Major New US Industry at a Crossroads:

A US LNG Impact Study - Phase 2

Report by Commodity Insights and Market Intelligence

March 2025

S&P Global

Study Context

This study offers an independent and objective assessment of the economic, market and global impact of the U.S. LNG Industry built from a detailed bottom-up approach, at the asset and market level, technology by technology. It represents the collaboration of S&P Global Commodity Insights, and the Global Intelligence and Analytics unit within S&P Global Market Intelligence supported by the world's largest expert team of more than 1,400 energy and economic research analysts and consultants continuously monitoring, modeling and evaluating markets and assets. Explanation of the detailed study methodology is included in the Appendix. The analysis and metrics developed during the course of this research represent the independent analysis and views of S&P Global. The study makes no policy recommendations.

The study was supported by the US Chamber of Commerce. S&P Global is exclusively responsible for all of the analysis, content and conclusions of the study.

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For more information on this report, please contact:

Eric Eyberg

Vice President, Gas & Power Commodity Insights Consulting

Eric.Eyberg@spglobal.com

Leandro Caputo

Executive Director, Gas & LNG Commodity Insights Consulting

Leandro.Caputo@spglobal.com

Linda Kinney

Head of Business Development, Commodity Insights Consulting

Linda.Kinney@spglobal.com

For Media information on this report, please contact:

Jeff Marn

Executive Director, Public Relations, S&P Global

Jeff.Marn@spglobal.com

S&P Global Project Team

Project Chairman, Daniel Yergin
Vice Chairman, S&P Global

Executive Project Sponsor, Carlos Pascual
Senior Vice President, Global Energy, S&P Global

Expert Advisory Committee Lead, Michael Stoppard
Chief Global Gas Strategist, S&P Global

Emissions Advisory Lead, Eleonor Kramarz
Vice President,
Energy Transition, Commodity Insights Consulting

Project Director, Eric Eyberg
Vice President,
Gas & Power Commodity Insights Consulting

Project Manager, Horacio Cuenca
Senior Director,
Energy Transition, Commodity Insights Consulting

Project Team Leads:

Leandro Caputo**,** Executive Director, Gas & LNG Commodity Insights Consulting,

Mohsen Bonakdarpour, Executive Director, Global Intelligence and Analytics, Market Intelligence,

Ed Kelly, Executive Director, Gas & LNG Commodity Insights Consulting,

Madeline Jowdy, Global Head of LNG, Commodity Insights Consulting,

Relationship Manager, Linda Kinney, Head of Business Development, Commodity Insights Consulting

Communications Lead, Jeff Marn, Public Relations Executive Director, S&P Global

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We acknowledge our collaboration with providers of satellite-based and aerial remote sensing technology and emission data. Methane emissions are a significant factor in the variability and uncertainty of oil and gas supply chains. Observationally derived methane emissions, when accurately interpreted and contextualized, offer a more credible assessment than many past regulatory estimates. We have utilized the best satellite data sources available to S&P Global in the timeframe of the study, including Sentinel-2, TROPOMI, and GHGsat, to quantify methane emission rates over large areas and identify event-based point sources. Where available, we also leverage our data partnership with Insight M, which provides estimates from high-quality overflight data.

Contents

Study Preface and Scope

In the S&P Global December 2024 Phase 1 report, we examined the remarkable rise of the US liquefied natural gas (LNG) industry. In less than a decade, this sector has become a major export industry, contributing more than $400 billion to U.S. GDP and supporting hundreds of thousands of American jobs. This development has not only contributed positively to the US economy and export earnings but has also strengthened the international position of the United States and deepened relations with many other countries.

This Phase 2 companion study expands and complements key aspects of our first phase study:

1. The environmental impact of further development of US LNG – in particular, the potential net impact on global GHG emissions of 40 million tons of incremental LNG export capacity tied to projects that are on hold or in the pre-FID (Final Investment Decision) stage from the Phase 1 Base Case
2. A State and Congressional-district level economic impact assessment, analyzing the impact of US LNG across the national economy.
3. The potential benefits of infrastructure debottlenecking across the value chain, focusing primarily on the Northeast gas market

On the emissions front, Phase 2's central finding is that increasing US LNG exports leads to 780 million tonnes of CO_2e (GWP20) lower GHG emissions globally between 2028 and 2040 than would be the case if demand were met by the likely alternative sources. The study demonstrates why the bulk of demand – absent US LNG – would largely be met with other hydrocarbons, not renewables. This future saving equates to total road transport emissions in the UK over the same period. The reason for these savings is driven by the lower GHG intensity of US LNG compared to the average intensity of the combined energy sources that would replace that LNG in global markets.

This analysis shows that end-use combustion accounts for a significant 57 to 87% of the lifecycle intensity of coal, oil, gas and LNG. Varying levels of methane emissions in the supply chain prior to end-use lead to significant differences between the sources and pathways of each fuel. This highlights the need for frequent and reliable monitoring of methane emissions and the benefits of transparency in GHG intensity.

From a macroeconomic perspective, the Phase 1 Base Case outlook demonstrated that US LNG exports can contribute an additional $1.3 trillion to US GDP through 2040. This Phase 2 report illustrates that the economic impact extends beyond the seven core producing states, with 37% of jobs and 30% of GDP contributions occurring in non-producing areas.

The third part of the report examines the economic benefits of ending one major and costly distortion in the US energy system. This would be achieved by removing bottlenecks in infrastructure especially across the Northeast region. While the Northeast region has sufficient proved reserves to meet all U.S. demand for 17 years, existing pipeline constraints hinder optimal production. These result in gas prices in New York and Boston that are 15–40% higher than the national annual average, and 145% and 160% higher in the key winter heating month of January – imposing a heavy and unnecessary cost burden on consumers. Expanding egress capacity from the giant Marcellus supply by about 6 billion cubic feet per day could reduce January prices by 20% and 30%, respectively, from 2028 to 2040 (17-27% annualized), resulting in cumulative savings of $76 billion for consumers by 2040.

Key Findings

- Higher US LNG exports lead to lower overall global emissions by displacing the more GHG intensive fuels that would replace them. Specifically, the incremental emissions from US LNG's continued development (40 Mtpa of pre-FID or 'halted projects' identified in Phase 1 Base Case) are lower than the alternative energy sources displaced by 324 (GWP100) or 780 (GWP20)[1] million tonnes CO_2e between 2028 and 2040, equivalent to the total road transport emissions in the UK over the same period.
- End use combustion is responsible for 57–87% of GHG intensity for coal, oil, gas and LNG, with supply chain methane emissions the key driver of variation between fuels (e.g., domestic vs. international LNG, domestic versus piped natural gas imports, or different crude oil streams).
- Coal emits roughly 70% more greenhouse gases than the US LNG it would replace across all the alternatives analyzed

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- US LNG's unprecedented growth is enabled by an extended cross-state value chain, that reaches beyond the core-producing states – about 90% of every dollar spent remains within United States supply chains
- Of the annual average of 495,000 Us jobs supported through 2040, 37% will be in non-producing states. As many jobs will be supported in on-producing states as in Texas
- Over the same period, LNG Exports will contribute $1.3 trillion in GDP, with $383 billion or 30% in non-producing states. On a per capita basis, producing states benefit from a cumulative $13.2K GDP per capita

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- The US Northeast (NE) has vast amounts of low-cost gas reserves in the Marcellus and Utica formations (New York, Pennsylvania, West Virginia, Ohio), sufficient to meet nationwide demand for ~17 years
- Due to pipeline constraints these reserves are being developed at a suboptimal rate, pushing gas prices at Boston, Chicago and New York City Gates up 160% higher than the national gas market in peak months
- Expanding NE pipeline capacity by 6.1 Bcf/d could reduce HH gas prices by $0.20/MMBtu and significantly lower prices across the region. Cumulative nationwide consumer savings could reach $76 billion through` 2040

[1] Global Warming Potential (GWP) is a measure of how much heat a GHG traps in the atmosphere over a specific period (typically 20 or 100 years, defined as GWP20 or GWP100 respectively), relative to carbon dioxide. The warming potential of each greenhouse gas differs depending on the time horizon considered, as each gas has a different lifespan in the atmosphere and a different ability to absorb energy. The UNFCCC publishes two different time horizons to show the short- and long-term effects of GHGs on global warming: 20 years and 100 years. For this work, both GWPs of the AR6 are used to express emissions in carbon dioxide equivalent.

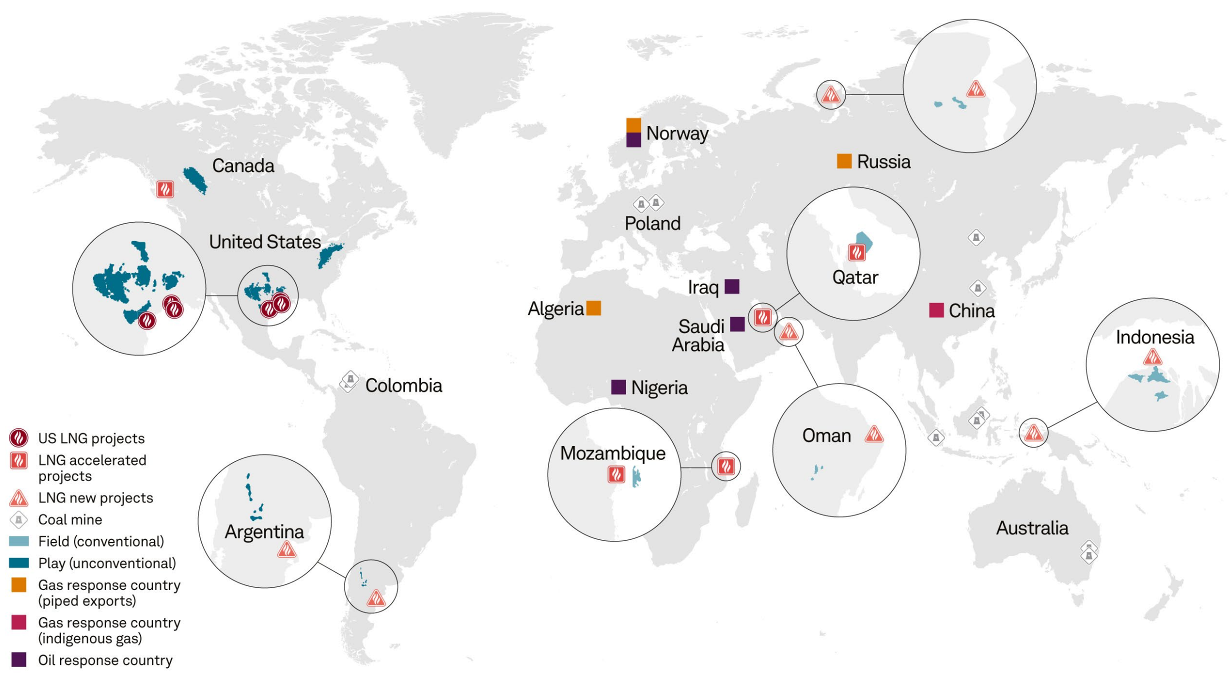
Beyond the Pause: US LNG Impact on Global GHG Emissions

Incremental US LNG exports in our Base Case from Phase 1 would result in 324 / 780 million tCO_2e (GWP100 / GWP20) lower emissions between 2028 and 2040 than the emissions of the global energy response, including coal, oil, indigenous and pipeline gas and renewables. This is equivalent the total road transport emissions in the UK over the same period.[2]

Key Methodology and Analysis Goals

If new US LNG does not materialize, something else will take its place. The cornerstone of any emissions impact analysis is therefore to compare the level of emissions from new US LNG relative to the emissions of that alternative. The first phase of this study determined the incremental US LNG projects, the alternative global energy supply sources and volumes[3], and the target markets affected that serve as the basis for this emissions assessment.

Figure 1. Global Map of Gas, LNG, Oil and Coal Supply Sources Analyzed in this Report



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[2] Cumulative emission avoidance over the period 2028-2040 corresponds to the annual avoided emissions shown in Figure 3 and detailed in the appendix, below. The 324 $MtCO_2e$ and the 780 $MtCO_2e$ are based on the 100-yr and 20-year GWP calculations, respectively.
[3] The global energy response to a halt in US LNG exports includes incremental indigenous gas production in China and Turkey, and increased gas imports via pipeline from Norway and Algeria to Europe, as well as from East Siberia to China.

This Phase 2 report was conducted to assess the impact on global greenhouse gas (GHG) emissions of 40 mmtpa incremental US LNG capacity (pre-FID or 'halted' projects in our Phase 1 Base Case) relative to the alternative energy sources displaced. It first assesses the lifecycle emissions associated with the drilling and completion, production, processing, transport, and end use combustion of US LNG to select end-markets. These results are contrasted against the lifecycle emissions of alternative fuels that would be substituted into the global energy system in the absence of these incremental US LNG exports. These sources include alternative LNG sources, indigenous gas production and piped imports, coal, oil, and nuclear and renewable power.

Several differentiating factors underpin the robustness of our methodology. First, S&P Global modeled multiple feedstock gas sources and destination markets for each incremental US LNG plant individually, based on current and expected physical flows, known contractual arrangements, and trade routes. These were then combined into a weighted average GHG intensity for the upstream and shipping segments of each LNG plant considered. Second, we allocated GHG emissions across the co-products of the oil and gas value chain on an energy basis. Finally, we incorporated the best sources available to us in the study timeframe of observed methane emissions quantification, both in the US and non-US gas supply chains.

The functional unit of this lifecycle assessment is 1 megajoule (MJ, lower heating value) of each energy source delivered to an end-use point near an LNG regasification terminal in the destination markets. The results are expressed in GHG-intensity terms as grams of carbon dioxide equivalent per MJ (gCO_2e/MJ). An energy-based emissions intensity allows for a uniform comparison across energy sources and along the various segments of the respective supply chains.

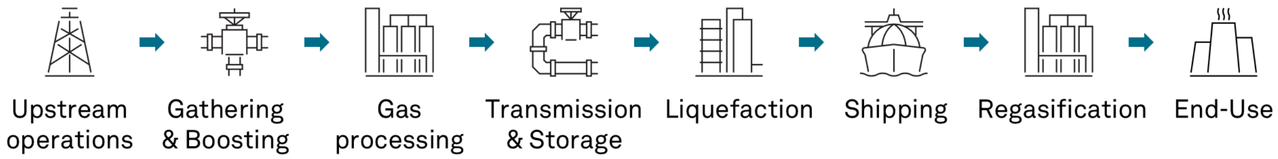
The modeling of the energy response done in Phase 1 accounts for heat-rate efficiency differences across the importing countries (i.e., the quantity of LNG vs coal or oil required to generate a kilowatt hour (kWh) of electricity). To avoid double counting, the functional unit of Phase 2 is defined on the basis of the energy delivered to the end use point, without considering end-use efficiency (e.g., power plant heat rates).

Greenhouse gases evaluated include carbon dioxide (CO_2) and methane (CH_4) resulting from fuel combustion, flaring, venting, and fugitive sources.[4] Using the global warming potential (GWP) of each gas is the established approach introduced by the IPCC to combine their emissions into a single metric. The relative impact of methane emissions on lifecycle intensity depends on the choice of the GWP factor. Results are shown using the 100-year and 20-year Global Warming Potentials (AR6 GWP100 and GWP20)[5] for comparability to other studies. All quoted figures are in GWP100 unless otherwise stated.

Both absolute emissions and the GHG intensity of the value chain segments for each fuel are estimated separately, from production to final combustion. Changes in product flows through the supply chain are considered by applying an energy ratio to the emissions in each segment to account for the separation of co-products, losses, and the use of the product as fuel. In the case of gas and LNG, only GHG emissions apportioned to the dry gas flowing into the liquefaction plant are considered throughout the value chain.

[4] This analysis excludes other greenhouse gases, such as nitrous oxide, that are relatively minor contributors to GHG intensity for the fuels studied
[5] Global Warming Potential (GWP) is a measure of how much heat a GHG traps in the atmosphere over a specific period (typically 20 or 100 years, defined as GWP20 or GWP100 respectively), relative to carbon dioxide

Figure 2. Major Supply Chain Segments Analyzed for LNG Emissions, Including for both US LNG and Alternative LNG Sources



Source: S&P Global Commodity Insights

The analytical approach taken for forecasting key supply chain segments is highlighted below:

US LNG Upstream & Midstream	▪ GHG intensities for the upstream segment (drilling and completion and well production/operation) are estimated for all relevant US plays for five tiers of wells, with each tier defined based on relative well productivity. ▪ Average upstream and midstream intensities are assigned to each LNG facility, weighted by the gas volumes delivered from each play, as determined by S&P Global Commodity Insight's upstream forecast per tier. ▪ The gas flow patterns between the upstream plays and the LNG facilities are aligned with current and expected physical gas flows that were validated by S&P Global's US gas experts.
Shipping Routes	▪ Emissions calculations incorporate weighted average distances between supply sources and consumption markets, accounting for fleet composition and vessel specifications.
Destination Markets	▪ The end-use markets for US LNG and alternative energy sources were identified in Phase 1, based on long-term demand forecasts by fuel and an analysis of global trade flows, considering both existing contractual agreements and projected flows.
End Use	▪ Combustion emissions for each fuel type are shown on a heat input basis given the choice of functional unit, as adjustments for differences in end-use efficiency were addressed in the global energy response analysis during Phase 1.

The methodological framework applied across the natural gas and LNG supply chain is largely based on the S&P Global Center of Emissions Excellence's core methodologies, in consultation with the Center's experts. The Center currently leverages historical supply chain emissions across key markets, including the US and Canada (and others that are not relevant for this study).

Two main points of divergence from the base methodology occur due to the scope of this report. First, new approaches were developed to estimate upstream and midstream intensities for the alternative sources of mostly conventional gas and LNG supply assessed (including Argentina, Mozambique, Russia, Indonesia, Oman and a new phase of development in Qatar). Secondly, this study leverages a wider set of observed methane data, namely Sentinel-2 and GHGSat for the countries listed above, and Insight M for a more granular perspective on US emissions.

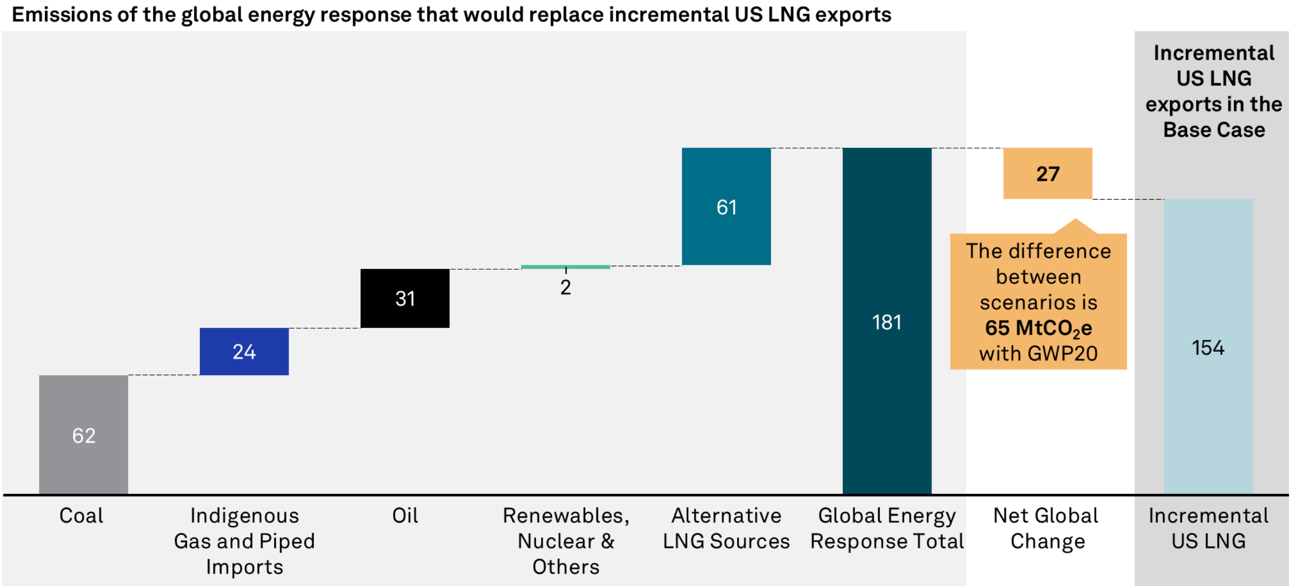
Incremental US LNG Exports Result in Lower Global GHG Emissions

In Phase 1 of this study, S&P Global modeled how the global energy system would respond to the US LNG 'Extended Halt' scenario, in which the six pre-FID or 'halted' LNG plants on the US Gulf Coast would not be built. This 'Extended Halt' would lead to the reduction of roughly 40 million metric tons per annum (Mtpa) of US LNG on average from 2028–2040. Global markets would respond to this drop in available incremental US-exports via 1) non-US LNG producers increasing supply, and 2) other energy sources emerging.

A scenario including incremental US LNG exports from the impacted projects would result in an average of 27 million metric tons of CO_2e ($MtCO_2e$) lower greenhouse gas emissions per year between 2028 and 2040, based on a 100-year global warming potential (100GWP), compared to the combined emissions from the global energy supply that U.S. LNG would replace. This is equivalent to roughly 3.6 million homes' worth of energy use for one year.

This impact is larger when considering a 20-year GWP (GWP20), with incremental US LNG exports leading to 65 $MtCO_2e$ lower emissions per year on average. This is equivalent to more than twice the emissions of all cars in Los Angeles county each year (14 million gasoline-powered passenger vehicles).

Figure 3. Annual Average GHG Emissions Difference Between the Global Energy Response to an LNG 'Halt' Scenario and the Incremental US LNG Exports in our Base Case, 2028-2040, Using the Midpoint Methane Intensity[6]
$MtCO_2e$, 100-yr GWP, yearly average 2028–2040, midpoint methane intensity



Source: S&P Global Commodity Insights

The lower global emissions level is driven by the avoidance of more GHG intensive fuels that would be part of the global energy response to reduced US LNG exports under the 'Extended Halt' scenario. The global energy response would include a combination of coal, oil, indigenous gas and piped imports, renewable generation, and alternative LNG sources outside the US.

[6] The volume of impacted LNG exports at risk and the response of the global energy system are based on the results of Phase 1. Midpoint methane intensity represents the middle of the modeled methane uncertainty range. For results on the full range of methane uncertainty, see appendix.

The uncertainty of our estimates of methane emissions in the global energy response is expressed as a range of methane intensity defined for each fuel. The figure above shows the midpoint of this range for each energy source. In contrast, CO_2 emissions are estimated with much greater certainty.

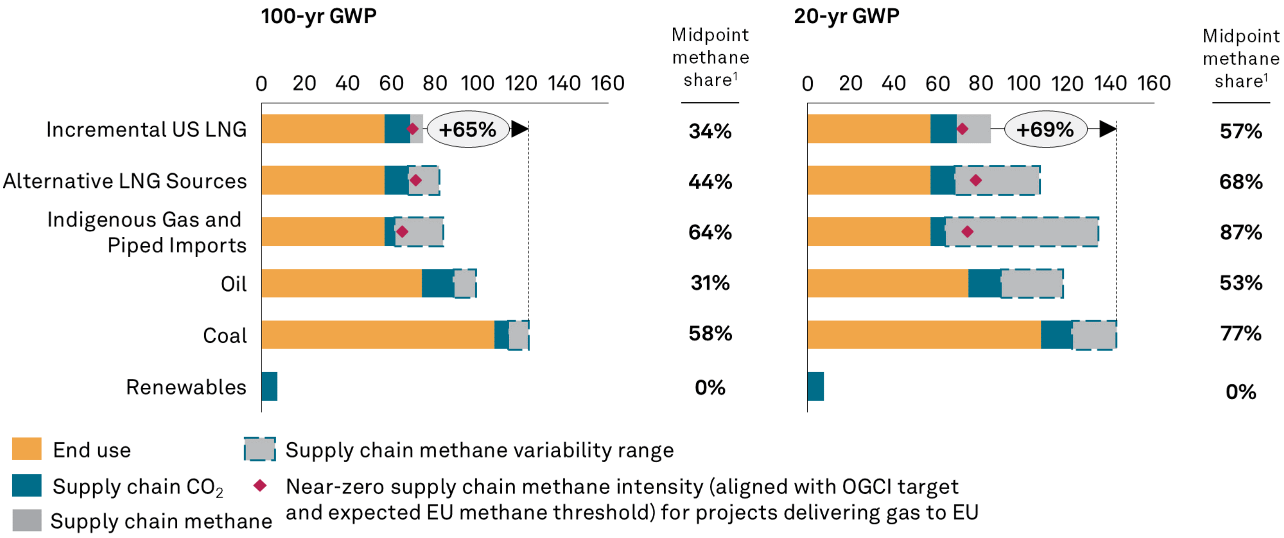
On a GWP100 basis, the six US LNG facilities affected by the 'Extended Halt' are projected to generate an average of 154 $MtCO_2e$ per year over the period 2028-2040. Without this incremental US LNG growth, however, the alternative energy sources that would replace it in the global energy system would result in 181 $MtCO_2e$ per year over the same period on average. The main contributors to higher emissions are coal and alternative LNG sources, which account for 62 and 61 $MtCO_2e$ per year on average, respectively. Indigenous gas and piped imports would emit on average 24 $MtCO_2e$ per year.

