Executive Summary

1. THE 2024 LNG STUDY: IMPLAUSIBLE SCENARIOS AND FLAWED ASSUMPTIONS

The Oxford Institute for Energy Studies (OIES) identifies significant flaws in the DOE Study methodology and conclusions. We concur. The core scenario of the DOE Study projects implausibly high global gas demand of 5,600 bcm by 2050, ≈20% higher than other major forecasts. Regional demand projections appear equally questionable, with unrealistic growth predictions in numerous regions and nations. While DOE forecasts a 31% increase in Henry Hub prices by 2050 under unconstrained USLNG exports, OIES suggests a more modest $0.15-0.30/mmbtu increase over 25 years.

2. THE GREENHOUSE GAS EMISSION INTENSITY OF USLNG VS. OTHER FUELS

Berkeley Research Group's (BRG) life cycle analysis across 13 global markets demonstrates USLNG's favorable emissions profile. In European markets, USLNG emissions intensity (477 kgCO2e/MWh) averages 9% lower than pipeline gas imports (526 kgCO2e/MWh), with particularly strong advantages over Russian imports. In Asian markets, USLNG emissions (498 kgCO2e/MWh) are 63% lower than coal supplies (1,330 kgCO2e/MWh) and 59% lower than pipeline imports (1,217 kgCO2e/MWh).

3. LOCAL ENVIRONMENTAL AND HEALTH IMPACTS

A separate BRG analysis finds fault with a Greenpeace USA and Sierra Club report claiming 149 premature deaths and $2.33 billion in annual health costs from the 32 planned and operating USLNG export terminals. BRG identifies several methodological flaws, including exclusive focus on costs without benefits consideration, reliance on permitted rather than actual emissions data, and use of static 2028 baseline emissions through 2050. The critique emphasizes the need for comprehensive cost-benefit analysis and validation against actual health outcome data from operating terminals.

4. THE DOMESTIC PRICE IMPACTS OF USLNG EXPORTS ARE NEGLIGIBLE

Research by R. Dean Foreman, PhD, demonstrates that USLNG exports have not significantly impacted domestic natural gas prices. His analysis shows that exports have stimulated new U.S. production and technological improvements. The U.S. natural gas resource base can support 100 years of production at current levels. Empirical data suggests no link between exports and Henry Hub prices.

5. GEOPOLITICAL AND ENERGY SECURITY SIGNIFICANCE OF USLNG EXPORTS

USLNG exports provide crucial strategic benefits through enhanced global energy security and destination flexibility. These exports proved critical in supporting European allies following Russia's invasion of Ukraine and offer reduced supply risks through diverse shipping routes that avoid vulnerable chokepoints. The flexibility of USLNG contracts and Henry Hub-linked pricing provide unique commercial advantages, while also serving as an important alternative supply source in sanctions-constrained markets.

To summarize our comments: The USLNG Association ("LNG Allies") believes that in making future non-FTA authorizations, DOE should place greater emphasis on observed data rather than theoretical price forecasts and continue to review the merits of each USLNG project on an individual basis. We also believe that the concerns about domestic price impacts and environmental harm—as outlined in former Energy Sec. Granholm's "summary" statement—have been overstated, while the economic, strategic, and environmental benefits have been downplayed. USLNG exports continue to benefit America and Americans greatly and to play a vital role in advancing global energy security and emissions reduction goals.

Comments of The USLNG Association ("LNG Allies")

1. THE 2024 LNG STUDY: IMPLAUSIBLE SCENARIOS AND FLAWED ASSUMPTIONS

The USLNG Association ("LNG Allies") has several concerns about the U.S. Department of Energy's 2024 LNG Export Study ("DOE Study" or "Study"), including the choice of the Pacific Northwest National Laboratory and its GCAM model, the implausible scenarios selected, and the many faulty assumptions used.

Our concerns align closely with the Comment by Mike Fulwood, Senior Research Fellow at the Oxford Institute for Energy Studies (OIES), published on 08 Jan. 2025. (Appendix A). Fulwood's Comment, "DOE Report on USLNG Exports: Implausible Scenarios and Flawed Assumptions" ("OIES Comment"), examines two main conclusions of the DOE Study and highlights significant concerns about its methodology and assumptions.

As discussed in the OIES Comment, the DOE Study concludes that under the Defined Policies (DP) scenario "with unconstrained USLNG exports," the Henry Hub price would be 31% higher in 2050 compared to a scenario with only operating and under-construction USLNG plants exporting. Specifically, the Henry Hub price in 2050 would reach $4.62/mmbtu compared to $3.53/mmbtu in the existing and under-construction scenario at real 2022 prices.

Additionally, the DOE Study concludes that the "unconstrained USLNG exports" scenario would lead to increased greenhouse gas (GHG) emissions compared to the existing/under-construction scenario, primarily because USLNG exports displace not only gas production in other countries but also lead to an increase in gas demand, with gas displacing some coal and oil but renewables as well.

After a thorough examination of the DOE Study, Fulwood concludes that more accurate modeling would likely show a $0.15 to $0.30 per mmbtu Henry Hub price increase over the next 25 years, "a much more realistic assessment of the possible impact." Additionally, "there would be no increase in GHG emissions and, to the extent that modestly higher USLNG did lead to some displacement of coal in power plants—driven by policy rather than relative costs—then GHG emissions would be lower."

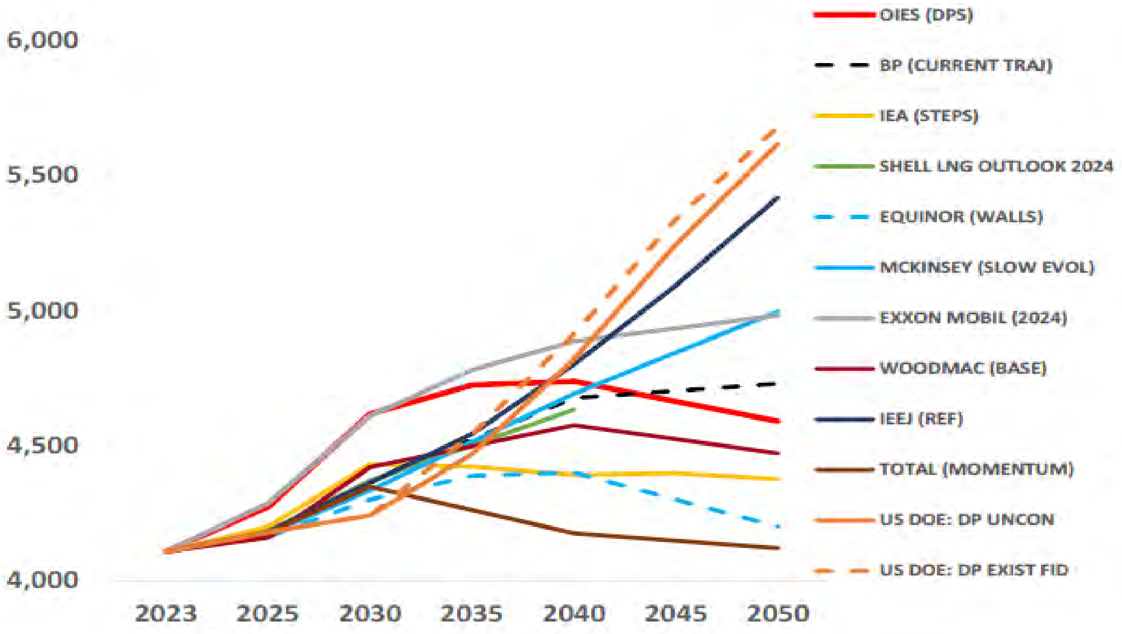
Implausible Scenarios

The OIES Comment identifies several problems with DOE's scenarios. The DOE scenarios are outliers compared to industry projections. By 2050, DOE projects annual global gas demand to reach over 5,600 billion cubic meters (bcm), which is ≈20% higher than other major forecasts. The DOE scenarios are the only ones (apart from the Institute of Energy Economics, Japan) which have global gas demand rising above 5,000 bcm/year in the period to 2050. (See Figure 1.)

Regional demand projections also show significant inconsistencies. For India, DOE projects annual demand of ≈400 bcm by 2050 (compared to 67 bcm in 2023). Japan's demand is projected to plateau at 125 to 135 bcm over the period, compared to current and declining demand of around 85 bcm. U.S. demand is projected to reach ≈1,100 bcm by 2050 (demand in 2023 was some 920 bcm).

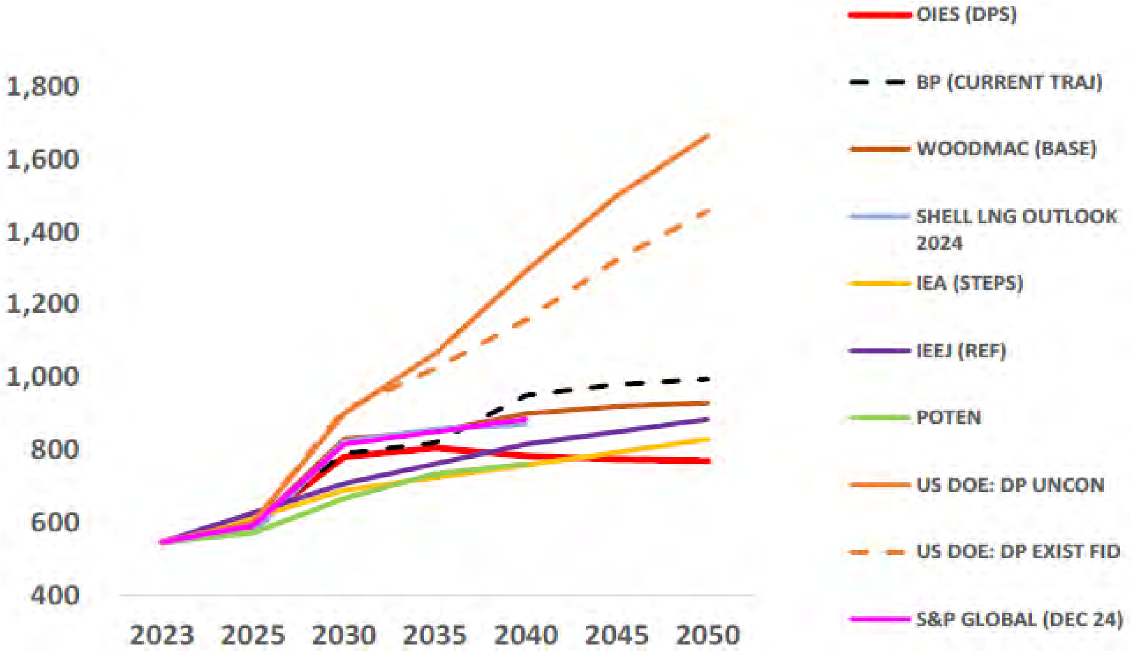
The OIES Comment also notes that DOE scenarios show markedly higher LNG trade volumes than industry projections. The DP Unconstrained scenario reaches over 1,650 bcm by 2050, while the DP Existing FID scenario exceeds 1,450 bcm. For comparison, the highest of the other scenarios—BP Current Trajectory—reaches just under 1,000 bcm by 2050. (See Figure 2.)

Figure 1: Global Gas Demand Scenarios (Billion Cubic Meters Per Year)



Source: OIES, Citing DOE Study, IEA, and Other Sources.

Figure 2: Global LNG Trade (Billion Cubic Meters Per Year)



Source: OIES, Citing DOE Study, IEA, and Other Sources.

Flawed Assumptions

The OIES Comment states that regional projections in the Study contain questionable assumptions. For China, LNG imports are projected to reach almost 300 bcm by 2050, representing 45% of total China gas demand. Such imports would exceed China's domestic production of 227 bcm. Russia's LNG imports reach some 75 bcm in DP Unconstrained in 2050, which is three times higher than Russia's LNG exports, while Central Asia imports some 30 bcm of LNG in 2050 in DP Unconstrained despite being landlocked.

In the Study, Argentina and Brazil are projected to import 42 bcm and 90 bcm respectively, while domestic production barely increases (which doesn't seem credible given their abundant gas reserves). Pakistan's LNG imports are projected to reach 75 bcm in 2050 in DP Unconstrained—imports at present are less than 10 bcm.

The OIES Comment also criticizes the DOE Study's market and cost assumptions. Using the DOE's projected Henry Hub price of $3.53, delivered costs are calculated at $8.50 to $9.00 for Europe and $9.80 to $10.30 for Japan. With higher Henry Hub prices ($4.62), costs would increase by another $1.25. The OIES Comment questions how USLNG could compete with other sources, noting that Qatar's LNG deliveries to Japan and Europe are in the $5 to $6 range. It is particularly questionable that USLNG can displace Middle East LNG, predominantly Qatari LNG, in the Asian markets.

Other Fundamental Problems

Several other fundamental problems are identified with the DOE Study. The GCAM model is calibrated to 2015, creating potential divergences as projecting from 2015 means it is almost certain the model is diverging in its projections between 2015 and now. Fulwood questions who would buy the additional USLNG volume in the Unconstrained scenario: "Who will contract for this incremental volume?" In his view: "It is plausible that an additional 50 bcm could go to FID and be contracted and even slightly higher numbers but not an additional 300+ bcm."

In conclusion, the OIES Comment suggests removing ≈470 bcm from the projections: 220 bcm for Europe, Russia, and Central Asia and 250 bcm from Japan, Pakistan, India, Argentina, and Brazil. "A more realistic scenario would see USLNG exports 50 to 100 bcm higher than current projections, increasing Henry Hub prices by between $0.15/mmbtu to $0.30/mmbtu by 2050, a much more realistic assessment of the possible impact."

The DOE Study's environmental impact conclusion is also challenged, with the OIES Comment stating that "if this increase in gas demand replacing renewables doesn't happen, then the conclusion, from the DOE Study, that a large increase in USLNG exports would increase global GHG emissions, completely falls apart."

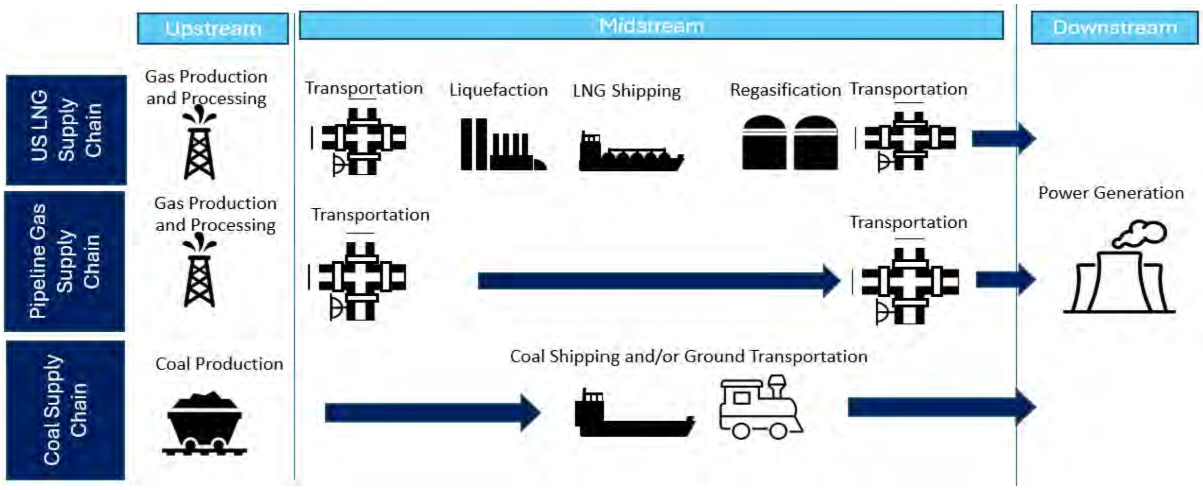
2. THE GREENHOUSE GAS EMISSION INTENSITY OF USLNG VS. OTHER FUELS

The Energy and Climate Practice of the Berkeley Research Group (BRG) has been working with LNG Allies and our partners to construct a framework to benchmark U.S. liquefied natural gas (USLNG) against competing fuels in key markets. What follows is a summary of BRG's life cycle analysis (LCA) of the greenhouse gas (GHG) emissions intensity of USLNG versus pipeline gas and coal using 2023 data. (The 2022 and 2023 BRG LCAs are in Appendix B.)

Background

BRG E&C conducted an independent LCA comparing GHG emissions of USLNG with competing fossil fuels for power generation across 13 global markets. The analysis, developed since 2021 and updated in Feb. 2025 (with 2023 data), focuses on CO2 and CH4 emissions, uses the 20-Year Global Warming Potential (GWP20) metric, and evaluates full supply chains from production through combustion. The 13 markets include eight European countries (France, Germany, Italy, Netherlands, Poland, Spain, Türkiye, and United Kingdom) and five Asian nations (China, India, Japan, South Korea, and Taiwan).

Figure 3. Scope of Supply Chain GHG Analysis

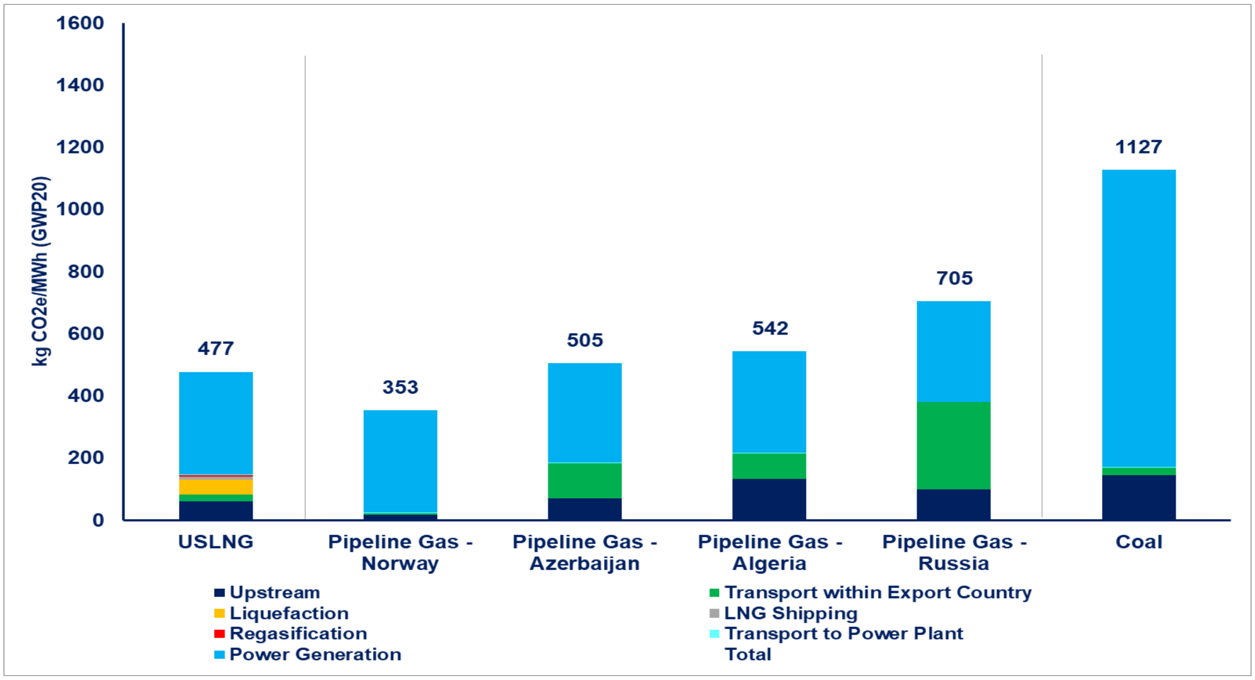


The study analyzed complete life cycle emissions for three fuel types: (1) USLNG imports, including CO2 and CH4 emissions from feed-gas production in the United States through processing, pipeline transportation, LNG liquefaction, LNG tanker shipping, LNG regasification, downstream gas transport, and combustion for power generation. (2) Pipeline gas imports, covering CO2 and CH4 emissions from the production, processing, transport, and combustion for power generation. (3) Coal supplies, encompassing CO2 and CH4 emissions from the production, processing, transport, storage, shipping (where relevant), export/import, and combustion for power generation.

