number of Wells	Hydraulic Fracturing Water (10^9 gal)	Produced Water (10^8 gal)	Oil (10^9 gal)	Gas (10^8 gal of oil equivalent)
Bakken	114	9,580	12,036	49	75	100	22
Eagle Ford	95	6,061	17,366	112	61	103	78
Midland	49	8,575	6,461	79	44	30	14
Delaware	36	5,272	7,070	51	113	40	26
Marcellus	51	7,139	9,651	70	12	3	214
Niobrara	21	7,438	3,842	21	5	14	11
Barnett	27	5,241	7,453	35	74	1	111
Haynesville	15	6,270	3,215	30	16	0.03	107
Fayetteville	21	6,386	4,717	24	-	-	55

Exhibit 4-3 from Kondash, Lauer, and Vengosh (2018) indicate that, parallel to the increase in lateral lengths of the horizontal wells and hydrocarbon extraction yields through time, water use has also increased. The relative increase in lateral length (4–60 percent) was, however, significantly lower than the increase in water use (14–770 percent). When water use per well was normalized to the length of lateral section of the horizontal well, in almost every case among oil producing regions, an increase in water use per length of the horizontal well is observed. This pattern was most evident in the Permian region, where water use increased from 4.4 cubic meters (m^3) per meter in 2011 to 29.3 m^3 per meter in 2016 for gas-producing wells (an approximate seven-fold increase), and from 3.9 m^3 per meter in 2011 to 21.1 m^3 per meter in oil-producing wells (an approximate five-fold increase). In all cases, with the exception of the Marcellus shale play in 2016, the flowback and produced water generation also increased through time, with particularly higher rates after 2014.

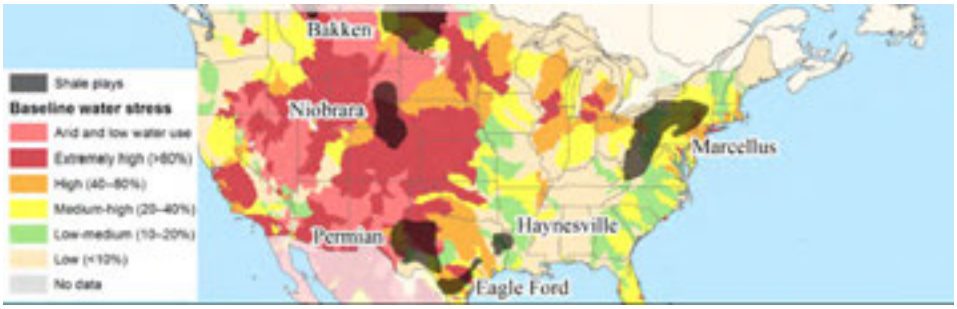
Exhibit 4-3. Water usage and lateral length by shale play



Used with permission from Kondash, Lauer, and Vengosh (2018)

Kondash, Lauer, and Vengosh (2018) also illustrate water conditions where the major plays across the United States are located, see Exhibit 4-4. The Bakken, Niobara, Permian and Eagle Ford plays are all located in arid to extremely dry climates where drought conditions have persisted for many years.

Exhibit 4-4. Baseline water stress and location of shale plays



Used with permission from Kondash, Lauer, and Vengosh (2018)

4.1.2 Water Quality

Concerns have been raised about potential public health effects that may arise if hydraulic fracturing-related chemicals were to impact drinking water supplies. The chronic oral toxicity values—specifically, chronic oral reference values (RfVs) for noncancer effects, and oral slope factors (OSFs) for cancer are available for the list of 1,173 chemicals EPA identified as "associated with hydraulic fracturing." These include 1,076 chemicals used in hydraulic

fracturing fluids and 134 chemicals detected in the flowback or produced waters from hydraulically fractured wells.

EPA compiled RfVs and OSFs for these chemicals using six different governmental and intergovernmental data sources. Ninety (8 percent) of the 1,076 chemicals used in hydraulic fracturing fluids and 83 (62 percent) of the 134 chemicals found in flowback/produced water had a chronic oral RfV or OSF reported in at least one or more of the six data sources used. Thirty-six of the chemicals used in hydraulic fracturing fluids have been measured in at least 10 percent of the hydraulically fractured wells drilled nationwide (identified from EPA's analysis of the FracFocus Chemical Disclosure Registry 1.0). Eight of these 36 chemicals (22 percent) had an available chronic oral RfV. The lack of chronic oral RfVs and OSFs for the majority of these chemicals highlights the significant knowledge gap that exists to assess the potential human health hazards associated with hydraulic fracturing (Yost et al., 2016).

Ecological risks to surface waters are present throughout the well life cycle and may manifest themselves differently locally compared to regionally. These risks can also vary temporally, as development activity like surface water withdrawal may only result in a single, brief impact, while the network of roads required for accessing well pads could increase erosion and sediment runoff for years. Previous work identified the primary risks to surface water quality as sediment runoff from devegetation, leakage and spillage of chemicals into surface waters, unsustainable water withdrawal, landscape fragmentation, and insufficient treatment of oil and gas wastewater prior to discharge (Krupnick, Gordon, and Olmstead, 2013; Slonecker et al., 2012; Drohan et al., 2012; Kiviat, 2013). Unfortunately, few sites exist where baseline environmental monitoring occurred prior to hydraulic fracturing operations commencing, greatly complicating efforts to precisely quantify the impacts of hydraulic fracturing, particularly if these operations are occurring in watersheds with preexisting anthropogenic influence and a host of existing ecological stressors (Mauter et al., 2014; McBroom, Thomas, and Zhang, 2012).

The surface water risks and impacts associated with unconventional resource development vary significantly by region (Clements, Hickey, Kidd, 2012). To date, those in the Marcellus region have been examined most extensively. This scrutiny has been motivated by the nexus of regionally specific risk drivers, such as high gradient terrains that could lead to increased erosion, an abundance of small streams, highly variable in-stream flow rates, and the high salinity of produced water in the Marcellus. Moreover, during the early development of the Marcellus shale in Pennsylvania, the state permitted the disposal of hydraulic fracturing brines in municipal wastewater treatment plants. The most recent studies suggest that to reduce the human and environmental impacts associated with this original practice, the State of Pennsylvania asked companies to adopt a moratorium on the disposal of produced water in wastewater treatment plants in the state (Wilson and Van Briesen, 2012; Wilson, Wang, and Van Briesen, 2013; Warner et al., 2013a; Wilson and Van Briesen, 2013; Renner, 2009 Abdalla et al., 2016).

The rapid development of unconventional gas extraction has increased the flux of both solid and liquid waste, fluxes proportionally much greater than those generated from traditional conventional well development on a per well basis. Drill cutting wastes from unconventional wells may contain more total naturally occurring radioactive materials (NORM) than

conventional wells for two reasons. Geochemically, the shale itself contains more NORM than sandstone and limestone reservoirs holding conventional reserves (Badertscher et al., 2023; Huang et al., 2017). Physically, the horizontal bore is usually much longer than the vertical bore, and a larger proportion of the drill cuttings comprises the NORM rich shale due to the directional drilling. The Pennsylvania Department of Environmental Protection (PADEP) reported drill cuttings with the following ranges: ^{226}Ra (below detection limit to 640 becquerels/kg) and ^{228}Ra (0.37–104 becquerels/kg) (PADEP, 2016).

Higher NORM values in solids and liquids resulted in higher downstream values of ^{226}Ra and ^{228}Ra as well. Stream water and sediments in areas bracketing outfalls of facilities treating waste from landfills accepting oil and gas waste indicate accumulation of NORM in the sediments. Given distance from the outfall, these accumulations are of similar magnitude to those downstream of brine treatment facilities reported in the literature (Warner et al., 2013b) and indicate additions from a low ^{228}Ra/^{226}Ra activity ratio source, consistent with Marcellus formation sources (Lauer, Warner, and Vengosh, 2018).

4.1.3 General Guidelines for Leading Best Practices on Water Remediation

Increasing demand for water for drilling and hydraulic fracturing in shale gas plays has driven operators to seek supplemental sources of water and alternatives to local freshwater supplies. Potential alternatives include industrial wastewater, water treatment plant outflows, abandoned mine waters, saline groundwater, and reuse of produced waters.

A 2023 report by the Groundwater Protection Council (GWPC) summarizes the most notable changes in produced water operational and management practices in each major production region (GWPC, 2023). The regions include both oil and gas production, with the Permian basin being the largest produced water region, producing 10.5 times more than the Bakken, 16.4 times more than the Eagle Ford, and 49 times more than the Appalachian region.

With many of these plays being in areas where water scarcity is an issue, reducing water consumption is critical. Therefore, produced water reuse technologies are critical as well. Once produced water is treated to fresh water or discharge standards, it can be reused. Exhibit 4-5 shows the major reuse outlets for treated produced water (Scanlon et al., 2020b).

Exhibit 4-5. Major produced water reuse outlets



Used with permission from Scanlon et al. (2020b)

When it comes to the beneficial reuse of produced water in any of the major development basins, the primary challenge to overcome is the desalination of the water by way of treatment and managing the associated products and wastes that are generated. Aside from the regulatory and liability challenges associated with the discharge of produced water, there are significant technical and economic challenges associated with large-scale produced water desalination systems. All the options for reuse shown in Exhibit 4-5 require the water to first meet a low salinity standard. The primary challenge faced by the beneficial reuse of produced water is the removal of total dissolved solids (TDS) or dissolved salt from the produced water matrix. Exhibit 4-6 shows the salinity ranges for different types of water (Horiba, 2016).

Exhibit 4-6. Different types of water salinity values

Salinity Status	Salinity (%)	Salinity (parts per trillion)	Use
Fresh	<0.05	< 0.5	Drinking and all irrigation
Marginal	0.05–0.1	0.5–1.0	Most irrigation, adverse effects on ecosystems become apparent
Brackish	0.1–0.2	1–2	Irrigation for certain crops only, useful for most livestock
Saline	0.2–1.0	2–10	Useful for most livestock
Highly Salinated	1.0–3.5	10–35	Very saline groundwater, limited use for certain livestock
Brine	> 3.5	> 35	Seawater, some mining and industrial uses exist

Produced water requires significant pretreatment prior to being subjected to any desalination process. The most prominent and proven water desalination technology deployed across the world is reverse osmosis, which becomes increasingly inefficient when TDS concentrations exceed 35,000 ppm (which is reflective of the salinity concentration in seawater). As the overwhelming amount of produced water in the United States is well above the levels to be treated by reverse osmosis, including produced water in the Permian (median TDS concentration: 154,000 ppm), this technology is not applicable.

Thermal (vapor) distillation would be considered "mature and proven" for this application. These distillation technologies typically consist of a mechanical vapor compression/mechanical vapor recompression component and have been in use for more than a decade in the oilfield treating produced water with limited acceptance due to throughput and costs. Thermal distillation technologies often require extensive pretreatment of the water before processing, including the removal of hydrocarbons, total suspended solids, and all hardness cations.

4.2 Current Water Research and Development

DOE funds R&D to advance sustainable water management technologies and approaches, responding to increased water demand from decarbonized power generation. Additionally, DOE seeks to provide alternative water resources in water-stressed areas by treating wastewaters from fossil energy activities, making those treated wastewaters available to end-users outside the fossil energy industry, and reducing environmental impacts of fossil fuel generation during the transition to clean energy. To accomplish these goals, DOE currently has R&D focused in three areas:

1. Characterization, treatment, and management of produced waters
2. Recovery of critical minerals – including rare earth elements and other resources for beneficial reuse
3. Alternative water resources and identifying opportunities to utilize them

The Produced Water Optimization Initiative (PARETO) is an optimization framework for produced water management and opportunities for beneficial use. The goal of PARETO is to develop a modeling and optimization application to identify cost-effective and environmentally sustainable produced water management, treatment, and reuse solutions.

PARETO will help with the following tasks:

- Buildout of the produced water infrastructure
- Management of produced water volumes
- Selection of effective treatment technologies
- Placement and sizing of treatment facilities
- Identification of beneficial water reuse options
- Distribution of treated produced water for reuse

The Water Management for Power Systems program will lead the critical national R&D effort directed at removing barriers to sustainable, efficient water and energy use at fossil power

plants by developing technology solutions and enhancing the understanding of the relationship between energy and water resources.

DOE and NETL will work together to overcome the following challenges:

- Reduce freshwater consumption by 50 percent
- Lower the cost of treating fossil power plant effluent streams by 50 percent

The produced water characterization effort will focus on the critical national R&D effort directed at characterizing produced water associated with sustainable oil and gas development. The work proposed is aligned with DOE-FECM's program goals to reduce freshwater consumption and to recover valuable resources from both effluent and alternative influent water streams. Leveraging its core capabilities, competencies, and authorities, NETL will move to partner with universities and industry to develop and increase the commercial readiness of technology options needed to treat and manage produced water from oil and natural gas operations.

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5 INDUCED SEISMICITY

Among the many impacts of anthropogenic activity on the Earth, one that has caused particular public disquiet in recent years is "induced seismicity," that is, minor earthquakes and tremors caused by industrial processes (Grigoli and Wiemer, 2017). Earthquakes have been detected in association with both oil and natural gas production, underground injection of wastewaters (i.e., wastewater disposal), and hydraulic fracturing (Rubinstein and Mahani, 2015). Each of these processes involves injecting large volumes of fluids at various pressures into underground formations.[y] Earthquakes from human activities have happened in multiple countries, including the United States (Shultz et al., 2020).

5.1 IMPACTS FROM INDUCED SEISMICITY AND ENERGY TECHNOLOGIES

The term seismic activity is generally used to describe vibrations of mechanical energy that pass through the earth, much like sound waves vibrate through the atmosphere. The seismic activity of a region is defined by the frequency, kind, and magnitude of earthquakes experienced in the region during a given period. The National Earthquake Information Center (NEIC) is the entity responsible for determining, as rapidly and as accurately as possible, the location and size of all significant earthquakes that occur worldwide. At present, the NEIC locates and publishes detailed data on the 30,000 "most significant" earthquakes that occur in each year (USGS, 2023).

While millions of earthquakes occur each year, not all are felt at the surface. Earthquakes with magnitudes of 2.0 or less generally cannot be felt at the surface by people, while earthquakes with magnitudes greater than 3.0 tend to produce noticeable shaking. Earthquakes with magnitudes greater than 5.0 are felt at the surface and have the potential to cause structural damage to buildings and property. Most earthquakes that do occur are in response to natural, yet sudden slips and shifts of large masses of rock along geologic faults.

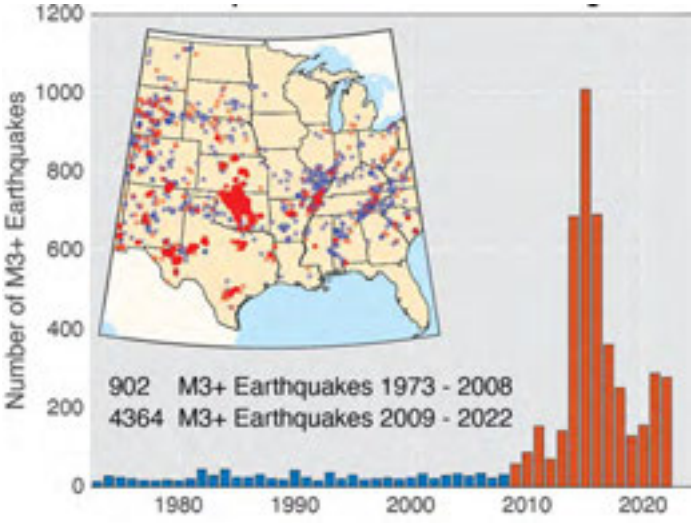
The seismicity rate in the central and eastern United States increased 40-fold from 2002 to 2012, predominantly as a result of human activities (Ellsworth, 2013; van der Baan and Calixto, 2017). This increase in seismicity rate in the central and eastern United States has largely been attributed to large-volume wastewater disposal wells injecting fluids into deep sedimentary formations (e.g., Keranen et al., 2014; Rubinstein and Mahani, 2015). Other human activities, including hydraulic fracturing (Skoumal, Brudzinski, and Currie, 2015) and carbon sequestration (e.g., Kaven et al., 2015), have induced seismicity to a lesser extent in the central and eastern United States (Skoumal et al., 2020).

Exhibit 5-1 presents the annual number of earthquakes (with a magnitude of 3.0 or larger) occurring in central and eastern areas of the United States for 1973–2022. Many of these earthquakes have taken place in areas where hydraulic fracturing has been and is actively occurring (e.g., Oklahoma) (USGS, 2022). Between 1973 and 2008, approximately 25

[y] Hydraulic fracturing involves injecting large volumes of fluids into the ground to release trapped oil and natural gas. Wastewater from oil and gas production, including shale gas production, is typically disposed of by being injected at relatively low pressures into extensive formations that are specifically targeted for their porosities and permeabilities to accept large volumes of fluid.

earthquakes of magnitude three or greater occurred on average annually. Since 2009, at least 58 earthquakes of this same size (magnitude of 3.0 or larger) have occurred annually, and at least 100 earthquakes of this same size have occurred annually since 2013. The annual number of earthquakes (with a magnitude of 3.0 or larger) peaked in 2015 when 1,010 magnitude 3+ earthquakes were recorded. Given their magnitude, most of these earthquakes are large enough to have been felt by people, yet not large enough to cause significant damage (USGS, 2022).

Exhibit 5-1. Earthquakes in the Central and Eastern U.S. 1973–2022



Source: USGS (2022)

The following are examples of induced seismic events in the United States that have occurred in basins where unconventional natural gas production via hydraulic fracturing has occurred.

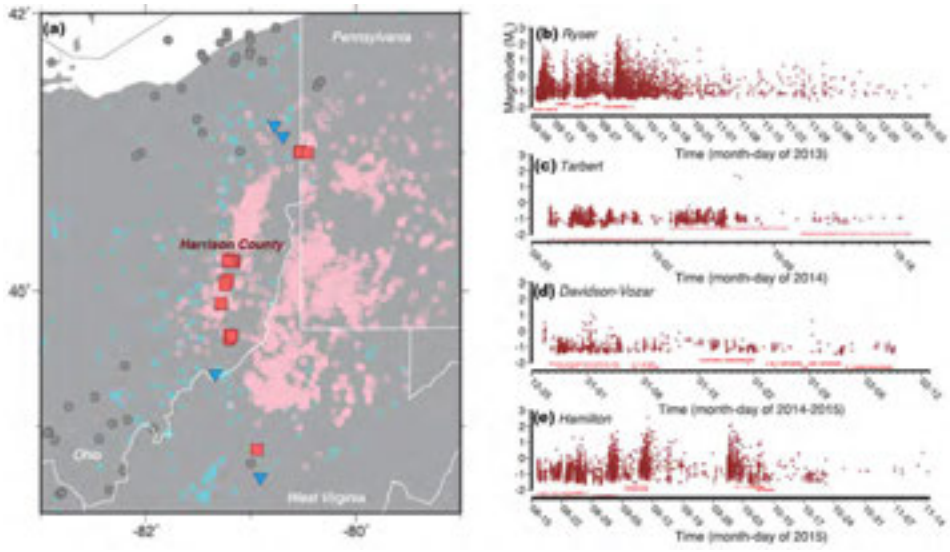
5.1.1 Utica and Marcellus Shales in the Appalachian Basin

The Appalachian Basin is currently the largest natural gas producing area in the United States The Marcellus and Point Pleasant Utica shale plays are both located in the Appalachian Basin and extend from New York to Kentucky. They each cover prospective areas of 190,000 and 220,000 km^2, with proven reserves of 135 and 24 Tcf of natural gas, and 345- and 210-MM barrels of oil, respectively (EIA, 2019b). Earthquakes detected in the basin as analyzed by Schultz et al. from 2013 to 2015 are presented in Exhibit 5-2.

The map on the left provides the location sequences of cataloged (magnitude > 2.0) seismic events in Ohio and neighboring states for 2010–2017. Blue triangles show earthquake sequences induced by wastewater disposal; red squares show earthquake sequences induced by hydraulic fracturing; and pink squares and blue triangles depict the horizontal and

wastewater disposal wells that remain in the area. Grey circles represent earthquakes assumed to be occurring from natural causes. The four graphs on the right provide the temporal distribution of hydraulic fracturing induced seismic events for four wells in Harrison County, Ohio (Schultz et al., 2020).

Exhibit 5-2. Location and timing of induced and natural seismic events in the Appalachian Basin



Used with permission from Schultz et al. (2020)

5.1.2 Anadarko and Arkoma Basins of Oklahoma

Dramatic increases in seismic activity have been reported for areas in both central and northern Oklahoma, where the Anadarko and Arkoma Basins are located. Historically, an average of one to two ML[z] ≥ 3.0 earthquakes has occurred in Oklahoma annually. The number of ML ≥ 3.0 earthquakes occurring in the state, however, rose to over 900 in 2015 (Ellsworth, 2013).

While the seismicity rate began to decline in 2016, the yearly total seismic moment[aa] of Oklahoma remained high in response to three Mw[bb] ≥ 5.0 earthquakes occurring during the year, including the Pawnee earthquake, the largest earthquake (5.8 Mw) ever recorded for the state of Oklahoma. The seismicity rate increase has generally been attributed to the disposal of large volumes of produced water into the Arbuckle Group basin (Haffener, Chen, and Murray, 2018).

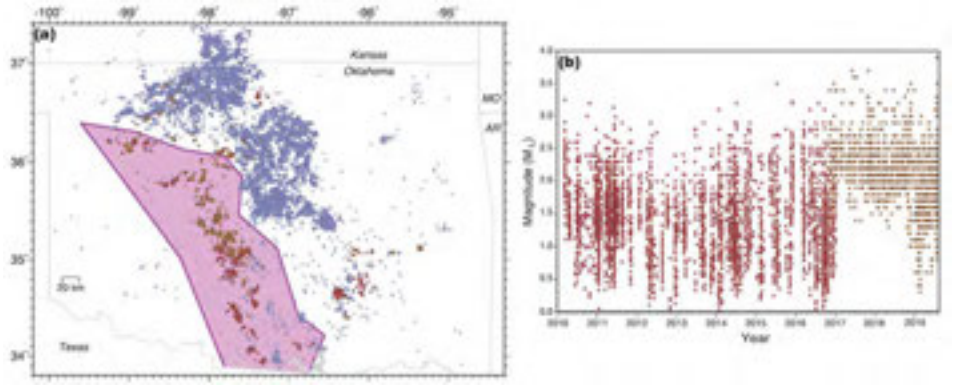
[z] ML refers to the magnitude on the Richter scale, where M stands for magnitude and L stands for local.

[aa] Seismic moment represents a measure of the size of an earthquake, depending on the area of rupture, the rigidity of the rock, and the amount of slip from faulting.

[bb] Mw is known as the moment magnitude of an earthquake. For very large earthquakes, moment magnitude gives the most reliable estimate of earthquake size.

Exhibit 5-3 shows the location (left) and magnitude (right) of induced seismic events in Oklahoma between 2010 and 2020. In the map on the left, seismic events from natural causes are represented by the blue circles, while induced seismic events are represented by the red (Skoumal et al., 2018) and orange circles (Shemeta, Brooks, and Lord, 2019). The graph on the right shows the number and magnitude of the induced seismic events over time (Skoumal et al., 2018; Shemeta, Brooks, and Lord, 2019).

Exhibit 5-3. Induced seismicity events in Oklahoma



Used with permission from Schultz et al. (2020)

5.1.3 Fayetteville Formation in the Arkoma Basin of Arkansas

Following the success of the Barnett Shale (Fort Worth Basin, Texas), the Fayetteville Formation in Arkansas became an early target for continued shale gas development in the United States. This unconventional play runs east to west across north central Arkansas, extending across nearly 150 km. By 2005, horizontal well completions in the middle to lower organic rich facies at depths typically 1–2 km were coming online and, by 2009, 0.5 Tcf of gas was being produced per year (Browning et al., 2014).