Uncertainty in the methane intensity estimates stems from our challenge in accessing high resolution, complete, frequent, and granular methane observation data outside of North America. S&P Global leveraged methane detection data from multiple sources, but the sample sizes, frequency, and detection thresholds were better for areas in North America than for other geographies for the data sources available to us during the time frame of this study. Flyover methane detection data accessed by S&P Global covers more than 280 billion pixels in the Permian basin alone, while the satellite data analyzed over non-US acreage averaged 0.9-13 billion pixels across the Middle East, Central Asia, and North Africa.

GHG Intensities are the Key Driver of Total Emissions Change

The difference in GHG emissions between the incremental US LNG exports and the global response is a function of the lifecycle intensities of each energy source, which are determined by end-use combustion. On average, the lifecycle GHG intensity of coal can be up to 69% higher (GWP20) than that of US LNG per MJ. Oil can be up to 32% higher and alternative LNG sources up to 10% higher.

Figure 4. Weighted Average Full Lifecycle GHG Intensity, Production to End Use[7]
gCO_2e/MJ and % share of methane emissions in the supply chain excluding end use



1. The share of methane emissions in the supply chain up to regasification, excluding end use, based on the midpoint range of methane variability

Source: S&P Global Commodity Insights

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For all fuel types considered, end use combustion accounts for the majority share (57% to 87%) of GHG intensity, as shown in Figure 4. The share of end use combustion over lifecycle intensity is

[7] Averages shown include the weighted averages of all feedstock gas and shipping distances to destination markets for each fuel

particularly high on average for coal and oil, accounting for 107.5 and 74.2 gCO_2e/MJ, respectively. In contrast, to deliver the same MJ, natural gas (both piped gas and LNG) end use combustion emits just 56.8 gCO_2e[8].

Methane is the key driver of variability and uncertainty in the supply chain. Within pre-end use supply chains, methane accounts for 34% of US LNG emissions, varying by LNG facility based on the unconventional resources supplying feedstock gas given the differences in upstream and midstream operations across plays. Alternative sources of global LNG, in contrast, are mostly supplied by large, conventional, dry gas reservoirs with typically lower fuel use intensities but more uncertain methane emissions. For alternative LNG sources, the share of methane emissions reaches 44% of total pre-end use supply chain intensity on average under our estimated range of variability. This methane share extends higher for the indigenous and piped imports, reaching up to 89-91% of supply chain emissions on the high end of our assumed range of variability for Algeria, China, and East Siberia.

The methane intensity of the international energy response is more uncertain than that of the US LNG value chain, given our limited access to frequent and reliable measurement data. In an effort to leverage the best available data beyond what S&P Global currently sources from TROPOMI's public methane detection data and aggregated US flyover detection results from Insight M, a dataset identifying 863 methane plumes with adjacent null observations over 17 countries was sourced from Sentinel-2 satellites for 6 months in 2024, and 1339 plumes and null observations were obtained from GHGSat for another 7 countries over 12 months in 2023.

These satellite data are highly valuable but still leave considerable uncertainty. The Sentinel-2 dataset detects emissions of 100 kg/hr or higher, and the coverage ranges between 7.5 billion pixels over the entirety of North Africa (3 million km^2) and 13.1 billion pixels over the Middle East (5.2 million km^2). In contrast, flyover methane detection data sourced from the partnership between S&P Global and Insight M for the Permian basin alone (0.2 million km^2) contains between 282 and 319 billion pixels and reliably detects emissions as small as 10 kg/hr.

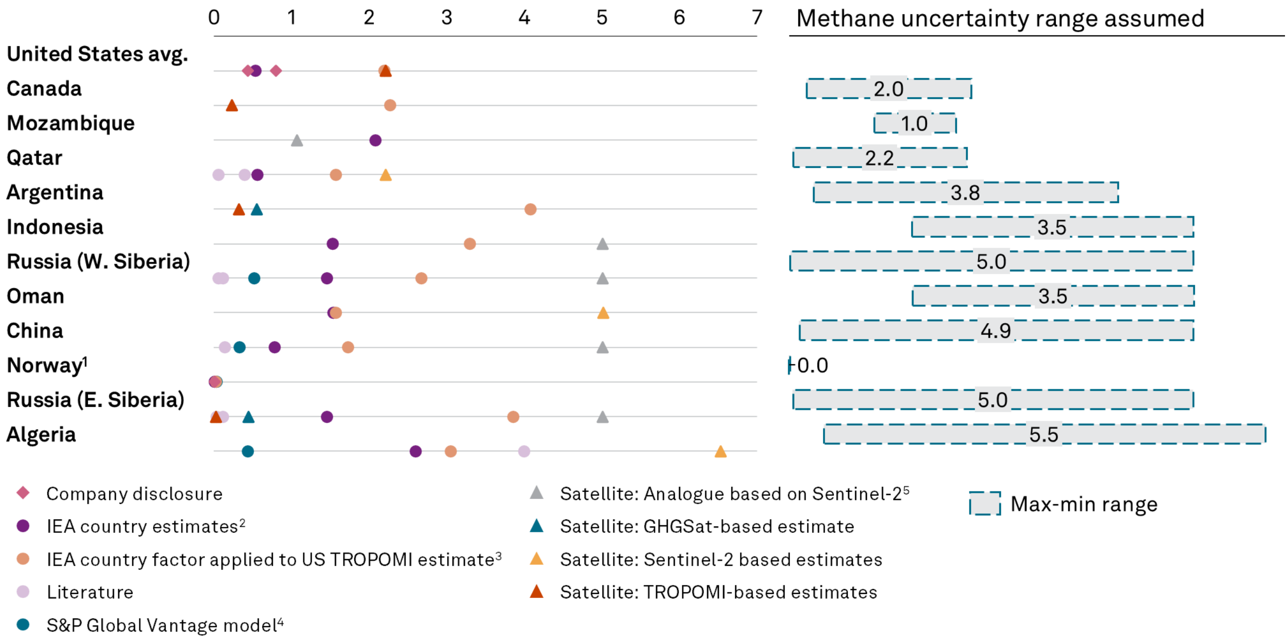
This discrepancy in data availability and resolution between the US and international observation is due to factors such as higher frequency of measurement campaigns in the US to which S&P Global has access, technical limitations in the ability of satellites to observe methane emissions for offshore operations and high latitude locations, and variability in regulatory standards and reporting practices across different countries.

In addition, operational constraints in data processing capacity within S&P Global also impacted the study's ability to capture TROPOMI's public methane concentration data and apply an inversion model across regions outside of the US, Australia and the few other selected locations for which external studies have been undertaken and gas intensities published.

To account for these limitations, we define ranges of methane intensity based on the available information and our satellite-informed estimates for each alternative source of LNG, domestic gas and piped imports, oil and coal. Figure 5 shows the methane intensity considered for each location for the various sources accessed and the associated range of uncertainty used in this analysis.

[8] Combustion emission factor sourced from the Oil Production Greenhouse Gas Emissions Estimator (OPGEE) model

Figure 5. International Methane Emissions Benchmarking, Production to Gas Processing
Intensity for relevant basin in each country, intensity in $\%CH_4$ released / $\%CH_4$ in gas stream[9]



1. Although no satellite measurement was available for Norway in our study, the range is based on company disclosure with limited variability given the strong regulatory pressure and record of methane measurement and control by operators in the country; 2. IEA methane Tracker 2024 normalized with S&P Global O&G production data per country; 3. Average of US TROPOMI measurements with a methane scaling factor from IEA; 4. Average estimates at the country level; 5. For countries where no measurement data is available, we include the average intensity for upstream derived from Sentinel-2 observations to determine the uncertainty range. Refer to the appendix for additional information on satellite coverage across regions.

Source: S&P Global Commodity Insights, leveraging TROPOMI, GHGSat, and Sentinel-2 observations; academic research (papers listed in appendix); and IEA's Global Methane Tracker

Methane Emissions Intensity

Following S&P Global's Center of Emissions Excellence methodology, methane intensity is expressed as methane emissions allocated to gas divided by the methane content of the throughput of the specific segment.

To allocate methane emissions to natural gas production, a gas ratio based on energy content is multiplied by the estimated methane emissions of the segment. The gas ratio varies across each segment as it is based on the energy content of natural gas divided by the total throughput energy (gas and other products) in that segment.

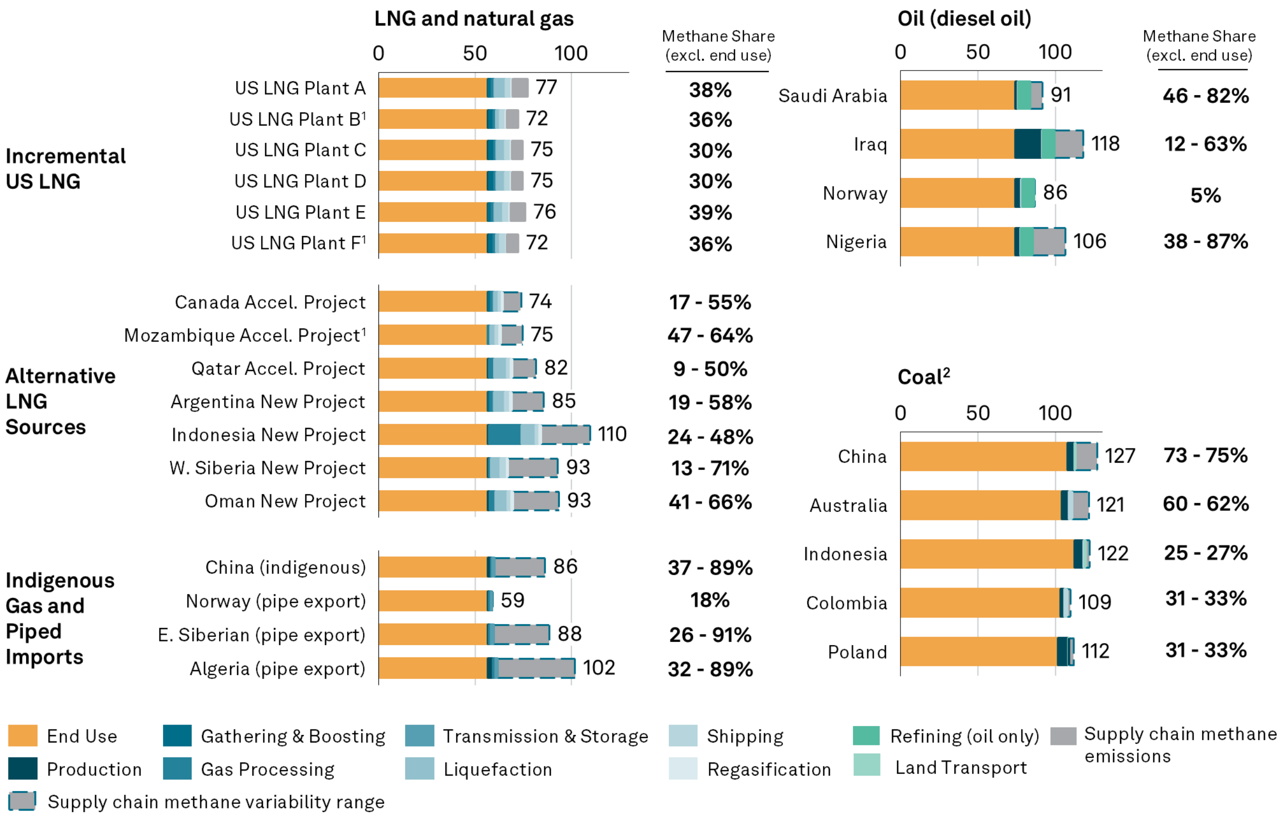
The average methane content in the gas composition assumed for each play/field is used to convert natural gas throughput to methane.

This method follows industry life cycle assessment (LCA) best practice of co-product allocation of GHG emissions. This is aligned with the Natural Gas Sustainability Initiative protocol[10], but other industry associations define intensity differently, including the Oil and Gas Climate Initiative (OGCI)[11].

[9] Expressed as methane emissions (on an energy basis) divided by methane content of the throughput, with marketable gas being the common denominator across the supply chain.
[10] Our approach differs with NGSI on the gas processing stage. The study uses an energy ratio whereas NGSI specifies specific process level allocation between different gas processing units.
[11] This study defines near-zero methane intensity as 0.20% of methane emissions in energy content terms attributed to gas divided by the total energy content of the throughput or production stream. This intensity target is aligned with OGCI's corporate methane target in predominantly gas-rich plays/fields. Note that OGCI expresses its intensity target in cubic meters of methane emitted per cubic meter of gas marketed at the point of sale. Given the lack of allocation of methane emissions between co-products, OGCI's approach penalizes oil and liquids-rich plays/fields. We use an energy allocated near-zero 0.20% intensity across all plays/fields.

The resulting GHG intensity of alternative sources of LNG and other fuels varies widely, mainly due to methane, but flaring, reservoir properties, and operations also contribute. Within each fuel group, the variability across sources of the same fuel is driven by supply chain emissions prior to end use. For each source of fuel, emission intensities vary based on gas composition, flaring and methane management, and operations management. Figure 6 shows the relative emission intensities across the various supply chains.

Figure 6. Supply Chain Lifecycle GHG Intensities of LNG, Oil, and Coal by Supplier, Excluding End Use
gCO_2e/MJ, 100-yr GWP



1. Electric-driven liquefaction plant assumed; 2. For the lifecycle analysis of coal, methane observation data are not available. Therefore, the methane range has been assumed as a sensitivity of the IPCC factors, aligned with the range obtained for gas analysis. See appendix for further details.

Source: S&P Global Commodity Insights

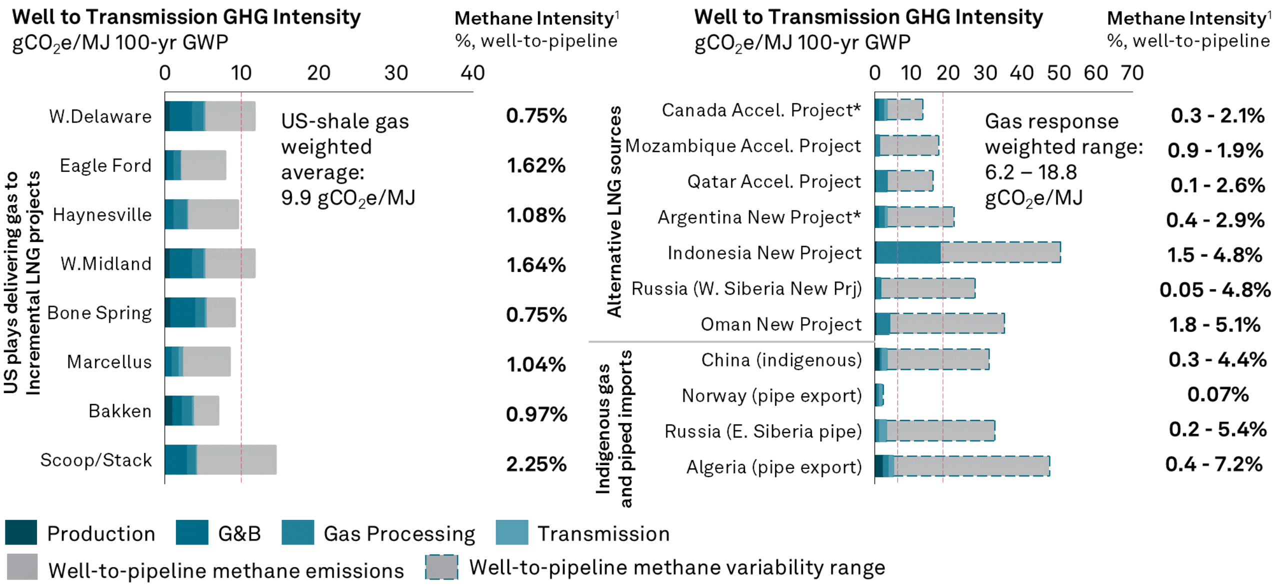
For each energy source, emissions from the combustion of fuels such as gas, diesel and indirect electricity imports along the supply chain depend on the specific operating conditions in each region or project. For example, the electrification of upstream and gathering operations in parts of key US plays and compressor drives for liquefaction is a key determinant of the GHG intensity of these segments.

To date, a limited number of LNG facilities use (or are planning to use) electric drives for liquefaction, including two of the US facilities studied and the accelerated project planned in Mozambique. The electrified liquefaction plants in the US and Mozambique utilize power from the local grid to meet their energy requirements. In Canada, the gas-driven liquefaction plant also leverages electricity from a hydro-dominated system to supply power for its auxiliary energy needs. In contrast, most liquefaction plants today and in the other regions analyzed are gas-driven, with auxiliary energy supplied by the onsite power generation.

Flaring emissions in the US and Canada are derived from the S&P Global Upstream Enhanced Emissions Model, informed by regulatory reporting data from the US EPA Greenhouse Gas

Reporting Protocol (GHGRP) and state-level sources. Flaring emissions for other locations are based on publicly available observed data from the Visible Infrared Imaging Radiometer Suite (VIIRS) processed through the S&P Global Flare Identification Model. In all locations, flaring volumes are attributed to individual facilities and allocated to oil and gas co-product throughput on an energy basis.

Figure 7. Upstream LNG and Natural Gas Total GHG and Methane Intensities[12]



Note: Only plays contributing >100 mmcf/d of production are shown. All US plays studied are unconventional gas sources. "*" denotes international unconventional gas sources; 1. Methane emissions intensity expressed as methane emissions (on an energy basis) divided by methane content of the throughput, where the common denominator is the marketable gas energy content.

Source: S&P Global Commodity Insights with measurements from TROPOMI

Across all sources of supply and all countries, this study assesses the impact on lifecycle GHG emissions of potential improvements to supply chain methane emissions to varying degrees. Given the global focus on US methane emissions and the higher levels of publicly available measurement data, many domestic operators are focused on incremental improvement aimed at reaching industry targets and proposed regulatory thresholds.

It is expected that the reduction of methane emissions in all supply chains analyzed will be largely driven by voluntary commitments and end-market policies, such as the EU Methane Regulation introduced in June 2024. Although fundamental aspects of this regulation are not yet defined, upstream producers seeking to sell LNG into the EU will be required to comply with a maximum methane emissions limit. The measurement, reporting and verification initiatives applied by gas producers will be the crucial driver of compliance with the EU Methane Regulation and of significant methane emissions reduction.

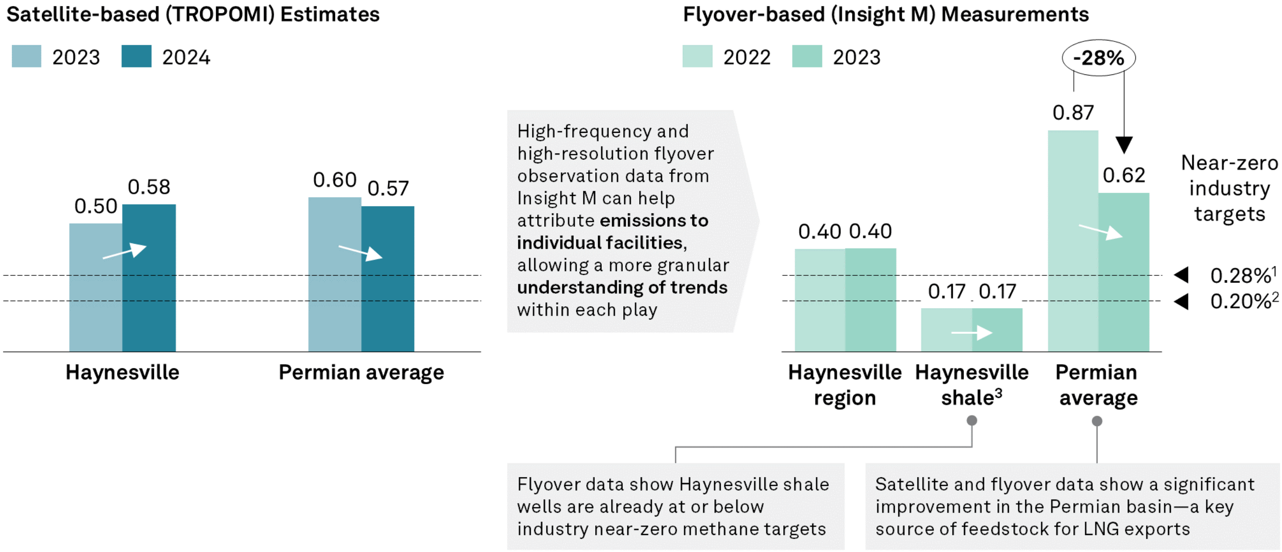
If those non-US LNG projects supplying LNG to the EU were to meet the near-zero methane emission requirements, the GHG intensity of the entire non-US LNG response would average just over 71 gCO_2e/MJ, 20% below our current midpoint estimate.

The US appears to already be making progress in this direction. High-frequency, high-resolution methane observation data in the US from the partnership between S&P Global and Insight M —a leading North American provider of flyover methane detection services— indicates that upstream efforts to reduce methane emissions are gaining traction. As Figure 8 shows, methane emissions

[12] Methane emissions on an energy basis divided by methane content of the throughput on an energy content basis.

from upstream oil and gas operations in the Permian Basin, which is a major supplier of feed gas to the incremental LNG exports evaluated, decreased by 28% in 2023 compared to 2022.

Figure 8. Evolution of US Oil and Gas Methane Intensities Based on TROPOMI and Insight M Measurements
%CH_4 released / %CH_4 in gas stream[13]



1. ONE Future Coalition target (production); 2. Near-zero energy allocated methane intensity, aligned with OGCI 0.20% target for gassy plays. 3. The Haynesville region has ~5,000 wells producing from the Haynesville Shale versus ~28,000 vertical wells producing from other formations.

Source: S&P Global Commodity Insights with measurements from TROPOMI, Insight M

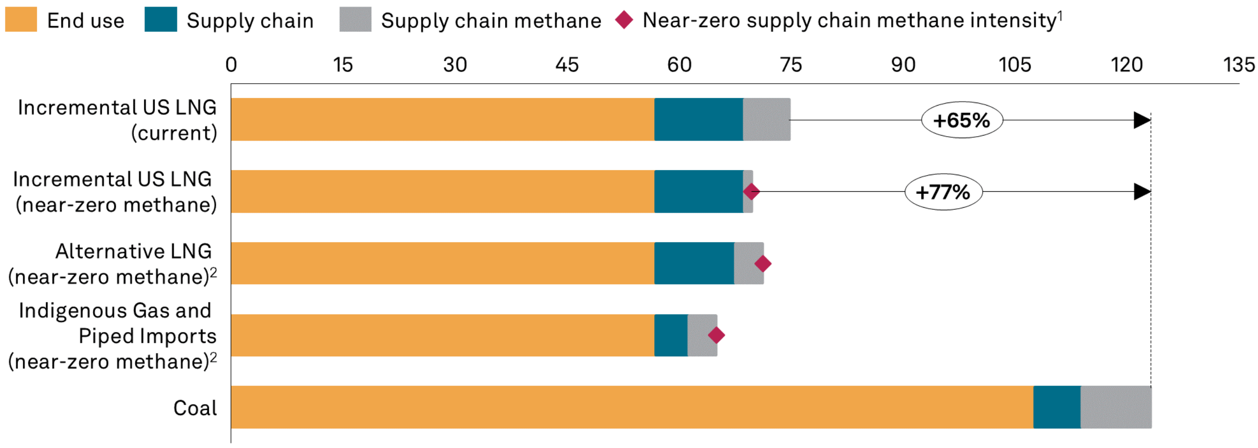
While our lifecycle intensity estimates use current TROPOMI-informed methane emissions, facility-attributed detection by Insight M allows a more granular understanding of trends within each play. Haynesville methane intensity, for instance, can be differentiated between horizontal wells producing from the Haynesville shale proper and older vertical wells targeting other formations. Haynesville shale production, the third largest source of feedstock gas for the impacted LNG facilities, seems to have already achieved methane rates close to the oil and gas industry's near-zero methane target[14] based on our analysis of Insight M data.