Results Using 2023 Data

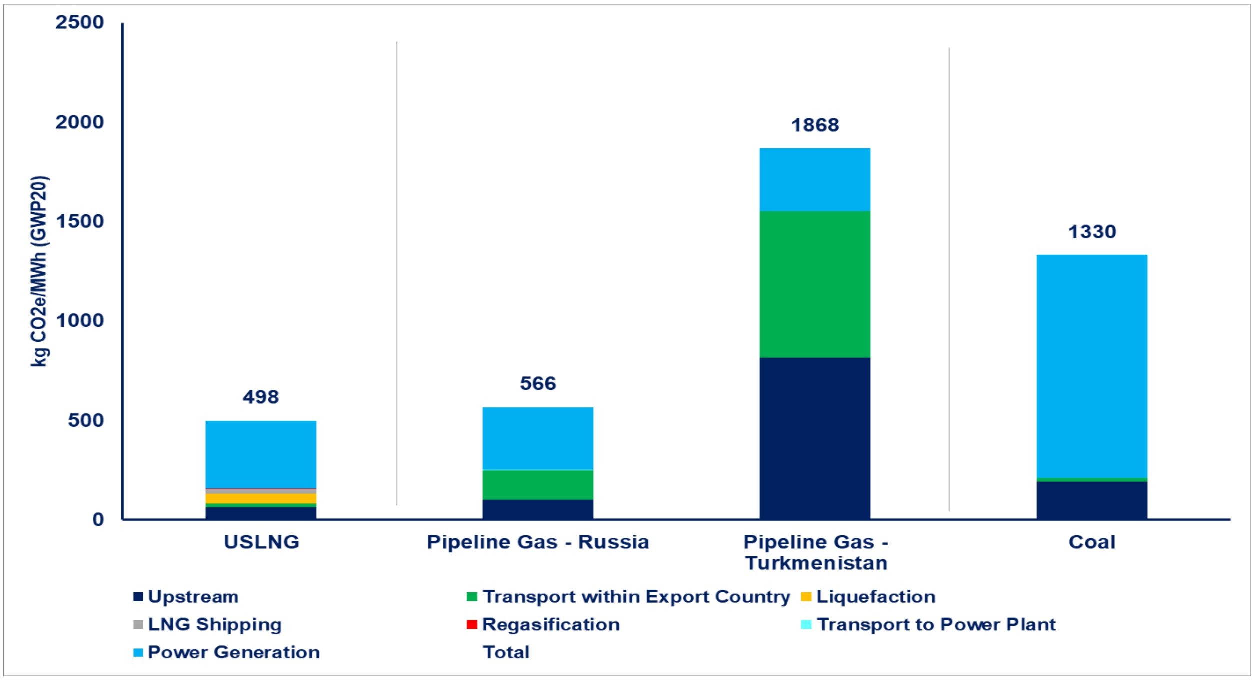
In European markets, USLNG emissions intensity averaged 477 kgCO2e/MWh, which was 9% lower than the 526 kgCO2e/MWh for the main sources of pipeline imports. More specifically, it was 32%, 12%, and 6% lower than that of pipeline gas from Russia, Algeria, and Azerbaijan, respectively, but 35% higher than that of pipeline gas from Norway.

Figure 4: GHG Emissions Intensity of USLNG, Pipeline Gas Imports, and Coal Supplies to Europe



In Asian markets, USLNG emissions intensity of 498 kgCO2e/MWh was 63% lower than that of coal supplies of 1,330 kgCO2e/MWh and 59% lower than pipeline imports of 1,217 kgCO2e/MWh.

Figure 5: GHG Emissions Intensity of USLNG, Pipeline Gas Imports, and Coal Supplies to Asia



The overall comparative results showed that coal was over twice as high as USLNG in both Europe and Asia. Additionally, pipeline gas in Asia was more than three times higher than USLNG in the case of pipeline gas from Turkmenistan and slightly higher than USLNG for pipeline gas from Russia. In Europe, pipeline gas was slightly more than half of USLNG for gas coming from Norway but a third higher than USLNG for gas coming from Russia.

Methodologically, the study uses mass balance methodology for USLNG and pipeline gas calculations, measures in kilograms of CO2e per megawatt hour (kg CO2e/MWh) of electricity generation, converts CH4 to CO2 equivalent using GWP20 value of 82.5 (from IPCC), and accounts for different chemical characteristics and thermal efficiency of power generation fleets in each country.

The BRG analysis demonstrates that natural gas, particularly USLNG, generally shows significantly lower GHG emissions intensity compared to coal across both European and Asian markets, with varying advantages over pipeline gas depending on the source and destination.

3. LOCAL ENVIRONMENTAL AND HEALTH IMPACTS

LNG Allies also retained BRG to analyze and comment upon the Greenpeace USA and Sierra Club report titled: "Permit to Kill: Potential Health and Economic Impacts from USLNG Export Terminal Permitted Emissions" from Aug. 2024. (Hereinafter, "Greenpeace Report" or "Report".)

The Greenpeace Report utilized the U.S. EPA's COBRA (CO-Benefits Risk Assessment Health Impacts Screening and Mapping Tool) to evaluate health impacts from USLNG export terminals and concluded that air quality impacts from the 32 planned and operating LNG export terminals would cause 149 premature deaths and $2.33 billion in health costs per year. Based upon these findings, Greenpeace and the Sierra Club recommended halting approval of any further USLNG export projects.

Authored by David L. Sunding, PhD, BRG Vice Chair, and Gina Waterfield, PhD, BRG economist and director, the BRG Commentary (Appendix C) presents several major criticisms of the Greenpeace Report. First, the authors argue that the conclusions lack support even if the estimates are accurate, because they focus only on costs and fail to consider benefits. As stated in the BRG Commentary: "Whether a project or activity is in the public interest depends on how its costs compare to the benefits it provides, and the [Greenpeace] Report provides no evaluation of potential local, national, or global benefits."

The BRG Commentary emphasizes that while all economic activities have associated costs, including health impacts, this alone doesn't justify their termination. Sunding and Waterfield reference a study published in Science that estimated that PM2.5 from 480 coal-fired electricity generating units was associated with 460,000 premature deaths over the period 1999 to 2020. Despite such impacts, these activities contribute to overall social welfare through various benefits.

The BRG Commentary identifies several methodological limitations in the Greenpeace Report. COBRA is described as a screening-level tool that should be followed up with comprehensive air quality analysis and health impact assessment. The accuracy of air quality modeling may significantly impact results, especially for population-dense areas distant from LNG terminals. Despite several USLNG terminals operating for years (such as Cheniere Energy's Sabine Pass since 2016) the Greenpeace Report relies entirely on model outputs rather than using actual health outcome data for validation.

Regarding emissions assumptions, the BRG authors note that the Greenpeace Report uses permitted emissions rather than actual emissions data, assuming maximum permitted daily emissions occur 365 days per year through 2050. This approach ignores potential technological improvements and regulatory changes, while using static 2028 baseline emissions for all future years.

The BRG Commentary also criticizes the Greenpeace Report's presentation of health costs, noting that these are primarily based on the value of statistical life (VSL). The default VSL of $14 million per expected premature mortality accounts for nearly 90% of the health costs reported, and these shouldn't be construed as healthcare costs or other pecuniary measures.

The environmental justice analysis in the Greenpeace Report receives particular scrutiny by Sunding and Waterfield. The authors argue that the methodology for analyzing nonattainment areas largely guarantees overlap with impacted areas due to population density. Importantly, there is no overlap between nonattainment regions and areas most impacted by LNG terminal emissions when the latter is defined on a per capita basis. Low nearby population density is generally a desirable feature in industrial facility siting.

Regarding climate vulnerability, Sunding and Waterfield argue that this comparison is inapt, given that climate change is a global phenomenon caused by global greenhouse gas emissions, not local emissions. The BRG Commentary suggests analyzing relevant environmental burden measures individually rather than using composite indices.

The racial and ethnic analysis in the Greenpeace Report, when focused on relevant states (Texas and Louisiana), shows mixed results. In Texas, while exposure is up to 20% higher for the Black/African American population than for the White population, it's generally relatively lower for other ethnic minorities. In Louisiana, exposure is lower for all minority populations versus the White population. Sunding and Waterfield argue that these states are the relevant points of reference due to their unique siting characteristics.

The BRG Commentary emphasizes several potential benefits ignored by the Greenpeace Report. At the local and regional level, these include construction and operation revenues, direct and indirect employment opportunities, and tax revenues for local and state governments (which could potentially improve healthcare through increased resources). Global benefits might include geopolitical advantages, diversification of global energy supplies, potential reduction in global greenhouse gas emissions, and environmental benefits depending on displaced energy sources.

The BRG Commentary concludes that while health impacts of LNG terminals deserve serious consideration, the Report's analysis is incomplete and methodologically flawed. A proper evaluation would require comprehensive cost-benefit analysis, consideration of offsetting environmental benefits, more robust methodological approaches, a more nuanced environmental justice analysis, focus on actual rather than permitted emissions data, and recognition of technological/regulatory changes over time.

Throughout their Commentary, Sunding and Waterfield emphasize that environmental and health impacts, while important, must be evaluated within a broader context of social welfare and balanced against potential benefits at local, national, and global scales. Such a broad balancing of costs and benefits is precisely what the Department of Energy does when it conducts individual (case-by-case) evaluations to ensure that each USLNG export authorization to non-Free Trade Agreement countries is consistent with the public interest.

The BRG Commentary suggests that making decisions about LNG terminals requires a more comprehensive and nuanced analysis than what was presented in the Greenpeace Report.

4. THE DOMESTIC PRICE IMPACTS OF USLNG EXPORTS ARE NEGLIGIBLE

LNG Allies has worked since 2023 with R. Dean Foreman, PhD, who is now chief economist for the Texas Oil & Gas Association. In Feb. 2024, Foreman updated the analysis originally prepared for LNG Allies a year earlier titled: An Examination of Whether USLNG Exports Drive Domestic Natural Gas Prices. The updated Foreman report from 2024 is in Appendix D.

According to Foreman's work, the relationship between USLNG exports and natural gas prices at Henry Hub shows that exports have not had any sustained and significant direct impact on natural gas prices. His conclusion is based on correlation analysis and a holistic fundamentals-driven framework that has accurately predicted U.S. natural gas prices.

Foreman found that USLNG exports have spurred incremental new U.S. production and led to improvements in technology and resource recoveries, generally adding to estimated domestic recoverable gas resources. For example, he cites the U.S. Potential Gas Committee's most recent estimates, which suggest that the resource base could enable future U.S. gas supply of 3,978 trillion cubic feet—equivalent to 100 years of production at 2022 levels.

We continue to believe that economic analyses based on actual observed data are much more informative than projections, no matter how good the models, scenarios, and assumptions used to produce the forecasts. Given the process-related concerns expressed earlier in these comments, we urge DOE to place greater emphasis on actual observations than on the price impact forecasts contained in the Study.

5. GEOPOLITICAL AND ENERGY SECURITY SIGNIFICANCE OF USLNG EXPORTS

The DOE Study highlights USLNG as a cost-competitive and stable energy source in the global market. We concur. The Study recognizes that destination flexibility—allowing offtakers to re-sell contracted cargoes—enhances global energy security. This flexibility proved crucial after Russia's invasion of Ukraine, when USLNG replaced much of Russia's natural gas exports to Europe, supporting our European allies and strengthening U.S. security interests. For many users, this adaptability makes USLNG more valuable than LNG from other nations.

While future global LNG demand remains uncertain, leading analysts project strong growth until at least 2040. Meeting post-2030 demand will require significant new export capacity. (See Fig. 2, above.) Most U.S. projects awaiting DOE non-FTA export authorization have already contracted their expected capacity to global customers, demonstrating clear market demand for USLNG.

CSIS COMMENTARY: BUYER PERSPECTIVES ON THE VALUE OF USLNG

The USLNG industry has key factors that elevate its geopolitical and market significance. USLNG adds substantial volumes to the global market, helps mitigate supply risks worldwide, and offers unique flexibility and pricing mechanisms valued by buyers. USLNG also helps allies cope with energy sanctions on other exporters.

USLNG volumes grew rapidly when the market needed new supplies. In 2023, the United States became the world's largest LNG exporter after Freeport LNG resumed operations and Calcasieu Pass ramped up. These exports helped European buyers avoid crisis when Russia reduced gas supplies. Though prices cooled after the volatility of 2021-2022, the market remains finely balanced, with high utilization rates meaning unexpected outages could quickly impact supply.

USLNG helps reduce supply risks. European cargoes from the Middle East and Australia must transit vulnerable chokepoints like the Persian Gulf and Suez Canal, as shown by recent Red Sea attacks. Asian shipments pass through contested waters of the Taiwan Strait and South China Sea. USLNG can reach Europe via the Atlantic and Asia via the Pacific, avoiding some risks. While not immune to disruptions, as seen with Panama Canal issues, this flexibility helps buyers reduce exposure to volatile regions.

USLNG offers unique commercial benefits. Traditional LNG contracts included long periods and strict delivery terms prohibiting resale. While providing supply security, these arrangements limited flexibility and market liquidity. USLNG changed this through ample domestic supply, infrastructure, and lower costs. New sellers could access volumes from the grid with suitable port facilities. Flexible terms let buyers arrange shipping and leverage FOB terms for cargo destination freedom. This creates price convergence between markets and offers Henry Hub-linked pricing, allowing better portfolio optimization.

USLNG adds security in a sanctions-constrained world. Energy sanctions create challenges for importers, and restricting exports makes adaptation harder. Recent U.S. sanctions on Russian LNG projects affect Western and Japanese contracts. Many importing countries remain concerned about supply security, and potential USLNG export restrictions worry buyers, who may seek alternatives from permitted projects or other suppliers.

Excerpted and condensed from: Geopolitical Significance of USLNG (CSIS, 07 Feb. 2024)

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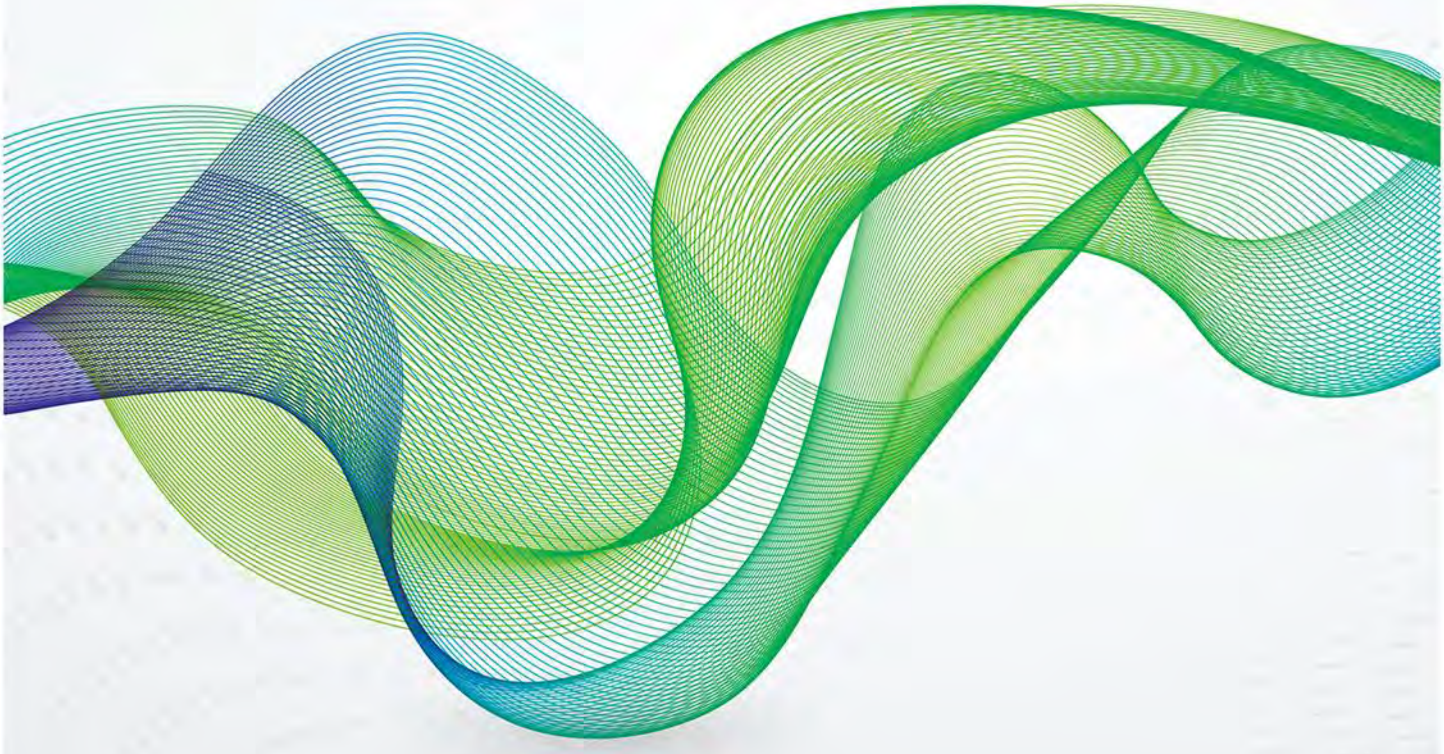
DOE Report on US LNG Exports: Implausible Scenarios and Flawed Assumptions



OIES ENERGY COMMENT

Mike Fulwood, Senior Research Fellow, OIES

Key Points

- The US Department of Energy (DOE) has published key scenarios on the outlook for US LNG exports which draw conclusions that are implausible and outliers in comparison with scenarios developed by industry players and reputable consultants, especially as regards the projected growth in LNG trade to 2050.
- The DOE scenarios include very aggressive growth in long-term gas demand in India and hence its LNG imports, much too high a level of LNG imports into Japan and China, as well as Argentina, Brazil and Pakistan. In addition, under the DOE scenarios, Russia and Central Asia begin importing large quantities of LNG and, even more bizarrely, Norway stops exporting pipeline gas to the EU and UK and instead ramps up LNG exports to over 150 bcm! These outcomes suggest a high degree of implausibility.
- The DOE scenario on which the key conclusions of the report rest, suggests that the unconstrained expansion of US LNG will increase gas demand in key LNG importing countries by displacing other fuels such as coal, oil and renewables. This is based on the cost assumptions in the model used (the Global Climate Analysis Model or GCAM) which would seem to be flawed since the full cost of delivering US LNG to Europe and Asia is in the \$10 to \$11 per MMBTU range, based on the Henry Hub prices from the DOE scenarios. The only way that an expansion of LNG exports would lead to a displacement of coal and oil would be to drive spot gas prices down to very low levels – maybe \$5 or less – as we saw in 2019. In order to displace renewables, these prices would need to be sustained for a long period, which would make US LNG uneconomic.
- Under the scenarios, the unconstrained expansion of US LNG also leads to the displacement of LNG exports from the rest of the world in key LNG importing countries by US cargoes. Again, the cost assumptions in GCAM would seem to be flawed to achieve this result, since a significant proportion of the LNG displaced by US LNG is from the Middle East, mainly Qatar, with a delivered cost, to Europe and Asia, which is half the delivered cost of US LNG.

1. Introduction

In mid-December, the US Department of Energy (DOE) finally published its long-awaited report on the Energy, Economic and Environmental Assessment of US LNG Exports[1]. The report consists of a summary and four appendices, contains a vast amount of data and comes to a number of key conclusions. This brief Comment will focus on two aspects and conclusions:

1. In comparison to the scenario where only existing US plants, plus those which have taken FID, are assumed to operate, the Defined Policies scenario with unconstrained US LNG exports results in Henry Hub prices being some 31% higher in 2050 (\$4.62 per MMBTU compared to \$3.53 per MMBTU in the existing and FID plants scenario at real 2022 prices). The modelled price increase is equivalent to about \$0.03/MMBtu for every Bcf/d of increased LNG export above existing and FID levels.
2. The Defined Policies scenario with unconstrained US LNG exports leads to an *increase* in GHG emissions compared to the existing and FID plants scenario. This seemingly happens because the much higher level of US LNG exports, displaces not only gas production in other countries but also leads to an increase in gas demand, with gas displacing some coal and oil but renewables as well. It is presumably largely the displacement of renewables with US LNG which leads to the higher GHG emissions.

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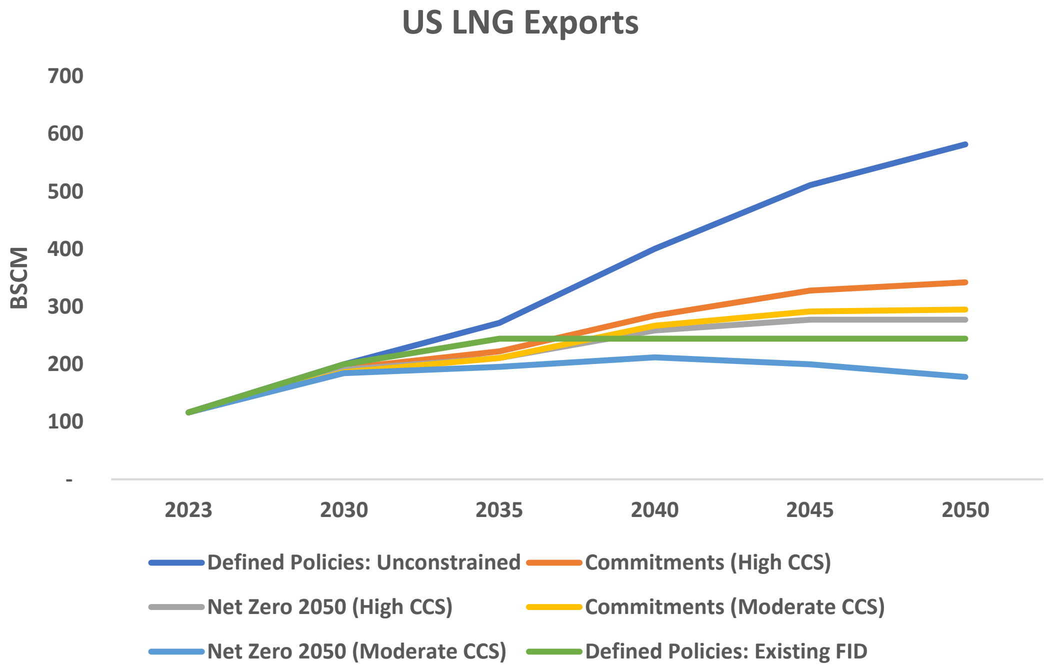
[1] ENERGY, ECONOMIC, AND ENVIRONMENTAL ASSESSMENT OF U.S. LNG EXPORTS, US Department of Energy, December 2024

The conclusions of the report – higher US domestic prices and more GHG emissions with much higher US LNG exports – would seem to fit the narrative the outgoing Democratic administration would have wanted. However, that does not mean these conclusions are credible.