The Fayetteville Formation has a history of seismicity that dates back to before the region was developed for oil and natural gas extraction. In September 2010, a series of seismic events reaching magnitudes close to 5.0 Mw on the Richter Scale occurred along the Guy-Greenbrier Fault within the basin. Not long after, on February 28, 2011, a 4.7 Mw earthquake—the largest ever recorded—occurred within the basin. This led to concerns that even larger earthquakes could potentially occur in the area, which resulted in an emergency shutdown order for any injections being put in place by the Arkansas Oil and Gas Commission. Analysis of the seismicity, injection patterns, and pore pressure diffusion built a strong case for the activation of the Guy-Greenbrier Fault by wastewater disposal (Horton, 2012; Ogwari, Horton, and Ausbrook, 2016; Ogwari and Horton, 2016; Park et al., 2020). In the neighboring states of Oklahoma and Texas, wastewater disposal by injection is understood to be the primary driver of induced seismicity.

5.1.4 Eagle Ford Shale Play in the Western Gulf Basin of Texas

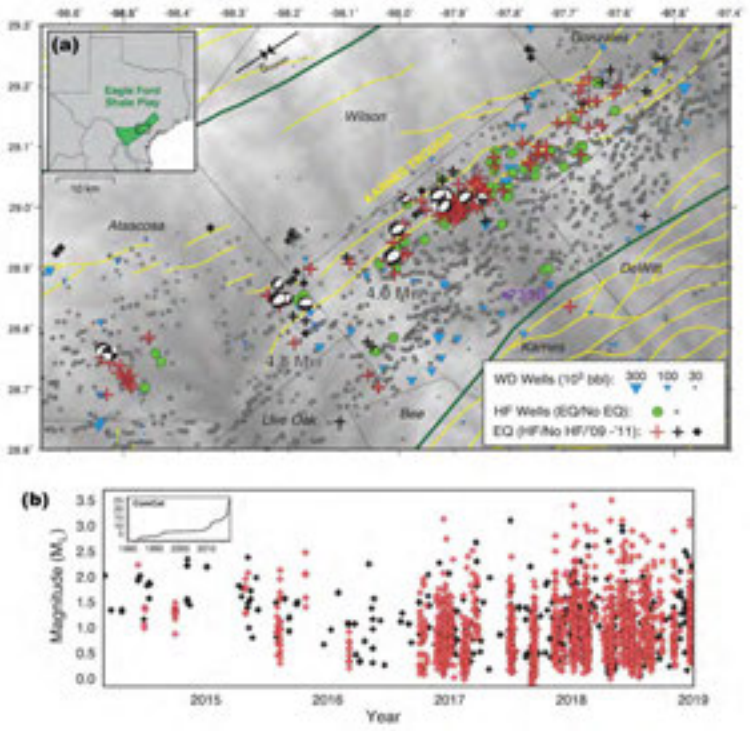
Texas has a long history of active oil and natural gas production, hydraulic fracturing, wastewater disposal, and general seismicity, some of which occurs within or near areas of pervasive faulting (see Exhibit 5-4a) (Ewing, 1990; Frohlich et al., 2016). Advancements in horizontal drilling and hydraulic fracturing since 2008 have prompted the Eagle Ford shale play to focus on hydrocarbon production from the Upper Cretaceous Eagle Ford and Austin Chalk Formations (Frohlich and Brunt, 2013; Martin et al., 2011; Pearson, 2012; RRC, 2019).

In 2018, the rate at which ML ≥ 3.0 earthquakes occurred in the Eagle Ford shale play was 33 times higher than background levels (3 earthquakes per 10 years during 1980–2010; see Exhibit 5-4b). Fasola et al. (2019) investigated seismicity that has occurred since 2014, in an effort to identify how hydraulic fracturing has contributed to seismicity within the play. Comparing both times and locations of hydraulic fracturing to a catalog of seismic activity, Fasola et al. (2019) suggest more than 85 percent of the seismicity that occurred was spatiotemporally correlated with hydraulic fracturing. More specifically, there were 94 ML ≥ 2.0 earthquakes correlated with 211 hydraulic fracturing well laterals.

Exhibit 5-4a provides a map from the Texas Seismological Network highlighting earthquakes (crosses) and focal mechanisms (beach balls) that have occurred since 2017. Hydraulic fracturing wells are indicated by black circles in Exhibit 5-4. Correlated earthquakes and hydraulic fracturing wells are displayed as red plus signs and green circles, respectively. Black diamonds show the earthquakes that occurred during 2009–2011 (Frohlich and Brunt, 2013). Purple square shows the seismic station (735B) used for template matching. Wastewater disposal wells are provided as teal triangles sized by median monthly volumes. Arrows show regional orientation (Lundstern and Zoback, 2016). Faults (Ewing, 1990) are in yellow.

Exhibit 5-4b provides the magnitudes of the various earthquakes both correlated and not correlated with hydraulic fracturing that occurred annually after 2011 within the play (the black and red plus signs shown in Exhibit 5-4a). The inset shows the cumulative number of earthquakes (magnitude ≥ 3.0) occurring in the area, available from the USGS Comprehensive Catalog.

Exhibit 5-4. Locations and timings of Eagle Ford hydraulic fracturing induced events



Used with permission from Schultz et al. (2020)

5.2 Induced Seismicity Research and Development

State regulators have long been focused on identifying the precise location and magnitude of earthquakes and determining their cause. When earthquakes can be linked to wastewater injection, regulators respond by ordering operators to cease or limit either injection rates and/or water volumes in nearby wells (EPA UIC National Technical Workgroup, 2015). Many regulators also require that new injection wells avoid areas near known active faults. In Oklahoma, these techniques have effectively reduced the number of felt earthquakes.

Similar procedures have been applied to hydraulic fracturing operations in some states. That is, when earthquakes are detected, operations are either modified or suspended (AGI, 2017). Oklahoma, Texas, and Ohio have all taken steps to mitigate induced seismicity linked to hydraulic fracturing.

In Texas, the state's Center for Integrated Seismicity Research (TexNet) is charged with monitoring, locating, and cataloging seismicity across the state. Capable of detecting and locating earthquakes with magnitudes ≥ 2.0, TexNet's backbone network improves

investigations of ongoing sequences of seismic activity by deploying temporary seismic monitoring stations and conducting site-specific assessments (Young et al., 2017). TexNet continues to conduct fundamental and applied research to better understand both naturally and potentially induced seismic events that are occurring across the state of Texas, their associated risks, and potential strategies for communicating with stakeholders and responding to public concerns raised regarding seismicity (Young et al., 2017).

Through the DOE-funded RPSEA, University of Texas researchers analyzed data collected by the portable NSF EarthScope USArray program to evaluate seismic hazards in different oil and gas producing regions. Results show that regions need to be studied individually before crafting regulations for injection management strategies due to the following results:

- In the Barnett shale play region, earthquakes occur near high volume injection disposal wells.
- In the Eagle Ford play region, earthquakes are not near injection wells, but follow increases in extraction of water/petroleum.
- In the Bakken play region, there are high volume injection wells but almost no earthquakes.
- There were eight times as many earthquakes in the Fort Worth Basin as reported by the USGS during 2009–2011, based on data collected by the transportable USArray.

Also funded through RPSEA, the Oklahoma Geological Survey in collaboration with the University of Oklahoma, the Oklahoma Secretary of Energy and Environment, and industry have:

- Improved the accuracy of locating earthquakes by adding permanent and portable seismic monitoring stations, the data from which is publicly available through the Oklahoma Geologic Survey's Oklahoma Earthquake Catalog.
- Documented a major increase in salt-water disposal in areas within seismically active areas.
- Mapped previously unidentified basement faults in Oklahoma that are now publicly available in open file maps
- Developed 4-D integrated models for risk assessment (Office of Oil and Natural Gas, 2016)

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6 LAND USE AND DEVELOPMENT

Land presents a critical yet often overlooked constraint to energy development, including the development of domestic natural gas. The growing land use footprint of energy development, termed "energy sprawl," likely causes significant habitat loss and fragmentation with associated impacts to biodiversity and ecosystem services (McDonald et al., 2009). Natural gas is growing as a transition fuel during the grid decarbonization process in the United States, making an understanding of its land use implications a critical and necessary consideration (Dai et al. 2023).

Expanding energy development is now the primary source of anthropogenic land cover change in natural ecosystems in North America (Allred et al., 2015; Trainor, McDonald, and Fargione, 2016), including eastern deciduous forests, boreal forests, prairie grasslands, sagebrush-steppe, and deserts (Copeland, Pocewicz, Kiesecker, 2011; McClung and Moran, 2018; Appiah, Opio, Donnelly, 2019). Land use and development issues associated with natural gas production include local surface disturbance; cumulative landscape impacts; habitat fragmentation; and increased traffic, noise, and light.

The Citizens Marcellus Shale Coalition (CMSC) (2011) explored two issues related to impacts of shale gas production on public lands and the other industries that rely on these lands. They also explored impacts on private property rights. CMSC stated that shale gas development must consider the cumulative impacts on state parks and forests and on timber and tourism industries as part of ensuring responsible stewardship of public resources. Property rights and environmental degradation are a growing public concern, and eminent domain laws, drill spacing requirements, and grouping of leased lands could help protect these rights. These findings are still relevant to current natural gas extraction.

6.1 SURFACE DISTURBANCE AND LANDSCAPE IMPACTS

The infrastructure needed to support the supply chain of electricity produced from natural gas involves production sites (production pads and their access roads), transportation facilities (e.g., gathering and transmission pipelines for natural gas), processing facilities, and power plants (end-use) (Dai et al., 2023). Such activities can disturb the Earth's surface, the impacts of which can extend over large areas and result in habitat fragmentation that impacts both plant and animal species. Mitigation options include adoption of best practices for site development and restoration, avoidance of sensitive areas, and minimization of impacts to disturbed areas.

Dai et al. (2023) used machine learning, remote sensing, and geographic information systems to obtain spatially explicit information on the land required to support natural gas production for use in power plants. Their analysis considered land use across five life cycle stages of natural gas produced for electricity production from wells (production stage), natural gas transportation via gathering pipelines (gathering stage), natural gas processing (processing stage), natural gas transportation via transmission pipelines (transmission stage), and gas consumption as fuel through combustion in gas-fired power plants (use stage).

For the production stage, Dai et al. (2023) mapped land-use for 100,009 wells located at 75,915 different well pads. Among the 100,009 wells examined, 31,716 were co-located. In non-

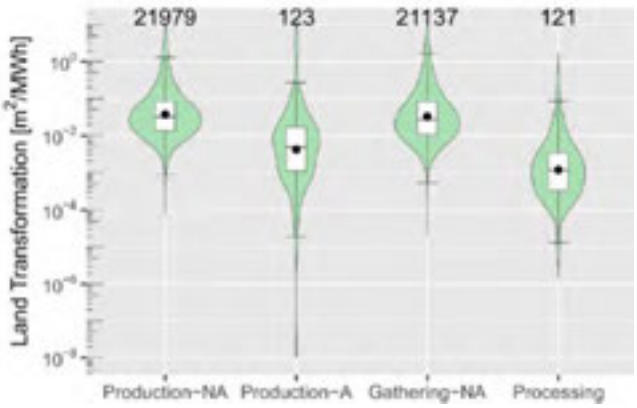
agricultural areas, results suggest vertical wells occupy ~4,000 square meters (m^2) less land per site than horizontal-/directional-drilled wells. During the gathering stage in both agricultural and non-agricultural areas, sites with horizontal-/directional-drilled wells require ~230 meters less pipeline in length on average than sites with vertically drilled wells. Whereas due to the requirement for larger width of right-of-way, the extent of land used is almost doubled for sites with horizontal-/directional-drilled wells than those with vertical wells. Results from Dai et al. (2023) are summarized in Exhibit 6-1.

Exhibit 6-1. Land use for the production, transportation, and processing of natural gas for use in gas-fired power plants

Stage			Unit	Average
Production	Agricultural	Directional	m^2 per site	9,346
		Vertical	m^2 per site	2,100
	Non-agricultural	Directional	m^2 per site	18,170
		Vertical	m^2 per site	14,090
Transportation by pipeline	Length	Directional	m^2 per site	597
		Vertical	m^2 per site	818
	Area	Directional	m^2 per site	20,157
		Vertical	m^2 per site	10,128
Processing			m^2 per (MM cubic feet per day)	4,318

Exhibit 6-2 from Dai et al. illustrates the land transformation by stage, finding that production in non-agricultural areas utilizes more land than agricultural areas.

Exhibit 6-2. Land transformation in natural gas production



Note: NA = non-agricultural area, A = agricultural area

Used with permission from Dai et al. (2023)

Notably, technological advancements will play a significant role in decreasing the amount of land that will be transformed during the life cycle stages of production, gathering, and consumption of natural gas—for both vertical and horizontal/directional wells. Directional drilling technology enables more than 20 wells to be drilled in a single pad, and each well could have a comparable amount of lifetime production. As a result, the total amount of production per site with directional-drilled wells can be an order of magnitude higher than the conventional sites with vertical drilled wells, which dramatically lowers the land transformation for production and gathering (Dai et al., 2023).

6.2 HABITAT FRAGMENTATION

The development of drilling sites for natural gas production can disrupt the habitat of both plant and animal species in several different ways. For example, habitat fragmentation can occur when infrastructure must be installed, or land clearing must take place to allow access to a well location. Land area that is occupied by well pads and the construction of pipelines are two of the leading causes of habitat fragmentation (Cooper, Stamford, and Azapagic, 2016; Langlois, Drohan, and Brittingham, 2017). The land area occupied for shale gas extraction typically can be reduced through the use of multi-well pads at one site, which have a surface footprint (and water use) per well two to four times lower than that of single-well pad sites (Manda et al., 2014).

The construction and installation of the infrastructure necessary for natural gas development can lead to a habitat being converted from a large contiguous patch of similar environments to several smaller, isolated environments. When contiguous core habitats are fragmented into smaller patches, many sensitive species are unable or unwilling to cross non-habitat regions to reach alternative habitat patches. While habitat loss can have an immediate impact on wildlife population, the ecological response to fragmentation is lagged, and affects different species at varying timescales (Makki et al., 2013).

A secondary impact of fragmentation is the creation of edges. Edges are generally defined as the 100 meters between core forest and non-forest habitat (PADEP, 2014; Kargbo, Wilhelm, and Campbell, 2010; Johnson et al., 2010). New edges affect the physical or biological conditions at the ecosystem boundary and within adjacent ecosystems (Fischer and Lindenmayer, 2007). Edge effects are believed to be detrimental by increasing predation, changing lighting and humidity, and increasing the presence of invasive species (Johnson et al., 2010).

Exhibit 6-3 provides a schematic depicting the habitat loss and fragmentation from natural gas production. Exhibit 6-3 progresses from infrastructure development that has quantifiable land impacts leading to temporally extended land changes—impacts that account for habitat loss and fragmentation.

Exhibit 6-3. General procedure for depicting land disturbance from natural gas extraction

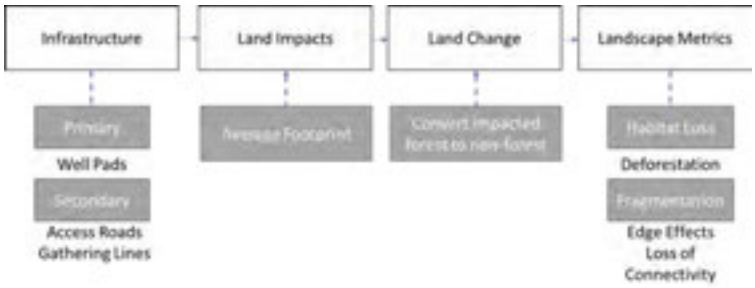
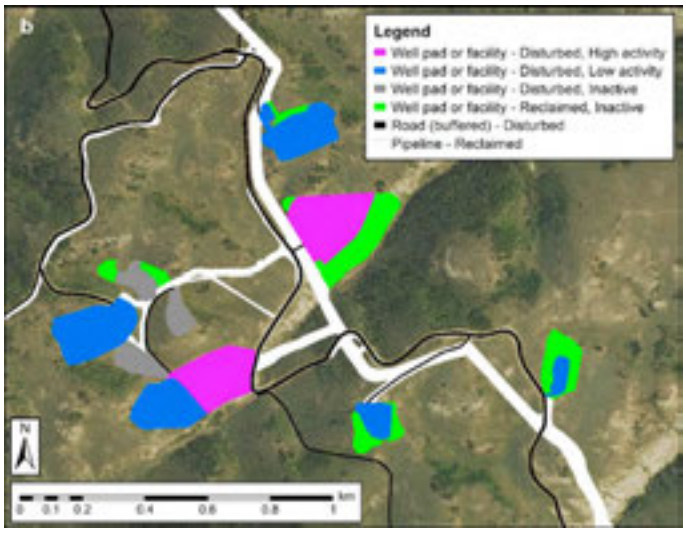


Exhibit 6-4 provides an example of energy infrastructure features digitized from 2013 National Agricultural Inventory Program satellite imagery overlaid with well locations reported in Colorado Oil and Gas Conservation Commission (COGCC) data. Each mapped feature (or portion thereof) was classified by type (well pad, facility, road, or pipeline) and by surface type (disturbed or reclaimed), and well pads and facilities (or portions thereof) were assigned an activity status (high, low, or inactive) (Walker et al., 2020).

Exhibit 6-4. Footprint of a well pad and surrounding infrastructure



Used with permission from Walker et al. (2020)

Each region where natural gas extraction takes place has unique species and habitat therein. Within those species, some are more greatly affected than others, whether it be core habitat fragmentation or edging.

Long-term effects of shale gas production on habitat disturbance will have to be evaluated as the development of these resources continues. Mitigation measures such as avoidance, best management practices, and prompt reclamation of the drilling site have been put forward as ways to best minimize the possible impacts that shale gas production may have on habitats. Habitat disruption can also result from a lack of surface water availability in response to withdrawals to support natural gas production and from erosion and chemical spills.[cc]

6.3 Noise, Light, and Traffic

Natural gas development processes are associated with both noise and light pollution, which can contribute to stress among those living in nearby communities (Down, Armes, Jackson, 2013; Korfmacher et al., 2013; Peduzzi et al., 2013; Witter et al., 2008a; Witter et al., 2008b). Construction, vehicles, drilling, compressors, flaring, and other processing equipment and facilities can all pollute by producing excessive noise and continuous illumination (Cleary, 2012).

6.3.1 Noise Pollution

A health impact assessment in Colorado identified noise pollution as an area of concern and noted that it occurs during drilling and completion operations, flaring, and because of vehicular traffic (Witter et al., 2013). Workers can be exposed to noise through many sources on site, including diesel engines, drilling, generators, mechanical brakes, heavy equipment operations, and radiator fans (Witter et al., 2014); therefore, hearing impairment is a noise-related health concern for workers on site.

A 2010 study using biomonitoring from Texas found residents reporting concerns about odors and noise apparently related to shale gas well and compressor station operations, although this was a separate, independent component from the biomonitoring portion designed to address residents' concerns (Texas Department of State Health Services, 2010). While the authors noted that it was difficult to determine if the levels were above acceptable limits that may be harmful to human health, and that noise may affect quality of life, this is speculative because noise levels were not measured to establish decibels of noise in the study area.

Noise standards for a single well pad may be met; however, the cumulative effects of multiple operations in one area might exceed these established decibel levels. In terms of setback distances, some noise regulations distinguish between maximum decibels for day and night, while others distinguish between maximum decibels for certain phases of the operation such as drilling, fracturing, and production; however, there is often variability and, in some areas, it is suggested that distances are set as monitoring points, not necessarily points indicative of being protective of health (Fry, 2013).

6.3.2 Light Pollution

Light pollution has significant implications for the environment and public health, and its effects have become more pronounced over time due to the increasing extent and radiance of artificially lit areas (Kyba, 2017). Substantial economic values have been attached to affected

[cc] The potential water use implications of natural gas are discussed in Chapter 4 – Water Use and Quality.

outcomes, such as biodiversity, recreation, and public health. With respect to human health, artificial lights at night are associated with sleep deprivation and mental health (Patel, 2019; Xiao, 2020); sleep deprivation, in turn, has been shown to reduce cognition and labor market productivity, as well as elevate mortality risks associated with dementia, heart attacks, and vehicle accidents (Hafner et al., 2017; Paksarian et al., 2020; Ma et al., 2020; Jin and Ziebarth, 2020; Prats-Uribe, Tobías, and Prieto-Alhambra, 2018.). A study in Australia quantified the financial and non-financial costs of inadequate sleep in 2016–2017 to be $45 B (Hillman et al., 2018) and another study estimates that $680 B is lost due to sleep deprivation across five Organisation for Economic Co-operation and Development (OECD) countries (Hafner et al., 2017; Boslett, 2021).

The impacts of light pollution also extend to human health and well-being. Artificial light disrupts melatonin secretion and circadian rhythm (Haim and Zubidat, 2015) with corresponding changes in mood regulation, depression, and sleeping disorders (Cho et al., 2016). Light pollution-driven changes in circadian rhythms may also have contributed to recent growth in obesity and metabolic dysfunction (Fonken et al., 2010). Growing laboratory and epidemiological evidence also support the long-hypothesized relationship between nighttime light exposure and cancer rates (Kerenyi, Pandula, and Feuer, 1990; Kloog, et al., 2010; Schwimmer et al. 2014; Jones, Pejchar, and Kiesecker, 2015).

Light pollution also has significant consequences for wildlife populations. It affects nighttime behavior and habits of terrestrial (Bennie et al., 2015) and marine (Davies et al., 2013) wildlife populations, particularly for species that use sunlight or moonlight for guidance. It disrupts natural sleep and reproductive cycles, geographical orientation, and predator-prey relationships (Longcore and Rich, 2004). Other effects of light pollution include changes in bird singing behavior (Miller, 2006), estrus patterns in nocturnal primates (LeTallec, Théry, and Perret, 2015), insect pollination (MacGregor et al., 2015), and fish biological rhythms (Brüning et al., 2015). These impacts have led to ecosystem-wide changes in biodiversity and growing disparities between entire taxonomic groups (Davies et al., 2013).

While there is some work speculating that light pollution associated with shale development induces psychosocial stress (Fisher et al., 2017), sleep and mental health issues (Casey et al., 2018), and adverse impacts to local ecosystems (Kiviat, 2013), the literature directly connecting the recent resource boom to light pollution is extremely limited. No work has documented the causal impact of U.S. shale development on light pollution.

6.3.3 Traffic

Traffic may increase in any given area because of unconventional natural gas development, but the magnitude of this increase has not been studied in depth. The phases of development that require the most traffic load involve well pad construction, drilling and well completion, and pipeline construction (Witter et al., 2014). It appears that changes in traffic patterns will be dependent upon the area and either the individual project or the cumulative effects of multiple projects in an area. Industrial truck traffic can be detrimental to health-related air quality due to vehicle exhaust, as well as pose an increased risk of motor vehicle crashes.

In the *Revised Draft Supplemental Generic Environmental Impact Statement on The Oil, Gas and Solution Mining Regulatory Program*, the New York State Department of Environmental Conservation (NYSDEC) identified temporary but adverse noise and visual impacts from construction activity and increased truck traffic among the potential land-use environmental impacts associated with natural gas production (Witter et al., 2014). Significant adverse impacts in terms of damage to local and state roads could also result. Among mitigation measures described for environmental impacts, NYSDEC suggests imposing measures to reduce the adverse noise and visual impacts from well construction. A transportation plan could also be required that would include proposed truck routes and assess road conditions along the proposed routes. Exhibit 6-5 tabulates the number of truck trips for a typical shale gas well (Massachusetts Institute of Technology [MIT], 2011).

Exhibit 6-5. Truck trips for a typical shale gas well drilling and completion

Activity	1 Rig, 1 Well	2 Rigs, 8 Wells
Pad and Road Construction	10–45	10–45
Drilling Rig	300	60
Drilling Fluid and Materials	25–50	200–400
Drilling Equipment (casing, drill pipe, etc.)	25–50	200–400
Completion Rig	15	30
Completion Fluid and Materials	10–20	80–160
Completion Equipment (pipe, wellhead, etc.)	5	10
Fracturing Equipment (pump trucks, tanks, etc.)	150–200	300–400
Fracture Water	400–600	3,200–4,800
Fracture Sand	20–25	160–200
Flowback Water Disposal	200–300	1,600–2,400
Total	**1,160–1,610**	**5,850–8,905**

The large volumes of water involved in hydraulic fracturing operations can create high volumes of road traffic given the majority of the water used for fracking is transported by truck. It should be noted that the large number of traffic movements shown in Exhibit 6-5 are worst-case estimates. In particular, re-use of flowback wastewater significantly reduces the amount of road traffic associated with hauling water, which represents much of the traffic movement. Furthermore, large-scale operators are also using pipelines to transport water to the site, substantially reducing the amount of road traffic (MIT, 2011).