Similarly, based on well- and facility-specific attribution of flyover methane observation, we can identify diverging behaviors between operator types. Wells in US plays are classified by S&P Global upstream research from tier 1 (best) to tier 5 (worst) based on productivity quintiles. Flyover methane intensity is observed to vary by well tier. We assume a strong correlation between well tier and operator type, with the highest productivity wells assumed to be operated by global integrated oil companies and large US independent operators. These wells are also assumed to supply most of the feed gas to the LNG projects under analysis.

In a future where all producers selling gas to Europe successfully meet the near-zero methane emissions threshold, the average lifecycle GHG intensity of incremental US LNG projects would be reduced by 7% on average, increasing the difference with coal intensity from 65% to 77% for US LNG relative to coal (on a GWP100 basis) as shown in Figure 9.

[13] Methane emissions intensity expressed as methane emissions (on an energy basis) divided by methane content of the throughput, where the common denominator is the marketable gas energy content
[14] See Decline in Permian Basin Methane Emissions Equaled the Annual Carbon Emissions Avoided by Every Electric Vehicle in the United States, New S&P Global Commodity Insights Analysis Finds - Dec 23, 2024. Note that methane intensities from the Permian basin report were re-expressed to the approach followed in this analysis for consistency (%CH_4 emissions/%CH_4 in throughput).

Figure 9. Average Lifecycle GHG Intensity, Production to End Use
gCO_2e/MJ, 100-yr GWP



1. Near-zero energy allocated methane intensity, aligned with OGCI 0.20% target for gassy plays. 2. Near-zero only for projects delivering to Europe.

Source: S&P Global Commodity Insights

Continued focus on methane reduction throughout the US LNG supply chain will be critical to maintaining a competitive advantage for US LNG in markets that have implemented or are considering implementing methane caps or carbon tariffs on LNG imports, such as Japan and South Korea.

Data Sources and Benchmarking

This GHG analysis incorporates the best available data at the time of the study from a variety of sources.

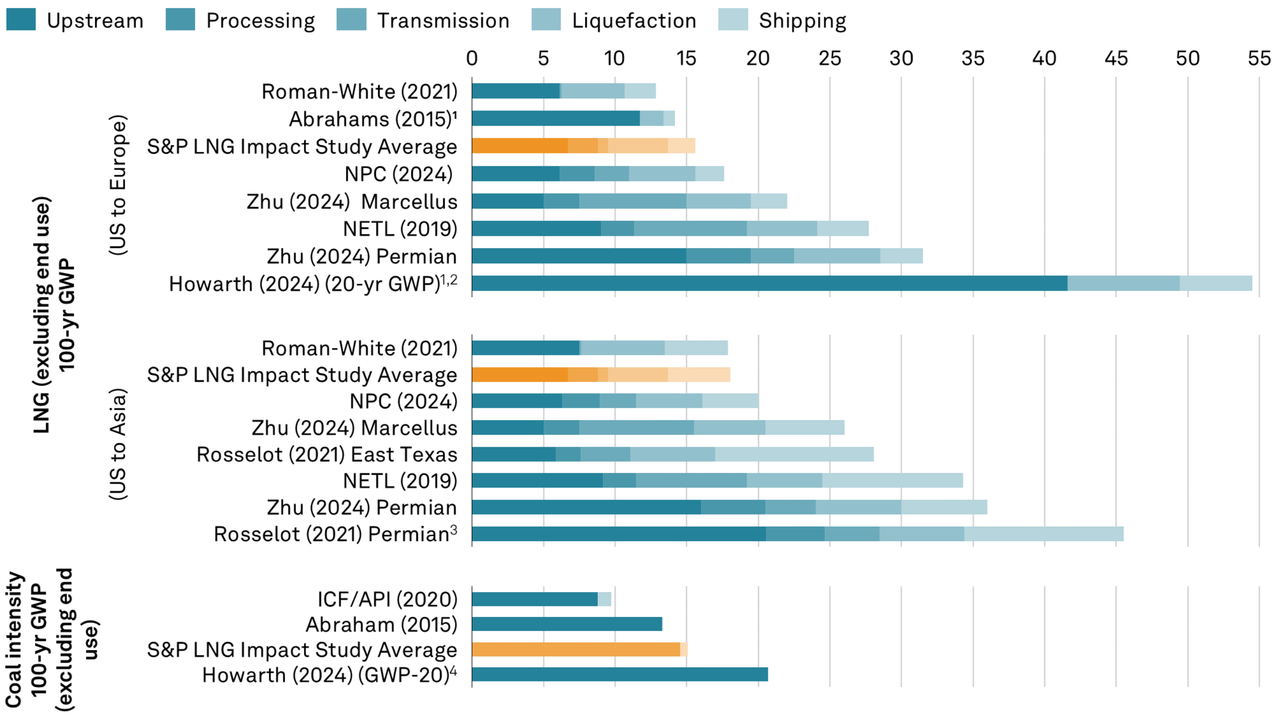
- **Observed data for methane and flaring:** Observed data is prioritized wherever possible. For US upstream and midstream operations, methane emissions are based on satellite observations from the TROPOspheric Monitoring Instrument (TROPOMI). Where robust airplane overflight measurements are available from Insight M, these data are used for evaluating differences between well types, operators and assessing changes in methane trends looking forward. For international methane emissions across gas and oil, observational data from a combination of GHGSat and the Copernicus Sentinel-2 satellite initiative are used. Flaring events are detected using raw data from the Visible Infrared Imaging Radiometer Suite (VIIRS) processed through the S&P Global Flare Identification Model. Raw data is processed by the S&P Global Analytics team as part of ongoing work with the S&P Global Center of Emissions Excellence.
- **Modeled and reported data:** The analysis also utilizes S&P Global's Energy Studio: Impact, which leverages reported data sourced from the federal (EPA) and state sources in the US and provincial-level and Environment and Climate Change Canada data in Canada for enhanced emissions modeling related to combustion and flaring supply chain emissions. Where reported data is unavailable in conventional plays, emissions are modeled based on S&P Global's QUE$TOR field development tool, using public field development plans (or an analogous field), leveraging key field and reservoir attributes (water depth, reservoir pressure, hydrocarbon characteristics, field operations, etc.) from S&P Global's E&P database.
- **Emission factors:** Where necessary, emission factors defined by the IEA, US EPA, IPCC, NREL, and academic studies are used for specific supply chain segments, such as for LNG shipping emissions (both fuel consumption and methane slip/boil off), coal mining and post-mining

methane and fugitive CO_2, oil upstream and refining emissions, end use combustion of all fuels, and operation of renewable electricity sources[15].

For a full description of data sources used in this analysis, see the appendix.

Overall, the GHG intensity results of this analysis fall within the range of similar studies published in recent years.

Figure 10. GHG Intensity Benchmarking, S&P Global Study Compared to Similar Studies
gCO_2e/MJ, 100-year GWP except were noted



1. The Abrahams (2015) and Howarth studies group upstream, processing, and transmission emissions into a single category, consolidated into 'Upstream' for this chart; 2. The Howarth study allocates all emissions to the gas stream instead of to all co-products on an energy basis. This study is also not explicit on a single destination market, but the results shown correspond to a 38-day trip; 3.The Rosselot study's results with allocation of all emissions to gas are 80 gCO_2e/MJ for East Texas and 177 gCO_2e/MJ for the Permian; 4. The Howarth study assumes coal is used domestically and excludes coal shipping; Note: Most of these studies use a functional unit of MWh of electricity generated or delivered. To enable comparisons with our study, all intensity results were re-expressed in MJ of fuel delivered to the plant, using the power plant efficiency factor quoted in the study. Where not disclosed, we considered a 55% efficiency for gas-fired combined cycle power plants and 40% for coal-fired plants.

Source: S&P Global Commodity Insights and published studies

The lifecycle analysis done by S&P Global is informed by industry best practices and follows methodologies laid out by the S&P Global Center of Emissions Excellence. Our estimates are enhanced in several ways by the use of proprietary global E&P and LNG data, enhanced well-level emissions modeling in North American plays, and the best observed methane emissions data accessible to S&P Global within the timeframe of the study.

First, for each LNG facility under analysis, this study considers a weighted average GHG intensity in the upstream and shipping stages rather than analyzing a single source or individual pairs of LNG plant and destination market. For each US LNG plant, a gas pathing exercise leveraging proprietary models identifies current and expected physical flows of gas from each key basin and unconventional play. The upstream segment GHG intensity reflects an average of each key source of supply weighted by the gas volume attributed to each plant. Non-US LNG projects tend to be

[15] IEA: International Energy Agency, US EPA: Environmental Protection Agency, IPCC: Intergovernmental Panel on Climate Change, NREL: National Renewable Energy Laboratory

integrated with a single or a few large conventional gas fields, or source their gas from a single unconventional play.

Similarly, the LNG shipping intensity is a weighted average of all the typical routes to the destination markets served by each export facility (identified on the basis of current trade flows and known commercial arrangements). Several of the studies reviewed consider single-play gas sourcing, and only pairs of a single LNG terminal with a single destination market.

Second, our analysis is aligned with LCA best practices, informed by S&P Global Center of Emissions Excellence, and the approach followed by most academic studies in the allocation of GHG emissions to all co-products in each segment of the value chain on an energy basis. The energy content of the production flowing through each segment of the value chain changes as the mix of co-products changes due to separation of products, gas processing, losses and use of gas as fuel. For example, for a well producing oil and associated gas, upstream GHG emissions are allocated to the wellhead stream of oil, natural gas, and the natural gas liquids (NGLs) included in the gas, based on the energy content of each product. As natural gas production is separated from oil before going through the gathering systems, emissions from the gathering stage are allocated to the energy content of just the natural gas (and NGLs) stream. Other studies reviewed assign all emissions entirely to the natural gas stream, significantly overstating its GHG intensity.

Third, we are uniquely placed to derive an intensity of methane emissions by leveraging our best-in-class global upstream oil and gas infrastructure and production databases to normalize methane rates from satellite plume detection. We capture plumes detected by the various satellite sources used and attribute them to specific facilities on the corresponding segment of the oil and gas supply chain leveraging our E&P infrastructure database. We then assess plume durations (using the midpoint approach) to estimate total methane emission rates. Methane emissions by facility are then normalized using hydrocarbon production data for upstream facilities, or throughput data estimated using processing capacity of midstream and downstream facilities. This approach relies on the detailed asset-level data developed and published by S&P Global.

Lastly, while our headline results are based on current levels of methane intensity, we also assess the impact of potential improvements in methane emissions that would be driven by regulatory requirements such as the EU Methane Regulation and voluntary industry commitments such as the OGDC Charter in the coming decade(s). This approach reflects the impact of the efforts in the oil and gas industry in addressing methane emissions, and the relative uncertainty associated with that potential improvement over time.

While the intensity results from this analysis fall within the range of similar studies, the strength of this study lies in the combination of two key elements: detailed modeling of supply chain GHG emission intensities across multiple energy sources, and a thorough analysis of global energy market responses to halted US LNG exports developed in Phase 1. Whereas previous studies have examined either emissions or market dynamics in isolation, our integrated approach captures the interplay between supply chain emissions and real-world energy substitution patterns that consider the inelasticity of energy demand in the short and medium term. As a result, this report provides a detailed and realistic analysis of the impact of US LNG on global GHG emissions.

Transcending Boundaries: The Broader Economic Impacts of US LNG

The Base Case of the US LNG industry is projected to create an average of 495,000 jobs and generate $1.3 trillion in GDP through 2040. Notably, 37% of jobs and 30% of GDP contributions will arise in non-producing states, impacting regions beyond the seven main producing states.

National Economic Impact Analysis

Phase 1 of S&P Global's study of the role of US LNG exports in the US economy detailed the historical contributions of US LNG exports to date, projected those contributions out to 2040 based on known LNG-related investments ("US LNG base case") and assessed how an extended halt of LNG exports could affect the national economy ("US LNG extended halt scenario"). Phase 2 in turn focuses on this industry's economic contributions by state and congressional district.

As LNG exports continue to transform America's trade outlook, this analysis provides both a state-by-state and congressional-district breakdown of the economic contributions of the US LNG base case and the extended halt scenario. This study illustrates not only the jobs and revenues associated with incremental gas liquefaction capacity development, but also provides a view of how the broader LNG value chain and supply chain are being shaped to optimize the economic opportunity associated with US LNG exports. The supply chain requirements are broad across the industrial mix including construction, manufacturing, logistics, IT and services.

Figure 11. Growth in the US LNG Export Industry Will Utilize Extended Supply Chains that Involve Both Producing and Non-producing States

	Industrial equipment & machinery	Construction & well services	Information technology	Logistics	Materials	Professional & other services
Representative spending categories	▪ Construction equipment	▪ Drilling wells support	▪ Hardware	▪ Freight transportation	▪ Frac sand	▪ Professional services
	▪ Upstream field equipment	▪ Operations support	▪ Software	▪ Pipeline transportation	▪ Chemicals	▪ Engineering services
	▪ Machines and cutting tools	▪ Upstream construction	▪ IT services	▪ Warehousing	▪ Cement and concrete	▪ Equipment rental
	▪ Medium / heavy-duty trucks and equipment	▪ Pipeline construction			▪ Steel and non-ferrous metal	▪ Financial services
	▪ Compressors, generators and cryogenic heat exchangers	▪ Liquefaction facilities construction			▪ Pipes and pipefittings	
Representative supplying states	▪ Michigan ▪ Ohio ▪ Minnesota ▪ Illinois	▪ Texas ▪ Louisiana ▪ Oklahoma ▪ Arkansas	▪ California ▪ Washington ▪ Texas	▪ Texas ▪ Louisiana ▪ Illinois	▪ Pennsylvania ▪ Ohio ▪ Wisconsin	▪ New York ▪ California ▪ Texas ▪ Florida

Source: S&P Global Commodity Insights

To further describe the considerable state-level economic impact of US LNG exports, it is important to place these federal results within the context of the national-level findings. We present below an overview of the national-level impact analysis completed in Phase 1:

- $408 billion in GDP contribution since 2016, supporting an average of 273,000 direct, indirect and induced US jobs
- US LNG industry growth is expected to double its US economic footprint to 2040. $1.3 trillion in GDP contribution supporting an average of 495,000 total US jobs. $2.5 trillion in revenues for US business, over $900 billion in expenditures, $165 billion in tax revenue, and $250 income per household per year
- Regulatory and legal uncertainty, beyond potential lifting of the LNG ‘pause,’ is putting growth at risk. That translates to over $250 billion in lost GDP growth and an average loss of more than 100,000 total US jobs

The remarkable growth of the US LNG exports sector is enabled by significant investments across the full extended value chain, from upstream exploration and production to pipelines and liquefaction activities. Since most of the technology, machinery & equipment, and know-how are homegrown, an overwhelming majority (over 90%) of every dollar spent throughout the supply chain remains in the United States. Furthermore, considering that LNG's extended value chain spreads across multiple states beyond core gas producing areas, the overall derived economic benefits extend to many non-producing states as well.

Regional Economic Impact Analysis

The state analysis framework was established as a system of linked state economies. As a result, the sourcing of inputs for the US LNG export value chain impacts states that are outside of the producing states. For example, the development of a liquefaction plant in Louisiana may rely on bank, financial and insurance services in New York (a non-producing state) and professional services primarily in Texas (a producing state). Capturing these connections highlights their indirect supply chain economic contribution. Furthermore, the economic multiplier includes the expenditure-induced impact that results from workers’ direct and indirect spending of their wages, and the follow-on supply chain effects.

Key State-level Findings

- While the $938 billion of cumulative direct capital and operating spending will be focused on projects within the seven producing states, the follow-on indirect and induced effects will result in 37% of the jobs (183,000 on average between 2025 to 2040) going to non-producing states.
- The remaining 63% of the jobs will be supported in the producing states. Texas will experience the strongest economic impact with supporting 183,000 jobs, on average, between 2025 to 2040 followed by Oklahoma supporting 34,000 and Louisiana at 30,000.
- Among the non-producing states, California, Illinois, Arkansas, and Florida are ranked at the top each supporting more than 10,000 jobs, on average, between 2025 to 2040.
- While 35,500 jobs, on average, will be at risk with the 'Extended Halt' Scenario in the non-producing states, 66,000 jobs, on average, will be at risk in the producing states.
- In the Base Case, cumulative GDP contributions will amass to $1.3 trillion. Roughly 30% or $383 billion will be generated in non-producing states.
- Combined federal personal and business income taxes will total $16 billion, 36% of which will come from non-producing states.

Economic Impact Analysis at the Congressional District Level

At the congressional district level, the economic contributions will be concentrated in the districts with significant upstream investment and operating expenses. Thus, the economic contributions will mainly accrue to the congressional districts within and around the Permian, Eagle Ford, Haynesville, Utica and Marcellus plays. As deeper investment will occur in these plays, the economic contributions will be even more pronounced in those congressional districts.

Key Definitions

Producing states are defined as those that are producing LNG (liquefaction facilities) or are part of LNG value chain in terms of upstream activities. The seven main producing states are Texas, Louisiana, Oklahoma, New Mexico, Pennsylvania, and Ohio. States with minimal expected future development – such as Maryland and Georgia – were classified as 'non-producing states', despite having existing LNG facilities.

Non-producing states are mutually exclusive to the producing states but will have an important contribution to the supply chain. These states, depending on their industrial mix and strength, will support the producing states in terms of required commodities, products, and services. States like Pennsylvania and Illinois will be key to provide the producing states with steel, fabricated products, machinery and equipment, respectively.

Regional Economic Contribution Analysis

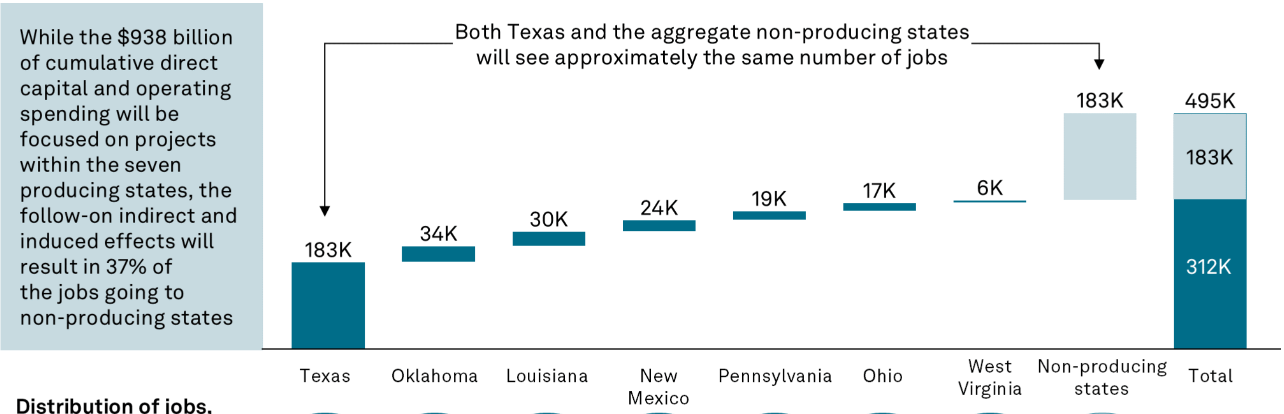
Analysis of the US LNG export development and its contribution to the US regional economies was conducted using a top-down/bottom-up approach. The contribution was assessed separately for direct, indirect, and induced contributions defined as follows:

- Direct contributions of US LNG exports are those activities required to produce natural gas, transport, and liquify at the terminal facilities.
- Indirect contributions are activities in industries that supply materials and services to the LNG export value chain and the activities of follow-on tiers of suppliers.
- Induced contributions are the economic effects from workers spending their wages and salaries on consumer goods and household items.

Although this phase of the study was performed on a state-by-state basis, the supply chain network of US LNG export between states was accounted for. It is widely acknowledged that the industrial bases of states such as Oklahoma and New Mexico cannot provide the full range of services, commodities and technology required by the US LNG export value chain. In fact, these states have seen considerable inter-state trade with Texas, Illinois, Michigan, California, and other states. Our methodology and model have accounted for this through a framework that has the US LNG export value chain activity relying significantly on the purchasing patterns outside of the producing states to support the industry.

To summarize the findings across the states, the results are presented in two distinct groups—producing states and non-producing states—across all major economic indicators.

Figure 12. Average Annual Jobs Supported in the Base Case
Annual average direct, indirect and induced jobs, 2025 – 2040

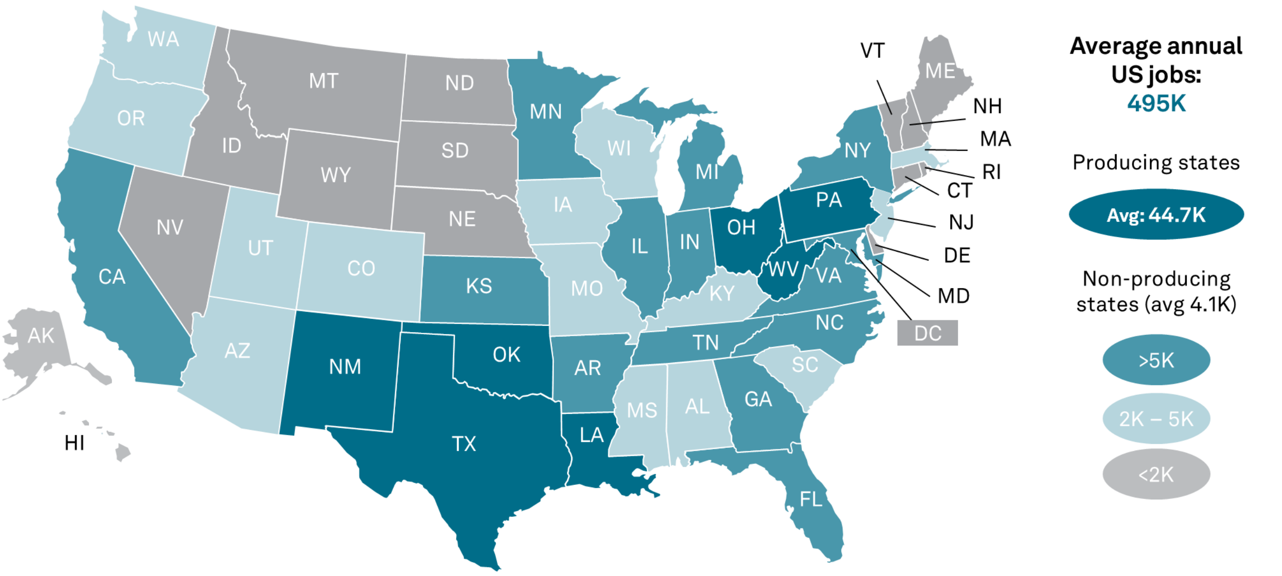


	Texas	Oklahoma	Louisiana	New Mexico	Pennsylvania	Ohio	West Virginia	Non-producing states	Total
Distribution of jobs, Base Case	37%	7%	6%	5%	4%	3%	1%	37%	
Jobs at risk, Extended Halt Scenario	41.5K	5.2K	5.0K	4.6K	4.2K	3.7K	1.9K	35.5K	101.4K

Source: S&P Global Commodity Insights

While the $938 billion of cumulative direct capital and operating expenditures will be focused on projects within the seven producing states, the follow-on indirect and induced effects will result in 37% of the jobs going to non-producing states.