The conclusion, that much higher US LNG exports would lead to higher Henry Hub prices, would seem to be reasonable. The issue relates more to the magnitude of the increase, which in turn relates to the Defined Policies unconstrained US LNG exports scenario, which incorporates implausibly high levels of US LNG exports.

The DOE report considers a number of scenarios for US LNG exports, as shown in Figure 1. The scenarios are fully defined in the DOE report. The analysis in this Comment will focus on the Defined Policies scenarios which will be referred to as Defined Policies: Unconstrained[2] and Defined Policies: Existing FID. In the latter case US LNG exports level out at just over 240 bcm while in the unconstrained case they reach over 580 bcm by 2050.

Figure 1: US LNG Export Scenarios



Source: US DOE Report

The report uses the Global Change Analysis Model (GCAM) to develop the scenarios. A more detailed description of GCAM is contained in the report. The report includes considerable amounts of data on the outputs of the scenarios but there is almost no information on the key assumptions, particularly in respect of the cost assumptions. The report notes[3] that *the demand for U.S. LNG exports in turn depends on its competitiveness relative to other sources of natural gas such as LNG from other major natural gas producing regions, availability and competitiveness of pipeline gas, and availability and competitiveness of domestic natural gas resources*. However, it is not possible to ascertain from the report what the key cost assumptions for those alternatives are. These are critical in respect of understanding how US LNG exports might displace gas production in other countries, lead to an increase in gas demand and also displace other fuels including renewables. This will be explored further in the Flawed Assumptions section. Firstly, the Defined Policies: Unconstrained and Defined Policies: Existing FID scenarios will be reviewed.

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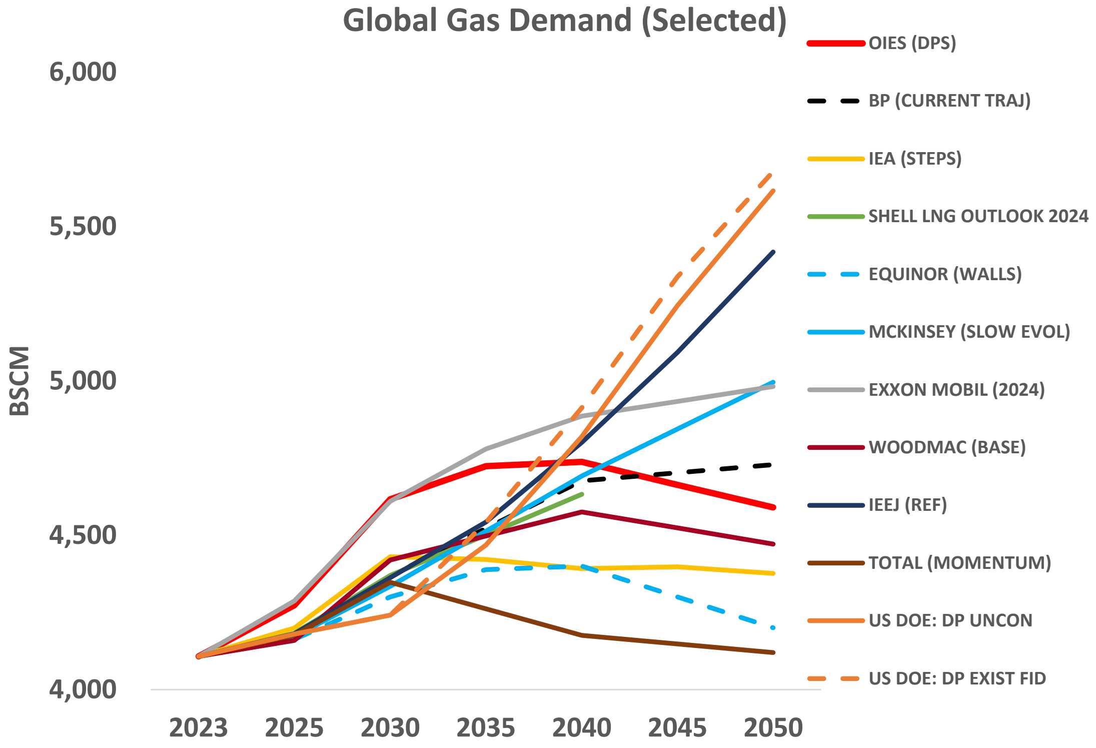
[2] This is Defined Policies: Model Resolved in the DOE report

[3] Appendix A page A-10

2. Implausible Scenarios

In the report, the Defined Policies: Unconstrained scenario using the GCAM resolves with US LNG exports unconstrained. Figure 2 below compares the two Defined Policies[4] scenarios with a number of recent scenarios, including the IEA STEPS and the OIES Declared Policies scenario. All these scenarios are not decarbonisation scenarios and certainly are nowhere near to achieving net zero. They might be broadly categorised more as "business as usual" or based on existing policies, which have some decarbonisation elements.

Figure 2: Global Gas Demand Scenarios



Source: DOE Report, IEA and various industry sources

The scenarios include recent ones from Shell, BP, Total, ExxonMobil and Equinor as the LNG industry players, as well as Woodmac, S&P Global and McKinsey as consultants and the IEEJ from Japan. The DOE scenarios are the only ones, apart from IEEJ which have global gas demand rising above 5,000 bcm in the period to 2050. ExxonMobil and McKinsey get close to that level by 2050 but the other scenarios peak in the 2030s or 2040s at 4,700 bcm or less. The IEA STEPS plateaus around 4,400 bcm with the OIES DPS peaking at over 4,700 bcm in the 2030s before declining slightly to 4,600 bcm by 2050.

The DOE scenarios have lower global gas demand than other scenarios through the early 2030s, before accelerating sharply thereafter. By 2050 the DOE scenarios are over 5,600 bcm compared with 4,700 for BP and 4,600 for OIES – some 20% or so higher. While the DOE scenarios are on the high side, relative to the "industry", they could be seen as being reasonably plausible at the global level. Looking at some of the individual countries, the DOE scenarios have China gas demand at over 600 bcm in the 2040s, which is a bit higher than other scenarios but not necessarily out of line with internal China projections. In the case of India, the DOE scenarios have demand at around or over 400 bcm by 2050 (2023 demand was 67 bcm),

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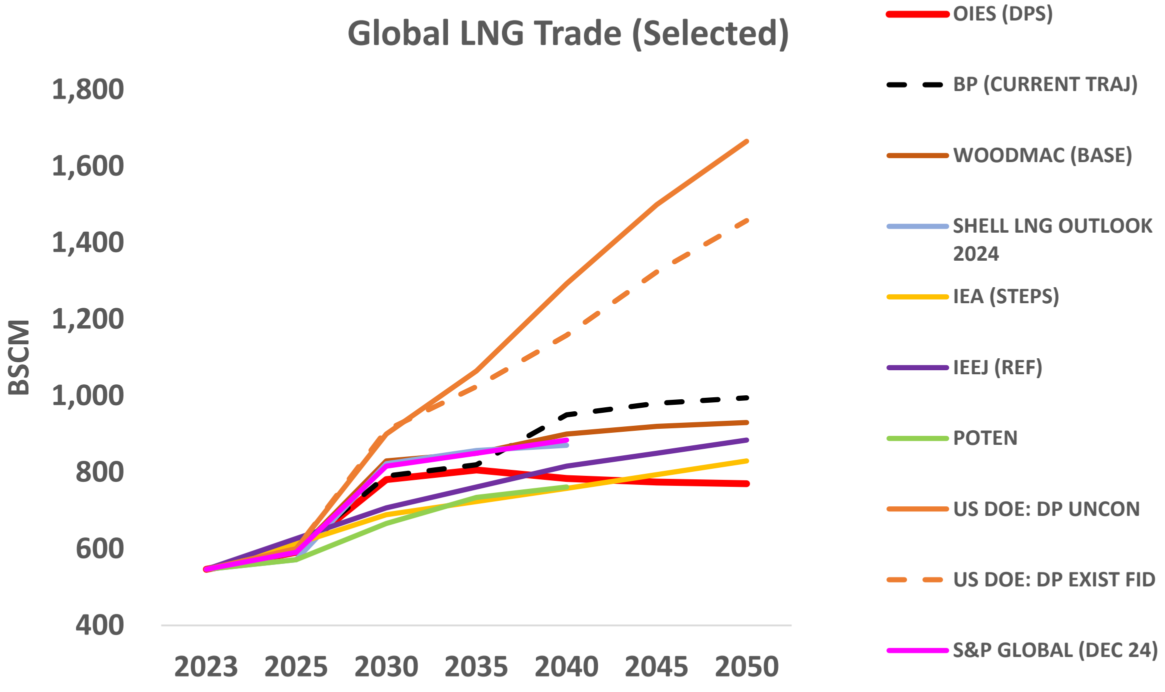
[4] The DP Exist FID scenario has slightly higher global gas demand than the DP Uncon scenario which seems odd as global LNG trade is much higher and gas demand is higher in the key LNG importing countries

which is considerably higher than almost all other scenarios and are definitely outliers. Japan demand also looks too high in the DOE scenarios, seemingly plateauing at some 125 to 135 bcm over the period, compared to current and declining demand of around 85 bcm. US demand also is projected to rise to around 1,100 bcm by 2050 (demand in 2023 was some 920 bcm)[5].

One of the problems of using GCAM may be that the model is calibrated to 2015 with the model parameters fitted to the IEA historical data. A lot has happened between 2015 and now, so projecting from 2015 means it is almost certain the model is diverging in its projections between 2015 and now compared to what has actually happened. This automatically builds in divergences which get amplified going forward.

Figure 3 shows the comparisons for LNG trade.

Figure 3: LNG Trade Scenarios



Source: DOE Report, IEA and various industry sources

There are fewer comparisons for LNG trade, but the DOE scenarios are significantly higher than industry and consultant scenarios, including IEA and OIES. LNG trade in the DOE DP Unconstrained scenario reaches over 1,650 bcm by 2050 and in the DP Existing FID over 1,450 bcm. The highest of the other scenarios – BP Current Trajectory – reaches just under 1,000 bcm by 2050, with other scenarios ranging between just under 800 bcm and just over 900 bcm. There is a degree of consensus, through to 2040, amongst Shell, Woodmac and S&P Global (in its most recent report), with LNG trade reaching some 900 bcm or just below that. The Woodmac base case then plateaus thereafter, reaching some 930 bcm by 2050. These 2040 and 2050 levels are somewhat higher than our OIES DPS, which may reflect our more sanguine view on China and India demand (especially India, where we are at the pessimistic end of gas demand). The Shell, Woodmac and S&P Global scenarios however are extremely plausible and the higher level of LNG trade than our OIES DPS and IEA STEPS can be easily explained.

In contrast, the DOE DP Unconstrained LNG trade scenario is some 80% higher by 2050 than, for example, the Woodmac scenario, with the DP Existing FID some 60% higher. The problems with the DOE scenarios

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[5] The US demand numbers coming out of GCAM are at odds with the numbers in Appendix B of the report, which is the domestic US analysis the DOE National Energy Modelling System, where gas demand in 2050 is around 820 bcm.

relate to the level of LNG trade, even in the DP Existing FID case and then the spread between the two DOE scenarios. The following are some key issues and highlights in relation to LNG imports in the DOE scenarios:

- China's LNG imports rise to almost 300 bcm by 2050 in DP Unconstrained, representing 45% of total China gas demand (slightly less in DP Existing FID). The 45% level is reached in 2025 with LNG imports at some 219 bcm – LNG imports are currently less than half that level. The 2050 level of just under 300 bcm is much higher than China production of 227 bcm. This seems highly unlikely from a Chinese government policy perspective, even if the level of China's gas demand in the DOE scenarios is reasonable.
- Japan's LNG imports average between 120 and 130 bcm over the 2025 to 2050 period, whereas they are now declining at around 85 bcm.
- India's LNG imports reach 260 bcm in DP Unconstrained and 230 bcm in DP Existing FID. These reflect the very aggressive gas demand growth in the scenarios and as noted earlier and are definite outliers.
- Argentina's LNG imports reach some 42 bcm in DP Unconstrained and Brazil's some 90 bcm. In both countries, domestic production barely increases, which doesn't seem credible given their abundant gas reserves, particularly Argentina.
- Pakistan LNG imports reach some 75 bcm in 2050 in DP Unconstrained – imports at present are less than 10 bcm and while some increase is expected, affordability tests the credibility of this projection.
- Europe is importing over 200 bcm of LNG in 2050 in DP Unconstrained and some 30 bcm less in DP Existing FID, but this seems to be a consequence of importing little or no pipeline gas from Norway, as Norway switches to exporting lots of LNG instead – see below.
- In a bizarre turn, Russia's LNG imports reach some 75 bcm in DP Unconstrained in 2050, which is three times higher than Russia's LNG exports. It is unclear what might drive Russia to import LNG.
- Even more bizarrely, Central Asia imports some 30 bcm of LNG in 2050 in DP Unconstrained despite being landlocked (apart from Georgia).
- All regions of Africa also import significant quantities of LNG, despite in some cases exporting LNG as well and having abundant gas reserves. Mexico's LNG imports also increase sharply, but neither DOE scenario has any LNG exports from Mexico.

There are also a number of problems in relation to LNG exports in the DOE scenarios:

- LNG exports from North Africa are projected to rise to over 150 bcm by 2050 in DP Unconstrained, several multiples of the current level, despite patchy resource depth and surging domestic demand growth, limiting gas available for LNG exports.
- There are almost no LNG exports from Southern Africa (which includes Mozambique and Tanzania) in either scenario, despite the region currently exporting from Coral FLNG and further facilities being built.
- The EU and Eastern Europe (defined as Belarus, Moldova and Ukraine) also export material quantities of LNG despite none of the countries having any LNG export facilities and no prospect of having any.
- While there are huge increases in US LNG exports in DP Unconstrained, Canada also sees LNG exports increase to 130 bcm by 2050. While some increase is likely this level seems implausible.

- LNG exports from the European Free Trade Association – in effect Norway – reach some 150 bcm by 2050 in DP Unconstrained – compared to 6 bcm at present. This level seems to be achieved by Norway stopping pipeline exports to the EU and UK and instead building multiple LNG export facilities, presumably sending some of this LNG to the EU! Maybe someone should notify the Norwegian Ministry of Energy to get their thoughts!
- Another region which supposedly is and will export LNG under the scenarios is South Asia, which in GCAM regions comprises Afghanistan, Bangladesh, Bhutan, Sri Lanka, Maldives and Nepal.

The above points on LNG imports and exports are just some of the key highlights, but the main point is that the levels of LNG imports and the source of LNG exports are not credible.

The difference between DP Unconstrained and DP Existing FID is a huge unconstrained rise in US LNG exports. The effect of this increase is twofold. Gas demand increases in LNG importing countries and US LNG also displaces LNG from other countries, leading to a decline in gas production in those countries. The analysis of what might drive these changes is discussed in the next section. The annual difference between US LNG exports in DP Unconstrained and DP Existing FID is some 150 bcm by 2040, 265 bcm in 2045 and 340 bcm by 2050. Around 60% of this increase seems to come from increases in gas demand in the LNG importing countries, notably in China, India, the EU and Japan, with just under 40% from the displacement of LNG from other exporting countries. This reduction in LNG from other exporting countries is across the board but notably LNG exports from the Middle East are some 40 bcm lower in the DP Unconstrained scenario than in the DP Existing FID scenario.

3. Flawed Assumptions

GCAM, from its description, appears to be driven by relative costs and technologies, so the gain in US LNG exports, both in displacement and gas demand increases is driven by relative costs. Unfortunately, no information is provided in the DOE report on the cost assumptions used in the GCAM, so we are very much in the dark as to how GCAM generated the gas demand increases in LNG importing countries and the displacement of LNG from other exporting countries by US LNG.

If the additional US LNG exports in the DP Unconstrained scenario are to increase gas demand in the LNG importing countries, then the LNG needs to displace other fuels, just over half of which seems to be renewables, followed by coal and then oil. The displacement of these other fuels, in the cost driven GCAM would only occur if the additional US LNG succeeded in reducing gas and LNG prices so that other fuels were displaced. By 2050 the Henry Hub price is $3.53 in DP Existing FID and $4.62 in DP Unconstrained, in real 2022 prices. Using the $3.53 as a basis for calculating the full delivered cost of US LNG to Asia and Europe, then the additional costs would be an extra 15% of Henry Hub for the cost of gas used in the liquefaction process ($0.50), the liquefaction capacity cost (say $2.50 to $3.00), the cost of shipping (some $1.50 to the Netherlands and $2.80 to Japan – depending on oil prices and tanker charter rates) plus the cost of regasification and entry to the pipeline system (assume some $0.45). The delivered cost of US LNG to Europe would be in the range $8.50 to $9.00 and to Japan in the range $9.80 to $10.30 - China and India would be another $0.20 higher. The higher $4.62 Henry Hub price would increase the delivered prices to Europe and Asia by another $1.25, raising the European delivered cost to around $10.00 and the Japan delivered cost to over $11.00.

The bulk of the increase in gas demand generated by the additional US LNG is in the Asian markets, notably China and India, with additional demand in Europe and also Argentina and Brazil. The output from GCAM is asking you to believe that $10 to $11 delivered US LNG to Asia can displace locally produced coal, or coal imported into Asian markets from neighbouring countries such as Indonesia and Australia. While displacement of oil might be possible – depending on the oil price – the displacement of coal seems unlikely at these prices. It can only be assumed that GCAM costs of delivered US LNG are much lower, unrealistically so. In respect of Europe, coal will have been largely eliminated from the energy mix by 2040, which means that any displacement by US LNG is likely to be renewables. Again, this seems unreasonable given a projected delivered cost of as much as $10 for US LNG to the European market.

The second element of the increase in US LNG exports between DP Unconstrained and DP Existing FID, is the displacement of LNG exports from other sources. A large proportion of the LNG is displaced from the Middle East, followed by North Africa, Canada and Australia, with smaller reductions from other sources. The market for that displaced LNG is Asia, from where some 60% of global demand is derived. It is particularly questionable that US LNG can displace Middle East LNG, predominantly Qatari LNG, in the Asian markets or indeed in European or other markets. Qatar LNG is particularly low cost, with the resource cost from the North field being very low because of the associated liquids, likely lower liquefaction capacity costs, and in respect of Asia at least, especially India, lower shipping costs. The delivered cost of Qatari LNG to Japan and Europe is likely to be in the $5 to $6 range, principally because of the very low resource cost – almost half the delivered cost of US LNG. North Africa LNG is principally destined for the European market, with low resource and shipping costs, while Australian LNG has the advantage of short shipping distances to Asian markets. Even Canadian LNG (West Coast) benefits from much lower shipping costs to the Asian markets than US LNG.

US LNG is relatively high-cost LNG in the current global market, especially if shipped to Asian markets, so it is difficult to see how $10+ LNG could displace other fuels in these markets and even displace much lower cost LNG from places such as Qatar. There have been episodes in the past, when low gas prices have led to an increase in the demand for gas relative to other fuels, notably in 2019 when a surge of LNG supply led to lower gas prices in Europe and Asia and coal to gas switching occurred (especially in Europe). Spot prices in Europe and Asia averaged around $5 per MMBTU in 2019 and were heading down, tipping below $3 in Europe even before Covid-19 hit. Spot prices at these levels also encouraged gas demand in the price-sensitive Indian market. Displacing coal and oil in the short term through lower prices, in fuel switchable markets, is one thing but displacing renewables is more of a long-term investment decision. While sustained prices at $5 to $6 per MMBTU might incentivise more gas-fired power, rather than renewables, these prices would destroy the long-term economics of US LNG – and most other LNG projects outside Qatar. Prices at $10 per MMBTU or above, however, seem unlikely to generate additional demand for gas.

The other element to note is that the LNG market remains heavily contracted and all the US plants are financed by long-term contracts. All the existing projects and those which have taken FID have long-term contracts. Even some of those yet to take FID have long-term contracts lined up in principle. In the DP Existing FID scenario, US LNG exports plateau at 244 bcm. By 2050 in the DP Unconstrained scenario, US LNG exports reach 582 bcm – some 338 bcm higher. Who will contract for this incremental volume? It is plausible that an additional 50 bcm could go to FID and be contracted and even slightly higher numbers but not an additional 300 bcm plus. The market for LNG needs to be established for contracts to be concluded.