The Eagle Ford Shale Task Force Report for the RRC identified increased traffic and deterioration of roads and bridges among the infrastructure impacts from shale gas development (Porter, 2013). Exhibit 6-6 lists estimates of the number of truck-trips-per-shale-gas-well in the Eagle Ford (Porter, 2013).

Exhibit 6-6. Loaded truck trips per gas well

Activity	Number of Loaded Trucks
Bring well into production	1,184
Maintain production (per year)	Up to 353
Re-fracturing (every 5 years)	997

These impacts are enough of a concern that the task force considered alternative financing methods to help meet the increased demands on roads and bridges (Porter, 2013).

Upadhyay and Bu (2010) surveyed the visual impacts of Marcellus drilling and production sites in Pennsylvania. They reviewed the drilling process, assessed direct visual impacts, and compared the results to the impacts of other technologies (e.g., windmills and cell towers). They also studied drill-pad density from map and aerial perspectives to examine the likelihood of seeing drill towers across a landscape, and the modeled potential impacts for increased drilling, making the following conclusions:

- Serious impacts from light and noise are a potential problem within a small radius of drilling sites.
- Indirect impacts like increased truck traffic, equipment storage, and temporary structures compose the most salient visual impacts, rather than the drill pads themselves.
- Timelines for site restoration of visual impacts vary significantly.

Upadhyay and Bu (2010) recommended that visual impacts be addressed during the siting and design phase and that nighttime impacts could be avoided by pointing lights downward.

The Resources for the Future (RFF) (2013) report also gave several options in their survey of experts under the category of community disruption. Included in this category, as well as in the habitat fragmentation section, were such risks as light pollution, noise pollution, odor, and road congestion. The industry respondents identified a number of these community disruptions as risk pathways of high priorities, while the other respondent groups identified more conventional (e.g., air pollution, water pollution) risks.

6.4 Reducing Potential Land Use Impacts

Linear infrastructure on private land contributed to the greatest loss of core forest. Unlike private land, the majority of pipelines on public land were collocated with roads, which likely reduced habitat fragmentation. Large public landowners can negotiate with a relatively small number of gas operators compared to private landowners (PADEP, 2016); therefore, individual landowners can make deals with different operators such that two different operators end up working in close proximity and duplicating infrastructure on private land rather than public land.

6.4.1 Mitigation Options for Habitat Fragmentation Impacts

Mitigation strategies related to pipelines enacted by state agencies have shown that fragmentation on public lands has been reduced more than on private lands, especially when multiple mitigation strategies are implemented on public land with the goal of reducing surface disturbance and impacts to forest. For example, the Pennsylvania Department of Conservation & Natural Resources (PADCNR) can limit the number of well pads per leased track (PADCNR, 2014). This method constrains development intensity (i.e., pad density) and encourages operators to increase the number of wells per pad, thereby maximizing per well drainage and efficiency (DOE, 2016). A widely implemented mitigation policy on state forest land requires gas infrastructure to utilize existing surface disturbance whenever feasible, including road networks, right-of-way corridors, or abandoned mine lands (PADCNR, 2014).

Similarly, Abrahams, Griffin, and Matthews (2015) found that requiring pipelines to follow existing roads prevented further fragmentation in a core forested region while allowing full extraction of the shale resource. Collocation is widely accepted as an effective mitigation strategy to reduce surface impacts (Bearer et al., 2012; Racicot et al., 2014); however, it rarely occurs on private land.

6.4.2 Reducing Light Pollution

Even two decades after the establishment of designated programs by NGOs to recognize and certify the quality of night skies and nighttime darkness resources, the very notion of what a "dark sky" is remains unsettled from a scientific standpoint (Crumey, 2014); while appropriate instrumentation can quantify night sky brightness, it cannot properly account for the human aesthetic experience of natural night. However, various lines of research increasingly suggest that unsafe thresholds of exposure to artificial light at night in terms of intensity, duration, wavelength, and timing likely exist for humans, plants, and animals. In this sense, light-sensing technologies applied in the field could effectively serve as "dosimeters" for monitoring these exposure parameters (Barentine, 2019).

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7 ~~JUSTICE~~ SOCIETAL CONSIDERATIONS FOR NATURAL GAS DEVELOPMENT

~~Granting authorizations to import and/or export natural gas into and from the United States could potentially generate and, in some cases, further perpetuate instances of energy, environmental, and social injustice. As disadvantaged communities (DACs) have long borne the brunt of the environmental impacts associated with energy development – such as those associated with natural gas production and related activities as described in the previous five chapters - it is critical the DOE's Natural Gas Regulatory Program has access to information that permits the promotion, advancement, and evaluation of energy, environmental, and social justice (hereafter, justice) in granting authorizations to import and/or export natural gas into and from the United States. As such matters are also factors affecting the public's interest.~~

The production and transportation ~~use~~ of natural gas in the United States, including natural gas exports, carries implications to energy, environmental, and social justice. Many of the nation's upstream natural gas production sites and transportation corridors are co-located in or near disadvantaged communities (DACs), and these communities bear disproportionate exposure to environmental risks and other types of harms that arise from these activities – even as some of them also rely on these activities to sustain their economies. ~~given the~~~~The promotion and advancement of justice requires first identifying~~ exposures to harms and burdens and then ~~ensuring such exposures are minimized, especially for DACs~~.

This chapter aims to 1) provide ~~information and potential guidance~~background on approaches to consider societal issues ~~for ensuring justice~~ during energy project planning, which is directly transcribable to natural gas market operations; and 2) provide ~~the public with~~ information on ~~how~~approaches specific to ~~the~~ DOE ~~has been considering justice~~. As natural gas is projected to play a significant role during the current energy transition, this chapter discusses societal considerations and justice concepts within the context of large-scale energy infrastructure planning decisions designed to enable the United States to achieve its goal of net-zero emissions by 2050. The review begins with a discussion of energy justice which includes a presentation of Spurlock et al.'s (2022) "Deep Decarbonization Framework," which aims to incorporate the three tenets of energy justice into energy infrastructure planning decisions.

The provision of information and potential guidance for ensuring a consideration of societal issues and justice during natural gas project planning is presented in terms of how DOE and some major energy companies are actively considering and incorporating justice-related concepts within their decision-making frameworks. This chapter ~~will~~ specifically discusses how DOE is incorporating societal considerations and justice strategies ~~in their~~ as part of efforts to right historical wrongs, including a summary of ~~what~~ tools ~~they have~~DOE has made available to understand how investments are distributed to DACs, and how justice is being incorporated into strategic plans.

~~These types of considerations drove the implementation of the Biden-Harris Administration's Justice40 initiative, which was mandated under Executive Order 14008 and has the explicit goal~~

that 40 percent of the overall benefits from certain federal investments flow to DACs (DOE, 2023b).[a] Introducing the Justice40 (DOE, 2023b) initiative framework to the ways in which the government measures the distribution of investment benefits attempts to right the historical wrongs of energy development—that is, to correct the historical missteps that have resulted in the inequitable, unequal outcomes seen today.

Doing so prior to the commencement of an investment also permits the identification of potential but not yet realized (i.e., a priori) positive and negative impacts to DACs. One avenue for identifying a priori impacts to DACs is through the development of a community benefits plan (DOE, 2022a). A community benefits plan is typically guided by four core policy priorities:

1. Meaningfully engaging communities and labor
2. Investing in America's workforce
3. Advancing diversity, equity, inclusion, and accessibility
4. Implementing an environmental justice plan the Justice40 Initiative

These key principles, when incorporated comprehensively into a project proposal—and fully executed on—help to ensure justice (DOE, 2022a; 2023b).

A central component of any community benefits plan is actively engaging with communities. The DOE's Office of Fossil Energy and Carbon Management (FECM) has created specific planning guidance for fostering community inclusion in the planning process for large energy infrastructure projects. The guidance promotes inclusive and sustainable outcomes that reflect community visions around stakeholder engagement with communities and tribes; diversity, equity, inclusion, and accessibility plans; explicitly focuses on Justice40 goals; and the creation of quality jobs (FECM, 2022a; FECM, 2022b). This includes a clearly defined framework for engagement that prioritizes meaningful two-way communication (FECM, 2022c).

As research on the ways in which justice concepts are being considered for natural gas market activities is limited, this chapter aims to 1) provide information and potential guidance for ensuring justice during energy project planning, which is directly transcribable to natural gas market operations; and 2) provide the public with information on how the DOE has been considering justice. As natural gas is projected to play a significant role during the current energy transition, this chapter discusses justice concepts within the context of large-scale energy infrastructure planning decisions designed to enable the United States to achieve its goal of net-zero emissions by 2050. The review begins with a discussion of energy justice which includes a presentation of Spurlock et al.'s (2022) "Deep Decarbonization Framework," which aims to incorporate the three tenets of energy justice into energy infrastructure planning decisions.

The provision of information and potential guidance for ensuring justice during natural gas project planning is presented in terms of how DOE and some major energy companies are

[a] Covered investments include those related to the clean energy transition both in energy production and the advancement of net-zero emission transportation, including affordable housing and "green" workforce development and training, as well as those focused on remediation of legacy pollution, clean water initiatives, and wastewater projects.

~~actively considering and incorporating justice-related concepts within their decision-making frameworks. Information will specifically discuss how DOE is incorporating justice strategies in their efforts to right historical wrongs, what tools they have made available to understand how investments are distributed to DACs, and how justice is being incorporated into strategic plans.~~

7.1 Energy Justice

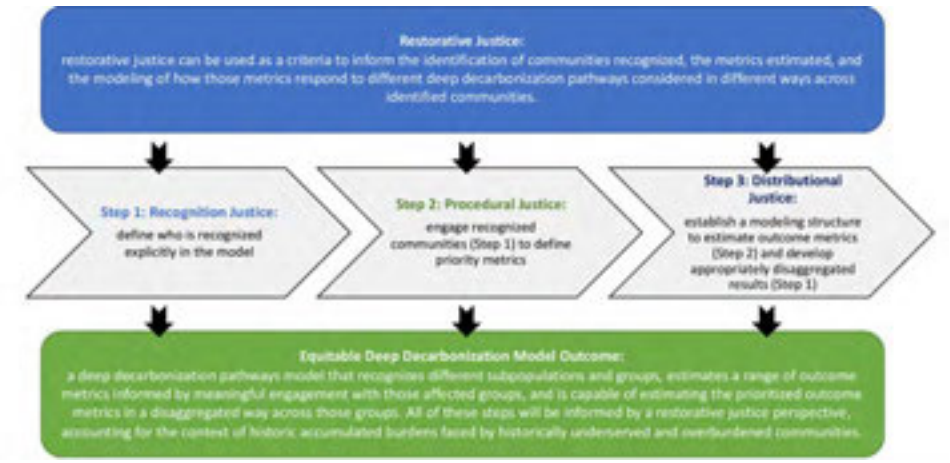
DOE defines energy justice as the goal of achieving equity in both the social and economic participation in the energy system, while also remediating social, economic, and health burdens on those who have historically been disproportionally harmed by the energy system (DOE, 2022b). Energy justice explicitly centers the concerns of communities—in particular those at the frontline of pollution and climate change, working class people, indigenous communities, and those historically disenfranchised by racial and social inequity (e.g., DACs) (Initiative for Energy Justice, 2023). A just energy system is one in which energy is accessible, affordable, clean, and democratically managed for all communities (Initiative for Energy Justice, 2023).

Qian et al. (2022) describe energy justice as focused on considering the fairness with which energy policies are implemented and other energy-related decisions are made. Using energy justice as a decision-making framework, Iwińska et al. (2021) outline the focus of this emerging area of literature as one that seeks to both understand and consider how the policy-making framework surrounding the production and consumption of energy resources can be fairer—for example, understanding how the implementation of a new energy policy designed to lower emissions would impact rates of energy poverty (i.e., percent of households who are unable to meet their energy needs) (Bednar and Reames 2020).

Noting the need to consider how energy policies and other decisions (that are being designed to enable the U.S. to achieve its deep decarbonization targets) might perform in terms of their influence on justice, Spurlock et al. (2022) developed the "Equitable Deep Decarbonization Framework"—see Exhibit 7-1. Anchored in the core tenets of recognition, procedural and distributional justice (each discussed in the following sub-sections of this report) the framework represents an effort to create a shared language and enable meaningful collaboration between scholars and practitioners of energy justice and modelers of decarbonization.

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Exhibit 7-1. Flow of energy justice decisions



Used with permission from Spurlock, Elmallah, and Reames, 2022

7.1.1 Recognition Justice

At its core, recognition justice deals with respect and consideration. Spurlock et al. (2022) present the concept as a demand to recognize that divergent views exist on how policymakers can best address issues of energy justice. Those views reflect the unique, diverse backgrounds of individual communities, and that their perspectives and opinions reflect their unique histories. Incorporating those voices in the energy transition is critical to ensuring policymakers implement project development that seeks to serve all. Equitable outcomes begin with the recognition that disenfranchised communities must be re-enfranchised and re-empowered to ensure their histories and perspectives are heard in a meaningful way.

7.1.2 Procedural Justice

Spurlock et al. (2022) present procedural justice as essentially the effort to include all voices. This is the idea that DACs are overburdened and underserved, and their disenfranchisement can only be corrected when their voices are intentionally included in the start-to-finish process of advancing project and policy development. In other words, stakeholder engagement must be done early and often to ensure the priorities of DACs are of primary focus as the priorities of the project or policy.

7.1.3 Distributional Justice

Distributional justice is focused primarily on both the equitable and inequitable distribution of benefits across communities (Spurlock et al., 2022). It is a concept focused on the well-being of individuals, which spans the gambit of human outcomes such as psychological well-being, societal well-being, and physiological well-being (Deutsch, 1975). Distributional justice delves

into the question of which matters more—equity or equality—and where need might dominate when identifying unjust distributions.

Fairness is a key concept within distributional justice and can be characterized as a problem for geospatial analysis (Bouzarovski and Simcock, 2017). Across the energy supply chain, distributional justice is a problem of implied risk responsibility as well as costs and benefits (Heffron and McCauley, 2014). In addition to inequities created by a historical lack of inclusiveness is the risk that those structural deficits will compound under a changing climate. In other words, unless addressed, the deficits of the past will likely increase as the climate changes—much like a revolving line of credit tends to grow faster over time when a balance is carried from one period to the next.

7.2 JUST ENERGY TRANSITIONS

The current energy transition presents a generational opportunity to make significant progress in ameliorating historical injustices (Wang and Lo, 2021). As technology has evolved and capital has flowed into large-scale energy infrastructure investments, a concerted effort to accrue the economic and social benefits associated with these technologies and investments in DACs may prove fruitful in spurring a more just outcome from the energy transition. Equally possible is the ability to start mitigating the systemic injustices that have plagued these same communities in response to historical decision-making.

This is not always as clearcut as it might seem. For example, the wholesale shift toward and then away from natural gas use is harmful to communities reliant upon energy industry revenues—especially when local governments tie public services and infrastructure investments to these revenues (Haggerty et al., 2018). Fully considering the need to balance an energy transition with preserving local government functionality requires a goal-setting process that includes these nuanced considerations.

Articulation of these goals can be achieved by addressing a handful of broad topics including poverty reduction (Lo and Broto, 2019; Koehn, 2008; Colenbrander et al., 2017), amelioration of historical energy injustices (Jasanoff, 2018; Delina and Sovacool, 2018; Carley and Konisky, 2020), and opportunities for economic growth (Yang, Cao, and Lo, 2018; Ehresman and Okereke, 2015). Wang and Lo (2021) argue that the energy transition is an apt vehicle for fixing historical wrongs if it can simultaneously account for environmental costs DACs already suffer from; the reality that climate change will likely exacerbate these pre-existing environmental costs; and a decision-making process steeped in the tenets of assuring energy justice.

Moving forward into a new energy landscape that is sustainable requires policymakers to try and avoid repeating historical injustices—emphasizing the need to empower communities through efforts like Community Benefits Plans and Agreements with justice frameworks (the bedrock of transition planning) (Wang and Lo, 2021; Williams and Doyon, 2019). Pai, Harrison, and Zerriffi (2020) provide the framework for researchers to consider strategies to preserve the well-being of fossil-fuel-reliant communities that are at risk of large, sudden population losses when the primary industry disappears. Preserving the human capital of these communities is a critical goal for ensuring the energy transition policy provides opportunities for all. Pai,

Harrison, and Zerriffi (2020) summarize more than a dozen requirements that would facilitate policymaker efforts to ensure a just transition, but they underscore one: the requirement of intentional effort for long-term planning with routine efforts to conscientiously engage with affected communities.

Community Benefits Plans

Community benefits plans are a key element of the Biden-Harris Administration's Justice40 initiative, which was mandated under Executive Order 14008 and has the explicit goal that 40 percent of the overall benefits from certain federal investments flow to DACs (DOE, 2023b).[b]

Guided by the Justice40 initiative, The DOE's Office of Fossil Energy and Carbon Management (FECM) has created specific planning guidance for fostering community inclusion in the planning process for the research that it funds, which includes large energy infrastructure projects such as carbon capture and storage facilities. The guidance promotes inclusive and sustainable outcomes that reflect community visions around stakeholder engagement with communities and tribes; diversity, equity, inclusion, and accessibility plans; explicitly focuses on Justice40 goals; and the creation of quality jobs (FECM, 2022a; FECM, 2022b). This includes a clearly defined framework for engagement that prioritizes meaningful two-way communication (FECM, 2022c) and the development of a community benefits plan. (DOE, 2022a).

DOE's community benefits plans are guided by four core policy priorities:

1. Meaningfully engaging communities and labor
2. Investing in America's workforce
3. Advancing diversity, equity, inclusion, and accessibility
4. Implementing an environmental justice plan These key principles, when incorporated comprehensively into a project proposal—and fully executed on —help to ensure justice (DOE, 2022a; 2023b).

A central component of the community benefits plan is actively engaging with communities. Doing so prior to the commencement of an investment also permits the identification of potential but not yet realized (i.e., a priori) positive and negative impacts to DACs.

7.2.1 Fossil Fuel Employment and Revenue

One aspect of ensuring a just energy transition for the United States is the management of unemployment in fossil-fuel related industries—including industries that produce and consume natural gas. There is an associated risk that pivoting away from fossil fuel resources too quickly

[b] Covered investments include those related to the clean energy transition both in energy production and the advancement of net-zero emission transportation, including affordable housing and "green" workforce development and training, as well as those focused on remediation of legacy pollution, clean water initiatives, and wastewater projects.

removes employment opportunities in regions that have long relied on these industries for economic support (i.e., where these industries have provided the bulk of available jobs and have historically been the core driver of local economic growth). Fossil fuel-related jobs losses can result in a significant loss to local government revenues, long-term declines in the economy, and a potential cycle of population loss from which a region is unable to recover.

In many regions of the United States where fossil fuel industries have historically dominated, unions are mobilizing to "ensure that the transition to a clean energy economy keeps workers at the center—all the while benefitting the greater communities in which they live" (Department of Labor, 2023). Unions are viewed as invaluable structures for elevating and empowering the voices of DACs in the energy transition (Pai, Harrison, and Zerriffi, 2020; Newell and Mulvaney, 2013). Energy industries have a high unionization rate (Pai and Carr-Wilson, 2018) making them a practical vehicle for members to advocate for their communities and achieve a just transition[c] (Stevis and Felli, 2015). Directly approaching unions as potential enablers of cooperation with communities can help avoid rupturing communities through the kinds of mass, unplanned job loss that exacerbates population flight.

Often, mass job loss leads to dying communities characterized by broad negative health and social impacts. Intentional efforts to diversify local economies would increase the resilience of local economies (Lobao et al., 2016). Notably, increasing the diversity of local economies is a positive as it introduces a greater resilience and broad, regional growth (Freudenburg and Gramling, 1994).

Among the opportunities a just transition presents is the ability to reduce the gender gap in regions dominated by the fossil fuel industry, increase investment into local energy infrastructure, remediate historical environmental damage, retrain the local workforce to "skill up" the region's human capital, and shore up local government revenues through economic diversification (Pai, Harrison, and Zerriffi, 2020).

In the end, just transitions are achieved when local voices are not just heard but amplified during the energy transition process. This starts when governance strategies acknowledge the dignity of DACs and groups and engage those communities and groups in less divisive governance strategies (Grossmann and Trubina, 2021).

7.3 Energy Governance and Adaptive Management

Governance structures play a vital role in transitioning away from a carbon intensive economy, but the ability of these structures to provide an equitable or just transition is not guaranteed (Moss, 2009). Incorporating the concept of just outcomes begins with the governance structures of energy project development and planning (Newell and Mulvaney, 2013). Those who are in the position of governance are in a position of authority to achieve more equitable outcomes to benefit disadvantaged populations (Florini and Sovacool, 2009).

As Florini and Sovacool (2009) point out, governance is not simply government. Governance is an activity in which governments participate, but governance provides the framework that

[c] The term "just transition" originated within community-organizing efforts centered on labor unions (Eisenberg, 2018).

aligns the goals of government and intergovernmental organizations, while incorporating the needs of the private sector market participants and communities to collectively manage a process that ideally serves all groups. Even companies steeped in natural gas and oil industries recognize their responsibility to contribute to the transition and have established their own net-zero commitments and plans that need to be considered in broader energy governance strategies. A Baker Hughes's (2022) report outlined their efforts to meet company Diversity, Equity, and Inclusion goals; successes in reducing their own greenhouse gas emissions profile by 23 percent as compared to 2019 levels, and their $492 MM commercial innovation efforts in clean energy technologies such as hydrogen and carbon capture and storage (Baker Hughes, 2021).

Governance is necessary given two issues with which economists often wrestle. One issue is that society is not capable of ensuring equitable access to public goods and services without some overarching set of rules to facilitate that outcome and a governance structure to underpin such requirements and drive implementation. Another issue is that any economic or social activity tends to create what economists call “externalities.” That is, there are unintended results that can occur indirectly from the consumption of goods, provision of services, or other social interactions stemming from these activities.

The decommissioning of a coal power plant is a prime example of the need for governance to protect the public’s well-being from externalities, as an idle power plant could become the source of negative health outcomes for a community without intentional efforts to prevent such outcomes. Governance structures are necessary to deal with these two conceptual issues because there is no economic incentive to do so otherwise (Florini and Sovacool, 2009).

Perspectives can clearly vary within communities and that variation can affect governance structures (Wang and Lo, 2021). Community engagement is important, but it is not the magic elixir that solves the problem by itself. Ciplet and Harrison (2019) identify three conflicts that emerge in the effort to facilitate an energy transition: 1) between inclusivity and sustainability where inclusive processes that invite community engagement require more time to complete projects; 2) between sustainability and the need to recognize the unique value system for each community, which increases the complexity of sustainability goal pursuits; and 3) between equity and sustainability, meaning that the distribution of costs and benefits can conflict with or possibly detract from project performance.

In short, the lack of consideration for energy justice issues within the global framework of energy governance will likely perpetuate historical disadvantages within communities (Symons and Friederich, 2022). This is a function of existing power structures within current governance frameworks. Beyond that, Symons and Friederich (2022) show that the political sovereignty of communities making independent decisions over energy project development will always result in outcomes that serve each group’s self-interest and ignore the related externality problems. Without intentional adjustments to governance that deal with these structural problems, the current paradigm will continue to create winners and losers and perpetuate the current disenfranchisement of some communities and the diverse stakeholders living and working there.

Good governance strategies for energy project development require support from the government, reliable capital and operational funding, diversification goals for the economy, and diverse coalitions (Wang and Lo, 2021; Cha, Wander, and Pastor, 2020). Finally, the creation of ownership stake opportunities at the onset of project development for DACs is critical to ensuring that the tradeoffs between disenfranchised communities and the regional benefits of energy projects ameliorate losses. Greater rates of acceptance have been found to exist within communities with larger ownership stakes in energy projects (Hogan et al., 2022).