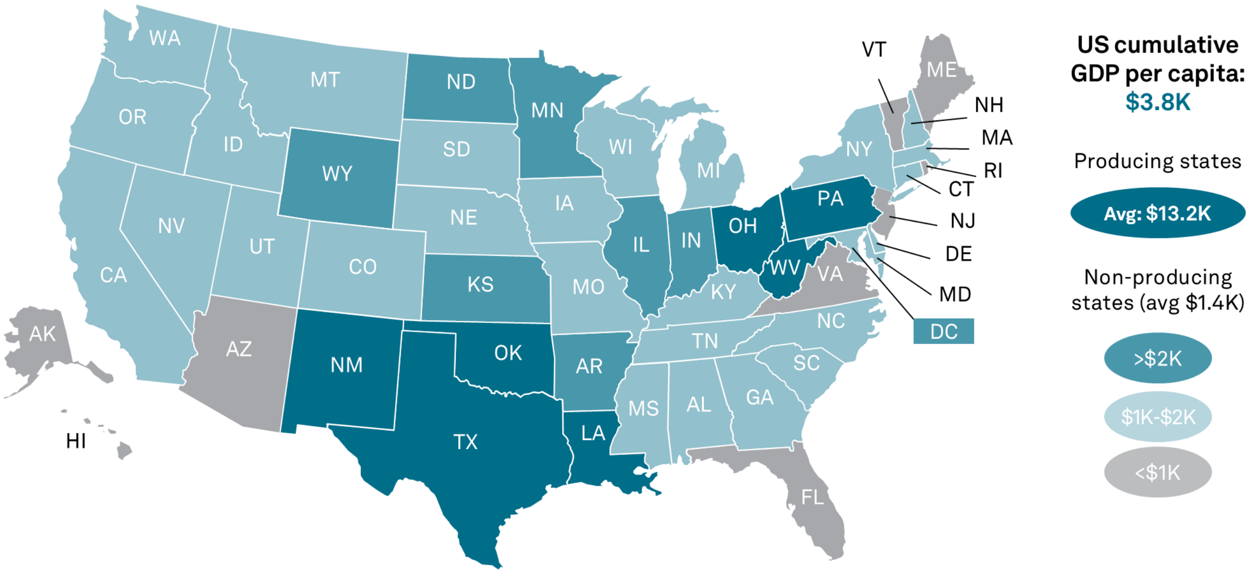
Figure 13. State-level Distribution of Jobs, Base Case
Average annual jobs, 2025 – 2040



Source: S&P Global Market Intelligence

On an absolute level, the distribution of jobs in non-producing states will show a 'halo effect' around producing states. Producing states like Texas and Louisiana will rely on states with relevant supply chain industrial mix (Illinois) and proximity for ease of access and transportation (Arkansas). When results are normalized—such as with GDP per household in the figure above—the proportional economic impacts are more widespread.

Figure 14. State-level Distribution of GDP Per Capita, Base Case
Cumulative dollars of GDP per capita 2025 – 2040

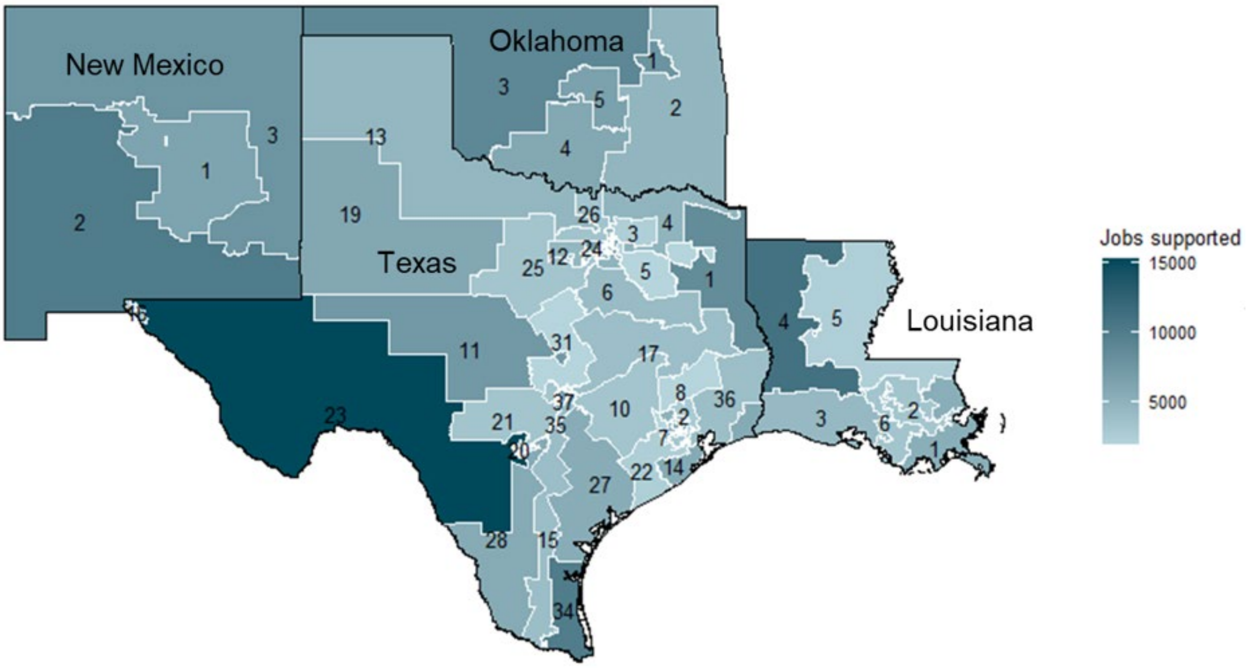


Source: S&P Global Market Intelligence

The impacts by congressional district were derived using two integrated processes. First, direct US LNG upstream, pipeline, storage, and export locations were determined using energy team inputs on upstream, midstream, and liquefaction activities, and the direct impact was funneled to those target geographies. Second, using a business demography dataset and a gravity model, mix and proximity of relevant industrial sectors were integrated with state results to derive the impact on congressional districts.

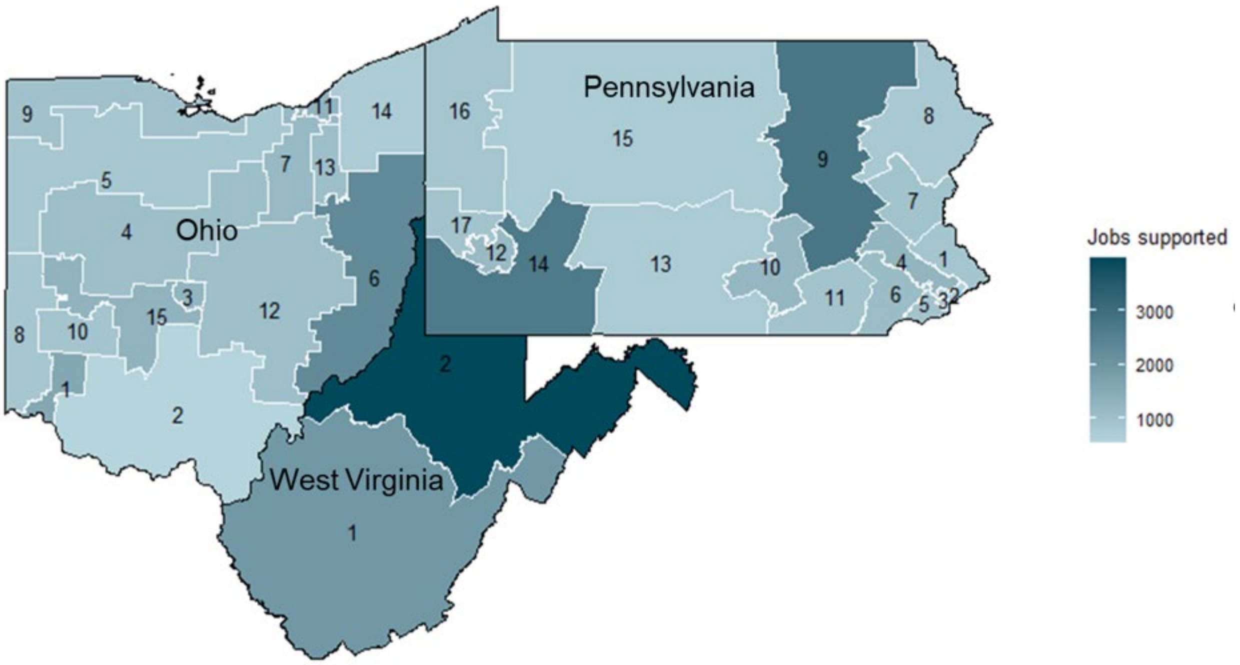
The following two maps show the two major clusters within the US LNG value chain—the Southwest and the Midwest/Mid-Atlantic. As expected, congressional districts with major upstream plays—Permian, Eagle Ford, Haynesville, Utica, and Marcellus—will have major economic implications.

Figure 15. Jobs Supported by Congressional District: Southwestern Cluster
Average: 2025-2040



Source: S&P Global Market Intelligence

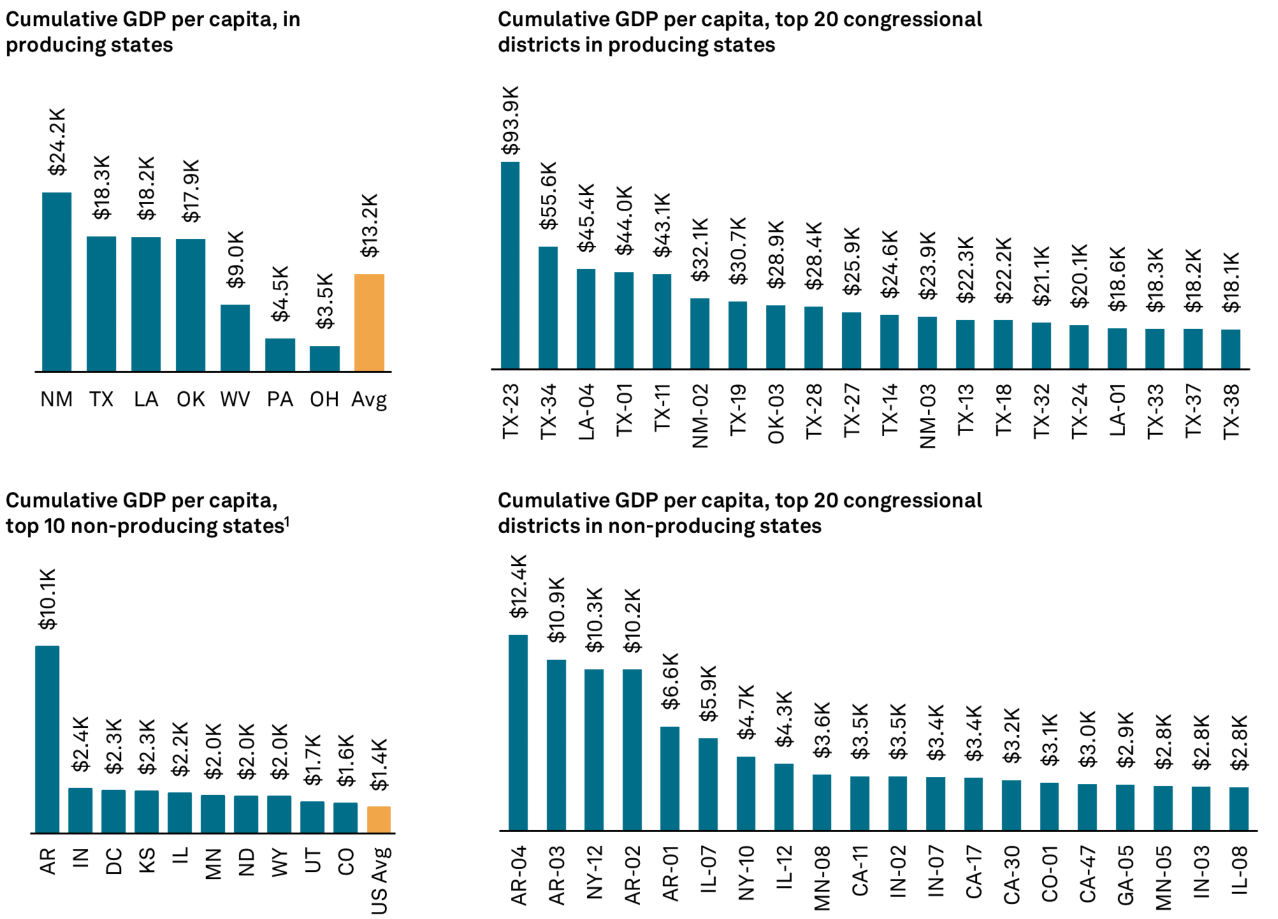
Figure 16. Jobs Supported by Congressional District: Midwest/Mid-Atlantic Cluster
Average: 2025-2040



Source: S&P Global Commodity Insights

Upstream investment in the Permian, Eagle Ford and Haynesville will lead to stronger wages per household in the Southwestern cluster.

Figure 17. Congressional Districts Most Benefited are in Areas with the Highest Direct US LNG Value Chain Activity, but Gains are Distributed Throughout the US
Units: cumulative GDP per capita, 2025 — 2040, in thousands of real 2024 dollars



1. The strong economic response of Arkansas on the state and congressional district levels is due to the role it will play as a key provider of upstream support services. The response of the New York congressional districts is due to the role they will play in providing financial and businesses services.

Source: S&P Global Commodity Insights

On its current trajectory, the US LNG Export industry will experience cumulative capital and operating expenditures exceeding $938 billion over the 16-year period from 2025 through 2040. These investments will stimulate economic contributions across the entire US economy, well beyond the seven producing states. Integrated multi-state supply chain dynamics will lead to about one-third of the jobs and GDP contributions accruing to non-producing states. Indeed, as many jobs will be supported in the aggregate non-producing states as supported in Texas.

On the congressional district level, the economic contributions will concentrate in districts with either (1) natural gas production and liquefaction activities or (2) businesses that are part of the extended supply chains serving the LNG Export industry. Consider the normalized economic metric of GDP per capita. Across the seven producing states, the average GDP per capita impact is $13,173. Thirty five of the 86 congressional districts in producing states will post even higher GDP per capita than this level, indicating a concentration of economic activity and value generation in these districts. The average GDP per capita impact for non-producing states is $1,391, with 115 out of 350 congressional districts exceeding this level.

Under the 'Extended Halt' Scenario assumptions, the non-producing states will bear approximately one-third of the economic contributions at risk. Thus, while the current trajectory of LNG exports will deliver positive economic benefits across the United States, an extended halt will trigger negative impacts that are felt both within and beyond the producing states.

Unleashing the Marcellus & Utica: Easing Pipeline Constraints in the Northeast

The Marcellus & Utica formations in the Northeast have ample low-cost gas reserves, enough to supply the nation for about 17 years, or the Northeast region itself for 77 years at current demand levels. Pipeline constraints are driving prices in Boston, Chicago, and New York City up 160% above average. Expanding pipeline capacity by 6 Bcf/d could save $76 billion by 2040.

Benefits of Permitting Reform in the Interstate Pipeline Sector

While the extensive US natural gas resource base is more than adequate to support growth in LNG exports, obstacles still exist to developing the pipeline infrastructure which would best capture this export growth opportunity. Expansions within states, not subject to US federal permitting jurisdiction, have occurred in a largely timely manner, unlocking the Haynesville and Permian resources and enabling the development of the gas export sector to date. However, pipeline expansions crossing state boundaries, subject to federal jurisdiction, have often faced delays, discouraging even potentially highly economic pipeline projects.

This section in the Phase 2 report analyzes potential benefits to consumers of potential changes allowing pipeline development to occur in a timely manner out of the lowest-cost dry gas production basins in North America, the Marcellus and Utica shales comprising a vast (over 600 Tcf) resource base across the states of Pennsylvania, West Virginia, and Ohio – and even beyond. This huge resource base remains constrained by pipeline exit capacity to markets currently and remains so throughout S&P's Base Case forecast as a result of the ongoing political and environmental opposition to building new interstate pipeline capacity in the US.

Methodology

S&P uses the Gas Pipeline Competition Model, a third-party (RBAC Corp.) model which optimizes flows across a detailed representation of the North American natural gas pipeline grid, including pipelines in the US, Canada and Mexico. S&P develops its own proprietary inputs, including forecast production across hundreds of individual supply areas and demand outlooks by sector for each state and region. This model optimizes flows while minimizing transport costs across all pipeline options available in the model, and the result is gas pricing differentials ("basis") across the North American continent consistent with S&P's overall forecast for production and demand. This model is a midstream industry standard and has been used on behalf of S&P's (and predecessor organizations') clients since the mid-1990s.

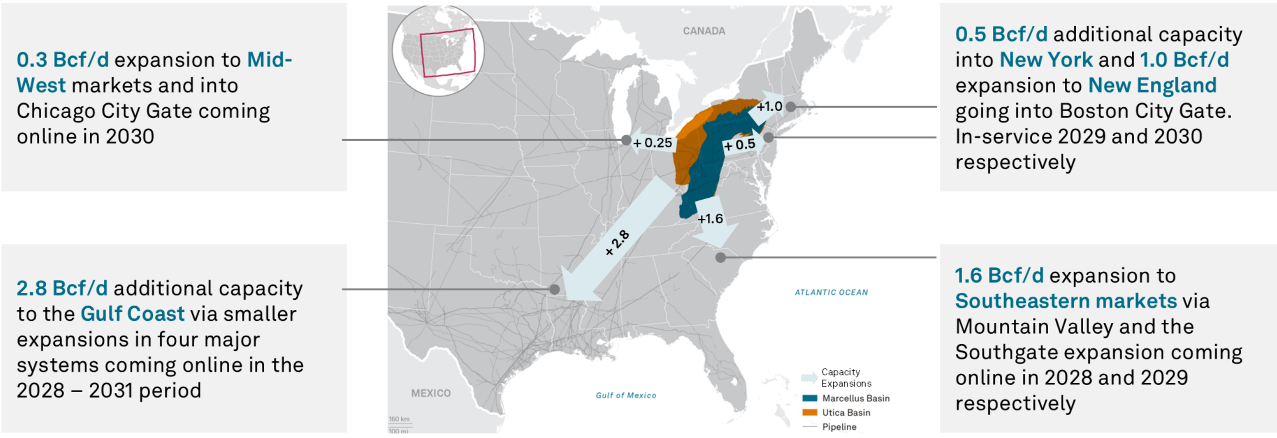
Increasing pipeline capacity between a supply area and a market area, all else equal, will increase the options for transportation services, reducing overall transport costs and thus reducing "basis" and delivered natural gas prices across that transport path. Unlocking the Marcellus and Utica shales involves assuming a certain number and capacity of pipelines being constructed which are not otherwise in S&P's Base Case forecast. To develop this set of pipeline additions, we considered past developments and proposals which indicate market interest, and our own outlooks for market needs. The resulting additions in the Northeast Pipeline Expansion Case include:

1. 1.0 Bcf/d of pipeline capacity into the Boston market, representative of several projects which have been proposed over the past decade,

2. 0.5 Bcf/d of additional capacity linking the Marcellus to New York City, representing many proposed such expansions of varying volumes,
3. 1.55 Bcf/d of capacity into the Southeast US, attracted by growing demand as well as expansion capability in the existing grid,
4. 2.8 Bcf/d, spread over 4 pipeline systems into the Gulf Coast. The size and depth of the Gulf Coast natural gas market, including LNG exports, is attractive to many producers, and access to Appalachian supplies would be attractive to many Gulf Coast consumers. Smaller expansions making full use of existing rights-of-way are considered more likely than one or two major expansions requiring new rights-of-way.
5. A small 0.25 Bcf/d into the Midwest US, assumed to the Chicago market area, is also included.

These expansions are assumed to occur over the 2028-2031 period, allowing time for more standard permitting processes and construction to occur. They are illustrated in Figure 18 below:

Figure 18. Illustrative Pipeline Expansions from the Marcellus and Utica



Source: S&P Global Commodity Insights
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S&P has also analyzed the effects on the benchmark Henry Hub natural gas price of adding this 6 Bcf/d of incremental capacity and the resulting additional low-cost supplies in the Northeast Pipeline Expansion Case, which displace an equivalent volume of production from higher-cost production areas including the Haynesville play in Louisiana and Texas, as well as multiple other plays across Texas, Oklahoma, and the Rockies. Overall demand was held constant for simplicity, and this analysis was conducted on a monthly basis, accounting for higher consumption levels and reduced pricing volatility in winter months.

Results – Gas Cost Savings that Far Exceed Pipeline Costs

The impact on the Henry Hub price of an additional 6 Bcf/d of lower-cost resources, offset by reduction in more expensive plays, was a reduction of approximately $0.20/MMBtu in real terms over the 2028 – 2040 period. For delivered gas costs, consumers throughout each region benefit as the pipeline expansions reduce the gas price at major wholesale trading index points within each region.

The average annual price difference between S&P's Base Case outlook and our Northeast Pipeline Expansion Case at each index point are multiplied across all demand expected in each region, on a monthly basis, to estimate overall cost savings. Savings in the winter are greater as winter pricing volatility is reduced, and these savings occur across higher winter consumption levels as well, especially in northern states. These delivered costs to consumers, especially in the Northeast US, are much more significantly reduced as the vast low-cost resource potential of the Marcellus and Utica shales is brought to bear through these pipeline expansions.

In the table below, capital costs are compared to the delivered cost savings less incremental operational expenditures (Opex) incurred to operate the expansions across each corridor of assumed pipeline investment. Additional savings across other regions (the West, for example) from the small reductions in the Henry Hub gas price are also likely but are not included below.

Figure 19. Capital Costs Versus Delivered Cost Savings Less Opex for Consumers in Destination Regions
Real 2024 $

	Capex[1] Estimated	% Decrease in wholesale prices	Annual Savings less Opex[2]	Savings per Household[3]	
				$/year	Cumulative
New England	$4.3 B	27%	**$1.02 B**	$110	$1,435
NY / New Jersey	$0.5 B	17%	**$1.41 B**	$63	$813
Midwest	$0.6 B	4%	**$0.93 B**	$17	$220
Southeast	$2.5 B	5%	**$1.14 B**	$13	$170
Gulf Coast	$6.4 B	4%	**$1.36 B**	$9	$118
	Total: $14.3 B		**Total: $5.86 B**		
		2028 – 2040 savings:	**~$76 B**		

1. Capex estimation based on analogues of historical expansions in the specific regions and/or public fillings; 2. Annual savings refer to savings for all gas consumers, including residential, commercial, industrial, power and others. These are net of incremental operating costs for expanded capacity; 3. Considers residential demand and gas consuming households per region, calculated as discount in gas price ($/MMBtu) multiplied by average consumption per gas-consuming residence for the period.

Source: S&P Global Commodity Insights

Notably, the total savings of $76B apply across all gas-consuming sectors. Of this, cumulative residential savings amount to $15B. Additionally, gas consumers in the power, industrial, and commercial sectors would realize savings of $27B, $22B, and $12B, respectively.

Cost savings are heavily concentrated in the Northeast US (New York/New Jersey and New England), where pipeline expansions have the largest impact on wholesale gas prices. With only approximately 30% of total estimated capital cost of all pipeline expansions occurring into the Northeast, average cost reductions of more than $1.00/MMBtu across the two regions results in New York/New Jersey and New England consumers capturing over 40% of all cost reductions associated with unlocking the Marcellus. Even accounting for ongoing pipeline operating costs, these regions' consumers would experience significant cost savings for both gas and electricity were these pipeline expansions to occur. In addition, these savings are calculated under assumed normal weather conditions for each month, not under extreme cold and the extreme prices that often result, as occurred this past winter and others before.