The final element that should be mentioned is that the LNG market has an element of self-regulation, as we saw in 2020, a feature especially true for US LNG. In 2020, as Covid-19 hit demand, spot prices in Europe began to drop below $3 per MMBTU and by summer were below $2. This narrowed the spreads between TTF and Henry Hub to below $1.25, at which point US LNG began to be shut in and did not start returning until the last quarter of 2020 when differentials widened again. This exposes the dichotomy at the heart of the DOE report scenarios. It may require $5 or $6 spot prices in key markets to generate gas demand but with Henry Hub at $4.62 per MMBTU in 2050, the margins are very tight, suggesting that a lot of US LNG would simply be shut-in.

4. Conclusions

In launching the report on 17 December, the outgoing US energy secretary Jennifer Granholm declared that “We can now assess the future of natural gas exports based on the facts”. Unfortunately, even a brief review suggests the “facts” as outlined in the DOE report are much closer to fantasy, with implausible scenarios and flawed assumptions.

The two DOE scenarios discussed in this Comment are very much high outliers in comparison to other scenarios, principally generated by the industry and reputable consultants. The DOE scenarios contain a number of totally implausible outcomes in terms of LNG imports. In the DP Existing FID scenario, these include Russia importing some 58 bcm and Central Asia some 28 bcm, Europe’s LNG imports totalling some 175 bcm by 2050 as a result of Norway’s pipeline exports being replaced with LNG. Making sensible adjustments by eliminating Russia and Central Asia imports and reducing Europe’s LNG imports by reversing the phasing out of pipeline imports from Norway, would reduce global LNG imports by some 220 bcm. In addition, Japan’s LNG imports are some 40 bcm too high, Pakistan’s imports some 30 bcm too high, India maybe 80 bcm too high and Argentina and Brazil at least 100 bcm too high – making an additional 250 bcm to add to the 220 bcm for Europe, Russia and Central Asia. In DP Existing FID total LNG trade was 1,458 bcm in 2050, so taking off some 470 bcm would get trade below 1,000 bcm, which is towards the top end of the range of industry and consultant scenarios from Figure 3, but at least close to a plausible scenario.

To move from the DP Existing FID scenario to the DP Unconstrained, where total LNG trade is 200 bcm higher, requires gas to displace other fuels, notably renewables, in Asian and European markets. The cost assumptions which drive this in GCAM are not disclosed but based on realistic cost assumptions this does not seem plausible. If this increase in gas demand replacing renewables doesn’t happen then the conclusion, from the DOE report, that a large increase in US LNG exports would increase global GHG emissions, completely falls apart.

Finally, the idea that US LNG would displace LNG from other exporting countries, especially Qatar, on a relative cost basis, also seems unlikely, based on more realistic costs than those used in GCAM.

However, this does not mean that US LNG exports could not be higher than the existing plus FID projects. With global LNG trade reaching some 900 to 1,000 bcm by 2050, as opposed to the OIES DPS and IEA STEPS which are around 800 bcm in 2050, then there is scope for US LNG exports to be some 50 to 100 bcm higher. This is far short, however, of the DP Unconstrained scenario. Based on the DOE report assessment of the impact on Henry Hub prices of $0.03 per MMBTU for every 1 bcf/d of higher US LNG exports, this would increase prices by between $0.15 to $0.30 per MMBTU – a much more realistic assessment of the possible impact. Additionally, there would be no increase in GHG emissions and, to the extent that modestly higher US LNG did lead to some displacement of coal in power plants – driven by policy rather than relative costs – then GHG emissions would be lower.

Comparative GHG Footprint Analysis for European and Asian Supplies of USLNG, Pipeline Gas, and Coal

February 11, 2025

BRG | ENERGY & CLIMATE

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1. INTRODUCTION AND SUMMARY

The BRG Energy & Climate practice (BRG E&C) has undertaken an independent life cycle analysis (LCA) of greenhouse gas (GHG) emissions of U.S. liquefied natural gas (USLNG) and competing fossil fuels used for power generation in 13 global markets.[1] Under development since 2021, this analysis uses a comprehensive model constructed by BRG E&C to regularly quantify the GHG emissions volumes and intensity of the LNG and competing fuel supply-chains at a systemic level for major trade corridors.[2] The model utilizes rigorous, analytic LCA methodologies and continuously updated data and information from the best available sources.[3] BRG published its first comprehensive LCA analysis based on this model in April 2024 using the most up-to-date information and data available at that time on a full calendar year basis (generally 2022).

In this report, we have since updated this analysis using the most recently available calendar full-year data for (generally 2023) and have made some methodological enhancements to accommodate more precise information that has become available (specifically in relation to pipeline transport and LNG shipping). The results of this updated analysis are presented in this report.

Scope of Analysis

The LCA presented in this report focuses on two key GHGs—Carbon Dioxide (CO2) and Methane (CH4), collectively the "GHGs"—and evaluates their emissions volumes and intensity for the full supply chains (See Figure 1) of USLNG, pipeline gas, and coal (collectively "Primary Fuels"). Each supply chain spans from upstream production or extraction, through midstream infrastructure and/or shipping, to downstream combustion in power generation in the thirteen European and Asian end markets. The end markets are as follows (see Box 1):

- **Europe:** France, Germany, Italy, Netherlands, Poland, Spain, Türkiye, and United Kingdom (U.K.).
- **Asia:** China, India, Japan, South Korea, and Taiwan.

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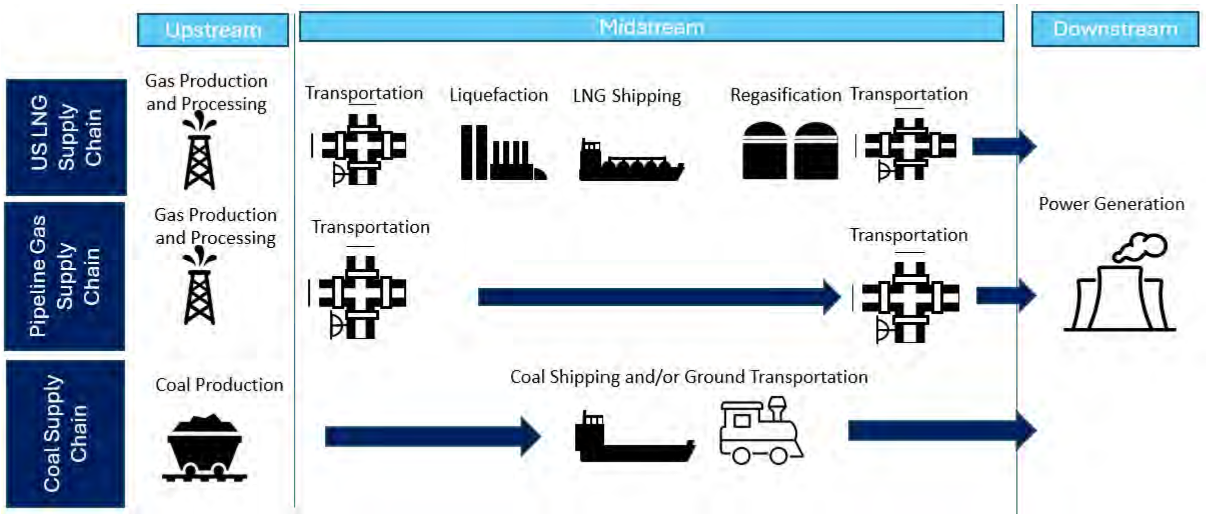
[1] We estimate the GHG emissions intensity of USLNG imports, Pipeline Gas imports and coal 2023 supply mix (including imports and domestic production). This work is underwritten by The USLNG Association (trading under the global brand name "LNG Allies").

[2] As such, this analysis does not analyze specific supply chains for individual companies or infrastructure but rather can be used as a benchmark for such analysis.

[3] This LCA is based on the latest available emissions information, which is for calendar year 2023. Our approach utilizes reported emissions data wherever publicly available and employs emission factors and estimations only to fill the gaps in publicly available data. The data was gathered from reputable sources among government agencies and multilateral organizations.

Figure 1: Scope of Supply Chain GHG Analysis

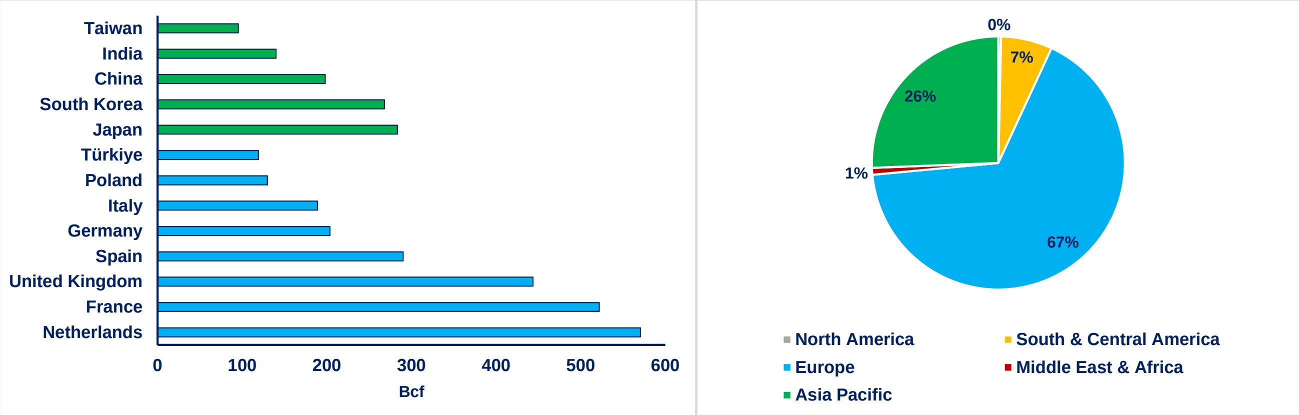


The analysis used the best and most current available data (generally from 2023) and converted CH4 emissions to a CO2 equivalent (CO2e) basis using the 20-Year Global Warming Potential (GWP20) of CH4 relative to CO2. As explained in Section 3, we used GPW-20 as the appropriate, “fit for purpose” metric to address the urgency of achieving substantial GHG reductions over the coming few decades, as compared to GPW-100 which is appropriate for longer-term analysis.

Box 1: Why these 13 countries?

USLNG exports from the contiguous 48 states began in Feb. 2016 and reached a 2023 high of 13.6 billion cubic feet per day (Bcf/d) in December 2023. In 2023, USLNG cargoes went primarily to Europe (67%) and the Asia Pacific (26%) with only small volumes flowing to the Americas (7%) and the Middle East & Africa (1%) (see Figure 2, right). The 13 markets analyzed in this study (eight in Europe and five in Asia, see Figure 2, left) represented 3.45 Tcf of USLNG exports in 2023, up from 3.10 Tcf in 2022.

Figure 2: 2023 USLNG Exports



For each of the 13 end markets covered in this report, the full life cycle GHG emissions of each competing fuel for electric power generation is analyzed as follows:

- **Imports of USLNG:** CO2 and CH4 emissions from feed-gas production in the United States through processing, pipeline transportation, LNG liquefaction, LNG tanker shipping, LNG regasification, downstream gas transport, and combustion for power generation.
- **Imports of Pipeline Gas (where available):** CO2 and CH4 emissions from the production, processing, transport, and combustion for power generation.[4]
- **Coal Supplies**: CO2 and CH4 emissions from the production, processing, transport, storage, shipping (where relevant), export/import, and combustion for power generation.

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[4] Upstream methane emissions for Pipeline Gas supply routes are taken by the IEA's Methane Tracker. IEA reports that: "Upstream includes all emissions from production, gathering, and processing on all onshore or offshore oil and gas facilities." See: https://www.iea.org/data-and-statistics/data-tools/methane-tracker (accessed March 2024).

Measurement of Fuel Supply Chain GHG Emissions

From mid-2021 through 2022, energy demand in Europe and Asia was primarily driven by the rebound in energy consumption following the deep downturn from the Covid-19 pandemic worldwide and the effects of the Russian energy curtailments before and after the invasion of Ukraine, which slashed Europe's energy supply, stimulated LNG imports, and led to a global LNG supply crunch and LNG price spikes worldwide.

In 2023, global gas and LNG prices moderated as markets began to re-equilibrate. Europe rebuilt its gas storage at a faster pace than many analysts had anticipated—aided to a large extent by USLNG exports to the continent—and slower energy demand growth in Asia attenuated competition for uncommitted LNG. Even so, average LNG prices remained elevated relative to much of the prior decade and global markets demonstrated tightness throughout 2024. Chinese and Indian demand growth returned to double-digit rates in the first half of 2024 and robust demand growth from emerging importers in southeast Asia and the Middle East further supported prices. Delays to several large-scale new liquefaction projects could result in further market tightness in the short-to-medium term.

Even during the energy security challenges of recent years, the climate change imperative has continued to produce significant decarbonization efforts in the electric power and industrial sectors. A critical initial requirement for GHG mitigation is the accurate estimation/measurement of emissions across fuel supply chains, including both CO2 and CH4.

Whereas governments and energy and industrial firms have been measuring and tracking CO2 and CH4 emissions for more than two decades;[5] there has been increasing focus on the material impact of CH4 emissions on the climate in recent years. When measured by the 20-year Global Warming Potential (GWP20), the per ton impact of CH4 is 82.5 times greater than the per ton impact of CO2 emissions.[6,7]

Given the urgency of decarbonization in the next few decades, several international organizations have called for coordinated efforts to measure/mitigate CH4 emissions in oil and gas production, coal mining, maritime transport, power generation, and industry. As a result, national, regional, and

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[5] The Kyoto Protocol, which was adopted in 1997 and entered into force in 2005, defined which GHGs to include in carbon accounting frameworks (including CO2 and CH4) and established a monitoring, review and verification system for the participating Parties (see here: https://unfccc.int/kyoto_protocol#:~:text=In%20short%2C%20the%20Kyoto%20Protocol,accordance%20with%20agreed%20individual%20targets.).

[6] GWP is a metric which represents the relative climate change impact of a GHG to its CO2 equivalent impact on global warming over a specified period. The GWP measures how much energy the emissions of 1 ton of a GHG will absorb over a given period, relative to the emission of 1 ton of CO2. The larger the GWP, the more the GHG warms the earth compared to the same volume of CO2 emissions over that period. Some international organizations use the GWP100 of 29.8x to account for CH4 emissions on an equivalent GWP basis with CO2. However, doing so on a 100-year basis would underestimate the near-term impact of CH4 emissions on global warming over the coming few decades. See: "Climate Change 2021, The Physical Science Basis", IPCC, 2021.

[7] The International Energy Agency reported in their annual global methane tracker report update, in March 2024, that global CH4 emissions from the energy sector remained near a record high in 2023. IEA Methane Tracker, 2024.

international efforts are targeting CH4 emissions, and this is one reason why natural gas producers and consumers are actively and aggressively addressing CH4 emissions.[8]

There are also pressing regulatory imperatives to accurately monitor, quantify, and abate emissions. In May 2024, the EU signed into law the EU Methane Emissions Regulation ("MER"), setting comprehensive, legally binding requirements to track and mitigate methane emissions for the first time. Upstream operators in the EU must begin implementing these requirements within 18 to 48 months of the Regulation's entry into force.[9] Additional restrictions on venting and flaring will tighten further by 2025 and 2027.

The new rules impose an obligation on EU-based importers to ensure that their suppliers meet equivalent standards. As of 1 January 2027, import contracts —whether new or renewed—must demonstrate that they adhere to the same MRV and methane mitigation practices that apply within the EU. In effect, this places the compliance burden on producers and exporters, who must provide verified data proving adherence to standards matching the EU's regulatory framework. The MER also imposes maximum methane intensity values from 2030 onwards.

If their LNG suppliers cannot demonstrate compliance with the stipulations of the MER, EU importers will be prohibited from finalizing new deals or extending existing ones. Moreover, individual EU member states will also have the power to impose (potentially very onerous) fines equal to a percentage of total global revenue on non-compliant suppliers—including those supplying LNG under existing contracts.

For LNG suppliers, the immediate concern will be how to establish data collection and verification systems that align with EU technical requirements. Most of the operational work, such as installing monitoring devices, training local personnel, and conducting regular inspections, will happen upstream, but the responsibility to prove compliance rests heavily on EU importers.

The focus on developing accurate measurements of CH4 emissions, in turn, is driving the rapid development of measurement technologies such as: ground monitors using gas spectrometers, aerial drones equipped with on-board gas analyzers, manned aircrafts with emissions cameras, and satellite emissions monitoring. Measurement technologies that operate at a large scale such as drones, aircrafts, and satellites are often referred to as "top-down" approaches. They vary in their ability to detect emissions at different temporal and spatial scales due to differences in their detection limit, meteorological conditions, and deployment frequency.

Satellite emissions monitoring involves sophisticated data analytics and processing to analyze oil and gas operations relatively consistently across national boundaries and international jurisdictions. This

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[8] CH4 (methane) is the principal component of natural gas and producers and consumers also have a financial incentive to minimize CH4 losses at all segments of the supply chain.

[9] Depending on whether the relevant assets are operated or non-operated.Operated assets are defined as a business or operating unit, which can be composed of several facilities or sites, including assets under the operational control of the operator. Non-operated assets are defined as assets which are not under the operational control of the operator.

is a new and rapidly evolving area for emissions measurement at a systemic level, comparable to the scope of this study.

Evaluating energy supply through the lens of GHG emissions intensity provides an important step towards the decarbonization of energy systems. Robust methodologies, enhanced data quality, and rigorous measurement and analysis of GHG emissions are crucial to achieving a comprehensive picture of the GHG footprint of energy supply chains overall and along each supply chain segment.

2. SUMMARY RESULTS

To provide a baseline to evaluate the challenges outlined above, this study provides an integrated analysis of CH4 and CO2 emissions across leading fuel supply chains (Coal, Pipeline Gas, USLNG) using the latest available data from reputable sources among government agencies and multilateral organizations in a detailed methodology designed to accurately compare the GHG intensity of these fuel imports and supplies for power generation in the selected nations.

Figure 3 and Figure 4 present our calculations of the full supply chain GHG emissions intensity of USLNG imports, Pipeline Gas imports, and Coal supplies to Europe and Asia, respectively.