7.4 Justice Considerations for Natural Gas

Natural gas will remain a key player in meeting energy demand throughout the energy transition. However, ~~as we are increasingly~~there is increased focused on justice concerns, particularly with energy development it is crucial to recognize both the opportunities and challenges that natural gas production and related activities present.

~~For example, natural gas flaring has the potential to harm the health of both humans and non-humans (i.e., animal species) yielding flaring a significant justice related matter concerning the distribution of risks, benefits and harms, and recognition of rights for communities where activity occurs (Aigbe et al. 2023).~~

While justice related concerns for natural gas production and related activities is an emerging area of research, the environmental effects of these activities on communities have been the subject of significant study and government regulation. As discussed in the preceding chapters, natural gas industrial activities can impact local air and water quality. For example, natural gas flaring has the potential to harm the health of both humans and non-humans (i.e., animal species) yielding flaring a significant justice related matter concerning the distribution of risks, benefits and harms, and recognition of rights for communities where activity occurs (Aigbe et al. 2023).

Additionally, hydraulic fracturing and injection of water for disposal purposes can induce seismic activities that impact local communities. Communities are also impacted by land use for natural gas industrial activities. In addition to preventing other uses of land, these activities can cause noise and light pollution.~~been being studied for a while.~~

There have also been studies of the local economic impacts of natural gas development. ~~For example, hydraulic fracturing in the early 2000s incited an economic boom for many communities in the Marcellus Shale region. Soon after concerns by residents within the communities hosting these projects led to research focused on how the size and composition of local populations, the development of local infrastructure, and the services being provided in these communities changed in response.~~

These studies found that the long-term impact of natural gas market expansion has been muted in terms of population growth. Communities that struggled with population loss or benefited from population gains prior to the expansion of activity tended to demonstrate the same patterns even after the initial bump from natural gas expansion, though many communities

found the composition of their communities skewed more toward younger men as a result of natural gas investments (Jacquet, et al., 2018). Longitudinal studies focused on younger, rural Pennsylvania youths in the Marcellus Shale region reported these persons were more optimistic expectations for their futures as a result of the boom in natural gas activity; while older adults presented more mixed opinions as they tend to consider the impacts beyond job opportunities such as increased traffic, higher rents, and generally a higher cost of living as a result of the temporary influx of people (McLaughlin et al., 2017).

The disparate concerns over natural gas project development within communities presents an opportunity to empower locals. Empowering these communities to monitor socioeconomic impacts of technologies similar to hydraulic fracturing have had somewhat unintended consequences overseas. By engaging communities in monitoring efforts, these projects bring them together in a way that empowers their voices, increases their participation in the planning process, and results in more benefits accruing within community households than when the community is excluded. This requires intentionality, consistency, and follow-through on the part of policymakers to ensure community voices have the platform to share their concerns (Haggerty and McBride, 2016). Broadly speaking, the provision of strong monitoring systems to preserve air quality and environment are key to enabling communities to trust that projects are authentically invested in the protection of household safety and security (DOE, 2022d).

Broad research into how private industry gains acceptance to engage in natural gas project development illustrates the importance of social justice in project developers' approach to the community. Across forty interviews held in Wyoming, Walsh and Haggerty (2020) revealed landowners and stakeholders largely pointed to the need for project development approaches to be rooted in procedural fairness, the demonstration of respect for communities needs and choices, as well as a fundamental sense of trust.

-While only around 13% of U.S. natural gas production occurs on federal lands, leases for oil and gas production on federal lands are administered by the Department of Interior are subject to review under NEPA that requires review for environmental impacts as they pertain to the human environment.

Commented [TC1]: 13% based on natural gas production from Federal lands of 4,882,439.827 mmcf in 2022 from ONNR (https://revenuedata.doi.gov/query-data?dataType=Production) and a value of 43,385,576 mmcf for total U.S. natural gas marketed production in 2022 from EIA (Natural Gas Marketed Production (eia.gov)).

Commented [TC2]: The National Environmental Policy Act (NEPA) applies to the execution of many of the Department of Interior's responsibilities with the goal of ensuring that information regarding environmental impacts is available to decision makers and the public before decisions are made . National Environmental Policy Act (NEPA) | U.S. Department of the Interior (doi.gov)

7.5 DEPARTMENT OF ENERGY ~~JUSTICE~~ INITIATIVES WITH JUSTICE COMPONENTS

The DOE has long been an active participant in efforts to ameliorate the negative impacts of legacy emissions and pollution while facilitating the pivot toward a more sustainable energy future. DOE's effort includes several programmatic responses where DOE plays a leading role in administrating change such as the Undocumented Orphan Wells program to target emissions and pollution from historical fossil fuel impacts on communities, as well as the Methane Mitigation Program, which focuses on today's use of fossil fuels. In addition, many of DOE's existing programs fall under covered programs within the Biden/Harris Administration's Justice40 Initiative. Beyond this, DOE is actively building out the capacity of the broader public to measure the state of disadvantage at the community level through the development of its Climate and Economic Justice Screening Tool.

7.5.1 Justice40 Initiative-Covered Programs

DOE has over 140 programs covered under the Biden/Harris Administration's Justice40 Initiative. Demonstrating the department's long-standing commitment to equity and social justice, many of these programs are decades-old efforts to ameliorate impacts of DACs across seven areas covered by Justice40 Initiative. That includes programs targeting climate change, sustainable and affordable housing, the remediation and reduction of legacy pollution, development of clean water and wastewater infrastructure, workforce development and training, development and preservation of sustainable and affordable housing, and cleaner transit options, as well as clean energy and energy efficiency (DOE, 2021).

DOE prioritizes social justice across myriad programs that focus on outcome-specific programs such as workforce development and holistic, process-oriented organizing efforts. Under DOE's Office of Economic Impact and Diversity, the Minority Education, Workforce Development, and Training Program supports small businesses, institutions that serve minorities explicitly, and nonprofits with grants targeting science, technology, engineering, and mathematics educational opportunities; strategic capacity building; general workforce development; and assistance in technical issues. From a holistic perspective, DOE initiated the Domestic Engagement Framework under FECM as an organizing structure to facilitate cohesive community engagement across stakeholders and tribes in an effort to deploy clean technologies. Built from a five-part series of engagement principles, the framework prioritizes two-way engagement, proactive engagement early in the process, place-based engagement, community-based knowledge, and the concerted effort to build out the capacity for community engagement (FECM, 2022a; FECM 2022b).

In deploying holistic frameworks to outcome-specific programs, DOE sets out a process-oriented mission within targeted efforts to foster the ability for communities to lead alongside federal agencies toward more equitable outcomes.

~~7.5.1~~7.5.2 Undocumented Orphan Wells Program

Under the Infrastructure Investment and Jobs Act of 2020, DOE was mandated with the directive to facilitate a targeted push to accelerate the energy transition. Within this package, DOE was charged with administering $4.7 B under the Undocumented Orphan Wells Program to plug, remediate, and reclaim orphaned wells.

Orphaned wells are oil or gas wells that were formerly productive in the nonrenewable extraction industry, but whose ownership status became unclear or nonexistent after operations ceased. In most cases, the firm with historical ownership of the wells no longer exists due to bankruptcy or the abandonment of the well occurred so long ago that ownership responsibilities could not be determined. As such, there is no readily identifiable entity or person with the responsibility to maintain the closure of the well in a manner that prevents the leakage of methane, hydrocarbons, or other miscellaneous chemicals and toxins that tend to pollute the surrounding areas, harm wildlife, increase the likelihood of disease in nearby

communities, and/or reduce the economic development and overall prosperity within the affected areas.

The exact number of wells is unknown, though current estimates of 300,000–800,000 wells implies the magnitude of potential impacts from orphan wells is significant (Interstate Oil and Gas Compact Commission, 2021). Coordinating across a handful of other federal agencies, lower-level governments, the Interstate Oil and Gas Compact Commission, and Indian Tribes, DOE created a research consortium at five national laboratories to find and characterize orphaned wells across the nation (DOE, 2022c).

~~7.5.2~~7.5.3 Methane Mitigation Program

Originally known as the Resource Technologies and Sustainability Program, DOE operates the Methane Mitigation Program under FECM. This program targets the non-trivial levels of methane emissions that emanate across the oil and gas value chain of current usage. This includes emissions produced in the upstream production of methane, emitted in the midstream processing efforts, produced in the transportation of methane, and escaping during the end-use consumption of oil and natural gas.

The primary goals of this program focus on preventing emissions across the value chain via data collection and processing efforts. Direct and remote emissions sensor technologies are deployed to identify leakage at its source. Data generated from this collection process is then passed through a data collection pipeline to then facilitate the funding of research and analytics. Altogether, from upstream activities to midstream delivery, these efforts are oriented toward quantifying the size of emissions at their point source in order to serve the detection, measurement, and mitigation of emission leakages across the value chain of fossil fuel consumption. The ultimate goal of this program is to minimize the harm of legacy systems of fossil fuel use necessary for the energy transition by prioritizing efficient, cost-reducing technologies while maximizing the value added during the transition (FECM, 2021).

~~7.5.3 Justice40 Initiative-Covered Programs~~

~~DOE has over 140 programs covered under the Biden/Harris Administration's Justic40 Initiative. Demonstrating the department's long-standing commitment to equity and social justice, many of these programs are decades-old efforts to ameliorate impacts of DACs across seven areas covered by Justic40 Initiative. That includes programs targeting climate change, sustainable and affordable housing, the remediation and reduction of legacy pollution, development of clean water and wastewater infrastructure, workforce development and training, development and preservation of sustainable and affordable housing, and cleaner transit options, as well as clean energy and energy efficiency (DOE, 2021).~~

~~DOE prioritizes social justice across myriad programs that focus on outcome-specific programs such as workforce development and holistic, process-oriented organizing efforts. Under DOE's Office of Economic Impact and Diversity, the Minority Education, Workforce Development, and Training Program supports small businesses, institutions that serve minorities explicitly, and nonprofits with grants targeting science, technology, engineering, and mathematics educational~~

~~opportunities; strategic capacity building; general workforce development; and assistance in technical issues. From a holistic perspective, DOE initiated the Domestic Engagement Framework under FECM as an organizing structure to facilitate cohesive community engagement across stakeholders and tribes in an effort to deploy clean technologies. Built from a five-part series of engagement principles, the framework prioritizes two-way engagement, proactive engagement early in the process, place-based engagement, community-based knowledge, and the concerted effort to build out the capacity for community engagement (FECM, 2022a; FECM 2022b).~~

~~In deploying holistic frameworks to outcome-specific programs, DOE sets out a process-oriented mission within targeted efforts to foster the ability for communities to lead alongside federal agencies toward more equitable outcomes.~~

7.5.4 Energy Justice Tools

DOE has initiated comprehensive programmatic strategies to ameliorate historical injustices and implemented big-picture frameworks to guide organizing efforts across these programs in a manner that empowers communities as partners. As part of these efforts the DOE's Office of Economic Impact and Diversity's Office of Energy Justice Policy and Analysis have invested in the development and maintenance of multiple public-facing tools that can be used to illustrate and evaluate questions, policies, regulations, and practices with respect to energy and justice (DOE, 2023a).

One such tool is the Energy Justice Dashboard (BETA), which can be used assess the proportion of federally funded underwriting of projects that provide benefits to DACs. This data visualization tool seeks to measure the distribution of benefits to historically underserved and overburdened communities. Built from EPA's EJSCREEN tool, the BETA tool identifies the proportion of burden from pollution and public health risks accrued at the census-tract level. By leveraging data to measure historical disadvantage, this tool helps support DOE assess data-driven outcomes from its programmatic efforts to right the injustices that have plagued so many communities.

~~Currently,~~ DOE has ~~been able~~ identified and measured the disadvantage of roughly 27,251 communities at the census-tract level using this tool. The deployment of tools such as BETA during the energy transition is key, particularly during the early planning stages, in creating the desired approach for community outreach and in the effort to structure governance strategies. Identifying where DACs are provides the high-level understanding into where deficits in outreach and inclusion have likely exacerbated the pervasiveness of disadvantage. ~~In doing so, concerted efforts to bring these voices into the development of large-scale energy infrastructure projects related to natural gas/LNG market opportunities is key~~ (DOE, 2023a). The Federal Energy Regulatory Commission (FERC), which has authority over the siting of onshore LNG terminals and interstate natural gas pipelines, established the Office of Public Participation specifically to empower, promote, and support public voices in infrastructure decisions made at FERC.

Commented [TC3]: Reference: Office of Public Participation (OPP) | Federal Energy Regulatory Commission (ferc.gov)

DOE has also developed a new Energy Justice Mapping Tool for Schools that builds on DOE's original Energy Justice Mapping Tool. This new tool is intended to allow users to explore and produce reports for a specific school facility which include but are not limited to the following metrics: 1) whether the school is located in a DAC, 2) whether it is in a rural location, 3) whether it is designated as a community shelter, 4) the percentage of students who are eligible to receive free and reduced priced meals, and 5) whether the school qualifies for Title I Schoolwide programming. Beyond its Energy Justice Dashboard (BETA) and the DOE is also currently developing the Energy Justice Mapping Tool - Disadvantaged Communities Reporter, which when operational will allow users to explore and produce reports on census tracts identified as DACs (DOE, 2023a).

7.6 INDUSTRY INITIATIVES

Some U.S. oil and gas trade associations have developed initiatives to promote energy justice principles. For example, the~~The~~ American Petroleum Institute (API) and its member companies have publicly ~~are~~ committed to safe and responsible operations related to the discovery, production, and delivery of energy resources including natural gas (API, 2023). Noting that justice considerations intersect directly with U.S. natural gas industry operations, given the impact these operations have on people's lives and communities, API has focused on actions that respect human rights, engage stakeholders, improve performance, and create local economic opportunities (API, 2023).

A significant portion of the collective efforts of its member companies have revolved around being a good neighbor and having a positive impact on in local communities. Member companies including Chevron, Concoco Phillips, and Chenerie have announced that they have implemented industry practices to foster broad stakeholder engagement during every phase of a project's development and operation (API 2023). Companies including Plains, Marathon Petroleum, and Chevron have invested in apprenticeship programs, STEM education, and local youth programs. API has also established Community Engagement Guidelines to promote the safe and responsible development of natural gas resources in communities where member companies operate.

~~7.7 SUSTAINABLE DEVELOPMENT~~

~~The impact of a region's political economy can clearly drive outcomes and upend what could be sustainable development of natural gas projects when that region's needs and culture is not considered. It also bears noting that inequality is a multi-dimensional concept that varies across countries and individuals that requires careful consideration (Laurent and Zwickl, 2021). As the communist states of the Eastern Bloc exited the Union of Soviet Socialist Republics, the effort to integrate into energy markets within the European Union revealed that variations in culture and geography dominated some preferences in energy project outcomes with respect to energy justice (LaBelle, n.d.). On the other hand, a study of sub-Saharan African nations revealed a positive relationship between democracy, energy justice, and growth (Opoku and Acheampong, 2023). Cultural differences aside, income and wealth inequality may drive many outcomes. Studies of European Union attitudes toward sustainability policies show that 41~~

~~percent country-level variance in negative attitudes correlates with differences in wealth and income (Pellegrini-Masini et al., 2021) and otherwise sustainable, positive policy changes are upended by how different communities perceive those policies within their local culture.~~

~~The desire to balance environmental protection and economic development in disadvantaged and frontline communities has led to the championing of a concept called "sustainable development." Summarized broadly, the idea is to balance the needs of current generations without harming the well-being of future generations. Within this movement, the needs of today's impoverished communities are heavily weighted under the theory that gains in wealth and income of today's generation beget gains in tomorrow's generation. In other words, the benefits of economic development compound over generations (Poppel, 2018).~~

~~7.8~~ CONCLUSION

Commented [TC4]: The other chapters end with actions and R&D.

~~Historical disenfranchisement of communities has often resulted in the creation of winners and losers with respect to policy impacts. To the extent that policies created the conditions under which DACs arise, those policies have likely been rooted in a fundamental lack of inclusivity as well as a lack of awareness and empathy during the planning and implementation processes of project development. As the United States continues to embark on a transition away from a GHG-intensive economy and a concerted push to net-zero carbon emissions by 2050, opportunities to right those historical wrongs will present themselves.~~

~~In closing, this~~ This chapter provides ~~a~~the framework for ~~energy justice considerations in natural gas development and transportation, pursuing inclusivity goals in its discussion of energy justice and energy poverty. The energy transition is presented as a catalyst for pursuing change with the intended outcome being a just transition for all. In the end, the vehicle for applying energy justice and energy poverty goals rests in the inclusive design of energy governance structures. In addition, the literature base of energy justice and energy poverty within the space of natural gas and LNG market development is strong and growing. With intentionality, the authors of future research can help to ameliorate those historical disenfranchisements and provide a framework for the kind of shared prosperity that generates strong growth for all. If there is one overarching idea throughout the social justice literature, it is that historically disenfranchised communities of people must be actively welcomed into the discussion early and often to be re-franchised and ensure their voices are heard (Weller, 2019).~~

~~7.9~~7.7 REFERENCES

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From: Curry, Thomas
Sent: Thu, 28 Sep 2023 14:22:04 +0000
To: Francisco De La Chesnaye; Sweeney, Amy
Cc: Iyer, Gokul; Scott Matthews; Jamieson, Matthew B.; Whitman, Peter C; Skone, Timothy; Daniel Hatchell
Subject: RE: LNG Export Report
Attachments:
DOE_FECM_LNG_Analysis_Report_FINAL_REVIEW_05Sep23_V2_ConsolidatedComments.docx

DRAFT – DELIBERATIVE – PRE-DECISIONAL

Hi All,

Attached is a consolidated set of comments on the LNG export report. Please review and let's discuss on tomorrow's call. The comments we shared from GC are included in this draft, but the IA comments are not included. We want to respond to the GC and IA comments separately and then incorporate the discussions into the report, as appropriate. Also, the comments in this draft from Tim are prior to his engagement with the LCA team. I think the LCA team already has this feedback. If there are conflicts, you should check with Tim.

As we have discussed, one of the key comments is a need to move away from qualitative descriptions like "small" and "modest" and toward quantitative descriptions.

Another key comment is the development of appendices with data behind each of the figures. I'll reply to Daniel's email on that topic separately.

Overall, we would like to advance the report as much as we can in the next week, recognizing we may have discussions to add based on the IA and GC feedback.

Tom

From: Francisco De La Chesnaye <francisco.delachesnaye@onlocationinc.com>
Sent: Wednesday, September 6, 2023 2:58 PM
To: Curry, Thomas <thomas.curry@hq.doe.gov>; Sweeney, Amy <amy.sweeney@hq.doe.gov>
Cc: Iyer, Gokul <gokul.iyer@pnnl.gov>; Scott Matthews <scott.matthews@keylogic.com>; Jamieson, Matthew B. <matthew.jamieson@netl.doe.gov>; Whitman, Peter C <peter.whitman@onlocationinc.com>; Skone, Timothy <timothy.skone@hq.doe.gov>
Subject: [EXTERNAL] RE: LNG Export Report
Importance: High

DRAFT – DELIBERATIVE – PRE-DECISIONAL

Tom,

We have corrected the problems with figure refences and page numbering. We also substituted Henry Hub prices in the final summary table and edited the discussion on carbon prices as discussed.
We believe covers everything.

Please see V2 of the Final Review Draft.

Bets, Paco

From: Curry, Thomas <thomas.curry@hq.doe.gov>
Sent: Wednesday, September 6, 2023 11:08 AM
To: Francisco De La Chesnaye <francisco.delachesnaye@onlocationinc.com>; Sweeney, Amy <amy.sweeney@hq.doe.gov>
Cc: Iyer, Gokul C <gokul.iyer@pnnl.gov>; Scott Matthews <scott.matthews@keylogic.com>; Jamieson, Matthew B. <matthew.jamieson@netl.doe.gov>; Peter Whitman <peter.whitman@onlocationinc.com>; Skone, Timothy <timothy.skone@hq.doe.gov>
Subject: RE: LNG Export Report

[EXTERNAL EMAIL] This email originated from outside of the organization. Do not click links or open attachments unless you recognize the sender and know the content is safe. If you are unsure and require assistance, Contact Technical Support at support@keylogic.com.

DRAFT – DELIBERATIVE – PRE-DECISIONAL

Thanks all for the quick work on this. I gave it a quick scan and wanted to flag two issues:

- Can you check the formatting associated with the figures on pages 22-27 (figures 4-6)? It looks like some of text got pulled into the title on page 24 and there is an errant "figure 6" in text on page 25.
- We like the summary table in the conclusion but were surprised that residential prices were included for S6-S7. Are those discussed anywhere else in the document? I didn't see them on a quick review. If we are going to have them in the table, we will need to explain them. For this draft, can you include a note at the bottom of the table saying that additional context for S6-S7 residential prices is being developed and will be included in a subsequent draft?

Tom

From: Francisco De La Chesnaye <francisco.delachesnaye@onlocationinc.com>
Sent: Tuesday, September 5, 2023 10:06 PM
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Cc: Iyer, Gokul <gokul.iyer@pnnl.gov>; Scott Matthews <scott.matthews@keylogic.com>; Jamieson, Matthew B. <matthew.jamieson@netl.doe.gov>; Whitman, Peter C <peter.whitman@onlocationinc.com>; Skone, Timothy <timothy.skone@hq.doe.gov>
Subject: [EXTERNAL] RE: LNG Export Report
Importance: High

DRAFT – DELIBERATIVE – PRE-DECISIONAL

Amy and Tom,

The combined team from PNNL, OnLocation, and NETL are pleased to submit the FINAL REVIEW DRAFT of the attached report "ENERGY, ECONOMIC, AND ENVIRONMENTAL ASSESSMENT OF U.S. LNG EXPORTS".

We look forward to successfully completing the FINAL Deliverable soon.

Best, Paco

Francisco De La Chesnaye | Vice President
m: (b) (6) | onlocationinc.com





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Sent: Tuesday, September 5, 2023 11:27 AM
To: Francisco De La Chesnaye <francisco.delachesnaye@onlocationinc.com>
Cc: Iyer, Gokul C <gokul.iyer@pnnl.gov>; Scott Matthews <scott.matthews@keylogic.com>; Jamieson, Matthew B. <matthew.jamieson@netl.doe.gov>; Peter Whitman <peter.whitman@onlocationinc.com>; Daniel Hatchell <daniel.hatchell@onlocationinc.com>; Jasmine Greene <jasmine.greene@onlocationinc.com>; Sweeney, Amy <amy.sweeney@hq.doe.gov>
Subject: RE: LNG Export Report

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Great! Thanks all for your work over the weekend. We very much appreciate it.

Tom

From: Francisco De La Chesnaye <francisco.delachesnaye@onlocationinc.com>
Sent: Tuesday, September 5, 2023 10:46 AM
To: Curry, Thomas <thomas.curry@hq.doe.gov>
Cc: Iyer, Gokul <gokul.iyer@pnnl.gov>; Scott Matthews <scott.matthews@keylogic.com>; Jamieson, Matthew B. <matthew.jamieson@netl.doe.gov>; Whitman, Peter C

<peter.whitman@onlocationinc.com>; Daniel Hatchell <daniel.hatchell@onlocationinc.com>; Jasmine Greene <jasmine.greene@onlocationinc.com>
Subject: [EXTERNAL] LNG Export Report

Tom,

We worked over the weekend to address all tenoning comments and complete the report. It is now going through a final technical edit review. We are planning to finish today by COB. I'll give you another status update later today.

Best, Paco

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

FINAL REVIEW DRAFT September 5, 2023

Prepared for:

Office of Resource Sustainability

U.S. DEPARTMENT OF ENERGY | Fossil Energy and Carbon Management

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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
EU	European Union
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

Commented [AA1]: Consider deleting. You only mention this once.

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 ~~A~~authorizations~~Authorizations~~ relating to those countries with which the United States does not have ~~which~~ 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 ~~P~~public ~~I~~interest~~Public Interest~~ determination, since 2012, the Office of Fossil Energy and Carbon Management (DOE-FECM) and its predecessor, the Office of Fossil Energy, ~~previously~~ has 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, ~~served~~ will served~~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.

Commented [TC2]: Let's add a paragraph on general limitations on modeling, consistent with the discussion at and following the leadership briefing. The Exec Summary should have a summary of caveats and the introduction should have a broader discussion.