Savings in other regions are much more moderate, with delivered gas costs driven largely by the reduction in the Henry Hub price. Even so, consumers in the Southeast and Midwest benefit on a net basis from these pipeline expansions. Consumers in the Gulf Coast would also benefit largely by the reduction in the Henry Hub price, and the large capital expense of expansions to that market make any net consumer benefit unclear. However, consumers are unlikely to pay for expansions toward the Gulf Coast. Instead, Appalachian producers are the most likely underwriters as they have been to date, paying for access to fair market value in the largest natural gas market in the world, one in which LNG exports offer significant growth potential.

Appendix A: Emissions Methodology

Background and Analysis Context

This appendix outlines the methodologies for estimating GHG emission across the LNG system, domestic and piped import natural gas, coal, oil, and nuclear and renewable supply chains used in this study. This methodology is based on emission estimation approaches employed by S&P Global's Center of Emissions Excellence, as well as various estimation tools including Upstream Solutions (including Vantage upstream field economics and GHG emissions), and CI Consulting. For regions not yet covered by these groups but relevant to the study as potential new sources of LNG supply, CI Consulting has applied the same approach in close collaboration with internal experts.[16]

For the purpose of analyzing emissions across the supply chain for each fuel, the flow from source to destination was modeled. For US LNG this includes the flow from upstream source to LNG facility, then on to destination market. These flows were determined through a detailed pathing analysis based on current and expected physical flows and have been calibrated using expert opinion from S&P Global gas analysts.

Functional Unit

The functional unit of this lifecycle assessment is 1 MJ of each energy source that makes up the global energy response described in Phase 1 (LNG, domestic and piped import natural gas, coal, oil, and nuclear and renewables) delivered and used in the impacted destination markets. This serves as the denominator for the GHG intensity calculation.

We use an energy-based emissions intensity in gCO_2e/MJ of product rather than on a mass or volume basis to remain uniform across each segment of the supply chain and to allow for accurate comparison across fuel types. The energy basis in MJ for the gas value chain is based on the lower heating value (LHV) of the dry gas that flows into the liquefaction plant.

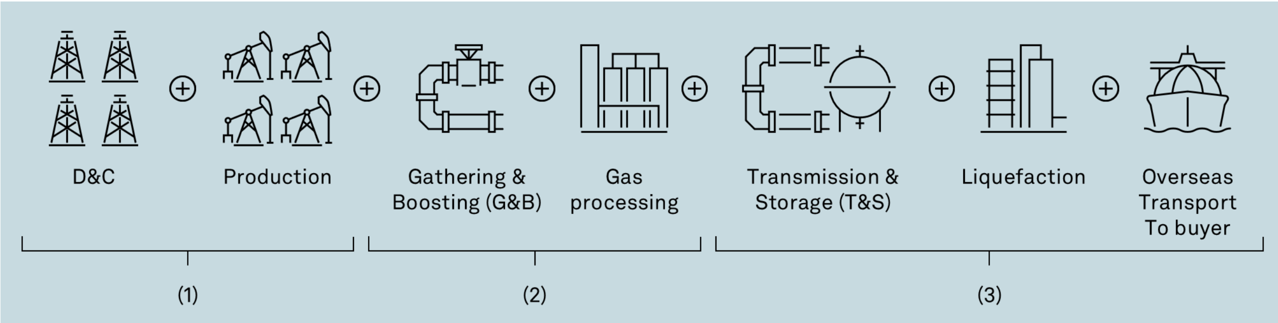
The energy efficiency of the end use (e.g. gas vs. coal power plant efficiency) was considered in the global energy balance model used in Phase 1. In Phase 2, the quantity of each fuel is taken as given, and therefore GHG impacts are compared on a delivered basis, not accounting for differences in the efficiency of end use (e.g., power plant heat rates).

For sources directly producing electricity (such as renewables), emissions intensities originally expressed in grams of carbon dioxide equivalent per kilowatt-hour (gCO_2e/kWh) were converted to an energy equivalency of gCO_2e/MJ using the conversion factor of 1 kWh = 3.6 MJ.

For each supply chain analyzed, the emissions intensity of every segment (expressed in gCO_2e/MJ) is multiplied by that segment's energy throughput. In the case of the gas and LNG value chains, these emissions are apportioned to the dry gas that flows into the liquefaction facility using an energy ratio. For example, to estimate the GHG emissions intensity of delivered LNG, each segment of the lifecycle is estimated separately with energy losses through each segment accounted for.

[16] As stated above, the basis of methodology for emissions analysis in the natural gas and LNG supply chain is largely based upon the S&P Global Center of Emissions Excellence methodologies and was developed in consultation with the Center experts. The Center currently focuses on existing supply chain emissions in key markets, including the US and Canada (and others, not relevant for this study). The primary changes from this base methodology have to do with new sources of gas and LNG supply identified in the LNG Halt analysis in countries including Argentina, Mozambique, Qatar, Russia, Indonesia, and Oman, as well as with the forward-looking projections for future emissions associated with these projects. This study also makes use of a wider set of observational data from Sentinel-2 and GHGSat to develop assessments for the countries listed above, as well as Insight M data for a more granular perspective on US emissions.

Figure 20. LNG Product Life-cycle Example Broken Down by Segment



Source: S&P Global Commodity Insights

The total carbon intensity across the LNG value chain up to the regasification point may be added up using the following equation:

$$\begin{aligned} Carbon\ Intensity_{LNG} \\ = \frac{gCO_2e_{D\&C+Prod}}{MJ_{NG}} + \frac{gCO_2e_{Gathering\ \&\ Boosting}}{MJ_{NG}} + \frac{gCO_2e_{PRocessing}}{MJ_{NG}} \\ + \frac{gCO_2e_{Transmission\ \&\ Storage}}{MJ_{NG}} + \frac{gCO_2e_{Liquefaction}}{MJ_{NG}} + \frac{gCO_2e_{Shipping\ \&\ End\ Use}}{MJ_{NG}} \end{aligned}$$

Where,

gCO_2e represents the absolute emissions allocated to natural gas of each segment of the value chain,

MJ_{NG} represents the energy content of the natural gas throughput of that segment.

Treatment of Co-Products

Crude oil and gas are typically co-produced at the wellhead and there is variability in the liquids content of all gas streams produced. Some have a large amount of NGLs (ethane, propane, butane) and higher carbon content liquids, often characterized as condensates.

When accounting for the GHG intensity of the dry marketable natural gas, emissions need to be apportioned to just the energy content of the gas supply chain. This is done by applying an energy ratio to the emissions at each segment of the supply chain.

The energy ratio is defined as:

$$Energy\ Ratio = \frac{MJ_{Natural\ Gas}}{MJ_{Natural\ Gas} + MJ_{Oil+NGLs+Condensates}}$$

Where,

MJ_X represents the energy content of each product's throughput in that segment.

The energy ratio changes throughout the value chain. In the beginning (Segment 1 of Figure 20), co-products of natural gas, NGLs and crude oil are produced so all the products must be accounted for in the energy content of the stream. After production, oil is separated from the rich gas and the rich gas is gathered and subsequently processed (Segment 2 of Figure 20). After processing, dry gas is collected, stored and transported to liquefaction facilities and LNG is transported further overseas. For the transportation and shipment segments and beyond, no emissions allocation to co-products is needed as all emissions are associated with marketable natural gas or LNG (Segment 3 of Figure 20).

Failure to follow the standard lifecycle approach of allocating emissions between co-products based on energy content leads to a significant overestimation of gas GHG intensity. As seen in the table below, most studies surveyed align with the energy co-allocation approach.

Table 1. Academic Studies Surveyed and their Main Parameters.

Study	Author(s)	Date Published	Geography Covered	GHG Emissions Allocation Approach
The greenhouse gas footprint of liquefied natural gas (LNG) exported from the United States	Howarth, Robert W.	October 2024	US exports using a world-average voyage time (38-day roundtrip)	Emissions fully allocated to the gas production stream
Reducing GHG Emissions from the U.S. Natural Gas Supply Chain	National Petroleum Council (NPC)	April 2024	US exports to Europe and Asia	Allocation on energy basis between the key co-products
LNG Supply Chains: A Supplier-Specific Life-Cycle Assessment for Improved Emission Accounting	Roman-White et al.	August 2021	US exports to China and Europe	Allocation on energy basis between the key co-products and fully to gas separately
Geospatial Life Cycle Analysis of Greenhouse Gas Emissions from US Liquefied Natural Gas Supply Chains	Zhu et. al	2024	US exports to China and Europe	Allocation on energy basis between the key co-products
Comparing greenhouse gas impacts from domestic coal and imported natural gas electricity generation in China	Rosselot at. al	2021	US exports to China	Allocation on energy basis between the key co-products and fully to gas separately
Life Cycle Greenhouse Gas Emissions From U.S. Liquefied Natural Gas Exports: Implications for End Uses	Abrahams et. al	2015	US and Russia exports to Europe	Not explicit

Source: Published Studies

Global Warming Potential

This analysis primarily focuses on the emissions associated with CO_2 and CH_4, which represent the majority of emissions and associated impacts from the LNG and coal supply chains. This study utilizes the global warming potentials (GWP) reported in the Intergovernmental Panel on Climate Change's (IPCC) Sixth Assessment Report (AR6). For this work, both the 100-year and 20-year GWPs are used to convert emissions to a carbon dioxide equivalent basis to align with the regulatory reporting requirements for the US and Canada.

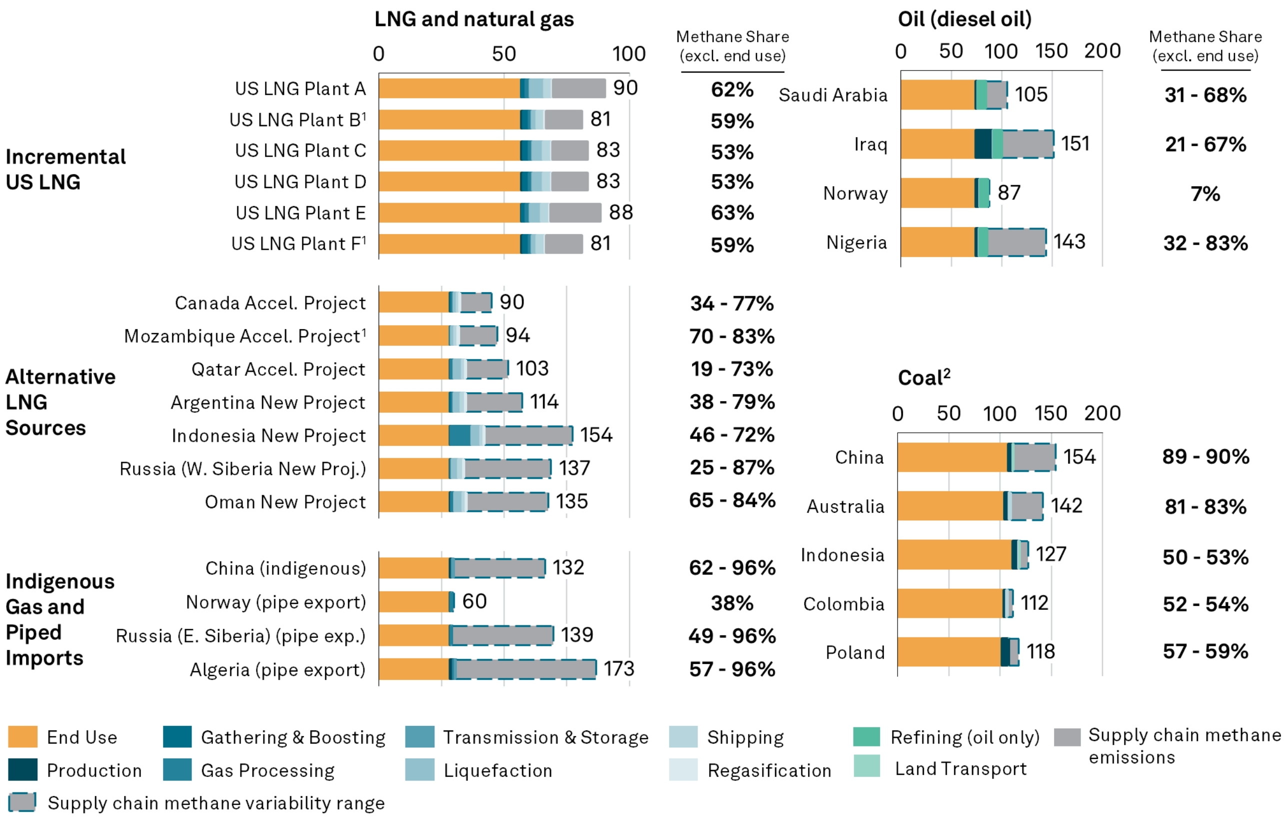
Table 2. 100-year and 20-year AR6 Global Warming Potentials of CH_4 and N_2O

Gas	GWP AR6 100-yr	GWP AR6 20-yr
CO_2	1	1
CH_4	29.8	82.5
N_2O	273	273

Source: S&P Global Commodity Insights

Considering a 20-year GWP emphasizes the relative impact of methane emissions on lifecycle intensity differentials across the various fuels, as seen below (compared to the 100-yr GWP intensities shown above in Figure 6).

Figure 21. Supply Chain Lifecycle GHG Intensities of LNG, Oil, and Coal by Supplier, Excluding End Use
gCO_2e/MJ, 20-year GWP



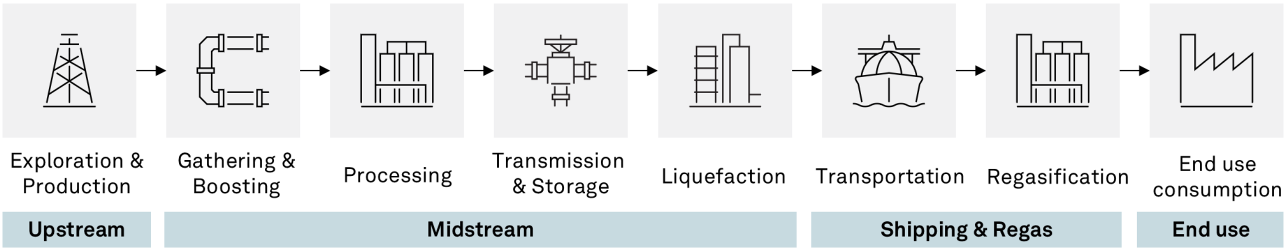
1. Electric-driven liquefaction plant assumed; 2. For the lifecycle analysis of coal, methane observation data are not available. Therefore, the methane range has been assumed as a sensitivity of the IPCC factors, aligned with the range obtained for gas analysis.

Source: S&P Global Commodity Insights

Data sources by geography and value chain segment

This study analyzes each segment of the LNG supply chain, from initial exploration and well development, through production, processing, transmission, and liquefaction, to shipping, and finally to end use.

Figure 22. LNG Supply Chain Segments Analyzed in this Study



Source: S&P Global Commodity Insights

For each LNG project impacted by the US LNG export 'pause', the project team identified the associated upstream assets/plays that supply the facility. Given that different components of the supply chain are applicable when sourcing from unconventional versus conventional resources and for associated versus non-associated gas, and the variation in data availability associated with different countries, each LNG supply chain is analyzed according to the following approaches.

Unconventional Gas

Emissions from gas production feeding the relevant LNG projects in the US, Canada, and Argentina from unconventional resources are modeled based on a combination of data sources. These include measurement-informed methane emissions estimates, as well as flaring and combustion emissions intensities derived from well type curves based on well production and emissions data.

Figure 23. Primary Data Sources by Supply Chain Segment for Unconventional Gas

Combustion emissions | Flaring emissions | Methane emissions

	Drilling & Completion	Production	Gathering & Boosting	Gas Processing	Transmission & Storage	Liquefaction	Shipping & Regasification	End Use Transportation & Combustion
United States	S&P Global IMPACT: enhanced emissions model calibrated against EPA		S&P Global Center of Emissions Excellence (CofEE): Emission factor based on EPA and other reported data				CofEE's EF & literature	OPGEE emission factors
	S&P Global IMPACT: enhanced emissions model calibrated against EPA		CofEE: Emission factor developed based on EPA reported data				N/A	N/A
	Measurement-informed estimates[1] based on TROPOMI and Insight M data assigned to value chain segments using EPA reported data						Emission factors	N/A
Canada	S&P Global IMPACT: enhanced emissions model calibrated against EPA		Reported data based on similar Alberta operations			CofEE's EF with reported data[3]	CofEE's EF & literature	OPGEE emission factors
	S&P Global IMPACT: enhanced emissions model calibrated against EPA		Based on VIIRS observation and EF derived from high-reliability reported data in US and Canada				N/A	N/A
	Measurement-informed estimates[1] based on TROPOMI data assigned to value chain segments using EPA and other reported data						Emission factors	N/A
Argentina	Based on analogue US plays taken from S&P Global IMPACT		Analogue from US emission factors			CofEE's EF with reported data[3]	CofEE's EF & literature	OPGEE emission factors
	Based on VIIRS observation and EF derived from high-reliability reported data in US and Canada						N/A	N/A
	Measurement-informed estimates based on GHGSat and TROPOMI data assigned to value chain segments using EPA and other reported data						Emission factors	N/A

1. TROPOMI estimates developed by S&P Global Center of Emissions Excellence and S&P Global Data Science team; 2 Liquefaction methane emission factor based on GHGSat and literature; 3 Leveraging average energy factors when no specific project data is available

Source: S&P Global Commodity Insights

Conventional Gas

For all other countries in this analysis, natural gas supplying the LNG plants is sourced from conventional resources. These projects are analyzed through a different combination of data sources, as shown below.

Figure 24. Primary Data Sources by Supply Chain Segment for Conventional Gas

Combustion emissions | Flaring emissions | Methane emissions

	Drilling & Completion	Production	Gathering & Boosting	Gas Processing	Transmission & Storage	Liquefaction	Shipping & Regasification	End Use Transportation & Combustion
Russia, Oman, Qatar, Indonesia, and other int. gas	Modeled in S&P Global QUE$TOR		N/A	Modeled in S&P Global QUE$TOR	N/A	EF developed with reported data (CofEE)[2]	CofEE's EF & literature	OPGEE emission factors
	N/A	Based on VIIRS observation	N/A	Based on VIIRS observation	N/A	CofEE emission factors	N/A	N/A
	Satellite measurements, reported data, and EF		N/A	Satellite, reported, & EF	N/A	Measurement informed[1] & emission factors	Emission factors	N/A
Mozambique	Modeled in S&P Global QUE$TOR		N/A	Modeled in S&P Global QUE$TOR	N/A	EF developed with reported data (CofEE)[2]	CofEE's EF & literature	OPGEE emission factors
	N/A (subsea completions)		N/A	Based on VIIRS observation	N/A	CofEE emission factors	N/A	N/A
	N/A (subsea completions)		N/A	Satellite, reported, and EF	N/A	Measurement informed[1] & emission factors	Emission factors	N/A

1. Liquefaction methane emission factor based on GHGSat and literature; 2. Leveraging average energy factors when no specific project data is available
Source: S&P Global Commodity Insights

Oil and Coal

Additional data sources are used for the analysis of the coal and oil supply chains.

Figure 25. Primary Data Sources by Supply Chain Segment for Oil and Coal Supply Chains

Combustion emissions | Flaring emissions | Methane emissions

	Upstream	Midstream	Downstream	End Use	Volume Allocations
Oil (all countries)	S&P Global Center of Emissions Excellence estimated modeled factors by crude grades	Emissions modeled	CofEE modeled factors	OPGEE & EPA emission factors	▪ Total shipped oil exports from source countries via Commodities at Sea ▪ Total destination import shares via Envisage/Global Gas analysis
		N/A	N/A	N/A	
	Satellite measurements and emission factor	N/A	Emission factors	N/A	
Coal (all countries)	Emissions modeled	Emissions modeled	N/A	OPGEE & EPA emission factors	▪ Total destination import shares via Envisage/Global Gas analysis
	N/A	N/A	N/A	N/A	
	UNFCCC emission factors	N/A	UNFCCC emission factors include stockpile emissions	N/A	

Source: S&P Global Commodity Insights

Methane

Methane emission estimates incorporate both vented and fugitive emissions across the LNG supply chain, as well as coal mine methane associated with coal extraction. As with flaring, observational data is prioritized when frequent and reliable measured data is obtained. For other locations, where observed methane data is less certain due to limited access, we leveraged literature, reported data, and emission factor-based estimates to define methane ranges.

In the US as well as in other jurisdictions, existing regulations like the EPA GHGRP require companies to estimate and report methane emissions from individual components. Component-level inventories that rely on default emission factors fail to provide both accurate and precise estimates of emissions. On a national scale, several recent empirical studies of US emissions suggest that the GHGRP methane values are inaccurate, as they significantly underestimate production emissions by up to 50% and lack precision[17].

Besides the common use of emitting equipment, such as pneumatic devices and storage tanks, these inaccuracies are partly due to the unpredictable nature of abnormal process emissions, which include high and unintended emissions events such as equipment malfunctions[18].

Methane Intensity Expression

Based on the S&P Global Center of Emissions Excellence methodology, methane emissions intensity is expressed as methane emissions (in energy basis) divided by methane content of the throughput, with marketable gas being the common denominator across the supply chain. This method allocates methane emissions across all co-products within each value chain segment, aligning with industry best practices of co-product allocation. This is aligned with the Natural Gas Sustainability Initiative (NGSI) protocol for production segment. Given the lack of detailed information for gas processing, the approach differs from NGSI as it uses an energy ratio whereas NGSI specifies specific process level allocation between different gas processing units.

OGCI defines the near-zero methane intensity target of 0.20%[19] in cubic meter of all methane emitted per cubic meter of gas marketed at the point of sale. The calculation used does not allocate to all co-products an energy basis given its exclusion in the denominator. While the target is useful for gas-rich plays/basins, it is unfair towards basins rich in liquids. Therefore, we define an energy-allocated near-zero 0.20% intensity across all plays/fields.

Measurement-informed Estimates and Methane Ranges

Methane emission observation sources used in this study differ across the regions under analysis as does the quality of observations. Two sources of satellite observation are available in some regions, in which case the methane range rate used is a combination of both sources.

- US, Canada, and Argentina unconventional plays: monthly averages of play-level daily emission rates ($kgCH_4/hr$) are quantified using TROPOMI large-area satellite observations and atmospheric inverse modeling, between January and December 2024. Additionally, the total methane emission observations are further allocated across the gas supply-chain segments (from production to transmission) based on EPA GHGI gridded 2018 data[20]. Emission estimates for US and Canada are provided by the S&P Center of Emissions Excellence. For Argentina, TROPOMI rates were processed by S&P Data Analytics team, and intensity estimated with S&P's oil and gas production data, following Center of Emissions Excellence methodology.

[17] Based on studies from Allen, 2014; Brandt et al., 2014; Zavala-Araiza et al., 2015; Alvarez et al., 2018
[18] Based on Zavala-Araiza, 2018
[19] See: https://www.ogci.com/wp-content/uploads/2023/08/OGCI-guidance-on-near-zero-methane-emissions.pdf
[20] Based on Maasakkers, et al., Oct. 19

- US Permian Basin and Haynesville Shale: Additional high-frequency, high-resolution plume detection data was obtained from the S&P Global and Insight M partnership. For consistency, these measurements are not used for the current emissions estimates for these two plays, which are based on TROPOMI observations like the other US reservoirs. These higher-resolution data are instead used to better understand the behavior of emissions intensity between different well types in the Haynesville Shale (by distinguishing horizontal wells producing from the Haynesville Shale from other, mostly vertical wells producing from other formations) and to confirm the trends in emissions reduction observed in the Permian Basin with the large-scale TROPOMI data.
- For international oil and gas methane emissions, observational data from a combination of GHGSat and the Copernicus Sentinel-2 satellites are used:
  - Point-source methane plume detection between January and December 2023 from GHGSat's high-resolution satellites were obtained by S&P Global from GHGSat for some of the areas of interest. These areas covered oil and gas value chains in Argentina's Vaca Muerta region, Russia (West Siberia over the Yamal peninsula); Qatar onshore operations, Oman; and LNG plants in operation globally.
  - Methane plumes from the European Space Agency's Sentinel-2 satellites with high spatial resolution and frequent revisit rates. Plumes and null observations between May 2024-Nov 2024 were obtained by S&P Global across select countries [21] including some directly analyzed in this study. Although methane emission rates are dependent on operator practices, ages of facilities and several factors specific to each basin, this extended data set was also useful to derive averages of methane intensity for segments of the oil and gas value chain across all countries with similar conventional development types (e.g., conventional onshore oil and associated gas fields, or gas processing types of varying capacities and functions) that were then included in our analysis.