Figure 3: GHG Emissions Intensity of USLNG, Pipeline Gas Imports, and Coal Supplies to Europe

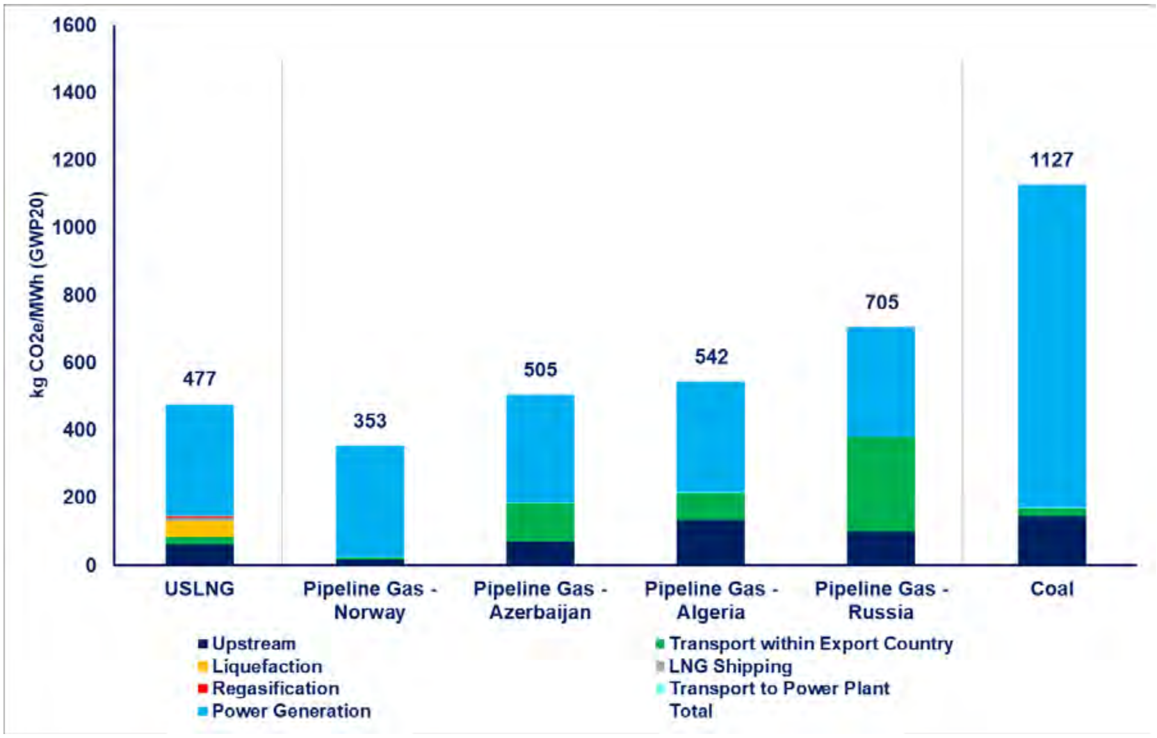
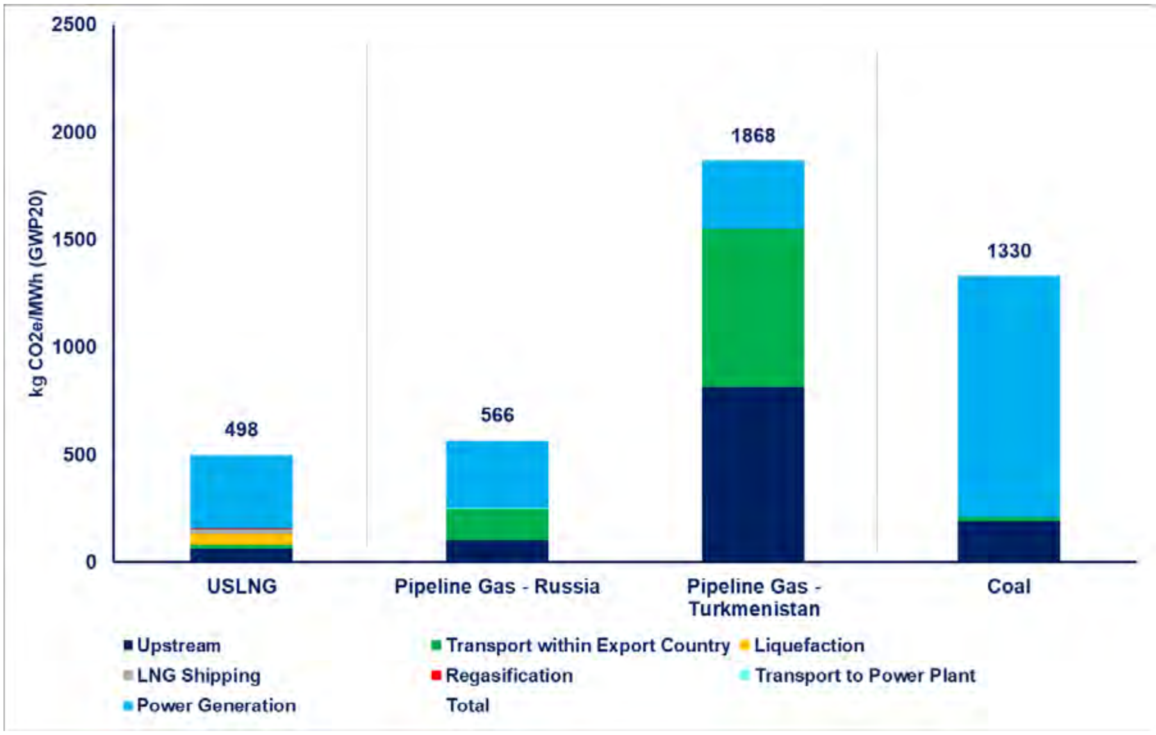


Figure 4: GHG Emissions Intensity of USLNG, Pipeline Imports, and Coal Supplies to Asia

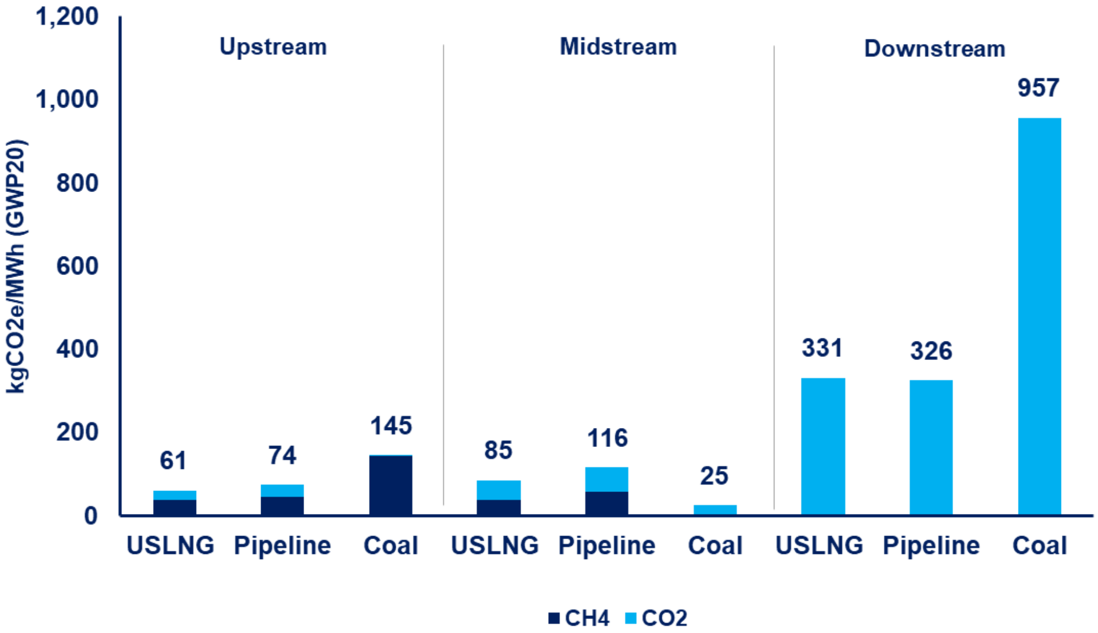


The results presented in Figure 3 and Figure 4 indicate that the GHG emissions intensity of:

- **Coal** was over twice as high as USLNG in both Europe and Asia.
- **Pipeline Gas in Asia** was more than three times higher than USLNG in the case of pipeline gas from Turkmenistan and slightly higher than USLNG for pipeline gas from Russia.
- **Pipeline Gas in Europe** was slightly more than half of USLNG for gas coming from Norway but a third higher than USLNG for gas coming from Russia.

Figure 5 and Figure 6 present the average breakdown of the GHG emissions intensity per primary fuel supply chain by CH4 and CO2 in Europe and Asia, respectively.

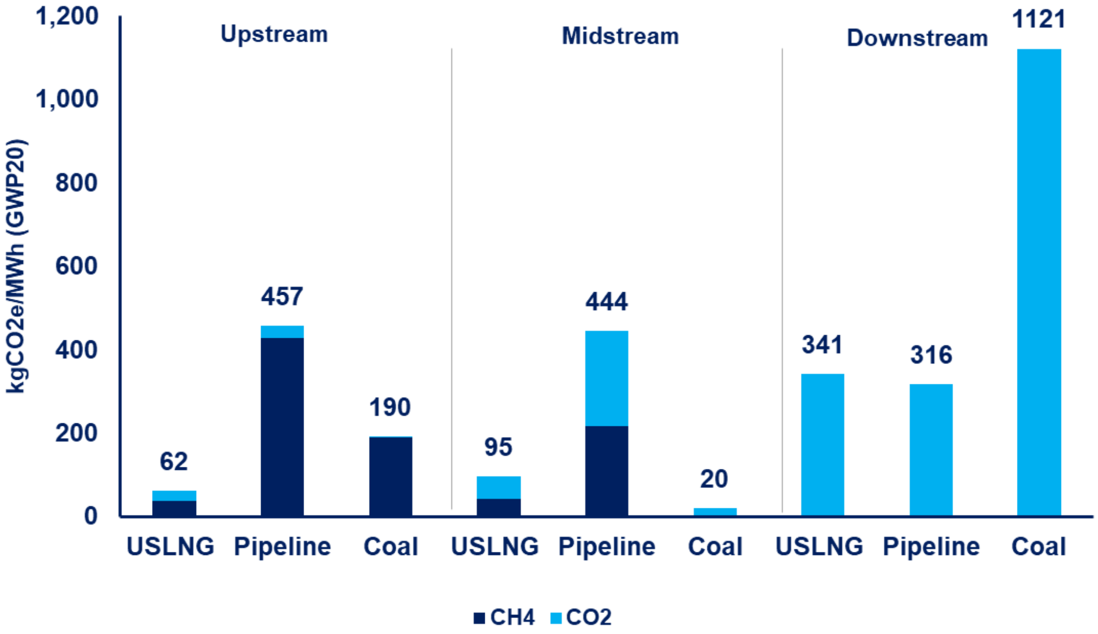
Figure 5: CH4 and CO2 Composition in the Primary Fuel Supply Chains to Europe



As illustrated in Figure 1:

- The "upstream" segments include production and processing for USLNG and Pipeline Gas and mining for Coal.
- For USLNG routes, the "midstream" segments include the transportation from production sites to liquefaction plants, the liquefaction process, shipping to destination countries, regasification, and pipeline transportation from import border to power station in the destination country. For Pipeline Gas import routes, the "midstream" segment represents the transportation to the export border and the transportation from import border to power station. For Coal supplies, "midstream" represents transportation via rail or ship from the production site to the import border and from there to power stations.
- For all Primary Fuels, the "downstream" segment represents natural gas consumption/combustion in the power sector of each destination country.

Figure 6: CH4 and CO2 Composition in the Primary Fuel Supply Chains to Asia



Box 2: What is different about this life cycle analysis?

Consistent with our study of 2022 data, the findings of this study differ significantly from the results of some other recent studies, which purport to show that the GHG emissions intensity of USLNG to be greater than that of coal when used to produce electricity. Our LCA differs from these studies in two principal respects:

- **Methodology:** This study employes a bottom-up methodology to arrive at a comprehensive comparison of the emissions intensity of the primary fuels for a specific historical time-period (2023) and specific trade corridors and supply chain segments. By comparison, the other studies are based on analyzing aggregated emissions information to develop general theoretical conclusions about the comparative GHG footprint of USLNG and coal supplies, without specific evaluation of regional, trade route, or timeframe distinctions.
- **Data Used:** To the greatest extent possible, we have used the most up-to-date emissions data and reported/measured emissions for each supply chain segment and delivery route. Other studies rely primarily on emission factors, many of which are outdated, as well as aggregated emission intensity results for gas and coal supply chains derived from other theoretical studies.

3. LIFE-CYCLE COMPARISON OF PRIMARY FUELS IN GLOBAL MARKETS

Approach

The study combines robust, commonly used methodologies for life-cycle emissions analyses with extensive literature review and the most recent, comprehensive, publicly available data to deliver a systemic evaluation of the full supply chain GHG emissions of Primary Fuel supply chains or trade corridors into the major USLNG importing markets.[10]

We calculate the GHG emissions intensity of each segment of the supply chain for all Primary Fuels, analyzed and presented in terms of kilograms of CO2e per megawatt hour (MWh) of electricity generation (kg CO2e/MWh). This metric represents the amount of CO2e emitted throughout each segment of the supply chain, from upstream production to final combustion for power generation, for each MWh of electricity generated. There are two important elements to note on the chosen metric:

- **Functional Unit:** Using the 1 MWh of electricity generated from each different fuel in each different destination as the “functional unit,” the analysis accounts for the different chemical characteristics of gas and coal, as well as the thermal efficiency characteristics of the power generation fleet of each destination country, namely the amount of energy used by a gas and coal power generation unit to produce one kWh of electricity (also known as a power generation “heat rate”). We note that there are other functional units commonly used to present full supply chain GHG emissions, such as MMBtu of fuel supply.
- **CO2 Equivalence:** In our analysis we calculate the CO2 and CH4 emissions in each segment of the supply chain. To account for these GHGs in an equivalent manner, we convert the CH4 emissions to their CO2 equivalent using the 20-year Global Warming Potential (GWP20) of CH4 relative to CO2. The GWP20 of CH4 used in this study is equal to 82.5, based on the latest report of the Intergovernmental Panel on Climate Change (IPCC).[11] In this analysis, we use GPW20 for CH4 emissions because we consider GWP20 as “fit for purpose” given the urgency of achieving substantial

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[10] The most recent data on CH4 and CO2 emissions used in this study are from 2023. There are instances where 2023 data is not available at the time of writing this report. For example, the latest update of emission factors for transport of natural gas was in 2019. In cases where 2023 data is not available, we use the next most recent data. See APPENDIX A for details of our data sources.

[11] Forster, P., T. Storelvmo, K. Armour, W. Collins, J.-L. Dufresne, D. Frame, D.J. Lunt, T. Mauritsen, M.D. Palmer, M. Watanabe, M. Wild, and H. Zhang, 2021: The Earth’s Energy Budget, Climate Feedbacks, and Climate Sensitivity. In Climate Change 2021: The Physical Science Basis. Contribution of Working Group I to the Sixth Assessment Report of the Intergovernmental Panel on Climate Change [Masson-Delmotte, V., P. Zhai, A. Pirani, S.L. Connors, C. Pean, S. Berger, N. Caud, Y. Chen, L. Goldfarb, M.I. Gomis, M. Huang, K. Leitzell, E. Lonnoy, J.B.R. Matthews, T.K. Maycock, T. Waterfield, O. Yelekci, R. Yu, and B. Zhou (eds.)]. Cambridge University Press, Cambridge, United Kingdom and New York, NY, USA, pp. 1017.

GHG reductions over the coming few decades, as compared to GPW100 which is more appropriate for longer-term analysis.

Box 3: Importance of Data Quality and Consistency

The results of this study (like all LCAs) depend upon the accuracy and consistency of the underlying emissions data for primary fuels that is available from public sources. To date, such data includes a mix of reported emissions and estimated emission factors.

The quality of GHG emissions measurement for specific energy production equipment and infrastructure across supply chains has been improving at a significant pace due to the development and proliferation of advanced technologies for ground level measurement and monitoring of GHGs with advanced sensors installed on critical equipment and/or aerial drones.

Further, for wider scale national and international systemic analysis, several independent entities already offer (or will soon provide) satellite imaging of GHG emissions enabling quantification of CH4 emission footprints of production areas, asset clusters, and transportation infrastructure across regions and countries.

It is possible that within a few years, accessing and analyzing such data can improve emissions measurements across regions, jurisdictions, and international boundaries to help level the playing field by providing for standardized quantification of the GHG emissions intensity of all fuel supply chains worldwide.

Methodologies

1.1.1 USLNG and Pipeline Gas imports

For the calculation of GHG emissions throughout the USLNG and pipeline gas supply chains, we used the commonly applied "mass balance" methodology.[12] This methodology is based on the following two principles:

- As gas flows through each part of the supply chain, from production all the way to final combustion for power generation, it is partially consumed to supply energy, and/or leaked, vented, or flared, such that the mass of natural gas decreases at each stage.
- GHG emissions depend on the quantity of gas flowing through each part of the supply chain.

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[12] Kirsten Rosselot, David T. Allen, and Anthony Y. Ku, "Comparing greenhouse gas impacts from domestic coal and imported natural gas electricity generation in China," in *ACS Sustainable Chem. Eng.* 2021, 9, 26, pp. 8759–8769.

The starting point of our methodology is the quantity (mass) of natural gas consumed at the power station of each destination country to generate 1 MWh of electricity, based on country-specific averages of powerplant heat rates. Following the principles outlined above, we work backwards to calculate the gas volumes from each preceding segment of the supply chain based on the chemical properties of natural gas and the losses incurred at each supply chain segment (i.e., the amount of gas consumed at each segment and/or the gas that is leaked, flared and/or vented).

In each segment of the USLNG and Pipeline Gas supply chains we calculated the GHG emissions intensity in kgCO2e/MWh of that segment, considering the quantity of gas necessary to produce 1 MWh of electricity in the destination country. Where applicable, we also summarize any methodological updates to our April 2024 study (for example, due to better data availability). Table 1 and Table 2 describe the methodology used in each segment of the USLNG and Pipeline Gas supply chains, respectively. Data sources used in our analysis are presented in Appendix A.

Table 1: USLNG Supply Chain Methodology

Supply Chain Segment	Methodology
Upstream Production and Processing	We use data from 2023 on GHG emissions during natural gas production and processing, in the four main U.S. gas production basins: Marcelus-Utica, Eagle Ford, Permian, and Haynesville. We estimate the origin and transportation routes of feed-gas, and we apportion the emissions from these basins to the seven U.S. large liquefaction plants (Sabine Pass, Corpus Christi, Freeport, Cove Point, Elba Island, Cameron, and Calcasieu Pass). We aggregate the CH4 and CO2 emissions of the seven liquefaction plants into three main exporting areas: o Gulf Coast Louisiana: Sabine Pass, Cameron, and Calcasieu Pass. o South Texas: Corpus Christi and Freeport. o East Coast: Cove Point and Elba Island.
Gas transportation from Production to Liquefaction	We calculate CH4 and CO2 emissions based on reported emission factors and adjustments for the distances covered in each route. To estimate the average distance traveled by the average molecule prior to liquefaction, we incorporate data from a recently published study analyzing the sources of gas supply to Cheniere's Sabine Pass and Corpus Christi liquefaction projects.[13]

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[13] See "Gas Pathing: Improved Greenhouse Gas Emission Estimates of Liquefied Natural Gas Exports through Enhanced Supply Chain Resolution", Selina A. Roman-White, Deeksha Mallikarjuna Prasanna, Amber McCullagh, Arvind P. Ravikumar, David Thomas Allen, Kavya Chivukula, Harshvardhan Khutal, Paul Balcombe, Gregory Ross, Brad Handler, Morgan Bazilian, and Fiji C. George. ACS Sustainable Chemistry & Engineering 2024 12 (46), 16956-16966. DOI: 10.1021/acssuschemeng.4c07162

Liquefaction	We calculate the CH4 and CO2 emissions during liquefaction based on emission factors.
Shipping	We calculate CH4 and CO2 emissions for LNG shipping based on actual emissions measurements for a specific voyage (as recorded for a recent peer-reviewed academic study), adjusted to account for the number and type of actual LNG carrier voyages that took place in 2023 between loading ports in the United States and discharge ports in each of the 13 countries analyzed. In our updated analysis, we have improved our coverage of the global LNG tanker fleet and, to the furthest extent possible, analyzed every shipment of LNG to each of the 13 destination markets on an individual basis.[14]
Regasification	We calculate the CH4 and CO2 emissions during regasification based on emission factors and adjusted for the heat rate of gas power generation at each destination country.
Gas Transportation to Powerplant	Like gas transportation from the production site to the liquefaction plant, for downstream gas transportation from regasification to the powerplant, we use reported emission factors and adjust for distances covered in each route.
Gas Combustion for Power Generation	In the power generation sector, we consider only CO2 emissions from the combustion of natural gas. We calculate CO2 emissions considering the specific heat rate of the power generation sector of each destination country in 2023.

Table 2: Pipeline Gas Supply Chain Methodology

Supply Chain Segment	Methodology
Upstream Production and Processing	For Pipeline Gas supplies to the destination countries, we first select the main origins of supplies to each country, focusing on gas imports in 2023 (where applicable). For Europe, the main sources of Pipeline Gas supplies in 2023 were Russia, Norway, Algeria and Azerbaijan. For Asia, China imported Pipeline Gas from Turkmenistan and Russia in 2023. We calculate the CH4 emissions during gas production, CO2 emissions from flaring, and CO2 emissions that occur in the processing stage in each supply origin country.

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[14] We exclude small-scale LNG and bulk-breaking of cargoes due to insufficient technical information regarding the emissions profiles and engine parameters of these vessels.

Gas transportation from Production Border	We calculate CH4 and CO2 emissions based on reported emission factors and adjust for the distances covered in each route.
Gas Transportation from Border to Power Plant	Following the same methodology as for the transportation from production site to export border, we calculate both CH4 and CO2 emissions based on reported emission factors and adjustments for the distances covered in each route.
Gas Combustion for Power Generation	Following the same methodology used for the USLNG supply chain routes, we calculate CO2 emissions for power generation based on our calculation of the country-specific heat rates of gas power generation in 2023.

1.1.2 Coal Supply Chain

To calculate total GHG emissions throughout the full supply chain for Coal, we analyzed each segment separately, based upon the amount of coal consumed to generate 1 MWh of electricity in each destination country. The main GHG emitted during the coal mining phase is CH4, whereas during the transportation and combustion phases, the main GHG emitted is CO2. Our methodology for the calculation for coal is presented in Table 3.

Table 3: Coal Supply Chain Methodology

Supply Chain Segment	Methodology
Upstream Coal Mining	To calculate CH4 emissions for the 2023 Coal supply mix, we performed a comprehensive Coal supply analysis for each destination country to determine the amount and origin of imported Coal and the amount of domestically produced Coal.[15] Then, we used data on CH4 emissions from coal mining in each coal supply source country to quantify the CH4 emissions intensity of each coal supplier for each destination country.

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[15] Coal supply mix information by country comes from UN Comtrade. Due to a lack of available information on Taiwan's coal supply mix, Japan and South Korea's coal supply mixes are averaged and then scaled based on energy consumption from Ember to create a representative coal supply mix for Taiwan. The UN Comtrade database we used does not differentiate between thermal and metallurgical coal imports. We assume that all imported coal is used in power generation.