Commented [TC3]: Global comments:
-The report needs an edit to improve consistency of voice.
-Make sure there is consistency in units. Consistent report units. GCAM uses EJ and NEMS is quads (quadrillion Btu). 1 quad = 1.-5506 EJ
a.There is a mix in the report currently.
i.Primary Energy: quads and EJ
ii.Gas production/Exports/Imports: Tcf and Bcf/day
iii.GHG emissions: Gigatonnes (metric tons), MMT (million metric tons)
iv.LCA/GHG: grams per megajoule
b.Recommend energy and mass be in metric units and volume (of gaseous natural gas) be reported in English units of cubic feet (industry standard convention).
-Move away from qualitative descriptions like "modest" or "small" and toward quantitative information with context for the reader to make a qualitative assessment.
-Include detailed data that can be used by the reader to understand figures in new appendices.
-In general, the report would benefit from more discussion of why the trends or results we are seeing are consistent with expectations. For example, making comments about US prices increasing in response to increased demand for natural gas.
-As we are developing responses to the IA and GC comments in separate documents, we should look to add context to this report.

Commented [ZA4]: This is not an (b) (5) (b) , and it is currently framed as such. (b) (5) .

Commented [LBD5]: I'm not familiar with "growth" as a noun modified by this word… if this is meant to mean both population growth and economic growth, suggest saying both. Or maybe it's just "economic growth"?

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 Energy Information Administration's (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 27.3~~4~~ 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 27.3~~4~~ 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

Commented [UP6]: Do we have to show by 2 digits in 2050? EIA's TIE article for example rounds to just 1-digit showing 27.3 Bcf/d which prob is better. https://www.eia.gov/todayinenergy/detail.php?id=56600

Commented [UP7]: S6 has a different background color than the other sections of the table? Also on the third column why is GCAM Market Response "white background" for S2-S5 but then "blue" for S7?

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.** domestic Ddomestic A**analysis** 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 National Energy Technology Laboratory (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 ofMost 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 $4.74/Mcf, both of which are less than the reference 2050 price expected in the most recent study[k] commissioned on the economic impacts from U.S. LNG exports in 2018.
4. U.S. residential prices were are projected to be 4% higher in 2050 when comparing a scenario that reflects global market demand for exports (S2) to the reference scenario (S1).
5. The value of industrial shipments remains essentially unchanged (increasing less than 0.1% by 2050) under a scenario that reflects global market demand for exports (S2) compared to the reference scenario (S1). The impact of increased LNG exports on GDP is essentially flat: positive by less than 0.1% across scenarios through 2045 while all changes are within 0.3% in 2050.
6. Global and U.S. GHG emissions do not change appreciably across the scenarios with current climate policy assumptions (S2 to S5) even though these scenarios vary widely in terms of U.S. LNG export outcomes. In these scenarios, global emissions range from 47.5-50.3 global net GHG emissions ($GtCO_2e$)Gt CO_2e and U.S. emissions range from 4.3-4.6 $GtCO_2e$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 U.S. 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

Commented [UP8]: Should "economically driven" have a hyphen or not? We seem to sometimes hyphenate it and sometimes not. I added hyphens but can be reversed.

Commented [ZA9]: Is a 30% price increase modest?

Commented [LBD10]: Hard to describe as a "modest" increase, if in constant dollars. The increase is almost 1/3.

Commented [LBD11]: Suggest specify real or current dollars

Commented [AA12]: Just FYI for tech writer: Previous references were not italicized.

Commented [UP13]: Shouldn't this be 49 Bcf/d based on S3 scenario (see page 21)?

Commented [WS14]: There is a notable difference in the way we present the data from our conclusions. When we reference GDP, gas consumption, and prices, we scale the effect against the global or national total, resulting in small percentage changes. When we talk about GHGs we scale the effect to units of gas exported. But the table in the appendix shows that the reduction in emissions between S2 and S1 is 50 million tons - or roughly 0.01% of global emissions. I recommend that we take a more consistent approach to characterizing the model results.

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.

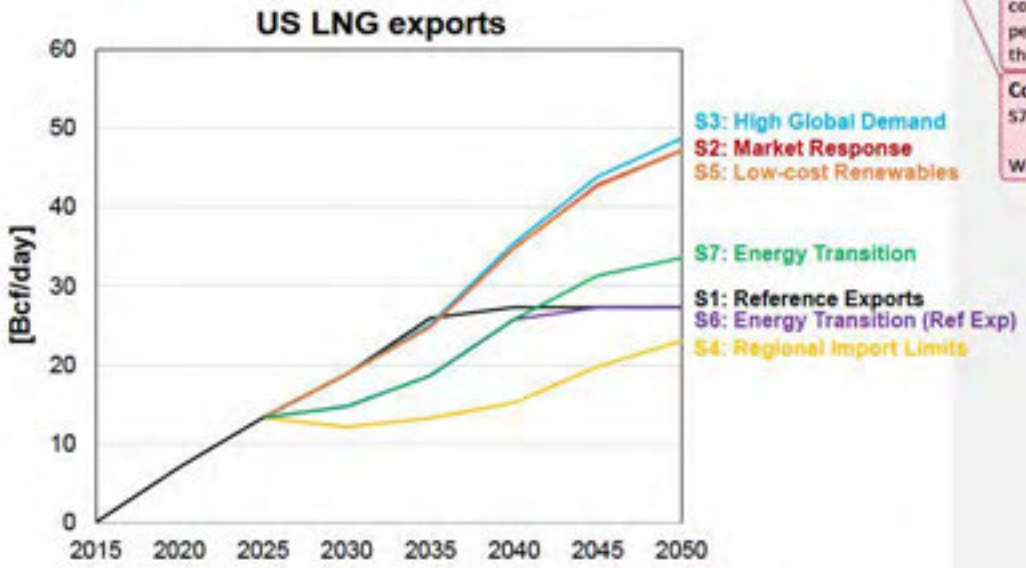


Figure ES-1. U.S. LNG exports across the scenarios explored in this study. Note that the U.S. LNG export outcomes for S2 and S5 were very close to each other.

Commented [WS15]: This sentence has way too many elements and needs to be re-written.

Commented [LBD16]: It's not completely clear to me why this comparison is made - it seems like there is a projected reduction in GHG emissions from S1 to S2, but it's small? A global reduction equal to 70% of the LC emissions of one large industrial user? If that's correct, it might be clearer to just present the percentage reduction, or say that it was essentially the same level of emissions.

Commented [ST17]: Did we run a non-CCUS S6 and S7 case?

What supports this finding?

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~~ has 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.

Commented [UP18]: Table 1 should be moved back to below paragraph 1 where it is mentioned.

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 domestic 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~~as well as 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 natural gas 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 AauthorizationsAuthorizations relating to those countries with which the United States does not have such 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 Ppublic iinterestPublic interest determination, since 2012, the Office of Fossil Energy and Carbon Management (DOE-FECM) and its predecessor, the Office of Fossil Energy, has 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 inputted 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.

Commented [AA19]: Perhaps I missed it, but it would be nice to have a section on "limitations" or a disclaimer or a brief description of what this study did not/cannot do.

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Commented [LBD21]: "input" seems awkward. "a reference"?

Commented [UP22]: Not sure what we mean by LNG exports were found in GCAM? I am assuming the volumes or level of LNG exports?

Commented [UP23]: What's the incumbent life cycle analysis? Is that different than the Life Cycle Analysis described in the Executive Summary?

[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 have 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. (the Infrastructure Investment and Jobs Act[8] also known as the Bipartisan Infrastructure Law (BIL) and Inflation Reduction Act[9] (IRA)). This report updatedupdated 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 includedare:

***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. , R, 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,

Commented [UP24]: Should we say "regional energy sources" as in the bolded heading? Local seems like in-country ng source is available versus in the region.

[8] Infrastructure Investment and Jobs Act, Pub. L. 117-58, (November 15, 2021), https://www.congress.gov/117/plaws/publ58/PLAW-117publ58.pdf.
[9] Inflation Reduction Act, Pub. L. 117-169, (August 16, 2022), https://www.congress.gov/117/plaws/publ169/PLAW-117publ169.pdf.

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.

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C. Organization of the Report

Following the Background ~~of LNG Export Studies~~ and Introduction sections of the Report, Section IV of the report 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~~Global and ~~the life cycle~~ Domestic A~~a~~nalyse~~i~~s, respectively, and the L~~l~~ife C~~c~~ycle A~~a~~nalysis 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.[10] 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 geo-political regions, along with representations of resources, technologies, and policy.

Commented [WS27]: When was this model created?

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 (NGP), 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.

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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

[10] 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.

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 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~~)~~[11] and in Canada, they are calibrated to Alberta marker prices from the BP Statistical Review.[12] 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.[13] 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 European Union [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 scenario.

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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.

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

[12] 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

[13] 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.[14] This results in ~~~~1~~approximately one 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.[15,16,17] 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, Scotland, United Kingdom.~~-~~ 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~~ retains 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

[14] 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.
[15] Fawcett, A. A., et al. (2015). Can Paris pledges avert severe climate change? Science, 350(6265), 1168-1169.
[16] Ou, Y., Iyer, G., et al. (2021). Can updated climate pledges limit warming well below 2°C? Science, 374(6568), 693-695.
[17] Iyer, G., Ou, Y., et al. (2022). Ratcheting of climate pledges needed to limit peak global warming. Nature Climate Change, 12(12), 1129-1135.

AEO2023 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

Commented [UP30]: Here the Table although the same as in Executive Summary has different coloring. Personally I think looks better blue/white versus two shades of blue throughout.

Commented [UP31]: Same comment on the 2-digits Bcf/d as I had in Executive Summary section. 1-digit would be better to show in a report.

B. NEMS Models and Analysis Methodology

NEMS is ~~an~~ nationalin 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.

Commented [AA32]: Consider: "It projects supply, demand conversion, imports, exports of major energy commodities, and drivers such as macroeconomic conditions…"

The NEMS model ~~is a modular energy system model. There are~~includes 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 Inflation Reduction Act (IRA) which includes most major provisions of the ~~law~~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~~IRA 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 Production Tax Credit (PTC) and Investment Tax Credit (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 Corporate Average Fuel Economy~~CAFE~~ standards.

Given the carbon capture opportunities and the net negative carbon technologies such as DAC and bioenergy with CCS (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~~ FECM's 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.

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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~~ is 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.

Commented [AA34]: Spell out if this is the first time mentioning these gases.

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.

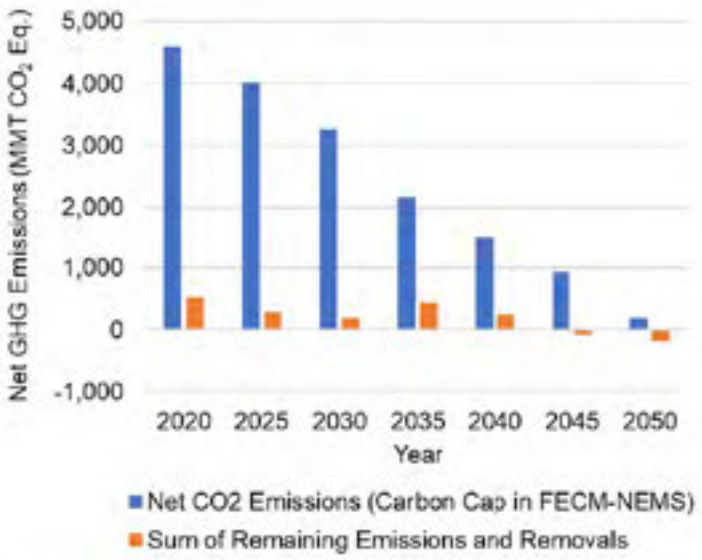


Figure 1. U.S. GHG emissions and removals in the net-zero scenarios

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

Commented [TC35]: I believe Tim has had discussions with the modeling team since adding comments to this draft, the comments here may have already been shared with the team.

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[18] 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)[19] and Greenhouse Gas Inventory (GHGI)[20]. 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.

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~~ natural gas liquids recovery, etc.

Commented [AA36]: Consider adding as parenthetical to the title of Table 3 - (NETL Natural Gas Model).

Commented [ST37]: 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.

Commented [AA38]: Spell out because this is the first time mentioning the IPCC.

[18] 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

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

[20] 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.

Transmission and Storage	Construction of pipelines, and movement of bulk quantities of natural gas in large 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 it needed to be subsequently adjusted.

Commented [ST39]: Report the LHV result here that aligns to GCAM.

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

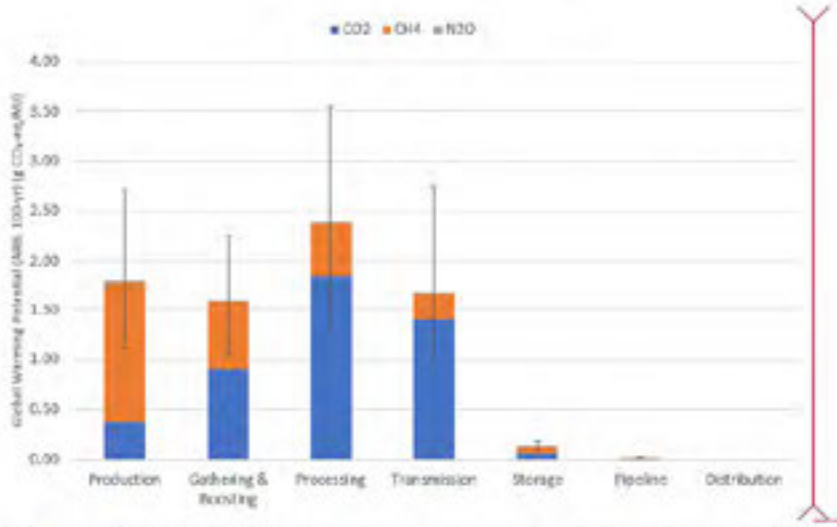


Figure 2. Life cycle GHG emissions from the 2020 U.S. average Natural Gas supply chain, HHV basis (Source: NETL 2023)

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[21]. 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.[22]

[21] 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.

[22] 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 [ST40]: 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".

Commented [ST41]: Needs completed.

Commented [ST42]: Please confirm that the US upstream was also adjusted to use the 2020 NG profile, as well as the GWP reference.

This change should also be noted in footnote 20.

Commented [ST43]: 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.

Commented [AA44]: A word appears to be missing here.

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 [LBD45]: Unclear what these two dimensions/adjectives are; could this just be "global market effects"?

Commented [ST46]: Page 51: MAF is defined as "market effect adjustment factor". Recommend removing effect for consistency with in the report.

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

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

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. The~~is~~This MAF can be calculated for every model year (2015-2050) and can also use linearly interpolated values for the non-modeled years.

~~IV.~~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*).

Commented [LBD48]: This stated order doesn't seem to start until after Section A?

Maybe it could be better explained here -- this seems to apply to Section B (S1 & S2) and C/D (S6 & S7), and then all scenarios together in other sections.

Section A treats the 7 scenarios in numerical order for export volumes, setting the stage for following sections.

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.

Commented [LBD49]: S3? S2 would have been discussed along with S1.

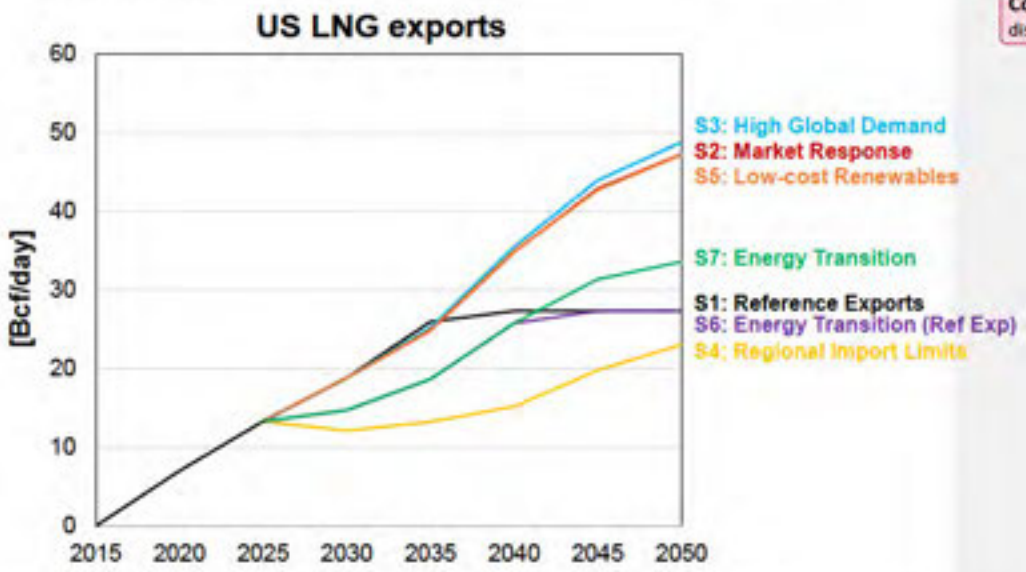


Figure 3. U.S. LNG exports across the scenarios. Note that the U.S. LNG export outcomes for S2 and S5 are very close to each other.

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.

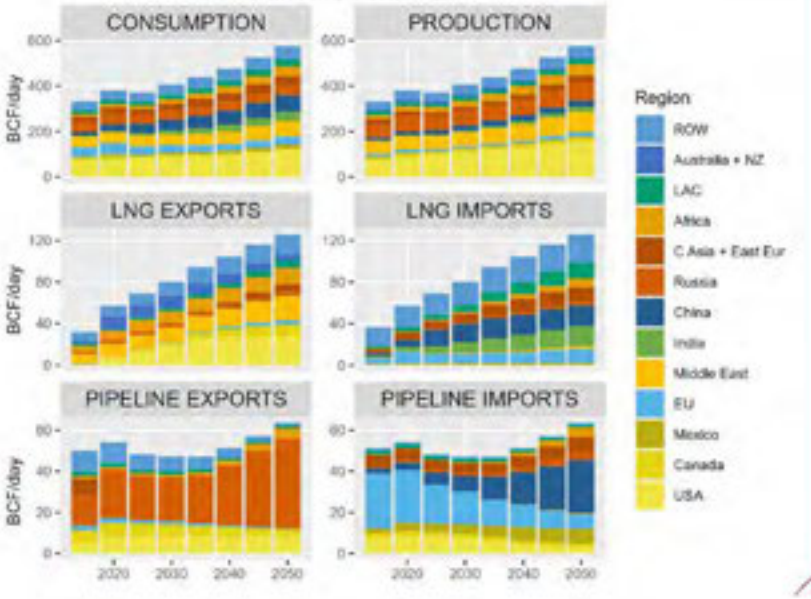
U.S. LNG exports under *S4* increased only to ~23 Bcf/day in 2050, emerging as the lower bound. The lower increase in U.S. LNG exports in *S4* compared to other scenarios was driven by international limits on natural gas imports to maximize the use of locally produced natural gas.

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 ~approximately 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 Aappendix A). Under *S1*, U.S. LNG exports followed the AEO2023 Reference case to grow to 27.34 BCF/day by 2050 (by design).

S1: Reference Exports



Commented [UP50]: Is this an assumption where all importing countries have readily available locally-produced natural gas they can use instead? Should we say regionally vs locally?

Commented [AA51]: Recommend spelling out instead of using symbol.

Commented [WS52]: Global comment: this report consistently uses bar charts rather than actual figures. Can we include all these figures in appendices?

Commented [WS53]: S1 shows global gas consumption increasing to 2050 (and maybe beyond?). Even S6 and S7 seem to show global gas consumption plateauing in 2045 (but not decreasing event then). Meanwhile, we understand that this month the IEA will release a global outlook document that will project gas consumption peaking this decade. This seems like a vast discrepancy and perhaps one that should be addressed. Is it feasible to run another scenario? If not, how would we defend the validity of our assumptions as compared to those of others?

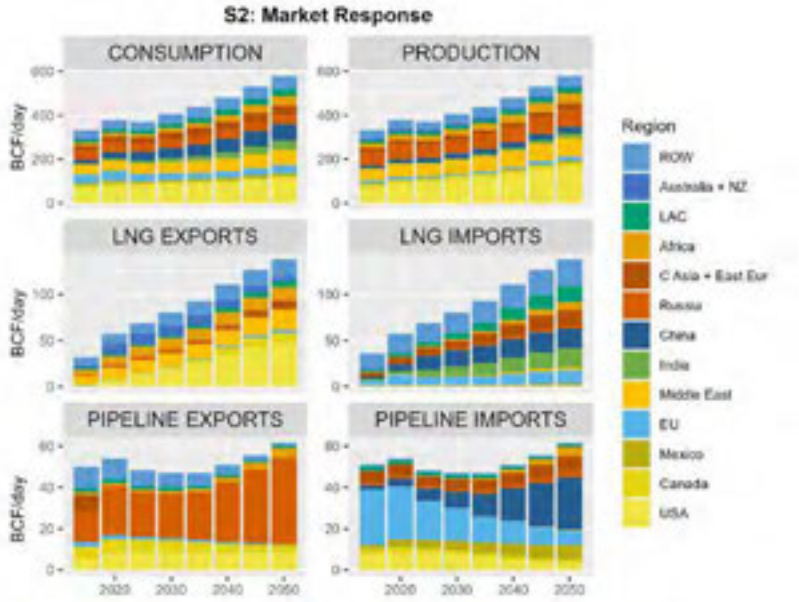


Figure 4 Natural gas consumption, production, and trade by region under S1 (upper) and S2 (lower)

As ~~Alternatively, as shown in Figure 5,~~ Uunder *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. Figure 5 shows the changes in natural gas consumption, production, and trade by region in S2 versus S1.

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.

Commented [WSS4]: Looking at the bar chart in figure 5, it appears that global gas consumption increases by roughly 5 bcf/day between S2 and S1. In other words, for every 4 Bcf/d of incremental US exports, global consumption goes up by roughly 1 Bcf/d. This does not seem accurately characterized as going up by a very small amount.

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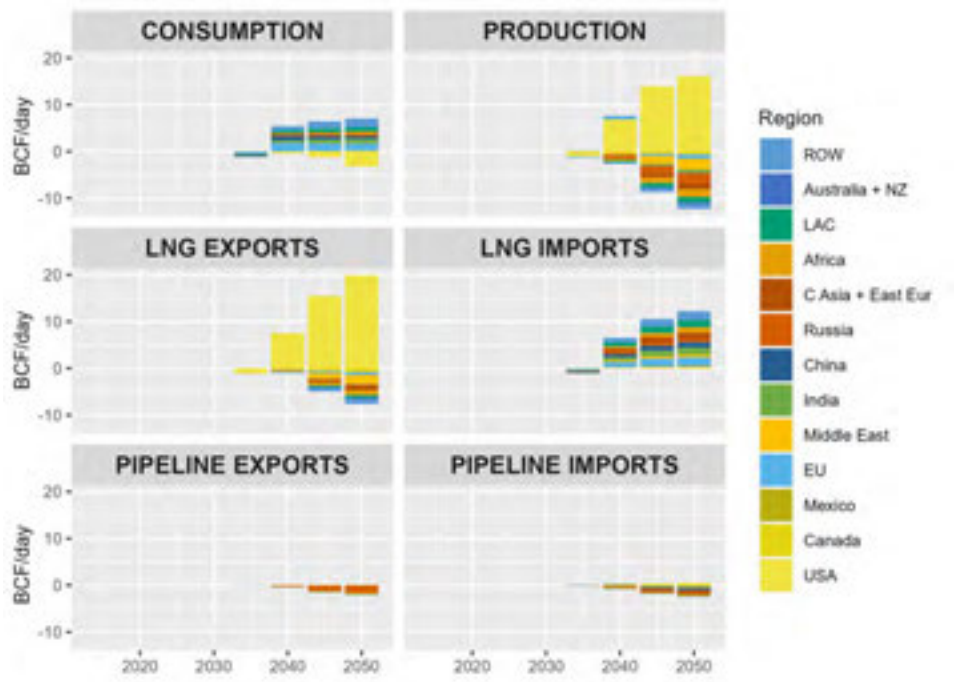


Figure 5. Changes in natural gas consumption, production, and trade by region in S2 vs. S1

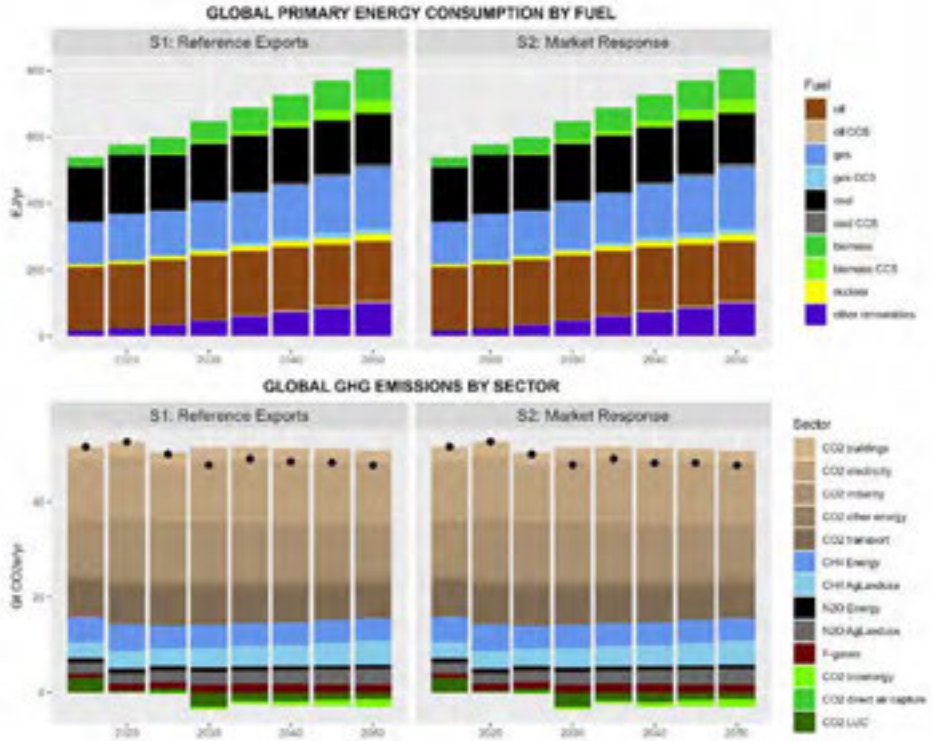


Figure 6. Global primary energy consumption by fuel and GHG emissions by sector under S2 and S1. Net GHG emissions are shown as a dot in each bar.