Where observed methane data is not available for some of the regions under analysis, this study uses analogues for the relevant segment of the supply chain based on Sentinel-2 emission intensities derived from observations in countries with similar types of O&G operations and expected methane emission behavior. For countries such as Norway, the range is based on company disclosure with limited variability given the strong regulatory pressure and record of methane measurement and control by operators in the country.

Additionally, other resources were assessed for international methane emissions across the O&G value chain to be considered:

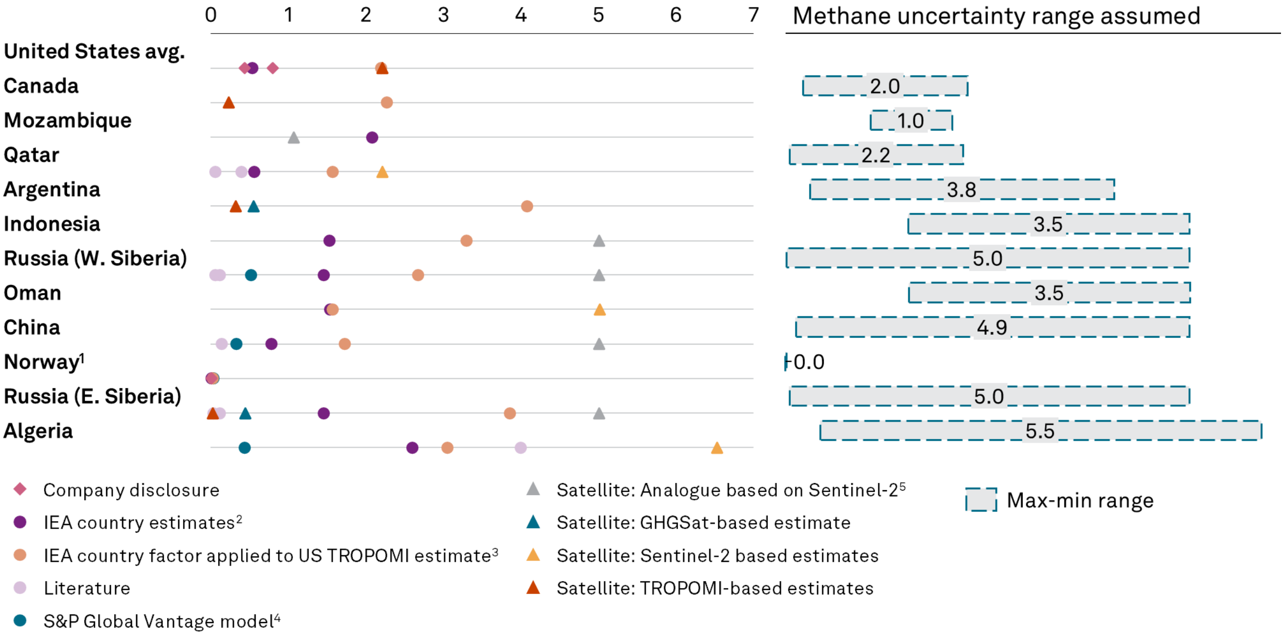
- Internal S&P resources such as Vantage, where methane estimates are obtained at the country level and normalized by total gas and oil production. Emissions are calculated using S&P Global standard conversion factors, emissions factors, and data on fluid/gas properties.
- Literature and other reported data such as EPA, Oil and Gas Climate Initiative, and operators' sustainability reports. Details on papers consulted are found in Table 3.
- Data from the IEA's 2024 Global Methane Tracker[22] was also leveraged in two ways:
  - Upstream methane emissions data from the Methane Tracker Database was normalized with S&P Global's country-level oil and gas production for that year. Additionally, as IEA defines Upstream from well development to processing, resulting intensities were further allocated by value chain segment to align with the ones in this report. The approach follows a similar segment allocation method as the one used for TROPOMI measurements in the US.
  - The IEA 2024 Global Methane Tracker also publishes a scaling factor used to derive methane intensities in other jurisdictions based on US operations. We have applied the IEA's scaling

[21] Sentinel-2 data was obtained by S&P Global for the following countries: Afghanistan, Algeria, Azerbaijan, Egypt, Iran, Iraq, Israel, Kazakhstan, Kuwait, Lebanon, Libya, Morocco, Oman, Qatar, Saudi Arabia, Syria, Tunisia, Turkey, Turkmenistan, United Arab Emirates, and Uzbekistan. Not all of these countries are directly analyzed in this study.
[22] Additional info found in:
https://iea.blob.core.windows.net/assets/d42fc095-f706-422a-9008-6b9e4e1ee616/GlobalMethaneTracker_Documentation.pdf

factor to the average methane intensity derived from TROPOMI observations of the US, covering the value chain from production to gas processing.

All the available methane intensity data from the various sources was then expressed in the same basis and ranges were determined for our analysis. Methane emissions were estimated for the minimum, maximum and midpoint of the range in each area, as shown in the figure below.

Figure 26. International Methane Emissions Benchmarking, Production to Gas Processing Intensity for relevant basin in each country, intensity in $\%CH_4$ released / $\%CH_4$ in gas stream [23]



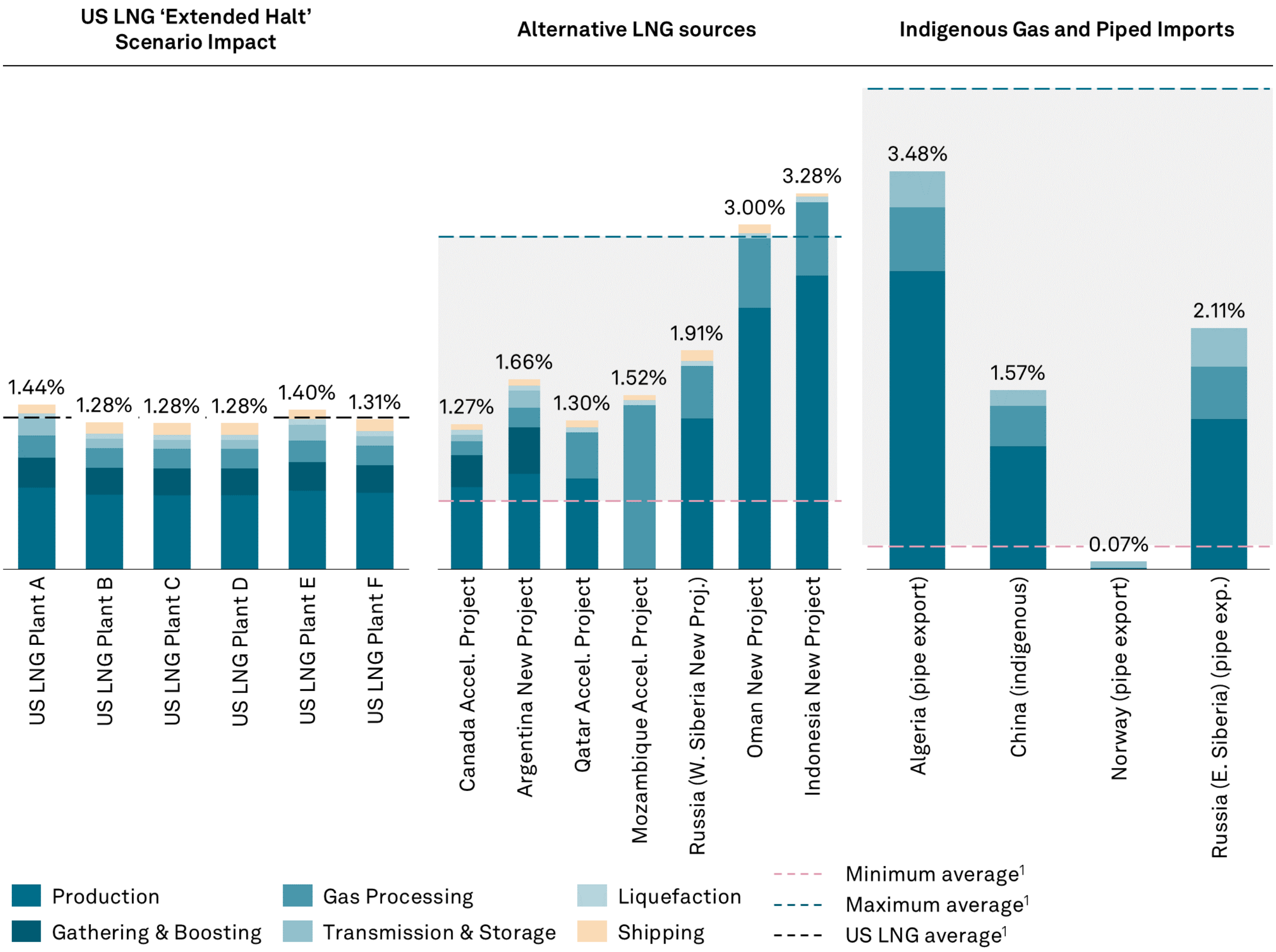
1. Although no satellite measurement was available for Norway in our study, the range is based on company disclosure with limited variability given the strong regulatory pressure and record of methane measurement and control by operators in the country; 2. IEA methane Tracker 2024 normalized with S&P Global O&G production data per country; 3. Average of US TROPOMI measurements with a methane scaling factor from IEA; 4. Average estimates at the country level; 5. For countries where no measurement data is available, we include the average intensity for upstream derived from Sentinel-2 observations to determine the uncertainty range.

Source: S&P Global Commodity Insights leveraging TROPOMI, GHGSat, and Sentinel-2 observations; academic research (papers listed in appendix); and IEA's Global Methane Tracker

The following figure summarizes the midpoint estimate for the impacted US LNG projects and each source of gas and LNG in the global response analyzed.

[23] Expressed as methane emissions (on an energy basis) divided by methane content of the throughput, with marketable gas being the common denominator across the supply chain

Figure 27. Midpoint Methane Intensity by Value Chain
Intensity for relevant basin in each country, $\%CH_4$ released / $\%CH_4$ in gas stream



1. Weighted minimum and maximum methane across groups

Source: S&P Global Commodity Insights

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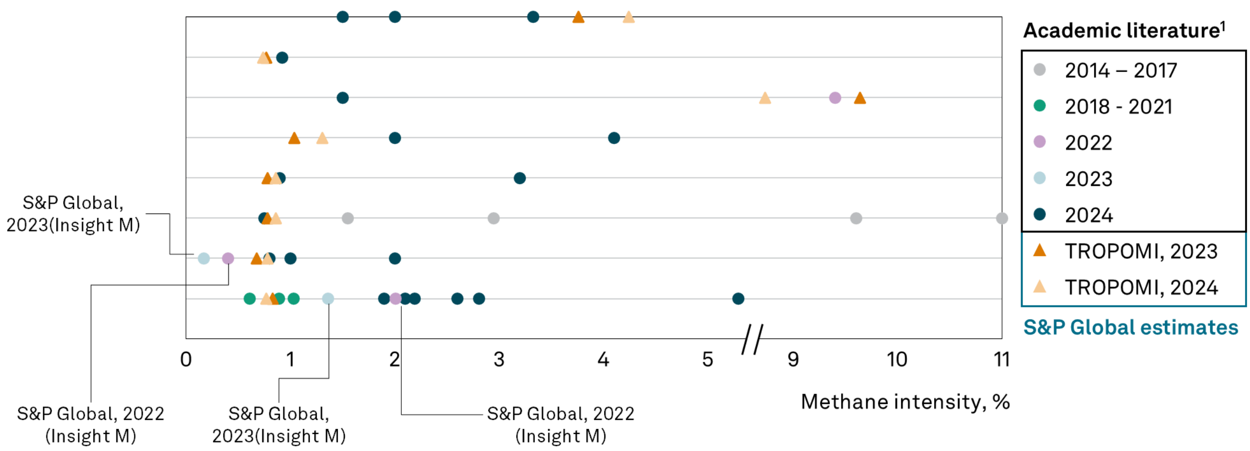
The variability in methane intensity of US LNG projects from the average is limited due to the blending of gas from different sources. Although the differences between individual US plays can be much larger, it is assumed that the LNG facilities analyzed draw gas from a combination of production areas, which reduces the differences between facilities. The variability of midpoint estimates is much greater for the global energy response. While midpoint estimates for some of these projects are in line or below the average for US LNG facilities, most projects have higher values. Estimates for new LNG projects in Argentina, Mozambique and for domestic supply in China are 17% higher than estimates for US LNG plants. The Russian LNG project in Western Siberia and gas exports via pipelines to China from Eastern Siberia average 51% higher, while new LNG projects in Oman, Indonesia and pipeline exports from Algeria to Europe can average over 125% higher than US LNG plants.

Figure 28. Upstream Methane Intensity (% of gas produced)



1. Academic studies considered shown below

Source: S&P Global Commodity Insights

Table 3. Overview of Global Methane Emission Studies Considered

Location	Study	Year Published	Basins Considered (US only) / Countries	
United States	Sherwin et al.	2024/2025	Barnett	Marcellus
			Denver Julesburg	Permian
	MethaneAIR	2024	Anadarko	Denver Julesburg
			Appalachian	Eagle Ford
			Bakken	Fayetteville
			Barnett	Haynesville
	Chen et al.	2022	Permian	
	Omara et al.	2016	Anadarko	Eagle Ford
			Appalachian	Haynesville
			Barnett	Marcellus
	Peischl et al.	2015	Fayetteville	Marcellus
			Haynesville	
	Caulton et al.	2014	Marcellus	
International	Chen et al.	2023	Argelia	Oman
			Iraq	Saudi Arabia
			Qatar	
	Zichong et al.	2024	China	
	Lechtenböhmer et al.	2007	Russia	
	Kleinberg, R. L.	2022	Russia	

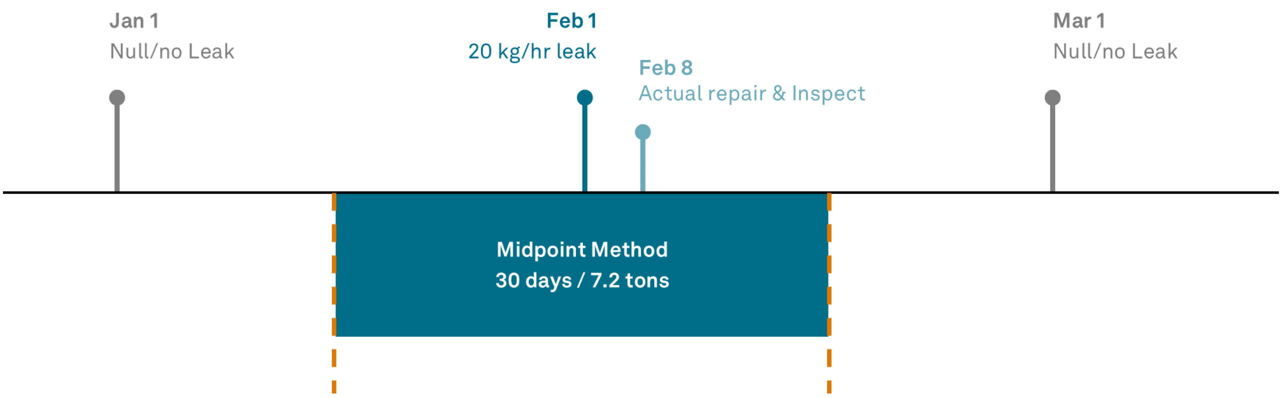
Source: S&P Global Commodity Insights

Methane Intensity Estimates Derived from Satellite Observed Plume Rates

First, all plume observations were attributed to the closest upstream oil and gas asset or infrastructure. Assets were categorized as either LNG plants, gas plants, pipelines, or upstream based on known asset data from EDIN. The upstream segment includes storage infrastructure, wells, and fields.

Second, plume duration was estimated for assets with adequate plume and null observations using the midpoint method. For non-observed plumes under the threshold duration was estimated based on typical leak durations for similar assets and similar size plumes. The midpoint method estimates duration using the midpoints between a leak observation and an adjacent null observation (i.e. no leak). As shown in Figure 29, a January 1 null observation followed by a February 1 leak observation then a March 1 null would result in a roughly 30-day leak duration assumption. Plume duration estimates results are summarized in Table 4.

Figure 29. Illustration of the Midpoint Method for Leak Duration Estimation



Source: S&P Global Commodity Insights

Leak duration using the midpoint method is computed by the following equation:

$$D = \frac{(T_2 - T_1) + (T_3 - T_2)}{2}$$

Where,

D is the total leak duration in days
T_1 is the date of the first null observation (e.g. January 1)
T_2 is the date of the leak observation (e.g. February 1)
T_3 is the date of the second null observation (e.g. March 1)

Table 4. Average Leak Duration Results for Observed Methane Data

	Average leak duration by plume size[24]			
Plume size (kg/hr):	< 10	10 – 100	100 – 1,000	> 1,000
LNG plants	90 days	22 days	17 days	6 days

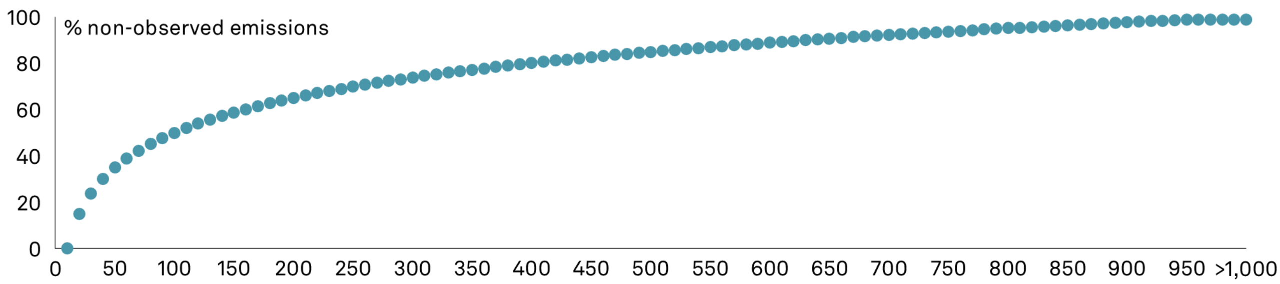
[24] For detection threshold of < 10 kg/hr and >1,000 kg/hr, it is assumed that all value chain segments will have similar durations as the upstream segment

	Average leak duration by plume size[24]			
Gas plants	90 days	65 days	50 days	6 days
Upstream	90 days	71 days	54 days	6 days
Pipelines	90 days	70 days	53 days	6 days

Source: S&P Global Commodity Insights

Third, we defined and accounted for the detection threshold per satellite source. GHGSat and Sentinel-2 have assumed detection thresholds of approximately 100 kgCH_4/hr and 1,000 kgCH_4/hr, respectively. A statistical distribution of plumes was defined using the distribution of plumes in the Permian basin from similar assets obtained from Insight M and select academic papers.[25]

Figure 30. Distribution of the Percent of Non-observed Plumes for Each Asset Type and Detection Threshold



Source: S&P Global Commodity Insights

Table 5. Percentage of Unobserved Plumes Assumed for Sentinel-2 and GHGSat

	% Unobserved Plumes Assumed			
Detection Threshold (kg/hr):	< 10	10 – 100	100 – 1,000	> 1,000
LNG plants	0%	N/A[26]	10%	50%
Gas plants	0%	N/A	10%	50%
Upstream	0%	23%	37%	77%
Pipelines	0%	N/A	37%	N/A

Source: S&P Global Commodity Insights

CH_4 volume is calculated using the plume rate and estimated leak duration. The percentage of unobserved plumes is applied to the total CH_4 volume rather than the plume rate. Adjusted CH_4 volumes by asset and country are calculated using the following formula:

$$Adjusted\ CH_4 Volume = \frac{Volume\ of\ Detected\ Plumes}{1 - \%\ Undetected\ Plumes}$$

Finally, as shown in Figure 31 below, measured methane emissions are normalized on an energy basis by using the gas production volume in the given area of interest to calculate intensity per unit of volume, followed by the energy content of CH_4 in MJ of the gas production related to the project being analyzed. These intensities are also shown as methane emissions on an energy basis divided by methane content of the throughput on an energy content basis, following S&P Global Center of Emissions Excellence methodology.

[25] Williams, J. P. et al. (2025) and Rutherford, J.S. et al. (2021)
[26] N/A: Information not available. Data not calculated

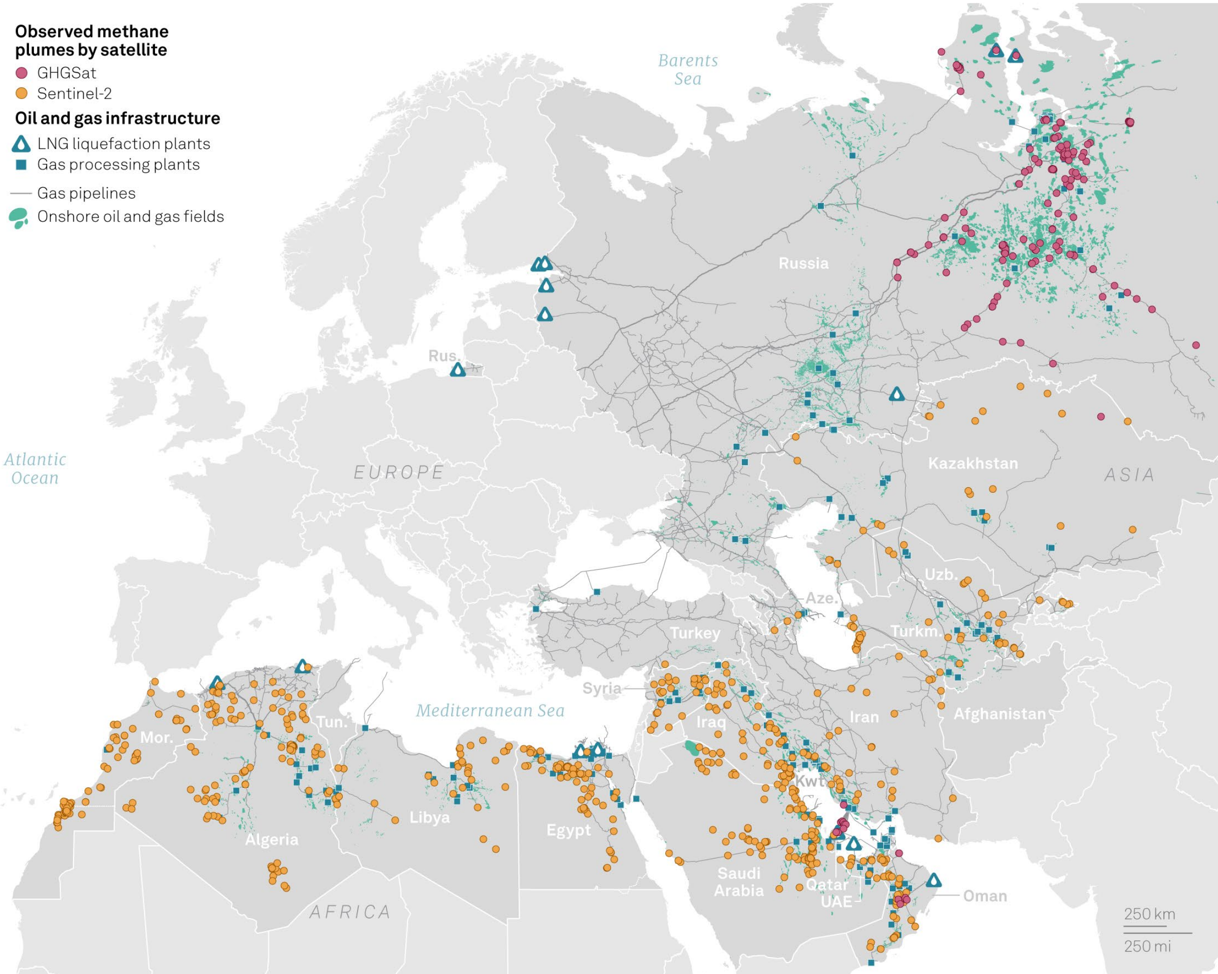
Figure 31. Sentinel-2 Estimated Upstream Methane Intensities for Selected Countries

Country	May-Nov 2024 O&G Production[1] Million boe	May-Nov 2024 CH_4 Plume Emissions $ktCH_4/yr$	Methane Emission Intensity $\%CH_4$ released / $\%CH_4$ in gas stream
Algeria	258	3,860	5.46%
Iran	710	1,555	2.30%
Libya	230	1,836	8.06%
Oman	351	1,307	3.95%
Qatar	153	162	1.14%
Saudi Arabia	1,919	2,823	1.50%
UAE	637	434	0.71%

1. Production adjusted based on Sentinel-2 analysis timeframe between May 2024 to November 2024

Source: S&P Global Commodity Insights

Figure 32. Select Sentinel-2 and GHGSat Observed Methane Plumes with Underlying Oil and Gas Assets from S&P Global Upstream Database



Source: Sentinel-2, GHGSat, S&P Global Commodity Insights, Upstream Content. Data compiled Feb. 27, 2025. Credit: CI Content Design © 2025 S&P Global. All rights reserved. Provided "as is", without any warranty. This map is not to be reproduced or disseminated and is not to be used nor cited as evidence in connection with any territorial claim. S&P Global is not an authority on international boundaries which might be subject to unresolved claims by multiple jurisdictions.