Coal transport to export border	Because inland rail is the most common means of transportation for coal,[16] we consider that coal is primarily transported by rail from the mine to the export border of the supply source countries. We calculated CO2 emissions based on emission factors for rail transport adjusted for distances covered in each route.
Coal transport from origin export border to destination import border	We estimated the shipping emissions of transporting coal overseas based on reported CO2 emission factors for dry bulk carriers.
Coal transport from import border to power station	Using the same approach employed for CO2 emissions for transportation from the mine to the export border, we estimated CO2 emissions based on emission factors for rail transport adjusted for the distances covered in each route.
Coal Combustion for Power Generation	For emissions from power generation, we calculated the CO2 emissions from the coal combustion based on the specific heat rate of the coal power generation sector of each destination country in 2023.

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[16] See: "The ultimate guide to coal mining and transportation: Processes, Techniques, and Environmental Impact", May 2023, Skillings Mining Review https://skillings.net/the-ultimate-guide-to-coal-mining-and-transportation-processes-techniques-and-environmental-impact/

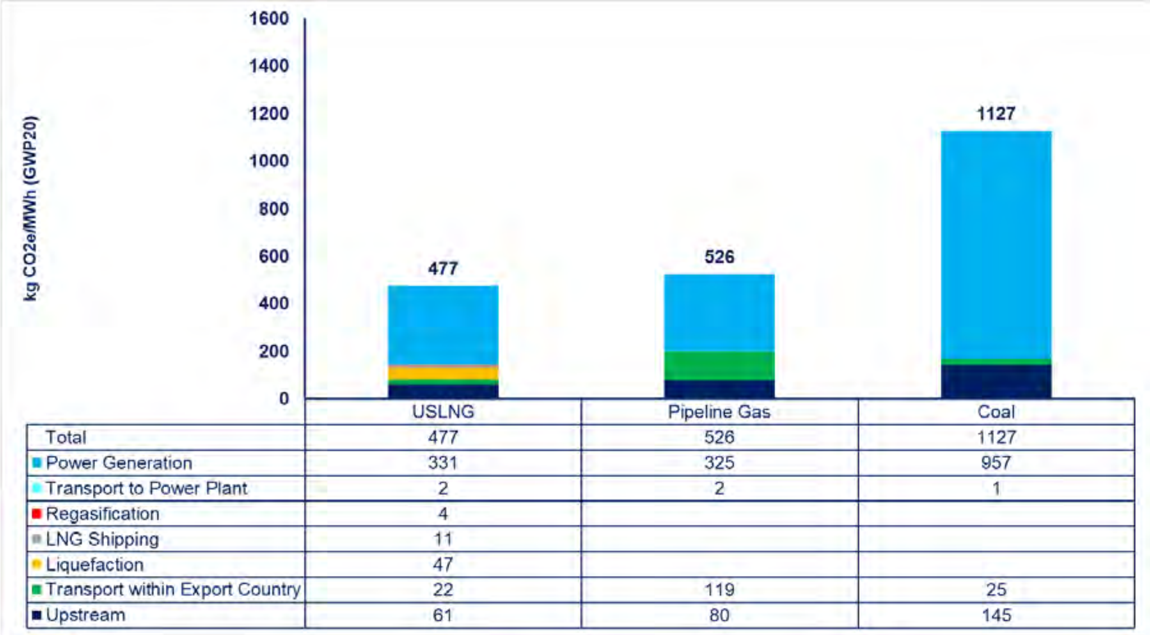
4. RESULTS AND CONCLUSIONS

GHG Emissions Intensity of USLNG, Pipeline Gas and Coal supplies to Europe and Asia

This section presents our aggregated results on the GHG emissions intensity of Primary Fuels in the European and Asian destination countries we analyzed. We present the breakdown of GHG emissions intensity by supply chain segment and the composition ratio of CH4 and CO2 emissions from each supply segment.

Figure 7 and Figure 8 compare the average GHG emissions intensity for USLNG, Pipeline Gas, and Coal imports and supply in Europe and Asia, respectively.[17]

Figure 7: Comparison of GHG emissions intensity of Primary Fuels in Europe (GWP20)



	USLNG	Pipeline Gas	Coal
Total	477	526	1127
🟦 Power Generation	331	325	957
🟦 Transport to Power Plant	2	2	1
🟥 Regasification	4		
⬜ LNG Shipping	11		
🟨 Liquefaction	47		
🟩 Transport within Export Country	22	119	25
⬛ Upstream	61	80	145

The results in Figure 7 indicate that for power generation in Europe the GHG emissions intensity of USLNG is 477 kgCO2e/MWh, which was:

- 58% lower than the 1,127 kgCO2e/MWh for Coal.

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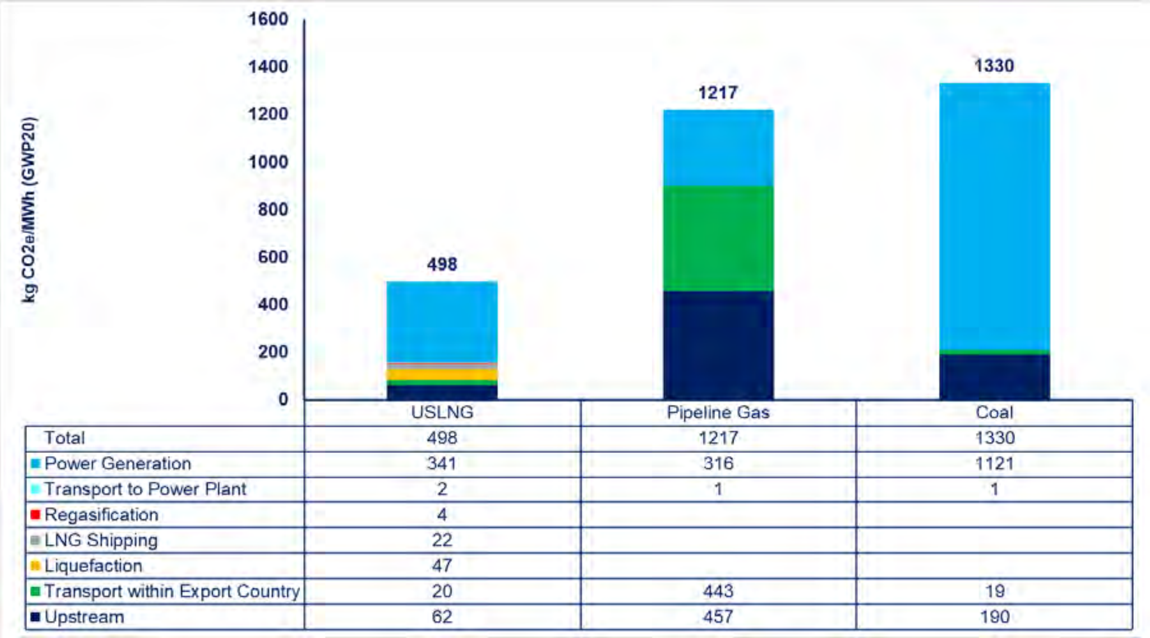
[17] In the following figures, USLNG represents an average of GHG emissions intensity of USLNG from three main production areas: Gulf Coast, East Coast, and South Texas. The GHG emissions intensity of each primary fuel supply route corresponds to the simple average of GHG emissions intensity of routes to the following destinations: Netherlands, Germany, United Kingdom, Italy, Spain, France, Türkiye, and Poland ("Europe") and China, India, Japan, Korea, and Taiwan ("Asia"). For USLNG and Pipeline Gas, we consider the GHG emissions intensity of imports to the countries analyzed. For coal, we consider the GHG emissions intensity of the 2023 supply mix in each destination, including domestic production. The segment "Transport within Export Country" includes emissions from shipping in cases of overseas coal transport.

- 9% lower than the 526 kgCO2e/MWh for the main sources of pipeline imports (which vary widely).

More specifically, the GHG emissions intensity of USLNG is 32%, 12%, and 6% lower than that of Pipeline Gas from Russia, Algeria, and Azerbaijan, respectively, but 35% higher than that of Pipeline Gas from Norway.

Figure 8: Comparison of GHG emissions intensity of Primary Fuels in Asia (GWP20)



	USLNG	Pipeline Gas	Coal
Total	498	1217	1330
■ Power Generation	341	316	1121
■ Transport to Power Plant	2	1	1
■ Regasification	4		
■ LNG Shipping	22		
■ Liquefaction	47		
■ Transport within Export Country	20	443	19
■ Upstream	62	457	190

By comparison, the average results in Figure 8 indicate that for power generation in Asia, the GHG emissions intensity of USLNG imports of 498 kgCO2e/MWh, which was:

- 63% lower than that of Coal supplies of 1,330 kgCO2e/MWh.
- 59% lower than the GHG emissions intensity of pipeline imports of 1,217 kgCO2e/MWh.[18]

Figure 7 and Figure 8 also indicate that the GHG emissions intensity of Coal combustion for power generation was around triple that of gas in both Europe and Asia, clearly demonstrating the superiority of combustion efficiency of natural gas compared to coal and therefore the higher heat rates of natural gas power stations compared to coal power stations. On average, for natural gas,

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[18] The GHG emissions intensity of Pipeline Gas in Asia exceeds USLNG imports and even that of coal supplies because of the very high CH4 emissions reported for the upstream and domestic transportation segment of Pipeline Gas from Turkmenistan to China.[18] The GHG emissions intensity of Pipeline Gas in Asia exceeds USLNG imports and even that of coal supplies because of the very high CH4 emissions reported for the upstream and domestic transportation segment of Pipeline Gas from Turkmenistan to China.

Europe and Asia had similar heat rates, and, therefore, the GHG emission intensity levels. The average heat rate for coal power generation in Asia was on average lower than that in Europe, resulting in higher GHG emissions intensity in Asia in this supply chain segment.

The supply chain composition of emissions intensity results also varied between the European and Asian power generation end markets. Figure 9 and Figure 10 present the average breakdown of GHG emissions intensity along the upstream, midstream, and downstream supply chain segments for USLNG, Pipeline Gas imports, and Coal supplies to Europe and Asia, respectively.

Figure 9: Breakdown of GHG Emissions Intensity Across Supply Chain Segments in Europe

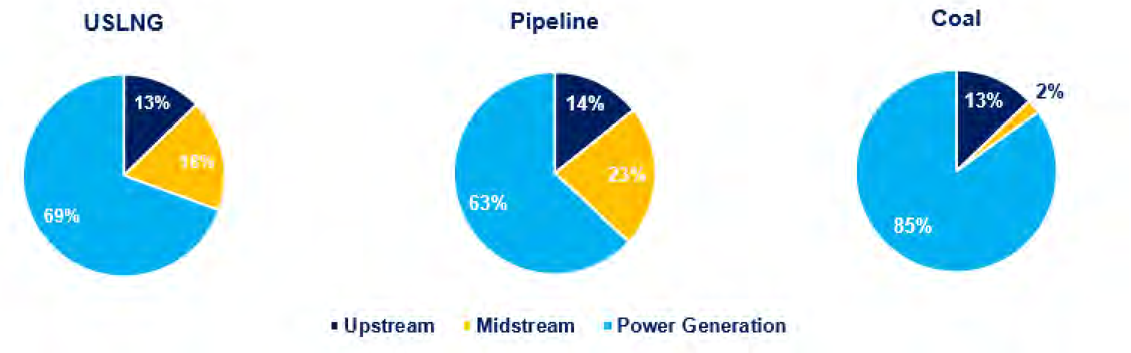

Figure 10: Breakdown of GHG Emissions Intensity Across Supply Chain Segments in Asia

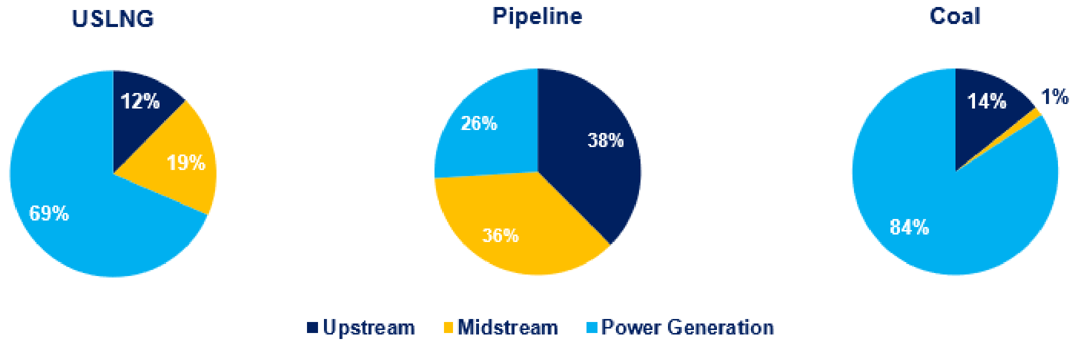

Figure 9 and Figure 10 indicate that:

- **USLNG:** For USLNG supply chains to Europe and Asia, some 69% of the GHG emissions intensity was concentrated in the power generation segment, with approximately 12% to 13% of emissions in upstream, and the remaining 18% to 19% in the midstream segment.

- **Pipeline Gas:** The GHG emissions intensity breakdown for Pipeline Gas imports to European destinations was similar to that of USLNG imports, with about 63% of emissions intensity concentrated in the power generation segment, 14% in the upstream, and 23% in the midstream. In sharp contrast, around 38% of the emissions intensity of Pipeline Gas imports to Asia was concentrated in upstream operations, 36% in midstream, and 26% in power generation.
- **Coal:** For Coal supplies to Europe and Asia, the vast majority of GHG emissions intensity was concentrated in the power generation sector, 85% and 84%, respectively, followed by 13% to 14% in upstream operations, and only 1% to 2% in the midstream segment.

Figure 11 and Figure 12 present the average breakdown of GHG emissions intensity by CH4 and CO2 in Europe and Asia, respectively.

Figure 11: CH4 and CO2 Composition in the Primary Fuel Supply Chains to Europe

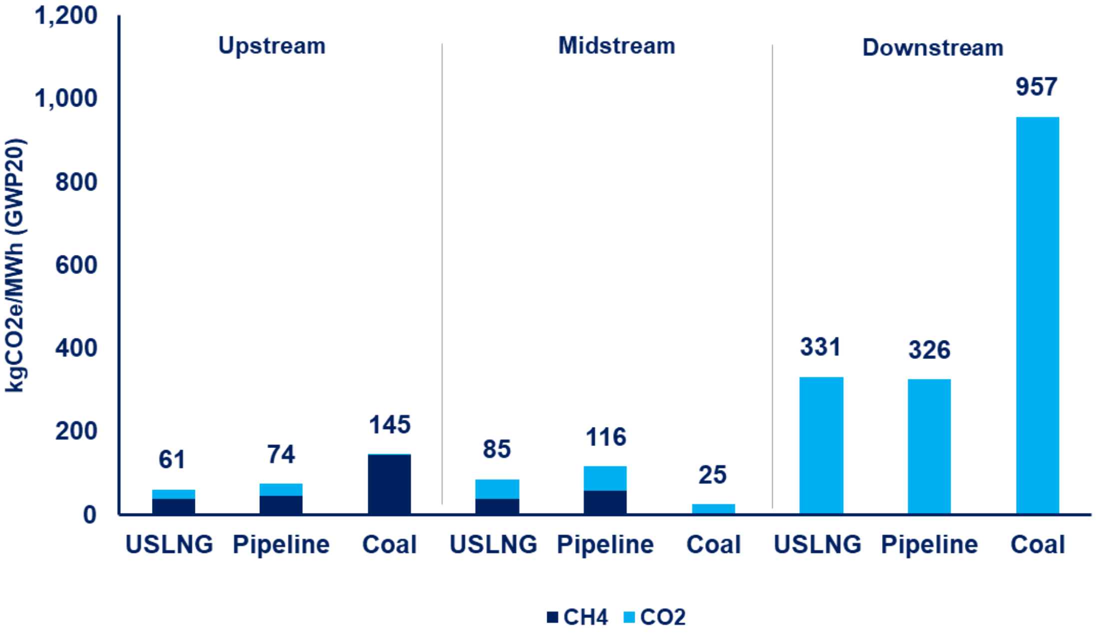

Figure 12: CH4 and CO2 Composition in the Primary Fuel Supply Chains to Asia

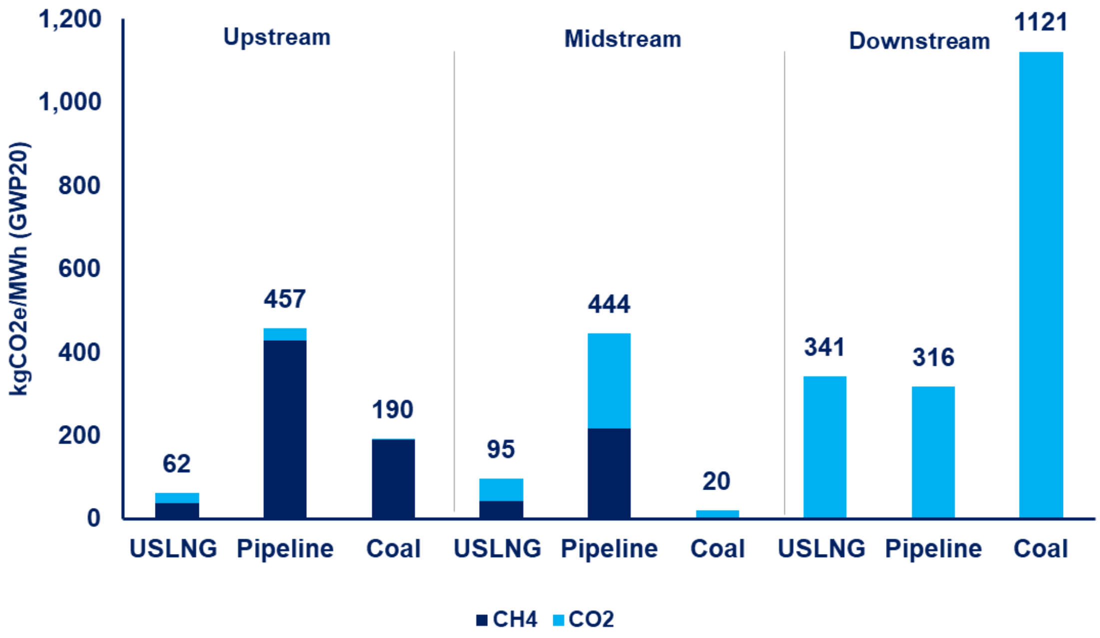

Figure 11 and Figure 12 suggest that for:

- **Upstream Segments**, the GHG emissions intensity of USLNG imports to Europe and Asia was roughly balanced between CH4 and CO2. By comparison, the GHG emissions intensity of Pipeline Gas imports to Europe and Asia was dominated by CH4 emissions from gas production and processing. Finally, the GHG emissions intensity of Coal supplies was 100% composed of CH4 emissions from coal mining.
- **Midstream Segments**, the GHG emissions intensity of USLNG and Pipeline Gas imports to Europe and Asia was composed of a balance of CH4 and CO2. By comparison, the GHG emissions intensity of Coal supplies to Europe and Asia was dominated by CO2 emitted during combustion in transportation carriers (rail and/or vessels).
- **Downstream Segments** are dominated by CO2 emissions for all fuel supply chain routes, driven by substantial emissions from combustion in power generation stations, especially for Coal. Therefore, the downstream GHG emissions intensity is solely comprised of CO2 emissions.

Figure 13 provides the global average breakdown of GHG emissions intensity into CO2 and CH4 for just the upstream and midstream segments of the supply chain (i.e., production, transportation, and delivery to the European and Asian border points of import) of Primary Fuel supplies.

Figure 13: Breakdown of Upstream and Midstream GHG Emissions Intensity (GWP20)

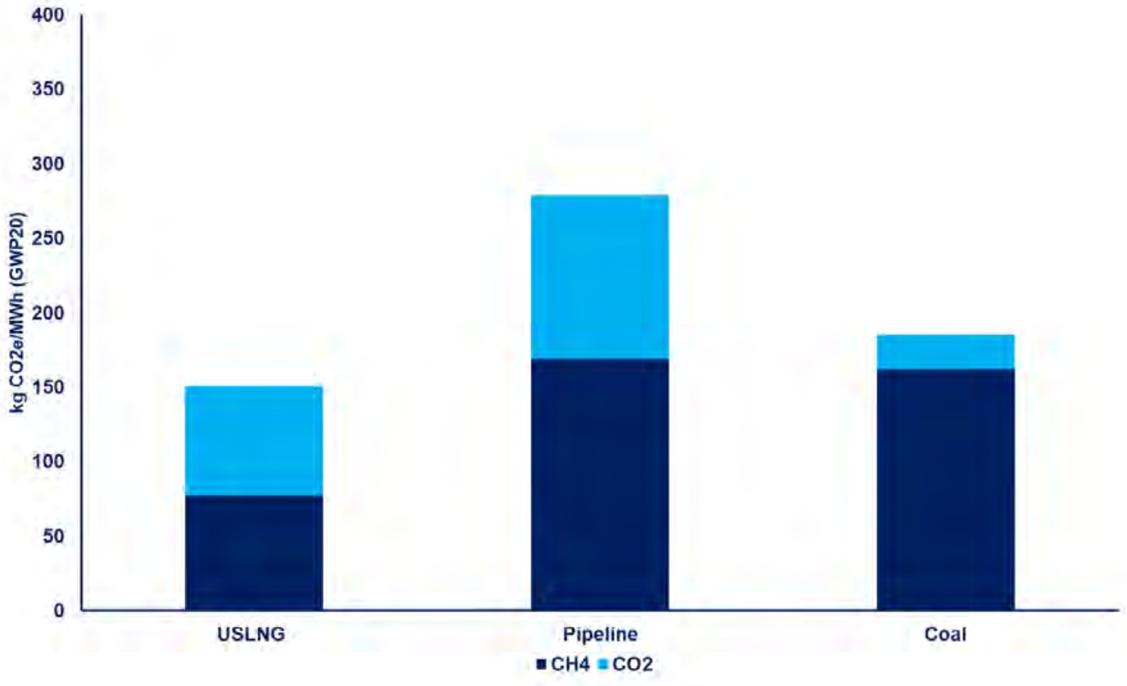

Figure 13 indicates that the GHG intensity of the fuel supply chains to border delivery points (i.e., excluding downstream transportation and power generation), CH4 emissions intensity represented, on average:

- 51% of total emissions intensity in the USLNG routes.
- 60% of total emissions intensity in the Pipeline Gas routes.
- 87% of total emissions intensity in the Coal routes.