Commented [ST56]: Need S2 minus S1 delta figures.

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

Commented [WS57]: Figure 6 is almost impossible to read. It seems like there are differences between S1 and S2 but the reader can't judge the magnitude just by looking at the bar charts.

Under *S6* and *S7*, global GHG emissions from all sectors of the economy are reduced significantly compared to *S1* and *S2* as shown in Figure 6 and Figure 7. 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*.

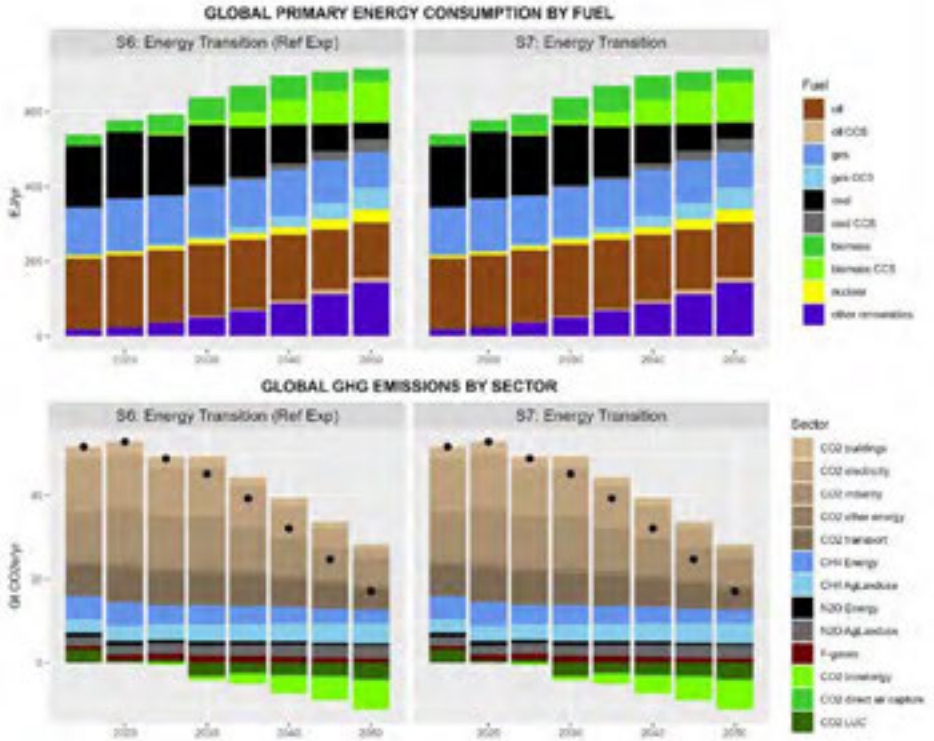


Figure 7. Global primary energy consumption by fuel and GHG emissions by sector under S6 and S7. Net GHG emissions are shown as a dot in each bar.

Commented [ST58]: Need S7 minus S6 delta figures.

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.

Commented [UP59]: Is this discussion related to Figure 8 or 9? Looks like one of these charts was dropped in and has no written content. All charts should be referenced with content. Prefer no drop and run charts 8 & 9.

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.[23]

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

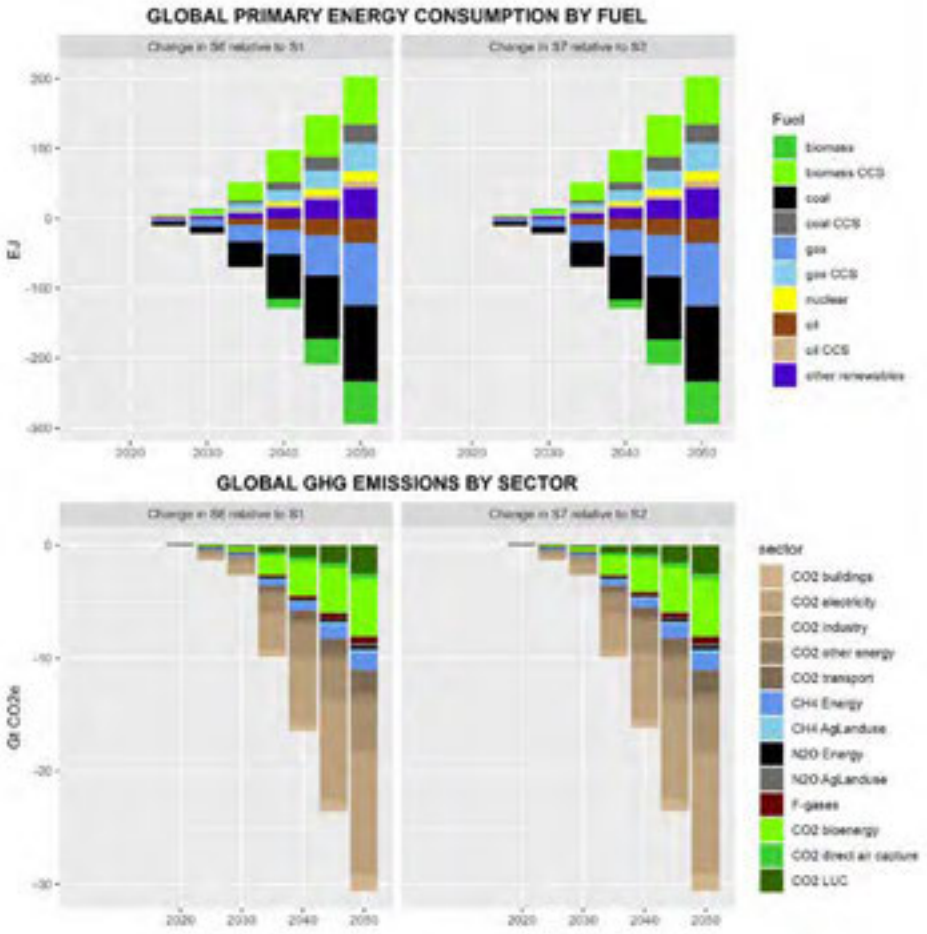


Figure 8. Changes in global primary energy consumption and GHG emissions under S6 and S7 relative to S1 and S2 respectively

Commented [ST60]: Recommend removing this figure. It is not related to LNG Exports. This result can easily be mis-interpreted given the focus of the project. This project is not about how effective climate policy is.

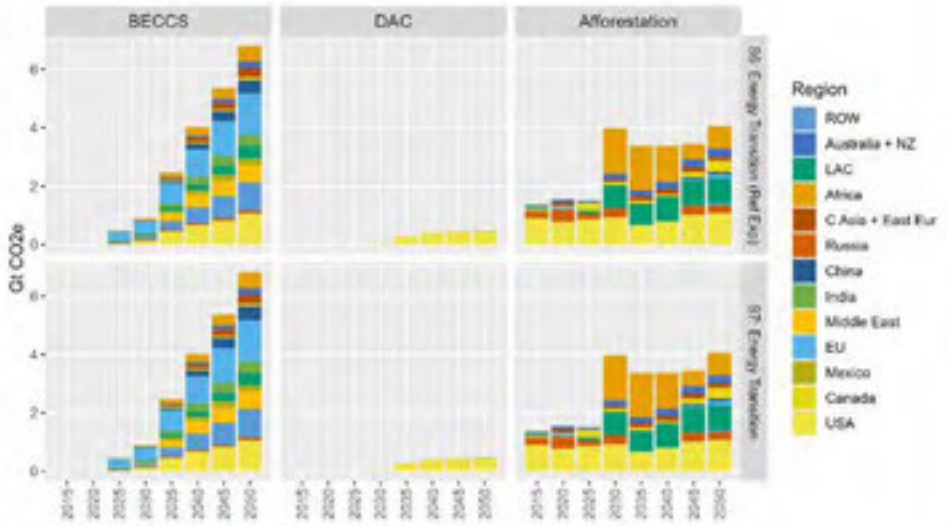


Figure 9. CDR deployment by type and region in S6 and S7

Commented [ST61]: Need delta figures. The key message is "what changed" when we increase exports. I can not ascertain this result from the current results display.

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.

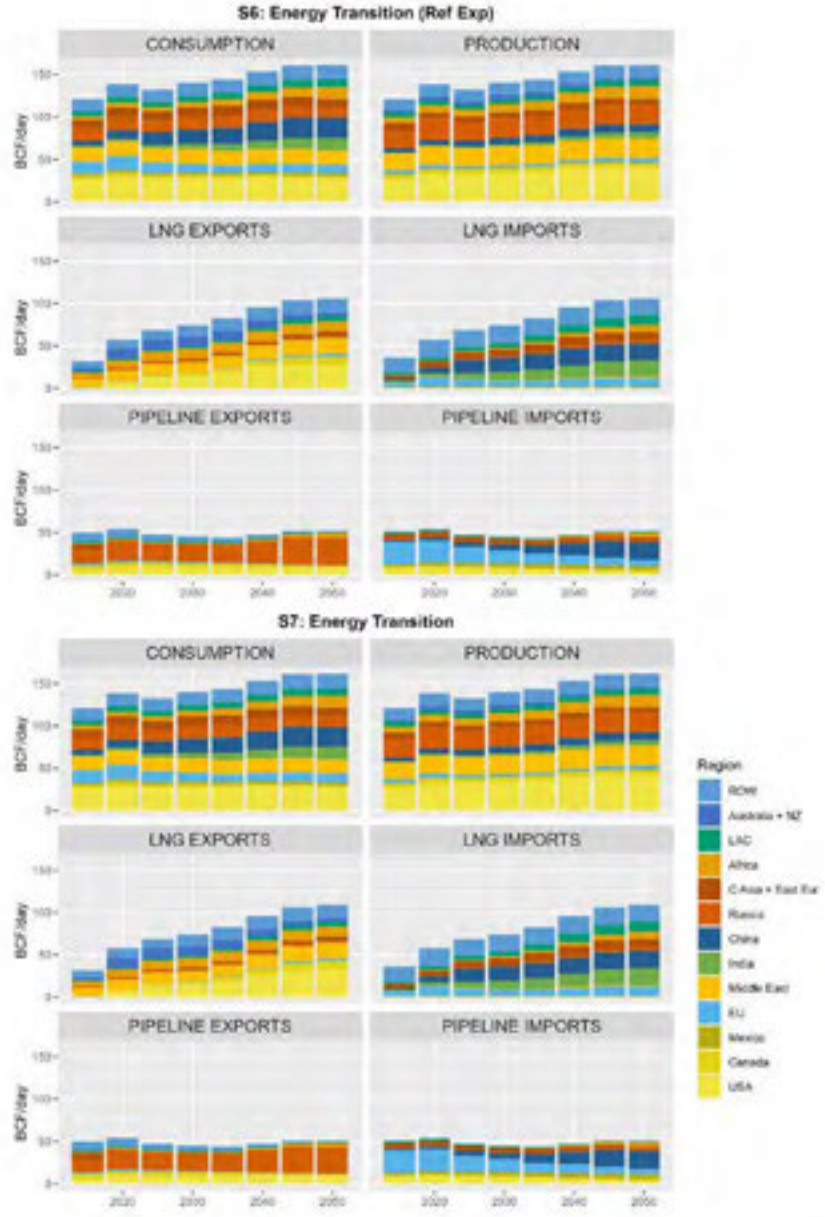


Figure 10. Natural gas consumption, production, consumption, and trade by region under S6 and S7

Commented [UP62]: Needs charts check. Looks like something going on with the Consumption and Production axis that are labeled as Bcf/d but with a max of 150 as the vertical axis (the way it was in prior draft in Tcf vs now Bcf/d). See also similar charts showing 600 Bcf/d on pages 22 and 23 for vertical axis which make more sense? Also the LNG exports between S6 and S7 hard to tell any difference with such small charts. They look identical with similar axis labels although difference may be small between 27.3 and 34 Bcf/d for the U.S.

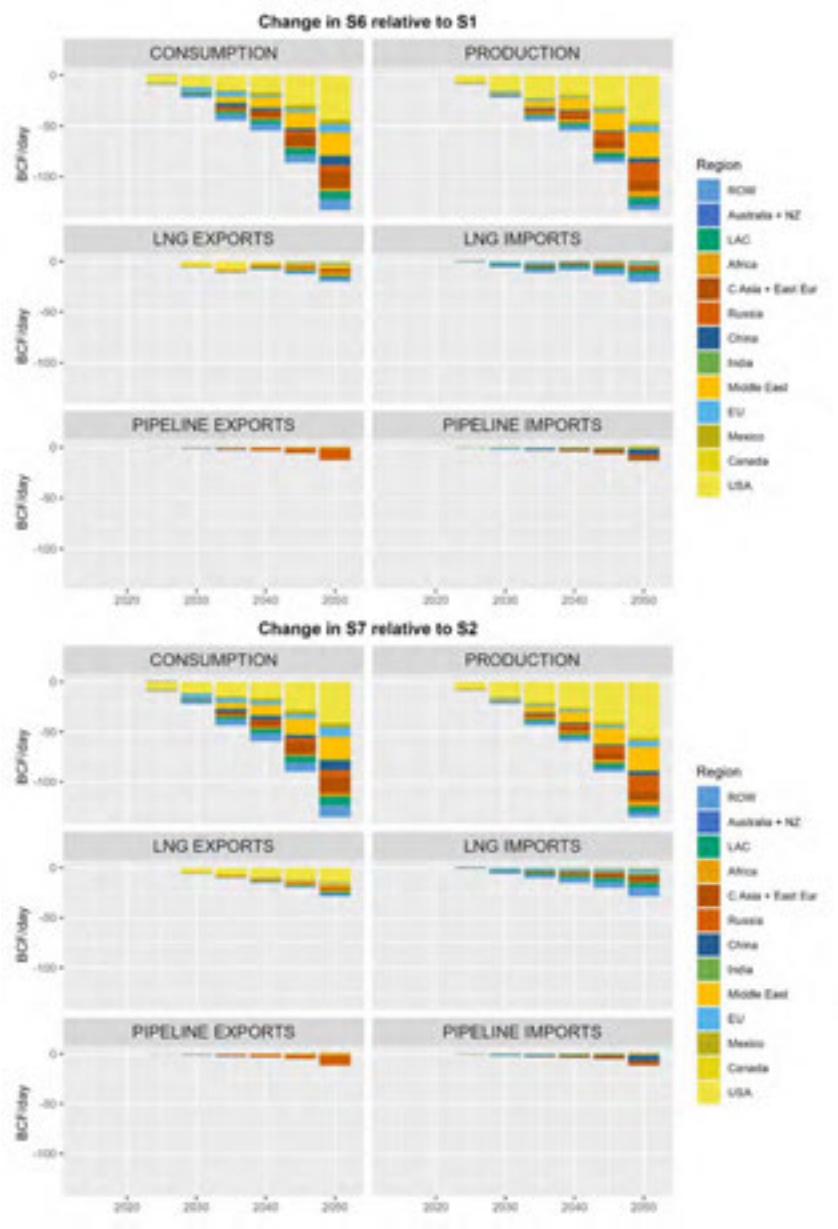


Figure 11. Changes in natural gas consumption, production, and trade by region: S6 vs S1 and S7 vs S2

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*.

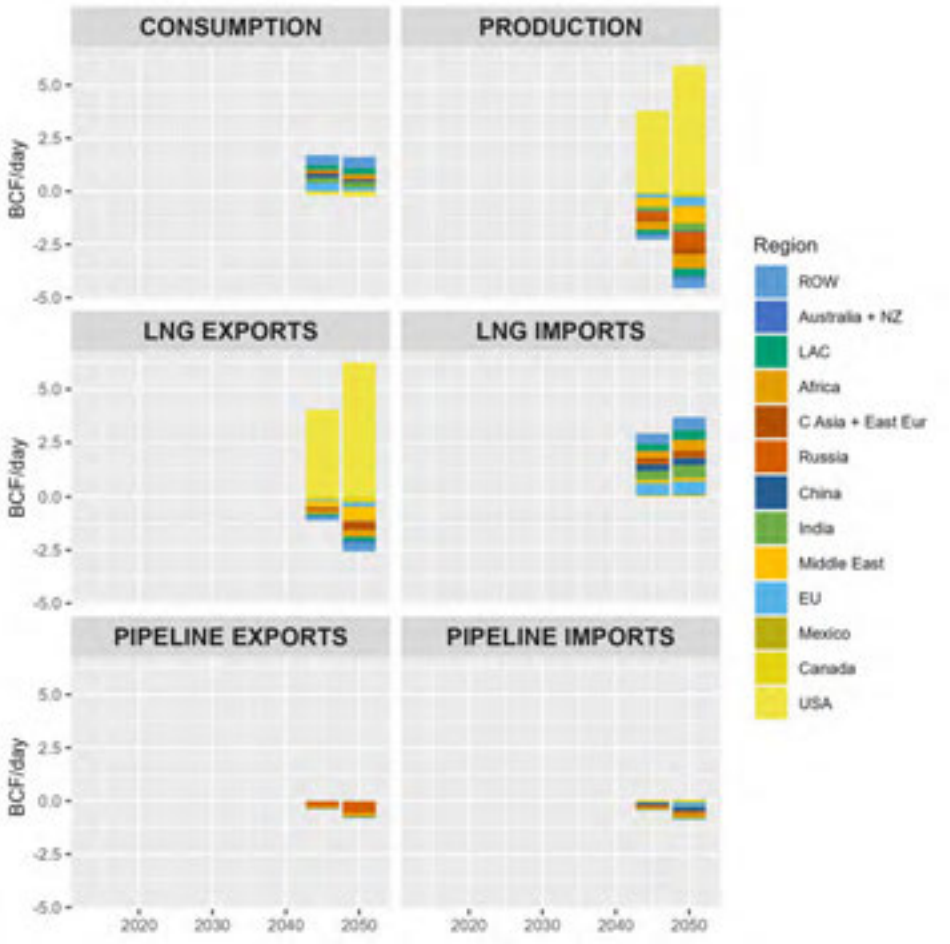


Figure 12. Changes in natural gas markets in S7 vs. S6

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.

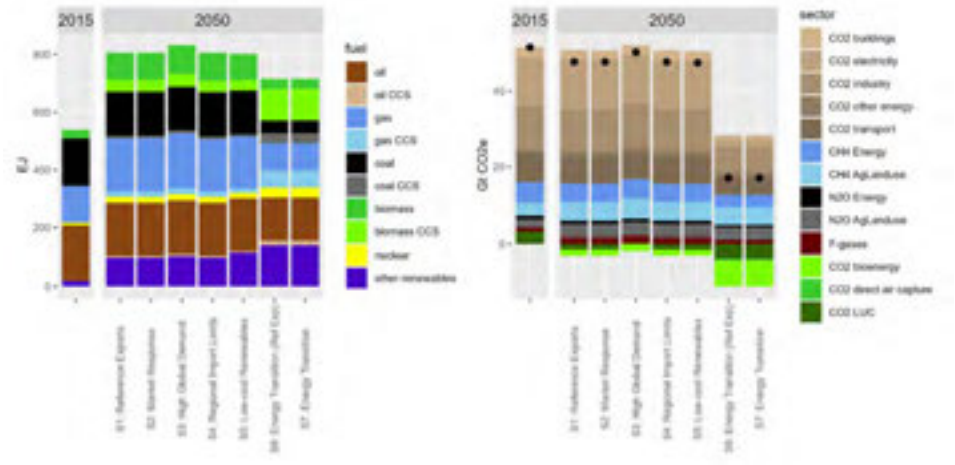


Figure 13. Primary energy consumption by fuel and GHG emissions by sector under all scenarios

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.

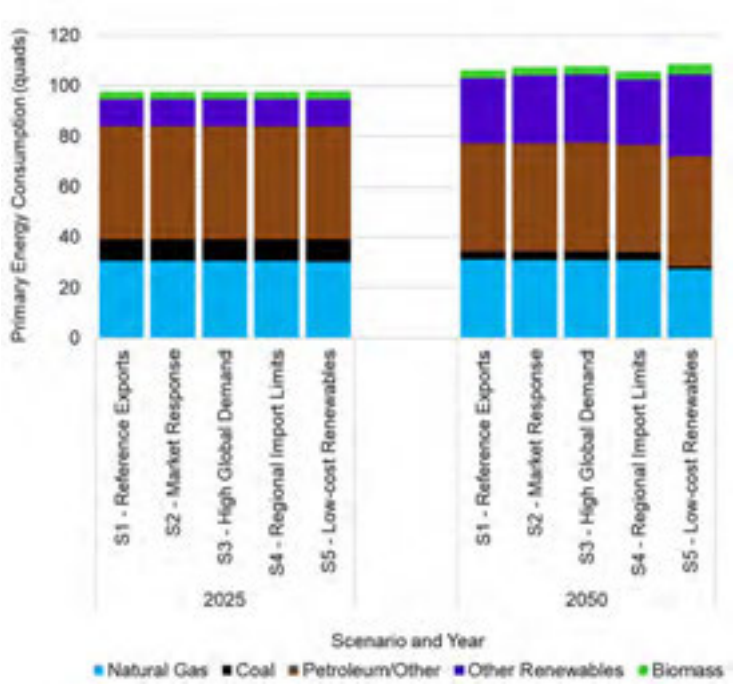


Figure 14. U.S. primary energy consumption, S1 through S5

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*.

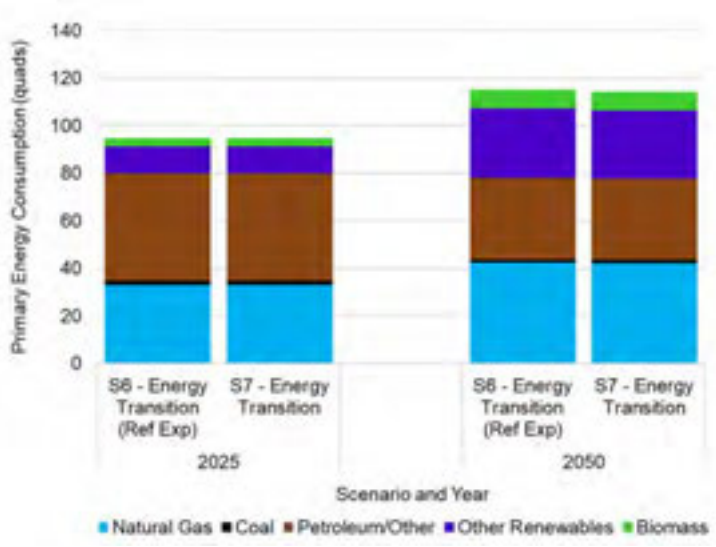


Figure 15. U.S. primary energy consumption S6 and S7

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, is 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.