The estimated pixel coverage of Sentinel-2 and GHGSat is based on the resolution of each satellite for the corresponding methane-sensitive band, 20x20 m^2/pixel and 25x25 m^2/pixel for GHGSat, respectively. Then, the total area of a region of interest is divided by the area of a single pixel based on the resolution of the satellite. A similar method is used to calculate Insight M coverage, where the resolution of the aerial image is approximately 1x1 m^2 /pixel for InsightM's Leak Surveyor instrument.

Table 6. Coverage Comparison of Methane Detection Sources

Play/Region/Country	Methane Detection source	Estimated Coverage (Billion Pixels)
Haynesville (2022)	Insight M	14.3
Haynesville (2023)	Insight M	36.1
Permian (2023)	Insight M	318.9
Permian (2024)	Insight M	281.9
Middle East	Sentinel-2	13.1
Other Asia	Sentinel-2	9.3
North Africa	Sentinel-2	7.5
Yamal Peninsula (West Siberia, Russia)	GHGSat	0.2
Vaca Muerta (Argentina)	GHGSat	0.04

Source: S&P Global Commodity Insights

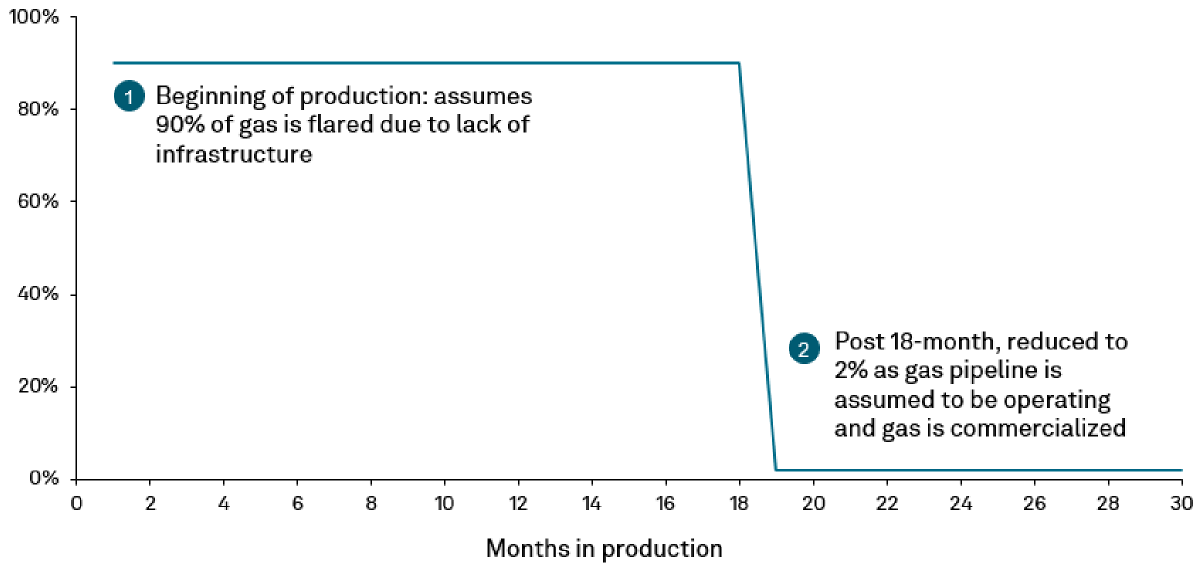
Flaring

Where possible, this analysis utilizes observed data rather than reported data to capture the most accurate and current emissions from the industry. These flaring observations are detected using raw data from the Visible Infrared Imaging Radiometer Suite (VIIRS) processed through the S&P Global Flare Identification Model. Where observational data is not available, the analysis relies on reported data sourced from Energy Studio IMPACT for North America and from Vantage for both conventional and unconventional supply chains outside the US and Canada.

Assumed Flaring Behavior in US Type Curves Development

Flaring emissions related to associated gas are often informed by the available takeaway capacity for natural gas as plays mature and more takeaway capacity is added, flaring typically declines. This analysis assumes that as oil and gas production ramps up over time, infrastructure development follows with an 18-month delay on average. After that time, flaring is largely reduced for associated gas to lower operational levels attributable to system balancing and security reasons. In line with this assumption, flaring intensity for associated gas is modeled at a higher level during the early production months, followed by a steep reduction. Non-associated gas acreage assumes a constant level of low operational flaring for maintenance, equipment shutdown, and security reasons.

Figure 33. Illustrative Flaring Intensity Reduction After 18-month Initial Period for Unconventional Development Associated Gas

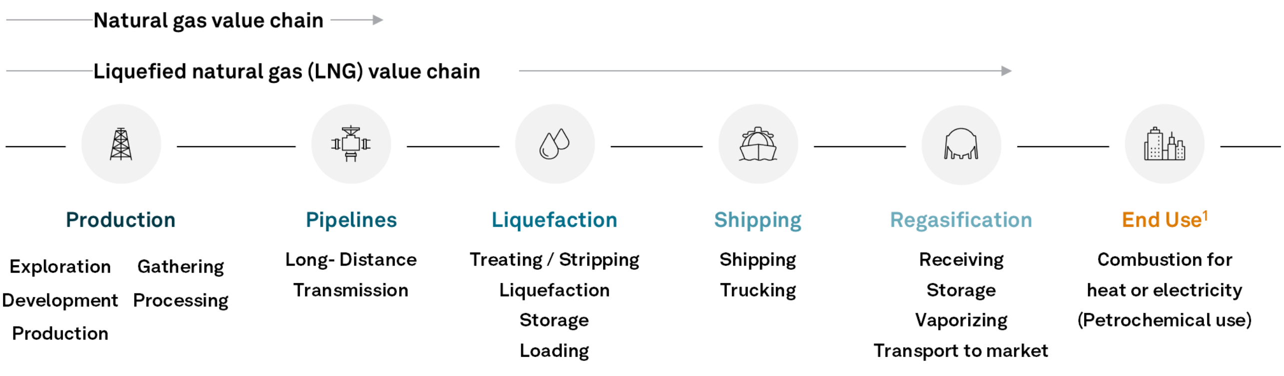


Source: S&P Global Commodity Insights © 2025 S&P Global

Natural Gas and LNG Methodology

This analysis evaluates the typical segments of the LNG supply chain, which adds additional segments beyond the natural gas supply chain that are particularly energy and GHG intensive.

Figure 34. Natural Gas and LNG Supply Chain Segments Analyzed



1. Both the natural gas and LNG value chain typically include a local distribution segment after long-distance transmission or regasification and before delivery to the final point of consumption. This study assumes delivery of natural gas, LNG, and alternative fuels to a point adjacent to the regasification terminal or transmission line to simplify comparisons across fuels. Petrochemical use is not included in the illustration of lifecycle GHG intensity.

Source: S&P Global Commodity Insights © 2025 S&P Global

Upstream

Unconventional Gas

Upstream emissions for unconventional wells in the US, Canada, and Argentina are estimated at the play level leveraging 2022 and 2023 vintage emission type curves using well-level enhanced emissions data from S&P Global's Energy Studio: Impact. Total emissions are estimated using a combination of production type curves and GHG emission curves in conjunction with forward-looking drilling and completion outlooks modeled in Phase 1 of this study and S&P Global's base case outlooks. These well development outlooks include well counts and drilling schedules by play and expected production levels.

- All wells from 2022-2023 vintages in each relevant North American play were used to develop production and emission type curves. We divide total gas and liquid production, as well as the GHG emissions related to combustion and flaring, by the well count from the vintage data. This provides the average production and emissions per well in each play over its ~25-30 year lifespan. In the US, the analysis covers plays in the Permian Basin, Eagle Ford, Haynesville, Appalachia and Mid-Continent. In Canada, the focus is specifically on the part of the Montney play in British Columbia.
- Wells are classified into tiers, from Tier 1 (best) to Tier 5 (worst), based on peak rate quintiles. This categorization helps adapt production and emissions to the drilling schedule by tier available for each play. Representative well production and GHG emissions type curves are developed for each tier.

In the case of Argentina, the Vaca Muerta shale production and GHG emissions were modeled using production and emissions type curves based on analogues from the US Appalachia region. The methodology involved selecting US wells from operators in the Utica and Marcellus plays with comparable vertical depths, horizontal laterals and fracking intensity as those seen in Vaca Muerta in recent years. US wells from 2015-2022 vintages were used to more closely match these characteristics in the Neuquén basin. Type curves were developed for the shale windows expected to supply the LNG project, focusing on well tiers 3 through 5 to match the current state of productivity differentials between US plays and Vaca Muerta.

For Argentina and Canada, a drilling schedule was developed to reach the feed gas volume plateau required to support the selected LNG projects. This assumes gas is sourced from both the dry and wet gas windows within the play. Drilling locations are chosen based on reservoir quality, accessibility, and proximity to existing infrastructure.

Using a bottom-up approach, gas intensities were calculated by integrating production and emissions data across a given play. This process starts with these production type curves that detail expected output over time, combined with emission curves for each emission category including flaring and combustion. These figures are scaled according to the number of wells and the drilling schedule to accurately represent play activity. The average energy content of the produced liquids and gas is then applied to normalize the GHG emissions results, with the final intensity expressed in gCO_2e/MJ apportioned to gas.

Conventional Gas

Conventional fields analyzed in the study include LNG projects from Qatar, Mozambique, Russia, Oman, Indonesia, and gas production from Algeria, China, and Norway. The production emissions include emissions from drilling and completion before production and operational emissions during the production process. The conventional fields analyzed for LNG projects in Qatar, Mozambique, Russia, Oman and Indonesia are evaluated using a similar bottom-up approach, where emissions estimates are derived from field-specific details sourced from Vantage reports, EDIN database and modeled in QUE$TOR software. EDIN database and Vantage reports provide reserve estimates and reservoir parameters for the fields that will supply gas to the liquefaction plant. Key parameters include feed gas composition from the basin, drilling and completion requirements, and field operations. Flaring emissions for conventional fields associated with LNG projects are estimated using VIIRS satellite data when high-quality data is collected.

For the domestic gas and piped import countries, whenever a specific development was identified as the major source of gas production, emissions were modeled following a similar approach of the conventional fields (i.e. Eastern Siberia). Alternatively, in other places where a specific source was unknown (i.e. indigenous gas from China), the combustion and flaring emissions were estimated using a country-level expected emissions divided by throughput from Vantage.

Upstream methane emissions mainly arise during normal production operations, routine maintenance and fugitive leaks. For each project, the calculated methane intensity for the production segment was incorporated (for additional information, refer to the methane section above).

For Mozambique, flaring, combustion and methane emissions are assumed to be minimal to zero due to the project's particularity of subsea completions with tie-back to onshore facility. Emissions are expected to occur at the onshore facilities, so during the gas processing and liquefaction stage.

Midstream

Gathering and Boosting

Emissions from gathering and boosting operations in conventional fields are integrated into the gas processing emission estimates modeled in QUE$TOR as part of the conventional field development. In most conventional fields analyzed, minimal to no additional compression was required to deliver gas from the field to the central gas processing plant.

For unconventional fields, modeled gathering and boosting emissions include combustion, flaring and grid electricity emissions. These emissions are modeled using emission factors developed by S&P Global's Center of Emissions Excellence. The combustion and flaring emission factors are based on reported EPA data in the United States, summarized at the basin level. Since scope 2 emissions are not required to be reported, grid emission factors are assumed to be the same as the electricity used for the transmission pipeline, as obtained from the literature[27].

For Canada, and Argentina, CO_2e emission factor was assumed to be comparable to Marcellus Shale in the US due to similar characteristics of the production stream.

Gas Processing

Gas processing emissions are modeled using average production recovery rates in a gas processing plant, which considers lean oil and propane refrigeration technologies. The combustion emissions occur during the burning of gas to power equipment such as compressors, pumps, and heaters, which are necessary for removing impurities and separating valuable heavy hydrocarbons. It is assumed that most CO_2 from the feed gas is vented in the acid gas removal unit (AGRU) during gas processing, and carbon capture and storage are not considered in this analysis.

For conventional fields, like the production segment, gas processing combustion emissions are modeled in QUE$TOR. Flaring emissions at the gas processing stage are estimated using VIIRs satellite data. Where satellite data is unavailable, a base flaring emission of 0.1-0.5% is assumed, depending on the location.

For unconventional fields, gas processing emissions including combustion, venting, and flaring are modeled using emission factors developed by the S&P Center of Emissions Excellence. Like gathering and boosting emission factors, gas processing emissions factors are calculated at the basin level. These are developed based on reported EPA data with fractionators removed as they fall outside of the report's emission boundary. Finally, it is assumed that gas leaves the processing plant aligned with standard pipeline quality specifications where CO_2 doesn't exceed 2-3% by volume. Therefore, it is assumed that around 90% of CO_2 is vented from the feed gas at this stage.

[27] Smillie S., Morgan MG., Apt J. (2023)

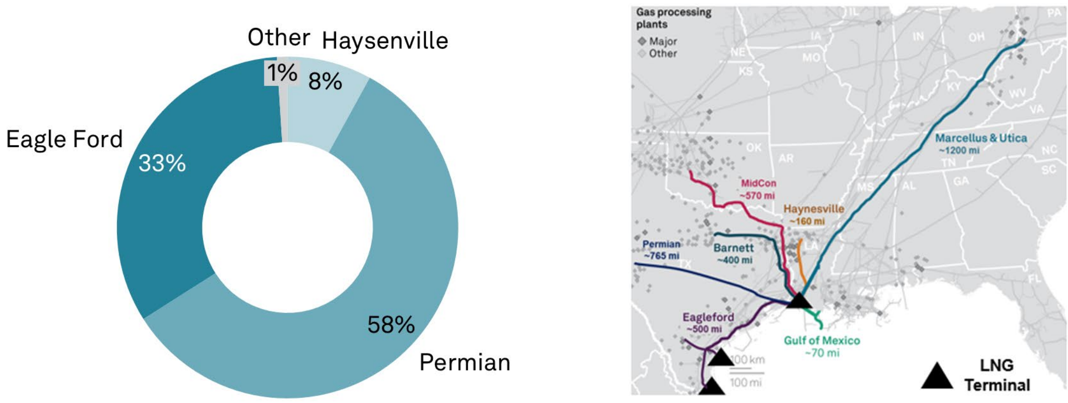
Transmission

Long-distance transmission pipelines are not included for LNG projects in Qatar, Mozambique, West Siberia in Russia, Oman and Indonesia. The gas processing and liquefaction facilities in these locations are situated near the upstream gas field infrastructure. For all the indigenous gas and piped exports in Algeria, China, Norway, East Siberia in Russia and for all unconventional LNG projects (US, Canada, and Argentina), long-distance transmission combustion and flaring emissions are estimated using S&P Global's Center of Emissions Excellence transmission factors, which are derived from reported US EPA data and normalized by distance and gas throughput. The resulting emission factor is expressed in $gCO_2e/(MJ*km)$. Methane emissions were estimated separately following the approach described in the Methane section.

Transmission distances for indigenous gas and piped imports were estimated based on the average distance from existing pipelines in selected gas fields to the major consumption areas assumed, using geospatial data to project and measure the average distance of pipeline pathways and determining the average distance of the analyzed pipelines. Unconventional plays in Argentina and Canada followed the same approach for calculating pipeline distance as indigenous gas and piped imports.

For the US unconventional plays, transmission emissions are based on estimated physical gas flows projected using the Global Pipeline Competition Model (GPCM) to assess how gas molecules travel to LNG facilities. This includes identifying key pipeline pathways, measuring the distance of each pathway, and calculating the volume-weighted average distance that gas molecules are projected to travel between each play and LNG terminal.

Figure 35. Split of Volumes by Source. Illustrative Example of a South of Texas Terminal



Source: S&P Global Commodity Insights © 2025 S&P Global

Table 7. Weighted Average Transportation Distance by Facility

Distance Weighted Average [miles]	
LNG Terminal 1	371
LNG Terminal 2	405
LNG Terminal 3	430
LNG Terminal 4	477

Source: S&P Global Commodity Insights © 2025 S&P Global

Liquefaction

Liquefaction emissions are calculated using the S&P Global Center of Emissions Excellence liquefaction model, which is adapted to the specific characteristics of the LNG facilities included in this analysis. When equipment-level details are unavailable for new facilities, data from existing nearby facilities are referenced. If such data cannot be obtained, a general energy factor for liquefaction is applied. This general liquefaction energy factor is developed based on existing liquefaction projects in Australia, Qatar, and the US, and accounts for various factors, including the ambient temperature impacts at each liquefaction location. The efficiency of gas turbines and electric motors considered in the general liquefaction energy factor is approximately 36% and 95%, respectively. Grid intensity factors sourced from S&P Global Power Analytics models are used to estimate the grid emissions associated with electrified liquefaction plants, where applicable. On-site power generation typically supplies power for auxiliary usage at the gas-driven plant. A general energy factor for this onsite power generation is based on existing liquefaction projects in Australia and Qatar. For the liquefaction plant in Canada, it is assumed that gas turbines can achieve 45% efficiency to drive the liquefaction process, and it uses a local hydro-dominated power grid for auxiliary consumptions. Table 8 below shows more details of liquefaction drivers.

Flaring emissions are sourced from a combination of VIIRS observation data and Center of Emissions Excellence factors for all non-US supply chains. US liquefaction flaring calculations are based on the average flaring intensity of existing liquefaction projects in the US, as reported by the EPA.

Country-specific satellite methane data sourced from GHGSat is only available for liquefaction plants in Qatar. For the rest, methane emissions are estimated based on a recent literature review[28] using multiscale, periodic measurements of US liquefaction terminals. These sources are based on a range of methane quantification methods, including aerial LIDAR, cavity ring-down spectroscopy, and ground-based optical gas imaging camera surveys. The detailed measurements provide reasonably accurate estimates of methane emissions at the US liquefaction terminals. It is assumed that methane emission intensities are around 0.045% for the liquefaction plants.

Table 8. Liquefaction Drivers by Facility Studied

Facility location	Liquefaction energy driver	Driver efficiency (%)	Liquefaction technology	Auxiliary energy driver
Qatar	Gas turbine	36%	AP-X	Onsite power plant with gas turbines
Russia	Gas turbine	N/A	AP-C3MR	Onsite power plant with gas turbines
Oman	Gas turbine	36%	N/A[29]	Onsite power plant with gas turbines
Indonesia	Gas turbine	36%	N/A	Onsite power plant with gas turbines
Argentina	Gas turbine	36%	N/A	Onsite power plant with gas turbines
Canada	Gas turbine	45%	Shell's Dual-Mixed Refrigerant	Grid electricity
Mozambique	Electric motor	95%	N/A	Grid electricity

[28] Zhu Y., Ross G., Khaliukova O., et al (2024)
[29] N/A: limited published details for the facility

Facility location	Liquefaction energy driver	Driver efficiency (%)	Liquefaction technology	Auxiliary energy driver
US electrified LNG	Electric motor	95%	N/A	Grid electricity
US gas-driven LNG	Gas turbine	37%[30]	ConocoPhillips Optimized Cascade, AP-C3MR	Onsite power plant with gas turbines

Source: S&P Global Commodity Insights and published resources

Shipping & Regasification

Shipping emissions are modeled using the Center of Emissions Excellence shipping model as a reference. The model developed by the Center of Emissions Excellence employs a comprehensive approach, covering over 650 long-haul LNG vessels, various propulsion types and reliquefaction systems. Nine propulsion types are included in this analysis: Tri-fuel diesel electric (TFDE), Dual fuel diesel electric (DFDE), Dual fuel with regasification and liquefaction (DRL), Steam turbine and gas engine (STaGE), Steam turbine (Steam), Steam turbine with reheat (Steam-reheat), Marine engine - gas injection (ME-GI), Marine engine - gas and diesel (ME-GA) and X-DF. The shipping emissions include combustion emissions across different propulsion types from the main and auxiliary engines during the voyage and loading processes. Additionally, fugitive emissions from incomplete combustion and boil-off gas are included, which are estimated based on International Maritime Organization (IMO) emission factors[31].

Shipping distances from supply to destination are based on the weighted average distances from each LNG facility to all respective destination markets. These destination markets are identified through existing contractual agreements and forecasted flows, modeled in conjunction with the Phase 1 analysis. The shipping distances between ports are measured using the S&P Global LNG shipping calculator, based on the most direct route from port to port. Fleet makeup and vessel retirement over time are also considered across the propulsion type. It is expected that most steam vessels will be replaced by newer models such as X-DF within the next decade. For LNG supply from Russia to Asia, additional travel distances and loading hours are considered for transshipment between icebreaker ships and conventional ships in the winter.

Regasification emissions include combustion emissions and fugitive emissions from vaporizers and the unloading process, associated with converting LNG back into its gaseous state. Limited in-depth research has focused on regasification emissions as they contribute relatively less to overall emissions compared to other components in the value chain. The emissions are estimated based on the regasification emission factor derived from the literature[32], which compares regasification emission factors from recent studies. The supply markets for LNG from the literature include the US, Australia, Russia and Qatar, with Asia serving as the main destination market.

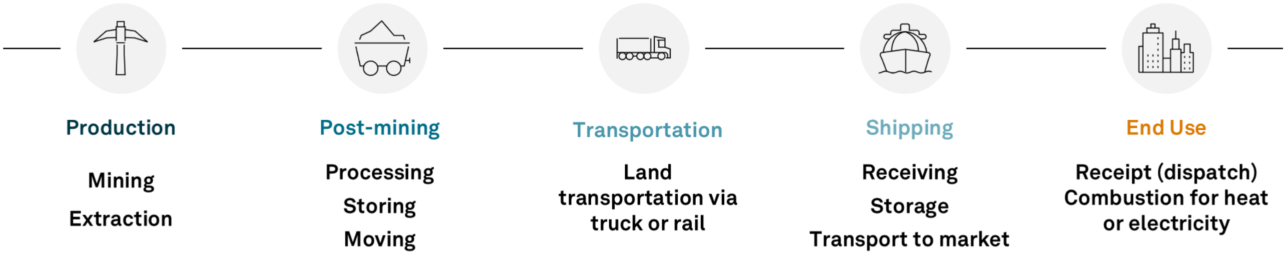
End Use

As discussed in the main report, end use emissions associated with natural gas/LNG in destination markets are based solely on the delivered energy combustion, and do not account for differentiated combustion efficiencies by end-use type. In this case, a single factor of 56.8 gCO_2e/MJ is used for all natural gas/LNG end use combustion. This combustion emission factor is sourced from the Oil Production Greenhouse Gas Emissions Estimator (OPGEE) model.