Box 4: Coal Mine Methane Emissions

Accurate accounting for methane emissions in coal mining is critical to developing a true "apples-to-apples" comparison of the GHG footprint of coal supply chains as compared to natural gas and USLNG. The CH4-intensive coal mining sectors of countries like Indonesia, India, China, and Russia[1] are critical to evaluate because coal supplies from these countries constitute a very significant share of the fuels used for power generation in many Asian countries.

[1] "Uncovering Indonesia's hidden methane problem", Dody Setiawan, Chris Wright, 12 March 2024. See also: "Methane leaks are supercharging the climate crisis", Ember, March 2023, available at: https://ember-climate.org/topics/coal-mine-methane/ (accessed March 2024).

Greenhouse Gas Emissions Savings

The comparison between the average GHG emissions intensity of USLNG imports and Coal supplies for power generation in the 13 European and Asian countries analyzed demonstrates the climate advantage of using USLNG instead of Coal in the leading foreign markets for USLNG.

Assuming that USLNG supplies are used to replace coal-fired generation with natural gas generation, we calculated the total quantity of CO2 and CH4 emissions that are saved on average by delivering a single USLNG cargo to Europe and Asia.[19] Our results indicate that on average:

- In the eight European countries studied, a single cargo of USLNG to produce electricity would have saved from 194,000 to 540,000 tons of CO2e as compared to coal-fired generation. The wide range of results reflects the different heat rates of power generation fleets in the destination countries and the varying GHG emissions intensities of the various USLNG and Coal supply routes.

In the five Asian nations examined, this equivalent range of GHG savings per average USLNG cargo was between 175,000 and 752,000 tons of CO2e.

Table 4 presents the potential range of GHG savings achieved by using USLNG imports to generate electricity instead of coal in Europe and Asia.

Table 4: GHG Savings from USLNG Replacing Coal for Power Generation [20]

Region	USLNG Imports in 2023 (MMtpa)	Corresponding number of cargoes	Range of Annual GHG Savings in 2023 (million tons CO2e)
Europe	70	718	139 - 388
Asia	28	286	50 - 215
Total	98	1004	189 - 603

Figure 14 illustrates the magnitude of potential annual savings using USLNG instead of coal in the power generation sector of the countries analyzed.

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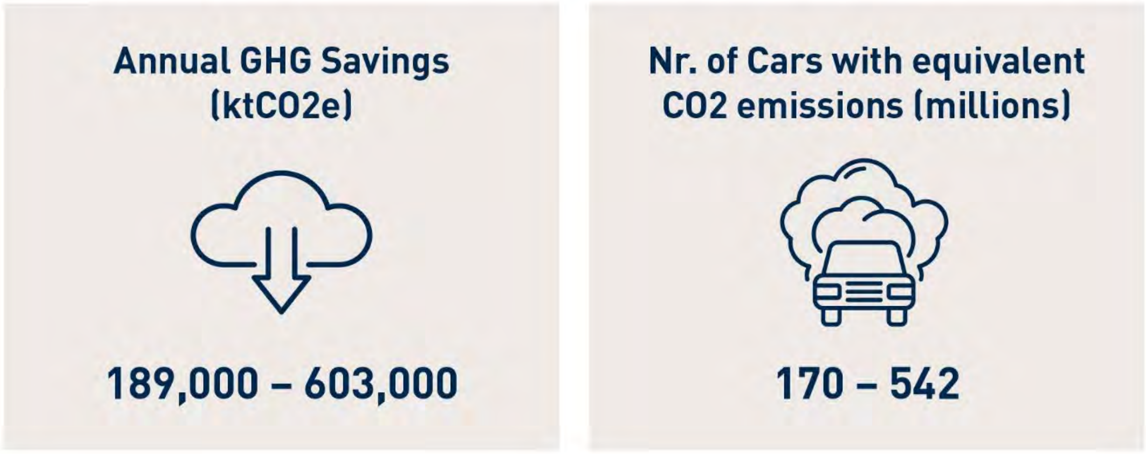
[19] This analysis assumes that importers can use USLNG cargoes instead of coal in the power generation sector, where the average LNG cargo contains 3.5 TBtu of energy.

[20] Numbers may not add-up due to rounding.

Figure 14: Number of Cars with Equivalent CO2 Emissions[21]



Data Constraints

The results of this study largely depend upon the accuracy and consistency of the underlying emissions data available from the leading public sources. To date, the leading sources of publicly available data on GHG emissions have established rigorous systems to encourage consistent data reporting, including a mix of reported emissions data and estimated *emission factors*. However, there are limitations in the available data, primarily with respect to the consistency between actual measurements and estimated factors. For example:

- Upstream and midstream emissions of the USLNG supply chain are based on detailed data reported to the EPA from relevant operators, at the level of producing basins or plays.[22] Emissions from coal mining are estimated using emission factors and individual mine characteristics instead of actual reported measurements.
- Similarly, data on emissions factors in the midstream segments of both Pipeline Gas and Coal supply chains is primarily based on generic emission factors for infrastructure (such as pipeline, rail and/or ocean transport of fuel), rather than actual emissions measurements.

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[21] We assume that a new car emits 108 gCO2/km, and the average distance travelled per year is 10,300 km. See: https://www.eea.europa.eu/en/newsroom/news/average-emissions-from-new-cars-and-vans; and https://www.odyssee-mure.eu/publications/efficiency-by-sector/transport/distance-travelled-by-car.html

[22] The quality of this data remains the subject of some controversy at present. See Genevieve Plant, Eric A. Kort, Adam R. Brandt, Yuanlei Chen, Graham Fordice, Alan M. Gorchov Negron, Stefan Schwietzke, Mackenzie Smith, Daniel Zavala-Araiza. Inefficient and unlit natural gas flares both emit large quantities of methane. Science, 2022; 377 (6614): 1566 DOI: 10.1126/science.abq0385

Comparison with Other Studies

Most recently, there has been an increased focus on the comparison of the GHG emissions of different fuels, including USLNG, Pipeline Gas and Coal. Recent studies conclude that, in some cases, the GHG emissions footprint of coal supplies for power generation can be even lower than that of USLNG.[23] Our review of these studies indicates that they differ from this analysis in several respects, as summarized in Table 5.

Table 5: Primary Differences between Studies

Areas of Difference	This study	Other studies
Methodology	This study employs a comprehensive, widely used methodology to separately calculate emissions intensity for each supply chain segment for actual USLNG, Pipeline Gas, and Coal trade routes in 2022.	Other studies aggregate general, theoretical emissions of natural gas, LNG, and coal supply chains without evaluating specific regional, trade route, or temporal distinctions.
Data used	To the greatest extent possible, this study has used the most up-to-date emissions data and reported/measured emissions for each supply chain segment and delivery route. For example, we: o Used actual 2023 data on the GHG emissions of upstream natural gas production in the US, as reported to the EPA. o Analyzed the GHG emissions of USLNG shipments to specified destinations using actual 2023 data on the vessels used and their voyage distances.	Other studies rely primarily on estimated emissions factors, which are often outdated. None of the studies we reviewed used specific trade route and/or supply chain segment data for GHG emissions. For example, these studies: o Do not rely on reported emissions for any part of each fuels' supply chain, o Do not analyze the composition and type of coal supplies used in each country, o Do not account for actual fuel shipping

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[23] For example, see Deborah Gordon *et al.,* "Evaluating net life-cycle greenhouse gas emissions intensities from gas and coal at varying methane leakage rates," 2023, in *Environ. Res. Lett.* **18** 084008; and Robert Howarth, "The Greenhouse Gas Footprint of Liquefied Natural Gas (LNG) Exported from the United States," 2024, in Energy Science & Engineering Volume 12, Issue 11 https://doi.org/10.1002/ese3.1934.

	o Thoroughly evaluated the composition and type of 2023 Coal imports in each destination country to accurately determine the GHG emissions of Coal supplies. o Analyzed the GHG emissions of power generation in each destination country based on the actual amount of each fuel used for power generation.	and/or transportation distances, and o Do not account for the actual heat rates of power generation segment in each country.

GHG Emissions Management

The quality of ground level and aerial sensors for GHG emissions measurement and monitoring is improving at an accelerated pace. Private companies, public organizations, and governmental bodies are focusing on GHG emissions measurement and monitoring as GHG mitigation is now a priority of corporate management and public policy.

Several companies and organizations have also started offering CH4 emissions data obtained through satellite imaging and sophisticated data analysis and processing. Currently, there are private companies offering satellite data on CH4 emissions at asset specific levels (for a fee), and in the near term, we expect several independent entities to publicly provide satellite data on GHG emissions of oil and gas operations, at the national, regional, and even local, asset-specific level. These developments could facilitate increasingly accurate and consistent quantification of the GHG emissions footprint of fuel production and transportation infrastructure and supply chains across regions and countries to level the playing field across jurisdictions where GHG measurement is mandatory, voluntary, or even unavailable or incomplete. As GHG mitigation commitments and policies mature worldwide, the increased use of satellite monitoring promises to facilitate the consistency of systemic analysis of GHG emissions and emissions intensity across fuel supply chains worldwide.

Further, the enhanced consistent monitoring, reporting, and verification/certification (“MRV”) of GHG emissions throughout the supply chain for energy imports is increasingly a central component of the value proposition for USLNG. The GHG emissions intensity of fuel supply chains is expected to impact future energy trade, taxation, pricing, and contracts. This study illustrates the value of mastering the GHG emissions footprint analysis for the supply chain of USLNG and other competing fuels into importing countries:

  - Clear identification and monitoring of emissions of the USLNG supply chain may unlock long-term contracting appetite by European and Asian buyers who are increasingly concerned about the sustainability of their gas imports in an accelerating energy transition environment, especially in light of upcoming regulations on the sources of natural gas.[24]
  - Access to transparent data and information on GHG emissions footprints is critical to lenders and private equity investors seeking to understand the environmental footprints of their existing portfolios, to fund new investments, and to adhere to ESG and sustainability regulations.
  - The favorable USLNG GHG emissions footprint—and rapidly improving standards for supply chain emissions measurement and monitoring—can enhance the competitive edge of USLNG against other energy sources by definitively and objectively demonstrating its lower GHG emissions intensity. Over time, this should support a price premium relative to other supplies with higher GHG emission intensities.

GHG emissions management is at the forefront of energy sector decarbonization efforts worldwide. Continuous improvement in MRV technologies and GHG emissions data analysis are becoming a priority for those governments and companies seeking to drive and implement sustainable GHG mitigation strategies. In the LNG industry, the sustained competitiveness of the fuel overall, and of specific LNG supply sources and routes, increasingly depends on the GHG emissions intensity of supply chains as well as on supply chain economics and pricing.

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[24] For example, in November 2023, a provisional agreement was reached between the European Parliament and European Council on a new EU Regulation to reduce energy sector methane emissions in Europe and global supply chains. See, European Commission, Press Release: "Commission welcomes deal on first-ever EU law to curb methane emissions in the EU and globally," Brussels, Nov. 2023.

APPENDIX A

DATA SOURCES

This analysis is based upon the following data sources and information.

- U.S. Environmental Protection Agency (EPA) Greenhouse Gas Reporting Program, 2024.
- U.S. Environmental Protection Agency (EPA) Greenhouse Gas Inventory, 2024.
- S&P Capital IQ.
- Kpler.
- UN Comtrade.
- U.S. Department of Energy (DOE).
- European Environment Energy.
- Statistical Review of the World Energy, 2023.
- International Gas Union.
- International Maritime Organization.
- Energy Information Administration (EIA).
- International Energy Agency (IEA) World Energy Balances, 2023. All rights reserved.
- IEA Methane Emissions Tracker.
- Intergovernmental Panel on Climate Change (IPCC).
- Eurostat.
- Climate Trace.
- Global Energy Monitor.
- Rosselot et al., “Comparing greenhouse gas impacts from domestic coal and imported natural gas electricity generation in China,” in *ACS Sustainable Chem. Eng.* 2021, 9, 26, pp. 8759–8769.
- Roman-White, S. Rai, J. Littlefield, G. Cooney, T. J. Skone, “Life Cycle Greenhouse Gas Perspective on Exporting Liquefied Natural Gas from the United States: 2019 Update,” National Energy Technology Laboratory, Pittsburgh, Sep. 2019.
- Kirsten Sinclair Rosselot, Paul Balcombe, Arvind P. Ravikumar, and David Thomas Allen, “Simulating the Variability of Methane and CO2 Emissions from Liquefied Natural Gas Shipping: A Time-in-Mode and Carrier Technology Approach,” in *ACS Sustainable Chem. Eng.* 2023, 11, 43, pp. 15632–15643.

- Paul Balcombe, Kris Anderson, Jamie Speirs, Nigel Brandon, and Adam Hawkes, “Methane and CO2 emissions from the natural gas supply chain: the importance of methane and carbon dioxide emissions,” Imperial College London, 2015.
- John Sherwood, Robert Bickhart, Emily Murawski, Zemin Dhanani, Blake Lytle, Patricia Carbajales-Dale, and Michael Carbajales-Dale, “Rolling coal: The greenhouse gas emissions of coal rail transport for electricity generation,” Journal of Cleaner Production, Volume 259, 2020, 120770, ISSN 0959-6526.
- Selina A. Roman-White, Deeksha Mallikarjuna Prasanna, Amber McCullagh, Arvind P. Ravikumar, David Thomas Allen, Kavya Chivukula, Harshvardhan Khutal, Paul Balcombe, Gregory Ross, Brad Handler, Morgan Bazilian, and Fiji C. George, “Gas Pathing: Improved Greenhouse Gas Emission Estimates of Liquefied Natural Gas Exports through Enhanced Supply Chain Resolution,” ACS Sustainable Chemistry & Engineering 2024 12 (46), 16956-16966

APPENDIX B

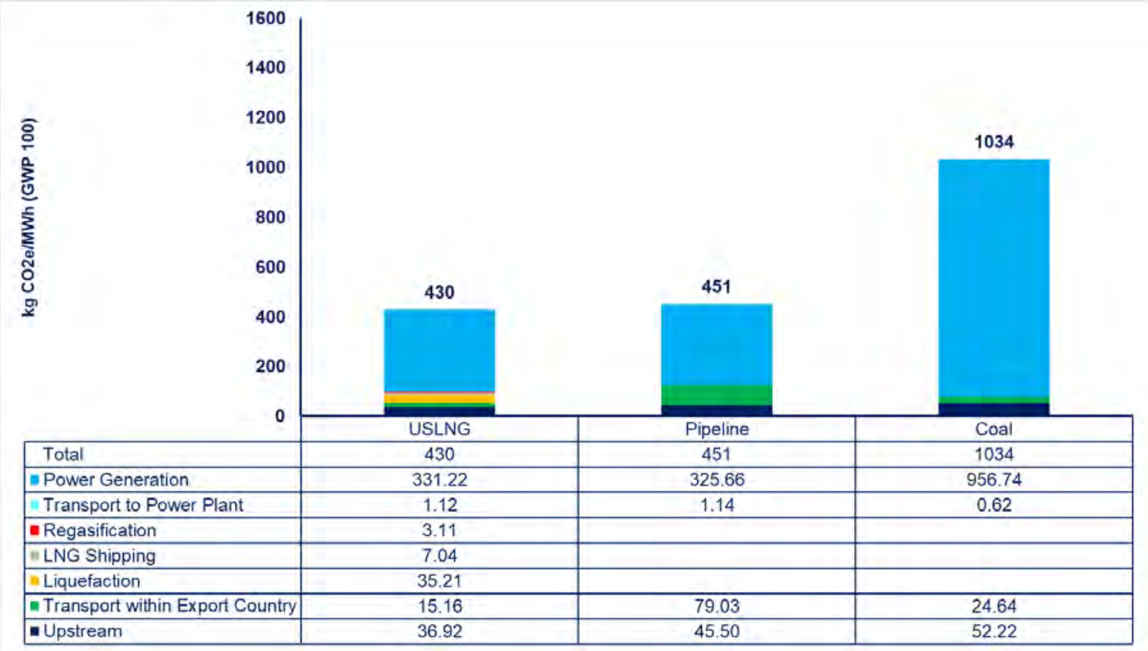
GWP100 EMISSION INTENSITY SUMMARY RESULTS

Another metric to quantify the CO2 equivalency between CH4 and CO2 emissions is the GWP100 (i.e., the Global Warming Potential of CH4 relative to CO2 emissions over a 100-year time horizon). This metric shows the effect of CH4 emissions 100 years after they were observed, in relation to the effect of CO2 emissions. The GPW100 of CH4 is equal to 29.8 (in comparison with GWP20 of CH4 which is equal to 82.5).[25]

Some institutions use the GWP100 as the metric of CO2 equivalency, for example the International Group of Liquefied Gas importers (GIIGNL) requires the use of GWP100 in its Monitoring, Reporting and Verification and GHG Neutral Framework.[26]

Using GWP100, Figure 15 and Figure 16 present the GHG EI of USLNG, Pipeline Gas and Coal supplies in Europe and Asia, respectively.

Figure 15: Comparison of GHG EI of Primary Fuel Imports and Supply in Europe (GWP100)



	USLNG	Pipeline	Coal
Total	430	451	1034
■ Power Generation	331.22	325.66	956.74
■ Transport to Power Plant	1.12	1.14	0.62
■ Regasification	3.11		
■ LNG Shipping	7.04		
■ Liquefaction	35.21		
■ Transport within Export Country	15.16	79.03	24.64
■ Upstream	36.92	45.50	52.22

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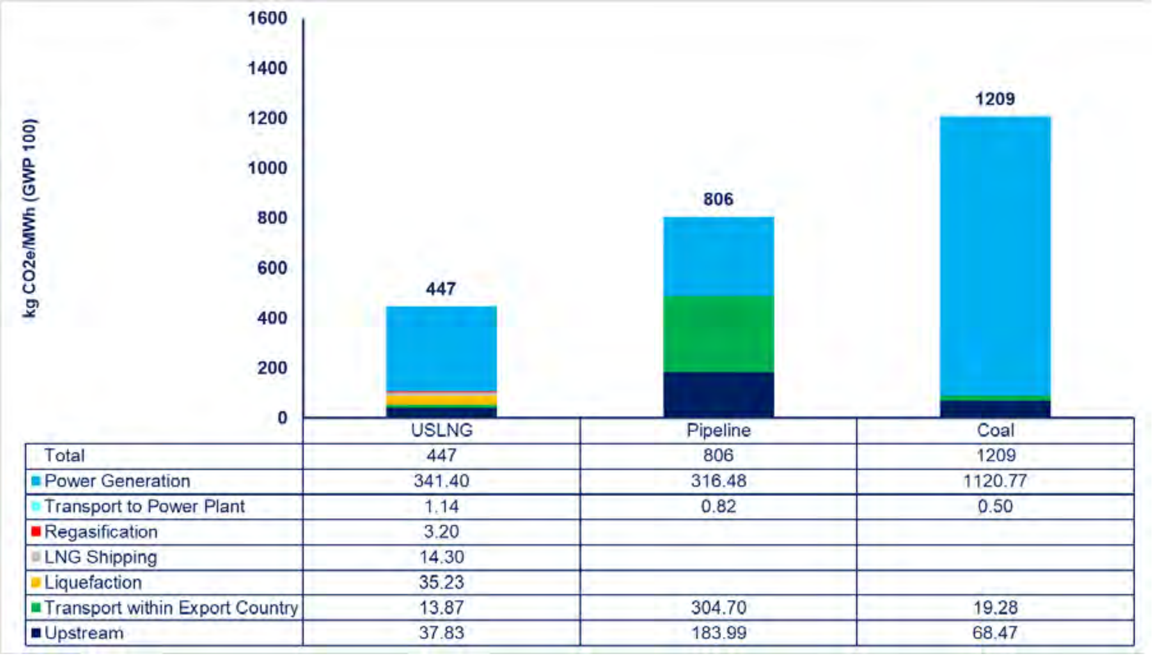
[25] Forster, P., T. Storelvmo, K. Armour, W. Collins, J.-L. Dufresne, D. Frame, D.J. Lunt, T. Mauritsen, M.D. Palmer, M. Watanabe, M. Wild, and H. Zhang, 2021: The Earth's Energy Budget, Climate Feedbacks, and Climate Sensitivity. In Climate Change 2021: The Physical Science Basis. Contribution of Working Group I to the Sixth Assessment Report of the Intergovernmental Panel on Climate Change [Masson-Delmotte, V., P. Zhai, A. Pirani, S.L. Connors, C. Pean, S. Berger, N. Caud, Y. Chen, L. Goldfarb, M.I. Gomis, M. Huang, K. Leitzell, E. Lonnoy, J.B.R. Matthews, T.K. Maycock, T. Waterfield, O. Yelekci, R. Yu, and B. Zhou (eds.)]. Cambridge University Press, Cambridge, United Kingdom and New York, NY, USA, pp. 1017

[26] See https://giignl.org/wp-content/uploads/2021/11/MRV-and-GHG-Neutral-Framework.pdf

Figure 16: Comparison of GHG EI of Primary Fuel Imports and Supply in Asia (GWP100)



	USLNG	Pipeline	Coal
Total	447	806	1209
🟦 Power Generation	341.40	316.48	1120.77
◽ Transport to Power Plant	1.14	0.82	0.50
🟥 Regasification	3.20		
⬜ LNG Shipping	14.30		
🟨 Liquefaction	35.23		
🟩 Transport within Export Country	13.87	304.70	19.28
⬛ Upstream	37.83	183.99	68.47

Table 6 demonstrates that using the GWP100 results in lower values for the total GHG EI as compared to using GWP20. This is because the impact of CH4 emissions is approximately 33% less when considering GWP100 instead of GWP20. Using GWP100 also slightly erodes the comparison between the GHG EI of USLNG and Coal across their full supply chains.