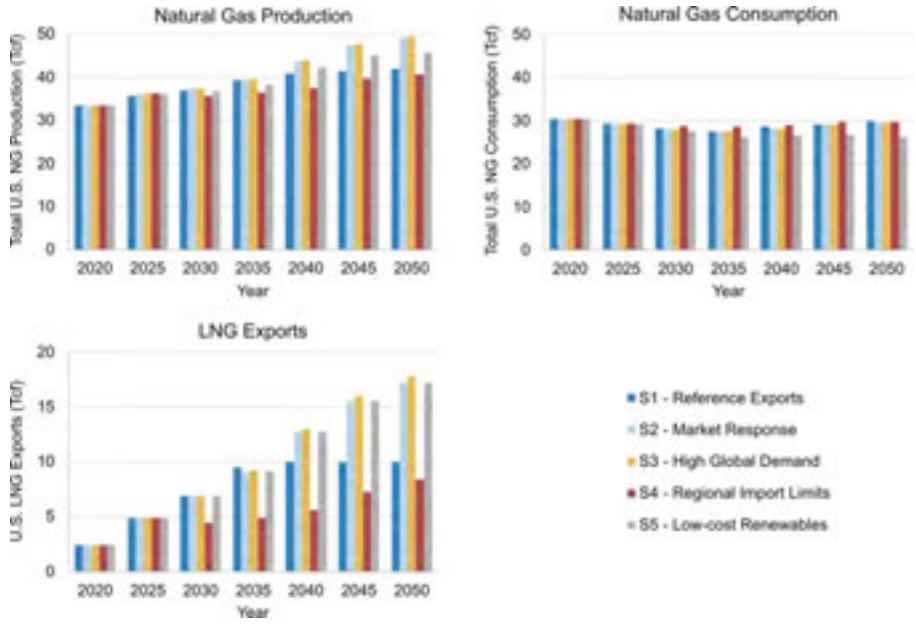


Figure 16. Total U.S. natural gas production, consumption, and export volumes over time, by scenario

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.

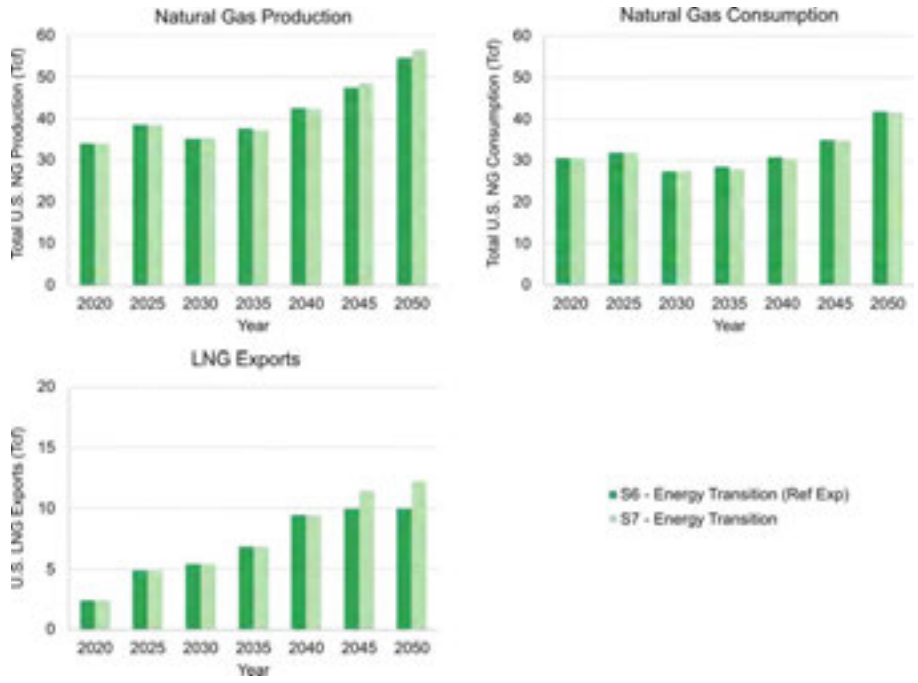


Figure 17. Total U.S. natural gas production, consumption, and export volumes, net-zero scenarios

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.

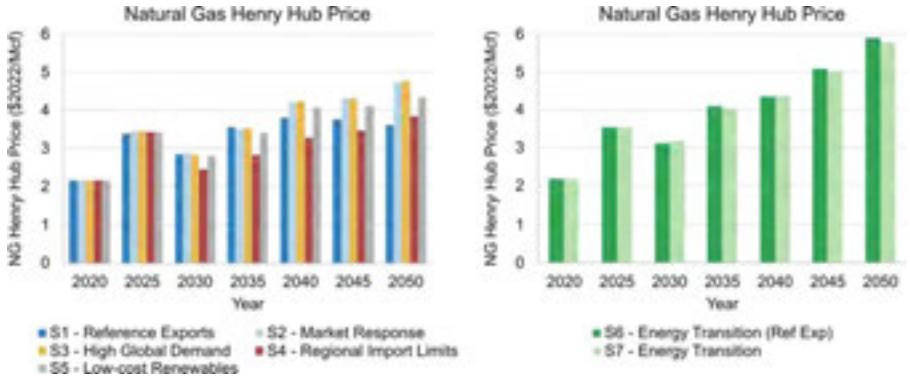


Figure 18. Total U.S. natural gas Henry Hub price by scenario ($2022)

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.[24] 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.

[24] 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.

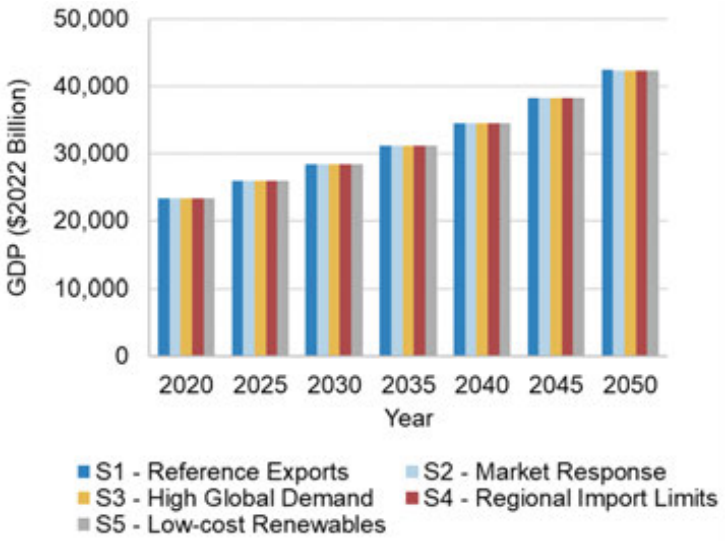


Figure 19. U.S. real GDP changes

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 [redacted] 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.

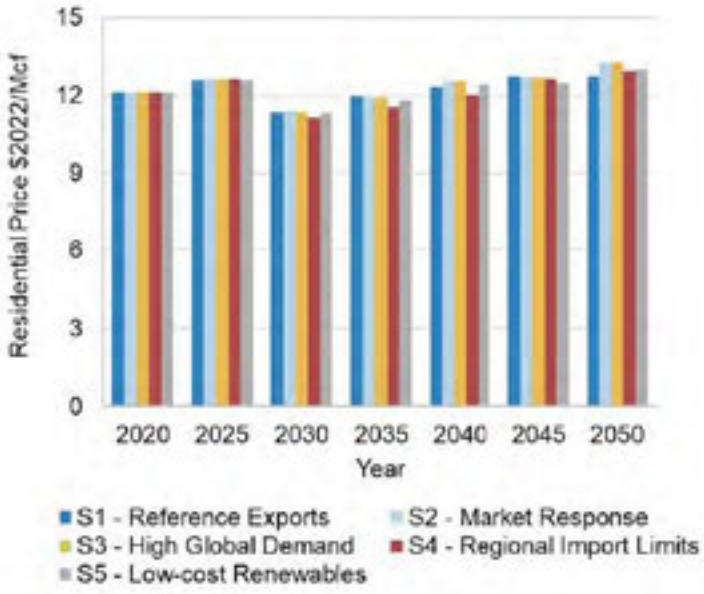


Figure 20. U.S. residential natural gas prices

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.

Commented [WS63]: A few points:
1. This data should be presented in numbers as well as visually.
2. We state that higher exports is positive on GDP until 2050, but S1 seems greater than S2 throughout the entire time series.
3. Does the last sentence mean we think that 0.3% of GDP is a small amount that doesn't warrant further discussion? 0.3% of 42 trillion is over 100 billion. Are we saying that incremental exports of 20 Bcf/d would reduce the size of the US economy by that amount? Over $5b per Bcf/d? If so that seems like a very consequential finding and one that should be explored in greater depth.

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Commented [UP64]: On page 36, we said that "increased LNG exports had a moderate effect on natural gas prices." Here we say "higher natural gas exports resulted in higher prices." Just flagging if this sounds inconsistent?G

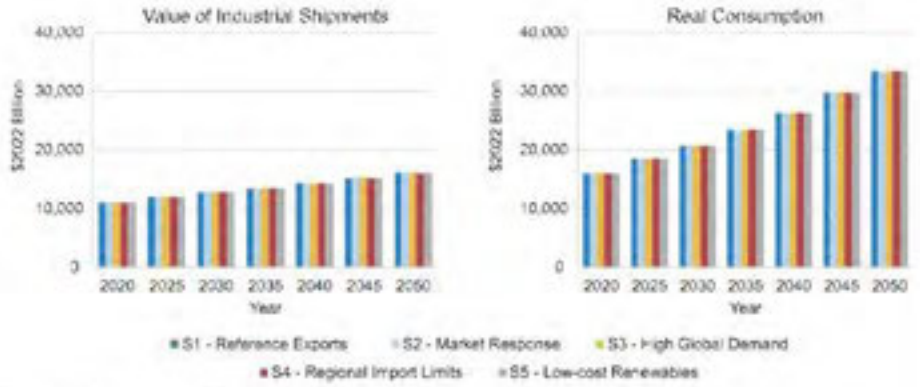


Figure 21. U.S. value of industrial shipments and real consumption

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~~the~~is~~ effect on natural gas prices 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%.

Commented [UP65]: Should this be LNG instead of NG? or does the NEMS analysis show benefits of all NG exports? We've been discussing LNG exports so far in the report so just checking?

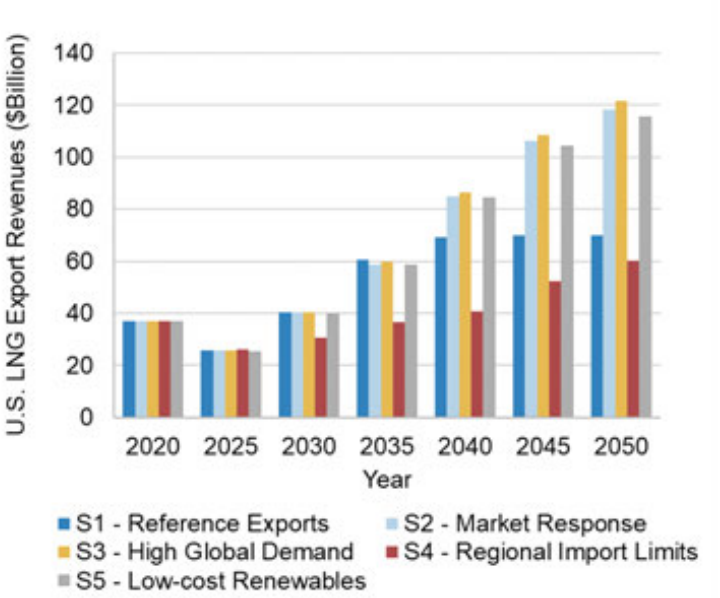


Figure 22. U.S. LNG export revenues

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~~ among scenarios in response to varying LNG export levels. Figure 23 plots CO_2 emissions from fossil fuels for *S1* through *S5*.

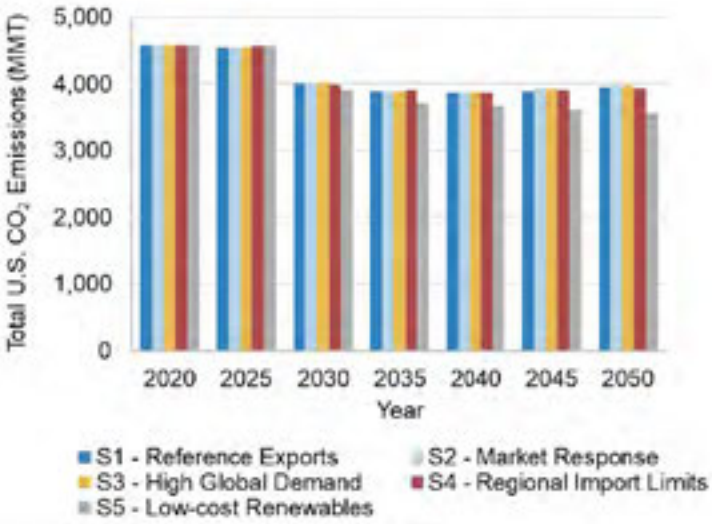


Figure 23. Total U.S. CO_2 emissions from fossil fuel combustion

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.

Commented [WS66]: Should these be 3940 and 3930?

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.

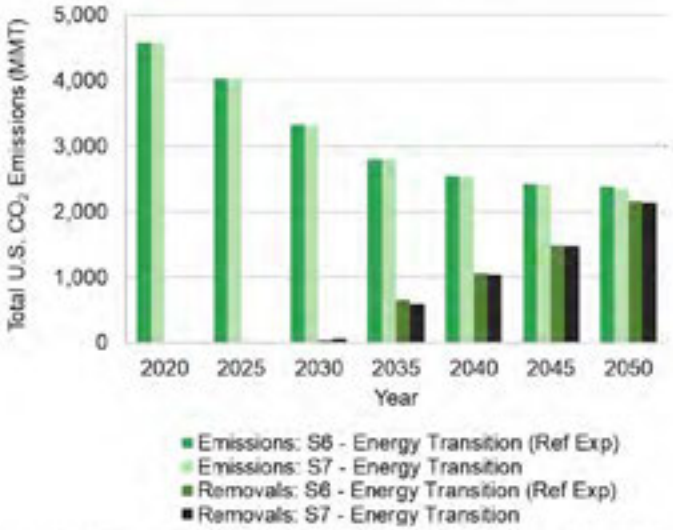


Figure 24. Total U.S. CO_2 emissions from fossil fuel combustion and removals, S6 and S7

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.

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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 [ST68]: 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.

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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.

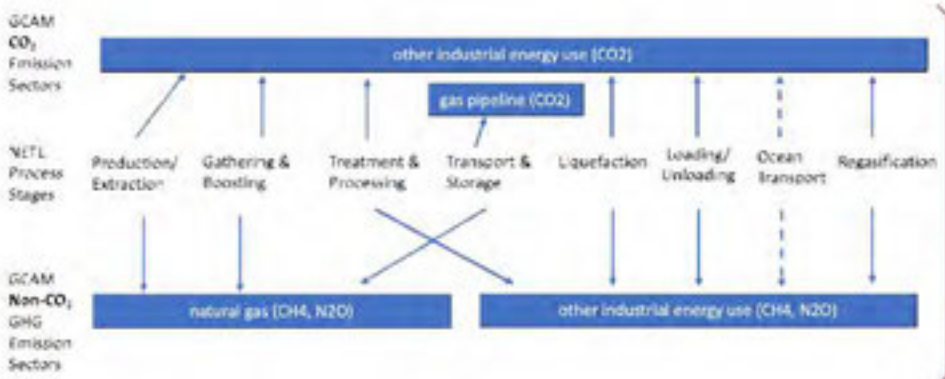


Figure 25. Mapping of NETL natural gas stages to GCAM sectors

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 and have the cumulative effect of reducing estimated emissions from the GCAM model by about 0.2% (in *S1* in the Year 2020).

Commented [ST70]: 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 [ST71]: The rest of the report uses "U.S." instead of "USA".

Commented [ST72]: See previous comment, this numeric values used need to be stated.

Commented [ST73]: 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 [ST74R73]: 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 [WS75]: If we used the GCAM estimate, how would that affect our GHG projections? Some will argue that we cherry picked a more favorable estimate, so it would be helpful to say that our conclusions are robust to that assumption.

Commented [ST76]: Why the italicized label? Not italicized in other parts of the report?

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

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).

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

Results (g CO_2e/ MJ, LHV)			
MAF Case	**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* MFAFsMFAs 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)

Results (g CO_2e/ MJ, LHV)			
MAF Case	**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

Commented [ST77]: 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 [ST78]: Add HHV results.

Commented [ST79]: Add HHV results.

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).[1] The MAF indicated that as U.S. LNG exports increased, the induced global market effects result in an 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.

V.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~~ provides a data 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 growgrow 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

Commented [TC80]: For the leadership briefing, Tim recalculated this interpretation as follows. Can you confirm these calculations and change the section to reflect this interpretation? (Tim also has the calculations in a comment below).

On a life cycle basis through 2050, the induced global market effects per unit of increased LNG exports are equivalent to an **overall reduction in GHG emissions** that is about:
27% of the estimated emissions associated with U.S. LNG delivered to Europe **under reference climate policy assumptions** (LHV basis, 24% on HHV basis)
15% of the estimated emissions associated with U.S. LNG delivered to Europe **under global decarbonization policy assumptions** (LHV basis, 15% on HHV basis)

Commented [ST81]: Reported as 7.44 previously in the report.

Commented [ST82]: Also report the result in LHV with the HHV result. (8.18 g CO2e/MJ, LHV basis)

Commented [ST83]: I calculate a 66% reduction. 70% is generous rounding.

Commented [WS84]: (b) (5)

Commented [ST85]: Results need to be also reported in context of delivered LNG to provide a more complete perspective on the actual magnitude

Commented [ST86]: Add: result through delivered LNG.

Commented [LBD87]: It's not completely clear to me why this comparison is made - it seems like there is a projected reduction in GHG emissions from S1 to

Commented [ST88]: This paragraph needs to explain how -3 translates to a 56% reduction upstream NG emission profile to support the key

Commented [ST89]: Was there any change in the upstream profile in S7/S6 when compared to S2/S1 for the US gas?

Commented [LBD90]: See comment above

Commented [UP91]: Shouldn't this be 49 Bcf/d based on S3 scenario (see page 21)?

(15-48 Bcf/day.)[25] 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 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 [illegible] generally 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

[25] 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/

Commented [UP92]: Here we're using 1-digit 27.3 Bcf/d versus 27.34 Bcf/d in earlier tables. I prefer 1-digit but we should be consistent with the decimal for the AEO 2023 forecast of LNG exports.

Commented [AA93]: Recommend adding clarifying language. Note description used early makes it clear that the reduction in production/export was from "other parts of the world." See:

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.

Commented [LBD94]: Hard to describe as a "modest" increase, if in constant dollars. The increase is almost 1/3.

Commented [LBD95]: This point was not included in the summary of findings in the Ex Sum.

Commented [WS96]: As noted above, this statement needs further explanation.

Commented [UP97]: Number check? 49?

Commented [LBD98]: It's not completely clear to me why this comparison is made - it seems like there is a projected reduction in GHG emissions from S1 to S2, but it's small? A global reduction equal to 70% of the LC emissions of one large industrial user? If that's correct, it might be clearer to just present the percentage reduction, or say that it was essentially the same level of emissions.

Commented [ST99]: Consider splitting the conclusions into two parts: S1/S2 and S6/S7 to improve clarity.

Commented [ST100]: Did we run another set of S6 and S7 results with and without CCUS? Where do these findings come from without CCUS?

Commented [UP101]: 2-digit here?

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* 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 [AA102]: See earlier comment re: clarifying language.

Commented [ST103]: 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~~Global Change Analysis Model's (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

Commented [UP104]: In the body of the report, we showed results in Bcf/d but in Appendix reverted back to Tcf making the comparisons of consumption and production not matching to the body of the report. LNG exports here are still shown as Bcf/d though so not consistent.