[30] Average efficiency of analyzed gas-driven plants in the US
[31] Comer B., Beecken J., Vermeulen R., et al (2024)
[32] Heath C., Ong C. (2022)

Coal Methodology

Figure 36. Coal Supply Chain Segments Analyzed



Source: S&P Global Commodity Insights

Based on the outlook for global replacement fuels to meet the LNG shortfall in the halt case, many countries around the world will also increase coal consumption in the short term to meet energy demand.

This analysis examines the lifecycle emissions of coal from several key supply countries. This includes coal produced and consumed domestically in China, Indonesia, and Poland. It also includes coal produced for export from Australia, Indonesia, and Colombia, which is supplied to a combination of India, Japan, South Korea, Taiwan, and Germany, along with a smaller portion directed to the rest of the world.

Coal industry upstream operations encompass mining activities for both underground and surface mines. Fuel consumption and electricity requirements are key drivers of upstream coal emissions. The model utilizes company reports, publicly available data from the Global Energy Monitor, and proprietary data from S&P Global to obtain production volumes and reported facility-level or company-level emissions for the largest exporting mines or mines of top exporting companies in each studied country. Where company-reported emissions data is unavailable, we apply country-level fuel mix and facility-level energy consumption data to estimate emissions from mining operations.

Production data and geological mine features, combined with IPCC factors, are used to estimate methane and CO_2 fugitive mining and post-mining emissions. Ventilation, system degasification, and post-mining emissions are incorporated into the modeling. Mining factors for underground mines include all seam gas emissions vented to the atmosphere from coal mine ventilation air and degasification systems. For surface mines, this includes methane and CO_2 emitted during mining from breakage of coal and associated strata, and leakage from the pit floor and highwall. The depth of the coal mine is one of the main drivers of emissions where emissions are much higher in deep mines, such as those typically found in China.

Post-mining factors for underground mines include methane and CO_2 emitted after coal has been mined, brought to the surface and subsequently processed, stored and transported. For surface mines, it includes methane and CO_2 emitted after coal has been mined, subsequently processed, stored, and transported. Variables such as production volumes, mine depth, and overburden depth are sourced from company reports, S&P Global CapIQ, and external geological data providers. These are combined with respective CH_4 and CO_2 emission factors from the IPCC to estimate emissions.

Additionally, for the methane sensitivity ranges, it's assumed ±5% change of the base IPCC intensity factor. Observed methane data from Satellite sources was not included given the lack of data points, particularly for the underground mines. Like the O&G methane emissions, the use emission factors might lead to underestimate the methane emissions for coal.

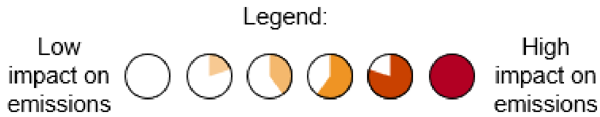
For midstream operations, S&P Global calculates fuel combustion required for mine-to-port transport, shipping, and port-to-plant transport. The model also considers post-mining emissions for handling and processing.

- Mine-to-port and port-to-plant transportation emissions consider transport type to the port (rail or road), load capacity, fuel type and specifications, and distances from mine-to-port and port-to-power plant based on Google Maps.
- Shipping emissions consider vessel capacity, percentage of load, ship speed, fuel type and specifications, and shipping distance calculated from the external open-source tool Ports.com.

All coal end use emissions are allocated to power generation. Variables including typical regional type of coal (bituminous, sub-bituminous or lignite), calorific value, CO_2 emission coefficient, and carbon content are used for the emissions intensity estimation. Power plants inputs include capacity in MW, the plant technology (subcritical, supercritical, ultra-supercritical), S&P Global's data on regional typical coal-fired power plant efficiency, and heat rate. As with natural gas/LNG end use, combustion efficiency was not included in the resulting emission intensity.

Table 9. Main Drivers of Coal GHG Emissions Intensity

Type of Mine	Underground	Methane IPCC factor	25 m³/ton ~0.75 g/MJ	
	Surface		0.3 m³/ton ~0.009 g/MJ	
Type of Coal	Bituminous	Heat content (MJ/kg)	27.8	
	Sub-bituminous		19.9	
	Lignite		14.9	
Shipping Distance	Asia → Asia	Emission factor (gCO_2e/MJ)	1.03	
	Asia → Europe		3.18	
	America → Europe		1.54	



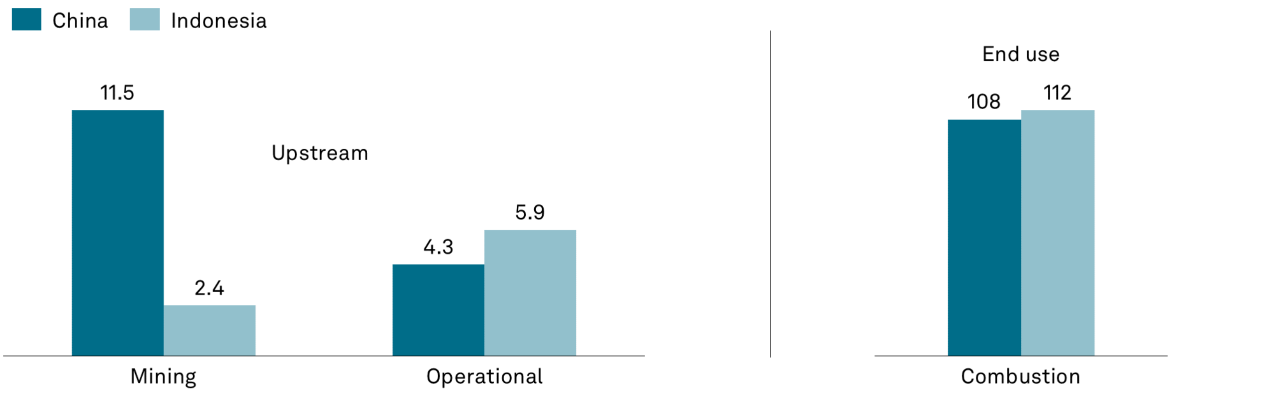
Source: S&P Global Commodity Insights © 2025 S&P Global

Table 10. Case Comparison: China vs. Indonesia

Country	Typical type of mine	Typical types of coal	Moisture percentage
China	Underground (high depth)	Lignite and bituminous	10%
Indonesia	Surface	Sub-bituminous and bituminous	20% and 10%

Source: S&P Global Commodity Insights © 2025 S&P Global

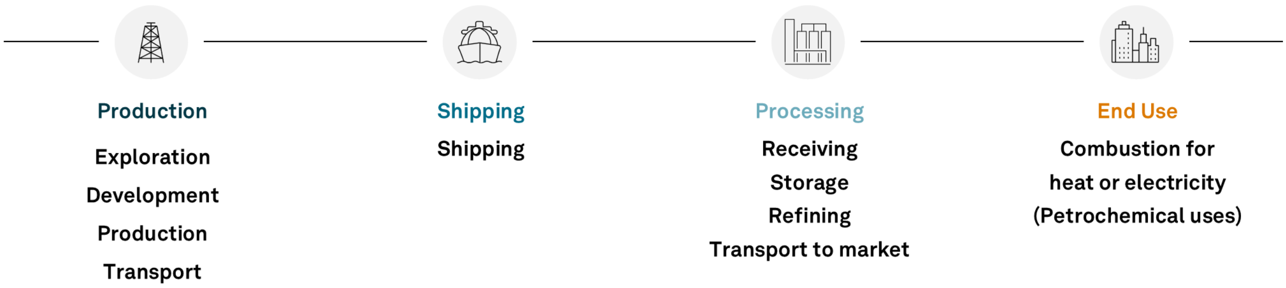
Figure 37. Coal GHG Emissions Intensities



Source: S&P Global Commodity Insights

Oil Methodology

Figure 38. Oil Supply Chain Segments Analyzed



Source: S&P Global Commodity Insights

Based on the Phase 1 energy modeling, the global oil response under the 'Extended Halt' scenario assumes an increase in demand for oil in China, India, JKT, South and Southeast Asia (primarily Pakistan and Bangladesh) and Europe. To meet this increased demand, supply is increased across four key supplier countries: Saudi Arabia, Iraq, Norway, and Nigeria.

Upstream oil production emissions are modeled by the S&P Global Center of Emissions Excellence using the OPGEE model, which evaluates over 100 emission sources across the upstream process stages. These upstream stages include exploration & development, production, surface processing, and transport[33]. Upstream emission intensities for select crude grades are published via Platts Connect. Additional analysis was conducted to integrate Sentinel-2 observed methane data into the upstream oil emissions, establishing a range of variability based on methane uncertainty as shown in the results. The methane emission factors from the Platts carbon intensities were updated from AR4 to AR6 to align with the study. For the methane variability, the low end of the range corresponds to the Platts carbon intensity, while the high end corresponds to the observed country-specific data or analogues from Sentinel-2. Similar to the gas analysis, we did not incorporate any variability for Norway due to the country's stringent policies and operator performance.

[33] For more details on the OPGEE model, see the OPGEE User Guide & Technical Documentation

For each of the four supply countries identified in Phase 1, an average upstream emissions intensity based on the Platts carbon intensities is taken across the major crude streams produced. Total demand volume to meet the US LNG supply gap was then allocated to each of the four crude oil supply countries based on the forecasted country-level production modeled via the S&P Global Annual Strategic Workbook's base case energy scenario (aligned with the Inflections energy outlook).

Shipping emissions for crude oil are based on the port-to-port distance, fuel type, propulsion efficiency, and vessel deadweight tonnage associated with select routes of study. Shipping distances are measured between the largest or second largest oil exporting/importing ports in each country of interest using the shortest distance available. Round trip distances including a laden and ballast journey are used. For JKT, a volume-weighted average was taken based on the annual average daily imports of crude oil via tanker in 2024 to each country. For Europe, the Port of Rotterdam in the Netherlands was used based on its role as the largest port in the region. For all routes, a typical very large crude carrier (VLCC) vessel consuming heavy fuel oil (HFO) was used to model tanker emissions.

Refining emissions are modeled by the Center of Emissions Excellence using the Refinery Cost and Margin Analytics (RCMA) model developed by S&P Global. In addition to providing granular data on profitability and operational metrics for 540+ refineries globally, this model also provides detailed carbon intensities of refineries covering emissions associated with both direct onsite emissions and indirect emissions attributable to imported electricity and hydrogen. The modeled emissions are aligned to the reported refinery emissions based on an extensive model validation process, such that the model gives generically close results to reported refinery emissions at a global scale. Additional modeling was conducted to account for the refinery methane emissions associated with each supply chain. This study assumes a rate of 4% of the total RCMA refining intensity is attributable to methane based on the global average of literature review[34].

End use emissions for each of the destination markets are based on the modeled crude oil end use consumption in each country, the associated crude oil product, and modeled emissions factor. End uses are broken into key categories including power, heat, industry, oil & gas, and others based on the ENVISAGE modeling of demand in each market. This analysis assumes that diesel combusted via turbine or industrial boiler is the primary substitute product used across end uses to meet the demand gap associated with the LNG 'pause'. Emission factors are sourced from the OPGEE model and the US EPA by product and combustion type.

Nuclear, Renewables, and Others

Despite the lack of direct emissions associated with most energy generation sourced from nuclear, renewables, and other types of carbon free energy, this study seeks to compare all energy sources on comparable terms. In line with the other fuels assessed, this analysis considers several operational and non-combustion emissions sources (such as operation and maintenance). All emission intensity data for nuclear, renewables, and others are sourced from the US National Renewable Energy Laboratory's (NREL) Lifecycle Assessment Harmonization project[35].

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[34] Source: Jing et al., 2020
[35] For more information on the NREL Lifecycle Assessment Harmonization project, see https://www.nrel.gov/analysis/life-cycle-assessment.html

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Appendix B: GHG Intensity Results

Lifecycle GHG emission intensity, showing midpoint methane intensity

Table 11. Incremental US LNG GHG Intensity Results
gCO_2e/MJ

Value Chain Segment	GWP AR6 100-yr	GWP AR6 20-yr
Production	3.50	8.69
Gathering & Boosting	3.22	5.08
Gas Processing	2.07	3.44
Transmission & Storage	0.72	1.65
Liquefaction	4.18	4.61
Shipping	3.68	4.40
Regasification	0.52	0.52
End Use	56.8	56.8

Source: S&P Global Commodity Insights

Table 12. Alternative LNG Sources GHG Intensity Results
gCO_2e/MJ

Value Chain Segment	GWP AR6 100-yr	GWP AR6 20-yr
Production	4.67	12.22
Gathering & Boosting	1.10	2.16
Gas Processing	5.55	10.42
Transmission & Storage	0.28	0.62
Liquefaction	4.57	5.01
Shipping	2.31	2.76
Regasification	0.53	0.53
End Use	56.8	56.8

Source: S&P Global Commodity Insights

Table 13. Indigenous Gas and Piped Imports GHG Intensity Results
gCO_2e/MJ

Value Chain Segment	GWP AR6 100-yr	GWP AR6 20-yr
Production	8.45	20.93
Gathering & Boosting		
Gas Processing	2.86	6.29
Transmission & Storage	1.88	3.82
Liquefaction		
Shipping		
Regasification		
End Use	56.8	56.8

Source: S&P Global Commodity Insights

Table 14. Oil Response GHG Intensity Results
gCO_2e/MJ

Value Chain Segment	GWP AR6 100-yr	GWP AR6 20-yr
Upstream	12.42	22.91
Shipping	0.36	0.36
Refining	7.65	8.29
End Use	74.16	74.16

Source: S&P Global Commodity Insights

Table 15. Coal Response GHG Intensity Results
gCO_2e/MJ

Value Chain Segment	GWP AR6 100-yr	GWP AR6 20-yr
Production	14.41	32.83
Shipping	0.51	0.51
Land Transport (coal only)	0.15	0.15
End Use	107.54	107.54

Source: S&P Global Commodity Insights

Appendix C: Regional Economic Impact Analysis

Table 16. Economic impacts by state: 2025-2040
Base case, cumulative real 2024$ or average annual jobs

State	Total Jobs Supported	Gross State Product ($M)	GSP per capita
US Total	495,373	1,299,028	3,764
Texas	182,830	599,732	18,282
Oklahoma	33,833	72,146	17,893
Louisiana	29,791	80,563	18,213
New Mexico	24,190	48,483	24,213
California	20,495	49,569	1,236
Pennsylvania	19,422	58,300	4,528
Ohio	16,814	41,526	3,542
Arkansas	14,997	30,163	10,094
Illinois	11,231	26,266	2,168
Florida	10,779	21,028	809
Indiana	7,657	16,593	2,422
New York	7,506	24,801	1,288
Michigan	7,130	13,994	1,425
Minnesota	6,689	11,978	2,017
Tennessee	6,622	10,119	1,360
West Virginia	5,933	14,848	9,046
Georgia	5,795	13,785	1,153
North Carolina	5,292	12,436	1,078
Kansas	5,178	6,203	2,275
Virginia	5,163	8,730	984
Maryland	5,156	8,859	1,378
Wisconsin	4,664	9,468	1,620
Washington	4,646	10,651	1,296
New Jersey	4,351	9,285	978
Colorado	4,235	10,390	1,624
South Carolina	4,066	5,594	1,005
Utah	3,903	6,229	1,687
Missouri	3,767	8,642	1,384
Arizona	3,593	7,316	862
Kentucky	3,509	6,299	1,382
Massachusetts	3,130	9,594	1,326
Alabama	3,075	6,035	1,198
Oregon	2,785	5,208	1,171

State	Total Jobs Supported	Gross State Product ($M)	GSP per capita
Mississippi	2,736	3,746	1,340
Iowa	2,277	4,510	1,451
Nevada	1,819	3,964	1,215
Connecticut	1,507	4,254	1,194
Idaho	1,349	1,918	1,001
Nebraska	1,243	2,695	1,371
New Hampshire	752	1,567	1,122
South Dakota	672	934	1,063
Maine	644	1,151	842
Montana	640	1,161	1,028
North Dakota	535	1,423	2,003
Washington, DC	532	1,649	2,300
Wyoming	503	1,138	1,999
Delaware	467	1,193	1,065
Alaska	438	648	927
Rhode Island	413	1,103	990
Vermont	336	622	994
Hawaii	285	514	356

Source: S&P Global Market Intelligence/ Data compiled Feb. 10,2025
Note: Base case, ordered by total jobs supported

Table 17. Economic impacts in congressional districts (2025-2040
Base case, highes impacts by district (cumulative real 2024$ or average annual jobs)

District	Total Jobs Supported	Gross District Product ($M)	GSP per capita
TX-23	15,274	64,339	93,871
TX-34	10,041	39,892	55,569
TX-01	8,495	33,541	44,047
TX-11	7,334	32,208	43,129
TX-37	6,767	16,744	18,202
TX-24	6,518	17,174	20,061
TX-32	6,323	17,327	21,061
TX-19	5,998	22,005	30,738
TX-18	5,822	19,448	22,204
TX-14	5,708	21,322	24,579
TX-28	5,681	21,851	28,363
TX-27	5,509	20,705	25,905
TX-33	5,371	15,773	18,255
TX-38	5,011	15,733	18,067
TX-07	4,994	14,095	13,906
TX-30	4,865	12,691	15,886
TX-04	4,805	12,678	15,255
TX-13	4,628	15,687	22,347
TX-12	4,519	13,345	12,986
TX-06	4,114	12,715	15,169
TX-35	4,017	10,955	11,063
TX-15	3,963	13,416	16,112
TX-36	3,904	13,336	16,536
TX-17	3,890	13,099	16,702
TX-20	3,869	8,802	9,290
TX-26	3,407	10,588	11,015
TX-21	3,345	8,452	9,103
TX-10	3,335	10,179	11,839
TX-25	3,334	10,742	13,274
TX-09	3,169	7,315	7,700
TX-02	2,792	9,171	9,003
TX-29	2,703	8,855	10,039
OK-03	8,968	21,770	28,903
OK-01	7,709	14,548	16,304
OK-05	6,553	13,188	15,928
OK-04	5,907	12,910	16,476
OK-02	4,696	9,731	12,553

District	Total Jobs Supported	Gross District Product ($M)	GSP per capita
LA-04	11,048	33,221	45,403
LA-01	5,362	14,391	18,576
LA-03	4,383	12,047	16,993
LA-06	3,363	7,688	9,944
LA-02	3,224	7,493	10,440
NM-02	10,088	21,732	32,111
NM-03	7,743	15,948	23,909
NM-01	6,359	10,803	16,405
PA-09	2,774	10,808	14,643
PA-14	2,688	10,958	15,215
AR-03	4,811	9,500	10,866
AR-04	4,066	8,396	12,421
AR-02	3,657	7,768	10,229
WV-02	3,983	10,684	12,465
WV-01	1,950	4,164	5,309

Source: S&P Global Market Intelligence/ Data compiled Feb. 10,2025
Note: Ordered by total jobs supported and grouped by state

Methodology and Approach

The model framework used was established as a system of linked state economies. As a result, the sourcing of inputs for the development of US LNG export activity will impact states that are not part of this industry's value chain. For example, the liquefaction facilities in Texas rely on bank, financial and insurance services in New York and professional services primarily in Texas. Capturing these connections highlights the indirect economic contribution. The leakages from the originating states will also affect the size of the GDP and employment multipliers, making them more accurate for states that do not fall within the US LNG export value chain.

In addition, while the value created by the US LNG value chain is attributed only to states with upstream, pipeline, and liquefaction activities, the allocation of capital expenditures among the producing and non-producing states is more involved. Capital expenditures act as direct impacts at both the state and industry levels. Estimating this sourcing requires complex analysis because a portion of that spending may be allocated to states—including non-producing states—that are not part of the US LNG export value chain. This spending will trigger direct, indirect, and induced impacts in states that provide goods and services for capital expenditure purposes. To ensure that these effects are included in the economic analysis, the economics team used industry input, expertise and proprietary databases, and extensive additional research to arrive at the best possible methodology to trace the supply chain among different states.

The research, expertise, and input from industry sources were integrated with a proprietary interstate trade-flow data set and with Business Market Insight databases to determine the sources of various products and services by state. For example, it is evident that US LNG exports using liquefaction facilities require machinery and equipment produced primarily in Illinois, Michigan, and Ohio. Since not all states in the US LNG export value chain produce all required inputs, they must import them from the other states and are assumed to do so in the model. Market Intelligence's trade-flow database was one of many sources used to determine the origin and destination of the various materials and equipment on a state-level basis.

The economic impact sequence begins with direct spending initiated by LNG production, transport, and liquefaction at export terminals. This initial spending sets off a chain reaction in the economy. Direct suppliers, who benefit from this spending, engage with their own suppliers, thereby starting the indirect contribution cycle. This cycle further stimulates economic activity as employees supported by the direct spending, along with the extended supply chain spending within their local communities, contribute to induced economic activity.

Each type of impact—direct, indirect, and induced—corresponds to specific levels of economic indicators such as gross domestic product (GDP), employment (in terms of jobs), wages, and taxes. The methodology for estimating these impacts is grounded in the analysis of inter-industry relationships, which are captured through national and state input-output tables. These models are designed to quantify contributions not only to GDP but also to labor income, employment, and tax revenues.

To facilitate the analysis, ratios of value-added-to-output, labor income-to-output, and employment-to-output, as well as tax contributions by industry, were generated at both the national and state levels. This data was sourced from public sources like the Bureau of Economic Analysis (BEA) and the Bureau of Labor Statistics (BLS), and private data from S&P Global. The resulting ratios for value added-to-output, labor income-to-output, and output-to-employment were compiled into look-up tables to streamline the analysis process. In practice, the gross output results for each industry were multiplied by the appropriate ratio to quantify the respective impacts on value added, labor income, or employment. For instance, to calculate the value-added impacts generated in a specific industry due to LNG production, the output results for that industry were multiplied by the corresponding value added-to-output ratio.

To build an economic impact model for the US and states plus Washington, D.C., S&P Global Market Intelligence developed an in-house US Economic Impact Assessment (EIA) model. The methodologies adopted in the model closely mirror those used by IMPLAN, REMI, and other providers of multipliers and economic impact analysis data. Market Intelligence used data from the BEA and also incorporated proprietary data into the modeling process, enriching the analysis and enhancing the accuracy of the impact estimates.

The EIA models used in the analysis employed a standard matrix balancing technique known as the RAS method. This method involves an iterative process that scales and rebalances the Direct Requirements Matrix, which is a version of the input-output (IO) table. The RAS method adjusts the rows and then the columns of the matrix until the coefficients converge, resulting in a balanced matrix that accurately reflects a targeted level of regional output. The application of the RAS method ensures that for a specified level of state output, the total of direct state intermediate purchases equals the total of direct state intermediate demand. This approach provides a robust framework for estimating economic impacts across various regions in the United States.

Multi-regional Economic Impact Approach

Market Intelligence enhanced its state Input-Output (IO) tables by integrating a multi-regional input-output model (MRIO), which enriches the analysis of economic interactions across different states. The MRIO model provides a framework for estimating not only the direct economic impacts of spending within a state but also the indirect and induced economic effects that arise from inter-state economic linkages. By capturing these spillover effects, the MRIO model offers a more complete perspective on regional economic dynamics, allowing for a better understanding of how economic activities in one state can influence states throughout the broader economy.

At the core of the MRIO approach is a gravity model designed to estimate trade flows between states. This model considers the geographical distance between states and the gross domestic product (GDP) of the industries involved as independent variables. The coefficients on the distance and GDP variables form the equations used to predict how much trade occurs between states based on their economic sizes and proximity. The MRIO model first determines the total interstate trade flow by comparing the total intra-state spending—calculated through the state RAS process—with the proportion of goods imported from outside the United States. This process allows for a clear delineation between goods and services produced within the state and those sourced from other states.

The model employs a straightforward formula to arrive at the total interstate spending for a particular state and industry. The total interstate spending (*Ts,i*) for state *s* and industry *i* is calculated by subtracting the intra-state spending (*Is,i*) and the total imports (*Ms,i*) from the gross output (*Gs,i*) of that state and industry. This relationship can be expressed as:

$$Ts,i = Gs,i - Is,i - Ms,\mathrm{i}$$

Any goods or services not sourced from within the state, but sourced from within the country, are classified as interstate trade flows. Once the total interstate trade is established, it is then allocated among different states and industries according to the coefficients derived from the gravity model.

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