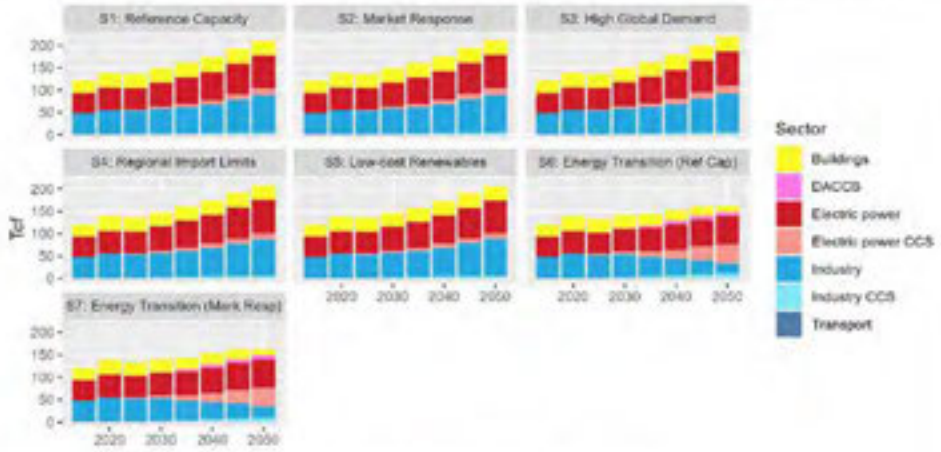


Figure A-1. Global natural gas consumption by sector across all scenarios

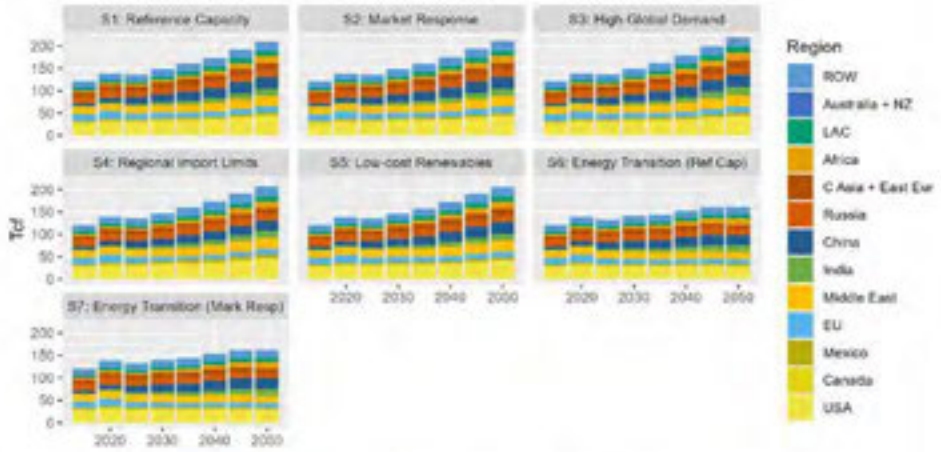


Figure A-2. Global natural gas consumption by region across all scenarios



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

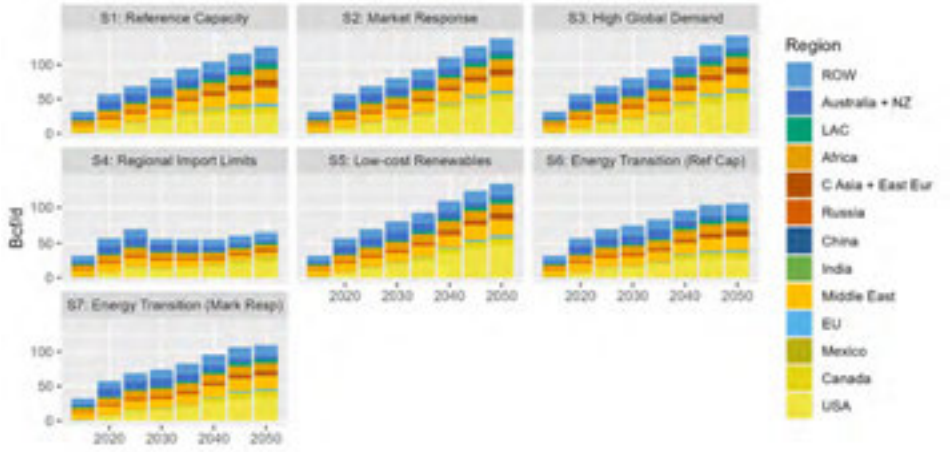


Figure A-4. Global LNG exports by region across all scenarios

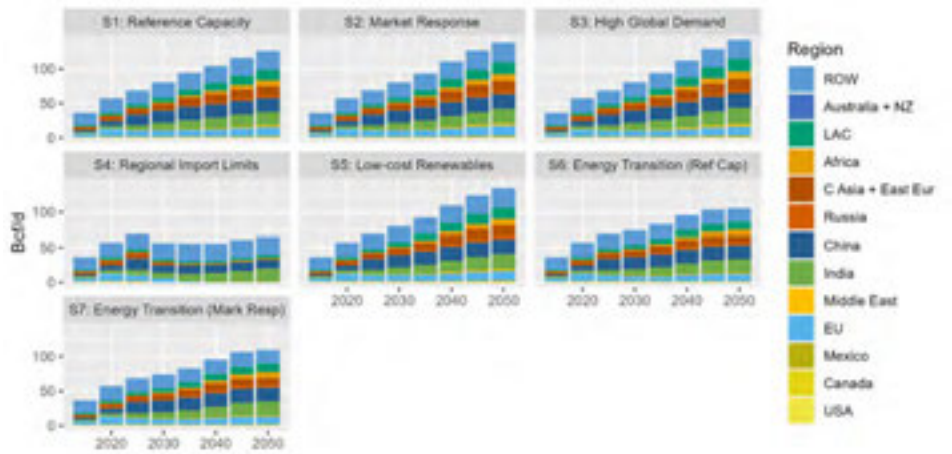


Figure A-5. Global LNG imports by region across all scenarios

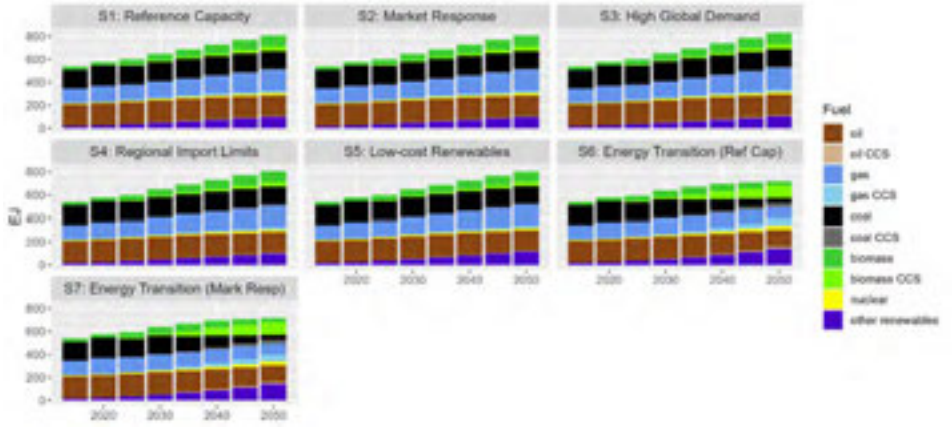


Figure A-6. Global primary energy consumption by fuel across all scenarios

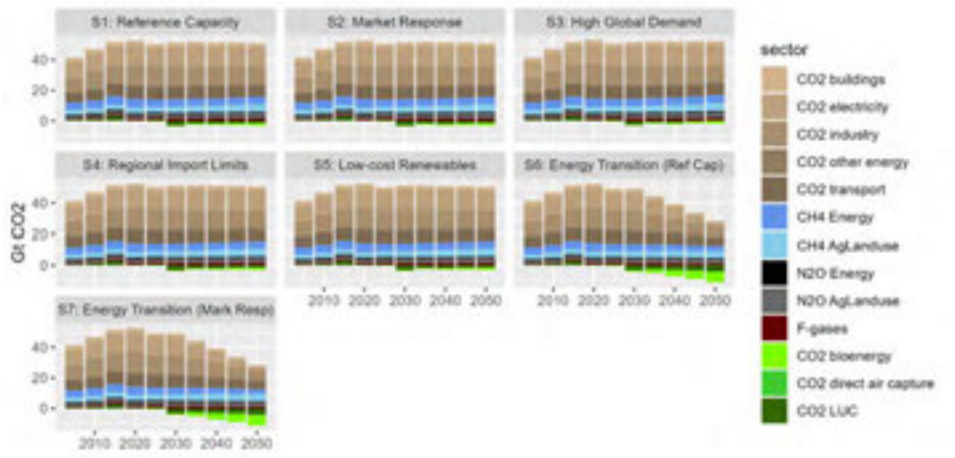


Figure A-7. Global GHG emissions by sector across all scenarios

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* and *S6* uses the EIA AEO2023 reference case, which calculates LNG export capacity endogenously; *S2* through ~~S6~~*S6* and *S7* 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.

Commented [UP105]: Is this sentence correct? Maybe was written pre-S7? I edited it but needs a check.

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

Commented [UP106]: Sounds too informal for a description of a model. Maybe just stick to the facts versus saying it is hard or simple.

Commented [UP107]: S7?

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.

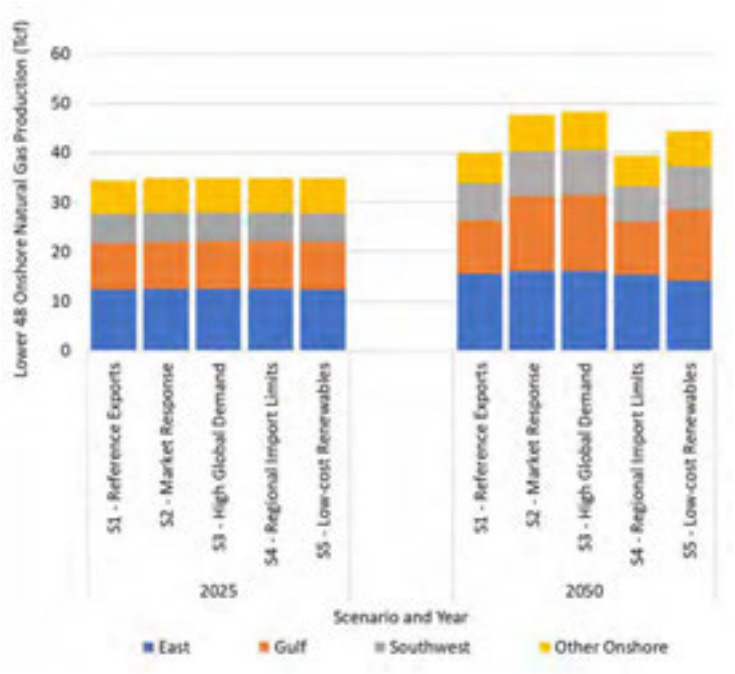


Figure B-1. U.S. Regional Natural gas production, S1 through S5

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.

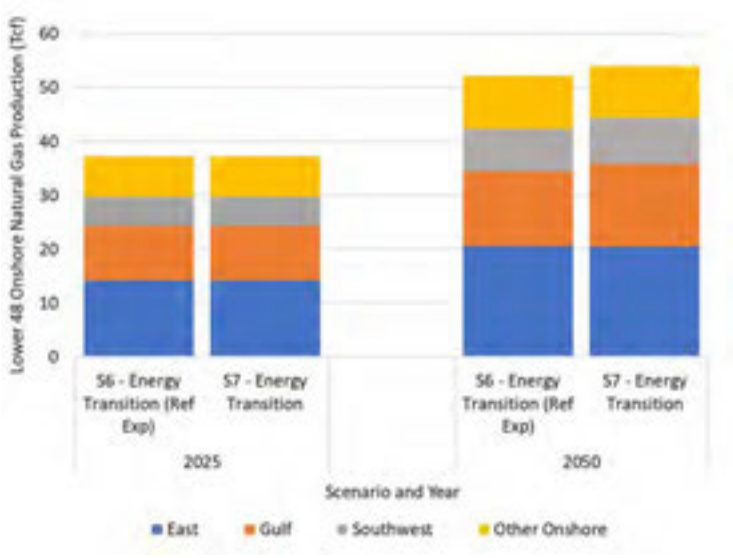


Figure B-2. U.S. regional natural gas production in S6 and S7

Onshore natural gas production grows significantly from 2025 to 2050 for both net-zero scenarios, rising from 37 Tcf in 2025 to 52 Tcf in *S6* and 54 Tcf in *S7*, respectively, by 2050. The large growth in natural gas production is primarily due to demand from DAC facilities, with only a small increase associated with elevated LNG exports in the *S7* scenario. Natural gas production rises in all regions, with the largest absolute increases coming from the East (6.4 Tcf in *S6* and 6.2 Tcf in *S7*) and Gulf (3.8 Tcf in *S6* and 5.3 Tcf in *S7*) regions and the largest increase by percentage coming from the Southwest (47% in *S6* and 58% in *S7*).

2. Natural gas consumption by economic sector

Figure B-3 plots natural gas consumption for electric power, industry, residential use, commercial use, and transportation over time for *S1* through *S5*.

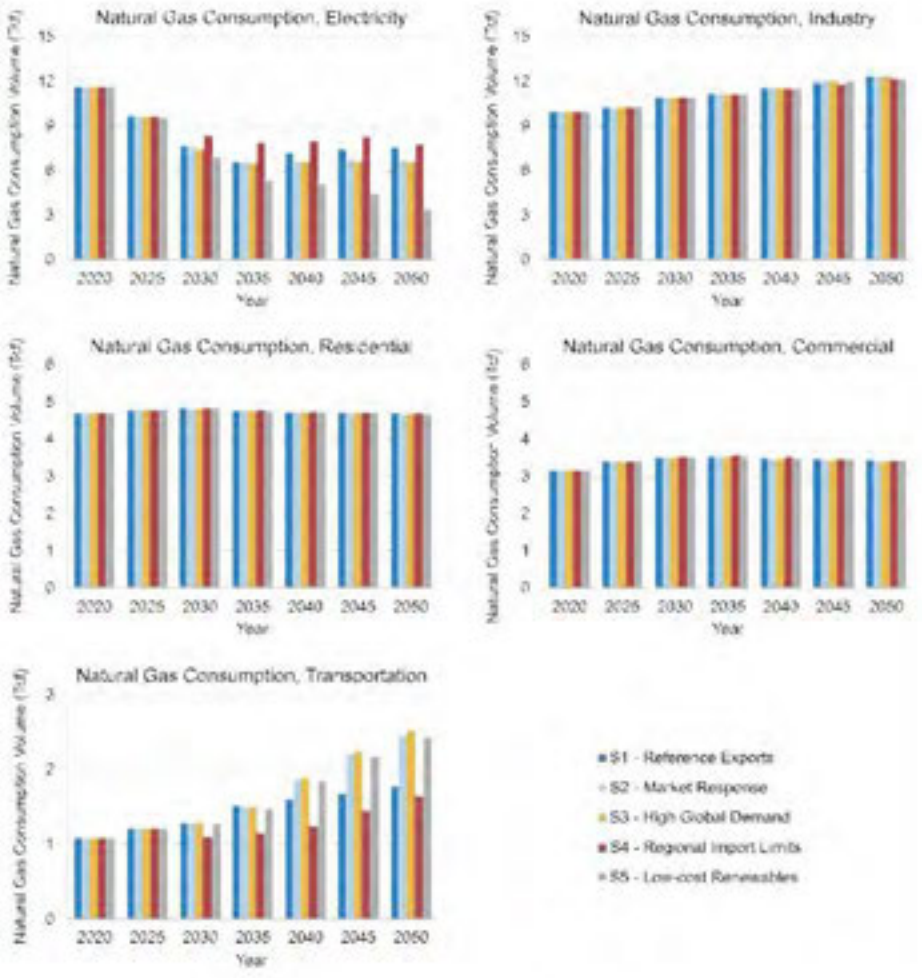


Figure B-3. U.S. natural gas consumption by sector, S1 through S5

Commented [UP108]: Hard to compare by sector data to the totals in the report as the report had the data in Bcf/d and in the Appendix we are now showing results in Tcf.

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.

Commented [UP109]: Do we want to say this like this-that it's complicated to go from AEO2023-NEMS to FECM22-NEMS? Again sounds too informal for a description of a model. All forecasting is complicated 😊

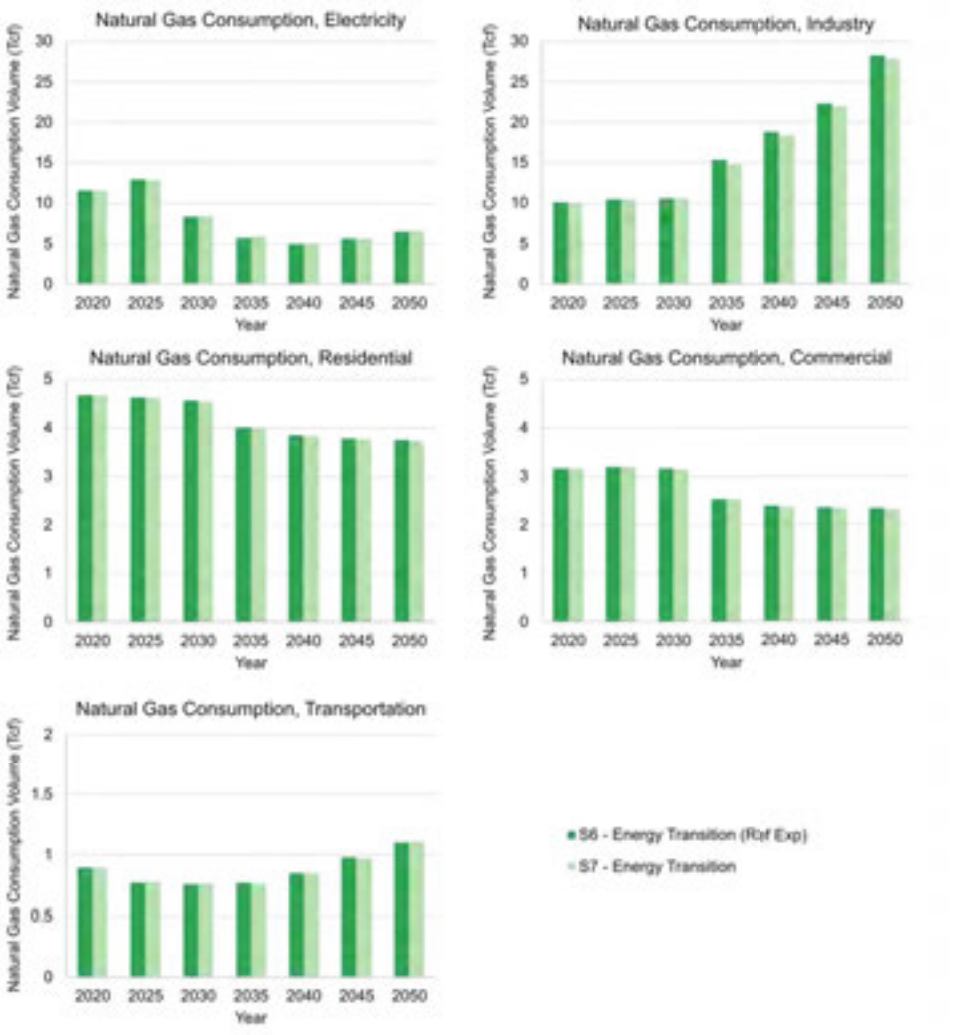


Figure B-4. U.S. natural gas consumption by sector, net-zero scenarios

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.

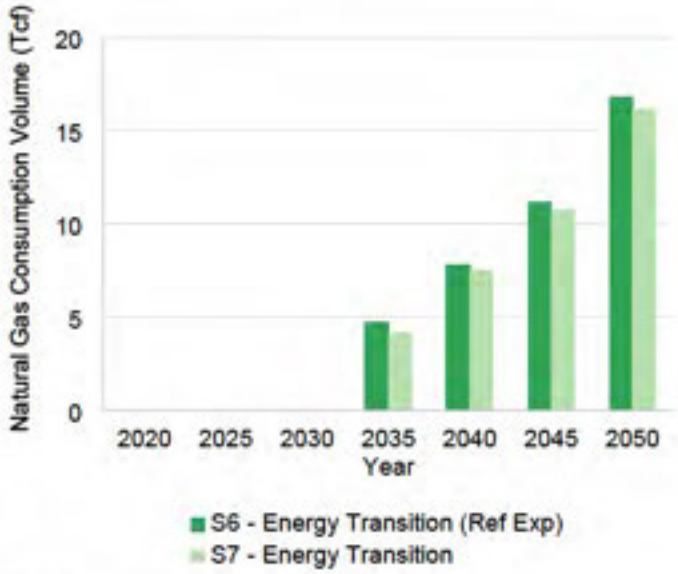


Figure B-5. Natural gas consumed for DAC, net-zero scenarios

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.

Commented [WS110]: Would be very helpful to state our assumptions regarding the cost of DAC over the 2035 to 2050 period.

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.

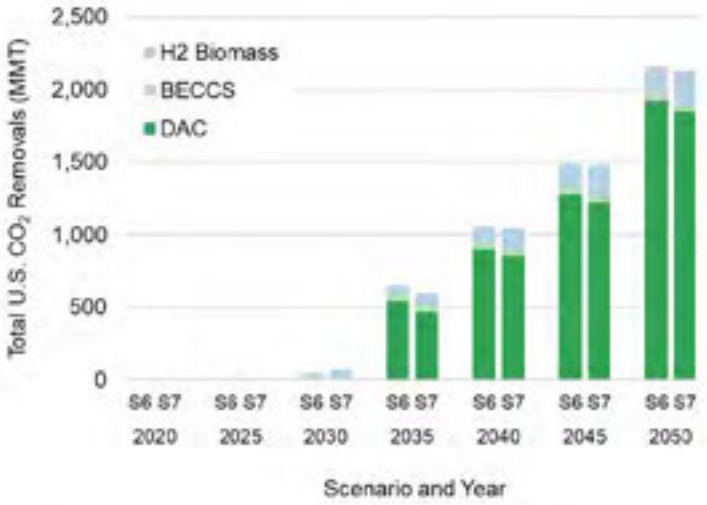


Figure B-6. U.S. CO_2 emissions and removals, net-zero scenarios

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.[26] 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.

[26] 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.

Commented [UP111]: What's OGSM? Needs to also be included under Acronyms/Abbreviations Table.

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 [ST112]: 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 [ST113]: Should this be NH to NH?

Commented [ST114]: Would this be north of the mason dixon line?

Commented [ST115]: 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.

Commented [ST116]: Why every 10 years of data when the raw data is provided on an annual basis from NEMS?

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

Commented [ST117]: How much variability in dry production volume is considered significant?
Northeast is a 55% increase.
60% decrease in Midwest.

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, SI

Commented [ST118]: No discussion of Table C-3.

Ratio compared to what?

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

Caption needs better clarity.

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

Commented [ST119]: Why 2041 results?

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

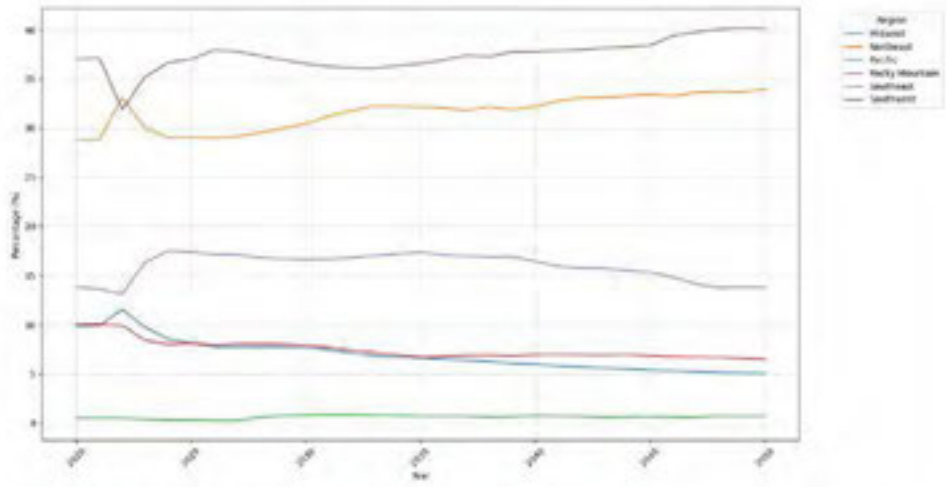


Figure C-1. Dry NG production percentage time-series for each region

This percentage can be multiplied with the 2020 GHG intensity values for each region from the NETL Natural Gas report[18] (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 ($gCO_2e/g\ CO_2e$/MJ) from 2020 NETL Natural Gas Report

Region	GHG /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 [ST120]: Hanging text??? Old text???

Commented [ST121]: GHG Emissions Intensity

Commented [ST122]: 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 [ST123]: How were the regional profiles converted to a single Weighted Average GHG Emissions Intensity value?

Commented [ST124]: GHG Emissions Intensity

Commented [ST125]: 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 [ST126]: This is a large caveat! The analysis should consider both dry production and GHG emissions intensity differences by year.

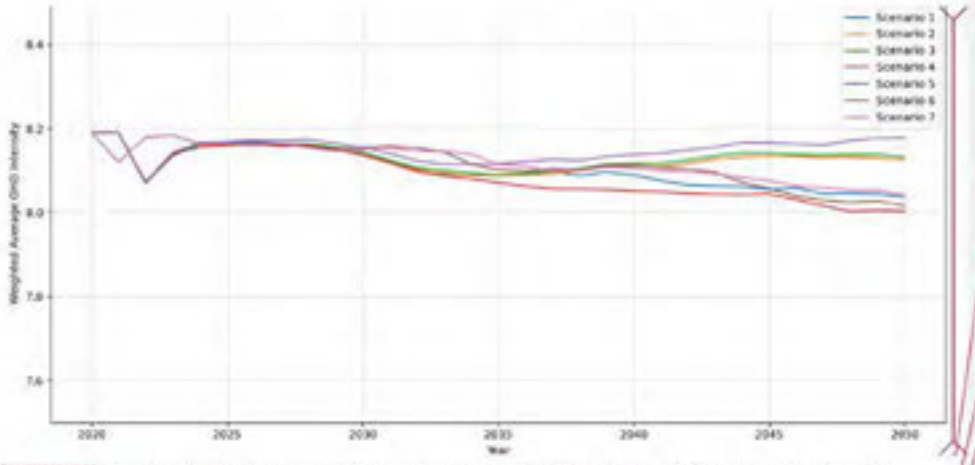


Figure C-2. Estimated U.S. Average GHG Intensity (g CO_2e/MJ) [S1 through S7], Production through Transmission [2020 - 2050]

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 (MtCO2/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 [ST127]: 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 [ST128]: Why does S4 have a steeper and lower GHG emissions intensity per unit of gas produced in 2050 than S6 or S7?

Commented [ST129]: 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 [ST130]: Odd phrasing. The other "Data Represented" descriptions do not explain "how" to use the data set.

Columns	Description
scenario	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 [ST131]: Capitalization of column heading names seems to vary in this table. Intentional?

Commented [ST132]: 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 [ST133]: Subscript

Commented [ST134]: 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 –
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

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.

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.

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

Commented [ST135]: ??? Not described in the text.

Commented [ST136]: What does this mean? Unclear.

Commented [ST137]: How was it preserved?

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

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)

	Estimated GCAM Emissions Intensity (Tg CO_2e / EJ, g CO_2e / MJ) [IPCC AR5 100 yr]		
GCAM Sector	**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)

	Estimated GCAM Emissions Intensity (Tg CO_2e / EJ, g CO_2e / MJ) [IPCC AR5 20 yr]		
GCAM Sector	**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).

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

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

Commented [ST138]: What does "with adjustments mean?

Commented [ST139]: 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 [ST140]: HHV or LHV results?

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 [ST141]: 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