Table 6: GHG EI to Europe and Asia Using GWP20 v GWP100

Total GHG EI (kgCO2e/MWh)	Europe		Asia	
	GWP20	GWP100	GWP20	GWP100
USLNG	477	430	498	447
Pipeline Gas	526	451	1,217	806
Coal	1,127	1,034	1,330	1,209

INTELLIGENCE THAT WORKS

Comments on Greenpeace and Sierra Club Report

“Permit to Kill: Potential Health and Economic Impacts from U.S. LNG Export Terminal Permitted Emissions”

Prepared for LNG Allies, The USLNG Association

David L. Sunding, PhD
Gina M. Waterfield, PhD

February 14, 2025

I Overview of Greenpeace/Sierra Club Report

Greenpeace and the Sierra Club published a report on the potential public health impacts of U.S. liquefied natural gas ("LNG") export terminals titled "Permit to Kill: Potential Health and Economic Impacts from U.S. LNG Export Terminal Permitted Emissions" in August 2024. The Report is intended to "inform the DOE process" by describing "the health impacts of air pollution from existing and planned LNG export terminals"[1] through the year 2050.

The authors of the Report use the EPA's CO-Benefits Risk Assessment Health Impacts Screening and Mapping Tool ("COBRA") to estimate changes in certain measures of public health that would result from emissions at operating and planned LNG export terminals across the continental U.S. COBRA takes as inputs changes in levels of certain air pollutants and precursors and translates these to changes in ambient concentrations of fine particulate matter ($PM_{2.5}$) and ozone (O_3) via a simplified air quality model. The air quality changes are then plugged in to concentration-response functions estimated in prior epidemiological studies to yield estimates of changes in the incidence of illnesses, premature mortality, and lost days of work and school attendance at a county-level scale. COBRA then assigns monetary values to these outcomes using various average value measures from prior literature.

On the basis of this analysis, the authors estimate that air quality impacts from the 32 planned and operating LNG export terminals included in their study would cause 149 premature deaths and $2.33 billion in "health costs" per year. The report concludes with several recommendations, including that no further LNG export projects should be approved or permitted, and that any projects that worsen climate change or local health outcomes are not in the public interest and should be rejected.

Even if the estimates presented in the Greenpeace/Sierra Club Report were correct, these concluding recommendations would not be supported. Whether a project or activity is in the public interest depends on how its costs compare to the benefits it provides, and the Report provides no evaluation of potential local, national, or global benefits. In addition to its incompleteness, the analysis presented in the Report contains several methodological weaknesses that limit its reliability. The Report does not indicate that planned LNG capacity presents environmental justice concerns when considering appropriate metrics and geographies. Each of these issues is discussed in the following sections of this commentary.

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[1] Heureaux-Torres, Johanna (Sierra Club), Chang, Andres (Greenpeace), and Donaghy, Tim (Greenpeace), *Permit to Kill: Potential Health and Economic Impacts from U.S. LNG Export Terminal Permitted Emissions*, August 2024, p.7. Available at https://www.greenpeace.org/static/planet4-usa-stateless/2024/11/47b90812-permit-to-kill.pdf.

II Benefit-Cost Considerations

In evaluating whether an activity or action is in the public interest, it is critical to undertake a balanced assessment of both the costs and benefits.[2] Virtually all economic activity is associated with costs, both monetary and otherwise, but these costs alone do not indicate that the activity should be avoided. From the perspective of social welfare maximization, the relevant questions are whether an activity's overall benefits exceed its total costs, and how any undesirable distributional consequences may be mitigated.

More specifically, activities ranging from electricity generation to food production, to manufacturing, to transportation, are all associated with emissions of criteria pollutants that have negative impacts on public health. These activities nevertheless contribute to social welfare. In the context of electricity generation, a recent study published in the journal *Science*, for example, estimated that $PM_{2.5}$ from 480 coal-fired electricity generating units was associated with 460,000 premature deaths over the period 1999 to 2020.[3] Similarly, a study based on EPA's COBRA estimated that removal of $PM_{2.5}$-related emissions from the electric power, transportation, building, and industrial sectors would prevent approximately 50,000 to 60,000 premature deaths per year.[4] While it is important to include such health impacts in a balanced benefit-cost assessment, they alone do not warrant the termination of economic activity.

LNG exports may provide a range of local to global benefits, none of which are considered in the Greenpeace/Sierra Club Report. At a local and regional level, the construction and operation of LNG export terminals generate revenues and create employment opportunities, both directly and indirectly through increased supply chain activity. They also yield additional tax revenues for local and state governments. Both individual and municipal financial resources can be used to improve healthcare provision and lessen the burden of disease. At a broader scale, LNG exports may confer geopolitical advantages, including diversification of global energy supplies. Depending on the energy sources that U.S. LNG displaces, LNG exports may also lower global greenhouse gas emissions and confer other environmental benefits.

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[2] Indeed, cost-benefit analysis is often a required component of federal rulemaking. *See* Congressional Research Service, *Cost-Benefit Analysis in Federal Agency Rulemaking*, Updated October 28, 2024. Available at https://crsreports.congress.gov/product/pdf/IF/IF12058.

[3] Henneman, Lucas, Christine Choirat, Irene Dedoussi, Francesca Dominici, Jessica Roberts, and Corwin Zigler, "Mortality risk from United States coal electricity generation," *Science* 382, no. 6673 (2023): 941-946.

[4] Mailloux, Nicholas A., David W. Abel, Tracey Holloway, and Jonathan A. Patz, "Nationwide and regional PM2. 5-related air quality health benefits from the removal of energy-related emissions in the United States," *GeoHealth* 6, no. 5 (2022): e2022GH000603.

III Methodological Issues

In addition to its incomplete scope, the analysis presented in the Greenpeace/Sierra Club Report is subject to several methodological limitations that undermine the reliability of its resulting estimates. First, COBRA is described as a screening-level tool that relies on a reduced form air quality model to translate user-supplied changes in emissions to changes in ambient air quality. EPA notes that COBRA is best used for initial analysis and "followed up with comprehensive AQ analysis and health impact assessment."[5] Given that in this case a substantial share of the estimated health impacts are from population dense areas fairly distant from LNG terminals, that are projected to experience relatively modest changes in air quality,[6] the accuracy of the air quality modelling may have a significant impact.

Second, although several U.S. LNG export terminals have been in operation for years, such as the Sabine Pass facility which added liquefaction capabilities in 2016, the health impacts presented in the Report are all model output. Inputs to the model are taken from the prior literature and were estimated in varying contexts. Given the length of time over which certain LNG terminals have been in operation, an analysis of actual health outcomes and value measures in the surrounding communities would provide, at a minimum, useful ground truthing for the COBRA model predictions and opportunities for calibration.

Third, the authors of the Report used permitted emissions to proxy for actual LNG terminal emissions, presumably multiplying permitted daily emissions by 365 to arrive at annual values. They further assume these emissions will continue to occur in each year through 2050. This approach ignores potential variation in daily operations that may result in actual emissions below permitted levels in certain periods. Again, given that several LNG terminals have been in operation for years, actual emissions data would constitute a more appropriate input. In extending the same analysis out to 2050, the authors also ignore the potential for regulatory changes, lessening demand for fossil fuels, and advances in abatement technology over the course of the next 25 years that may lower criteria pollutant emissions from LNG terminals.

Fourth, like the use of permitted emissions through 2050, the analysis presented in the Report relies on COBRA's 2028 baseline emissions of criteria pollutants for all years 2028 and beyond. In doing so, it ignores the historical reduction in such emissions and attendant improvements in air quality that have occurred in the United States in recent decades. As ambient air quality changes,

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[5] U.S. EPA State and Local Energy and Environment Program, *Estimating the Co-Benefits of Clean Energy Policies: CO-Benefits Risk Assessment (COBRA) Health Impacts Screening and Mapping Tool: How COBRA Works, April 17, 2024. Available at https://www.epa.gov/system/files/documents/2024-04/how-cobra-works_17-april-2024.pdf.*

[6] See Greenpeace/Sierra Club Report, Figure 4.

the impact of marginal increases in air pollutant emissions also change given non-linearities in concentration-response functions.

In addition to these analytical limitations, the presentation of the "health cost" metric in the Report is misleading. In addition to the number of premature mortalities, asthma cases, and lost school- and work- days, the authors report what they identify as "health costs" without explanation of what these costs represent. These costs are more accurately described as the monetized value of the morbidity and mortality effects estimated by COBRA, and they are in fact dominated by the value assigned to changes in mortality risk. This value, known as the "value of statistical life" ("VSL") reflects individuals' willingness-to-pay for reductions in the risk of premature mortality. As the authors note, the default VSL in COBRA is $14 million per expected additional premature mortality, which accounts for nearly 90 percent of the "health costs" reported by the authors.[7] While reductions in premature mortality risk are valuable and rightly assigned monetary value, the health costs presented in the Greenpeace/Sierra Club Report should not be construed as *healthcare costs* or other pecuniary measures.

IV Environmental Justice Impacts

The Greenpeace/Sierra Club Report further considers the impacts of operating and planned LNG export terminals from an environmental justice perspective along three dimensions. The authors assess the extent to which the air quality impacts of LNG terminals are concentrated in areas of nonattainment with national air quality standards, in areas of greater climate vulnerability, and among racial and ethnic groups. While consideration of environmental justice is important to the siting of industrial and manufacturing facilities, it should not be used to decide whether an industry or sector should operate at all irrespective of the benefits it provides.

In the assessment of nonattainment areas, the approach taken by the authors largely guarantees overlap with the areas most impacted by LNG terminal emissions. The authors identify the most-impacted counties and parishes in part based on population density. O_3 non-attainment areas are frequently densely populated urban locations with substantial ground-level precursor emissions. Indeed, as illustrated in Figure 6 of the Report, there is no overlap between nonattainment regions and areas most impacted by LNG terminal emissions when the latter is defined on a per capita basis. The difference in the areas identified as most impacted on a per capita basis versus in absolute terms is reflective of the relatively low population density of the

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[7] $14 million multiplied by 149 expected premature mortalities per year is $2.09 billion, equivalent to 90 percent of the reported $2.33 billion in "health costs."

areas proximate to the LNG terminals. Low population density is generally a desirable feature in industrial facility siting from the perspective of minimizing risks to public health.

The Report also describes overlap between the areas most impacted by LNG terminal emissions and areas of high "climate vulnerability," as defined by an index developed by the Environmental Defense Fund and Texas A&M University. This comparison is inapt, given that climate change is a global phenomenon caused by global greenhouse gas emissions, not local emissions. Vulnerability to climate change is a separate issue from exposure to nearby LNG terminal emissions, other than the extent to which U.S. LNG exports affect global greenhouse gas emissions overall. If climate vulnerability partly reflects measures of environmental burden that are relevant, those should be analyzed individually rather than as part of a composite index.

Lastly, the Report presents a comparison of exposure to LNG terminal air pollutants across racial and ethnic lines. When considering the populations of Texas and Louisiana only, rather than the United States overall, the comparison does not indicate systematic environmental justice concerns. Although exposure to ambient air pollution is up to 20 percent higher for the Black/African American population in Texas than for the White population, it is generally relatively lower for other ethnic minorities. In Louisiana, exposure is lower for all minority populations than for the White population. Given the unique siting characteristics of the Texas and Louisiana Gulf Coast for LNG export activity, the populations of these States are the relevant points of reference.

An Examination of Whether U.S. LNG Exports Drive Domestic Natural Gas Prices

R. Dean Foreman, Ph.D.[1]

February 15, 2024

Executive Summary

The U.S. energy revolution has been characterized by abundant natural gas production at affordable prices, benefiting American households and manufacturers, and establishing the United States as the world's top natural gas exporter. Before Russia's war in Ukraine escalated in February 2022, U.S. natural gas exports drove the globalization of natural gas markets. Since then, the United States has been a lifeline for energy consumers in Europe (and globally) as well as a counterbalance to Russia's weaponization of its energy exports.

Amid tumultuous and uncertain times, U.S. natural gas exports have remained near record-high levels per the U.S. Energy Information Administration (EIA)[2], but natural gas prices at Henry Hub, Louisiana, remained as low as $1.70 per million Btu (mmbtu) in early February 2024, marking the lowest real prices for the month on record since 1994.

Nonetheless, in their decision on January 26, 2024, to pause all pending approvals of new LNG export facilities (see here), the Biden administration has continued to point to U.S. liquefied natural gas (LNG) exports, which tripled in volume since 2019,[3] for the potential to raise domestic energy costs.

This decision neglects the evidence that U.S. LNG exports have actually motivated U.S. natural gas production growth and productivity, which in turn have exerted downward price pressures to the benefit of American consumers.

By limiting the growth for U.S. LNG exports, the Biden administration's intervention runs afoul of basic market principles as well as the demonstrated progress that has underpinned economic and energy security for American and global consumers.[4]

LNG Allies asked us to examine the impact of U.S. LNG exports on natural gas prices at Henry Hub by developing a statistically valid framework, updating the model we presented in May 2023 (see here).

The model has continued to explain and predict natural gas prices accurately, showing that U.S. LNG net exports have not had any sustained and significant direct impact on natural gas prices.

This conclusion is based on exhaustive correlation analysis, presented in Section I and detailed in the Appendix, as well as a holistic fundamentals-driven framework that has accurately predicted U.S. natural gas prices, in Section II.

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[1] Chief Economist, Texas Oil and Gas Association.

[2] In February 2024, the U.S. Energy Information Administration (EIA) estimated U.S. LNG exports of 12.0 billion cubic feet per day (bcf/d) and pipeline natural gas exports of 8.0 bcf/d.

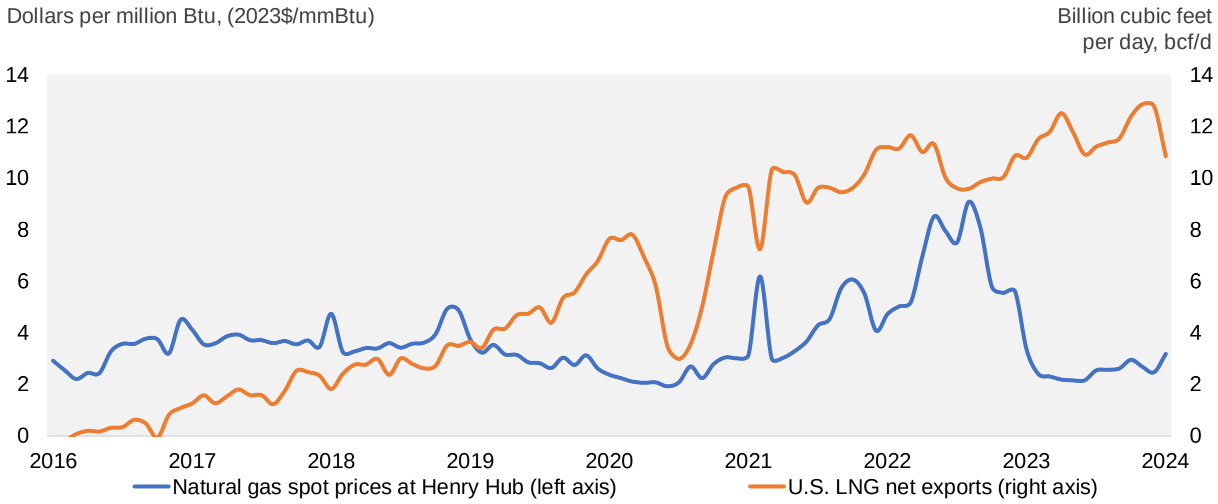
[3] U.S. LNG exports were 4.0 bcf/d in Q1 2019 per EIA.

[4] Environmental gains from the expanded use of natural gas to displace biomass and coal consumption are outside the scope of this analysis, but is well documented from multiple sources including the U.S. Energy Information Administration (EIA), Environmental Protection Agency (EPA).

The fact is that U.S. LNG exports have spurred incremental new U.S. production and led to improvements in technology and resource recoveries, which in turn have generally added to estimated domestic recoverable gas resources. The U.S. Potential Gas Committee's (PGC) most recent estimates suggest the resource base could enable future U.S. gas supply of 3,978 trillion cubic feet (tcf)—equivalent to 100 years of production at 2022 levels.[5]

I. Exploratory data analysis of natural gas prices at Henry Hub and U.S. net LNG exports

Chart 1. U.S. LNG Exports and Natural Gas Prices at Henry Hub, Jan. 2016 – Jan. 2024



source U.S. Energy Information Administration (EIA)

As a point of departure, consider Chart 1, which compares monthly U.S. LNG net exports and natural gas prices at Henry Hub from 2016 to January 2024. The U.S. became a net exporter of LNG for the first time in 2016. As of January 2024, U.S. LNG net exports increased by a multiple of over 40 compared with the average in 2016, while domestic real natural gas prices remained at record low levels for the month. Historically, there has been little to no evidence of a direct or causal relationship between the exports and domestic natural gas prices. As Chart 1 demonstrates, natural gas prices remained subject to seasonal variation but generally declined in 2019 through mid-2020 —and again beginning in late 2022 — despite increased U.S. LNG net exports.

We can identify periods, however, where there has been a statistically significant direct relationship between the exports and prices. Strong direct correlations appeared over rolling periods of six to 12 months during the 2020 pandemic, when exports and prices both decreased. Of course, the exports, domestic demand and prices for many things fell during the pandemic, so it is important to account for the effects of the pandemic.

Natural gas prices rose, and LNG net exports fell, with winter storm Uri in Feb. 2021. Despite the appearance of a statistically significant inverse correlation at that time, intuitively it is obvious that the storm affected the supply chain, and it was not the change in exports that drove prices. Similarly, as Russia's war in Ukraine began in Feb. 2022, domestic natural gas prices continued to rise through the shoulder season to winter, despite a slippage in U.S. LNG net exports. Consequently, two additional implications are that: (1) it is important to account for seasonal variation; and (2) correlation analysis does not establish causation.

Given the foregoing points, a proper analysis requires a statistically valid model that accurately explains natural gas prices based on the market fundamentals which intuitively should drive them. Before delving into such a model,

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[5] Potential Gas Committee reports future natural gas supplies in U.S. at highest reported level on record | Colorado School of Mines | Newsroom (minesnewsroom.com).

however, let us continue with a correlation analysis subject to the caveats about accounting for the pandemic, seasonality, and that correlation is not causation.

Analysis of the monthly LNG levels of exports and natural gas prices, from January 2016 to January 2024, shows a direct correlation of +0.36, which with 97 observations is statistically significant with 95% confidence. Over the same period, however, the correlation between monthly *changes* in LNG exports and natural gas prices shows an inverse correlation of -0.12 and remains positive if we employ past changes in LNG net exports of one to four months. Moreover, if we compare natural gas prices *changes with the changes* in LNG net exports from the prior month, the inverse correlation becomes statistically significant at -0.34 – and can flip sign while remaining insignificant with lagged changes in LNG net exports of up to four months.

Importantly, any inferences about the underlying relationships thus could depend on whether one compares levels, changes in levels, or levels with changes in levels — with or without lags in time. Accordingly, the Appendix presents several alternative correlation analyses and demonstrates that statistically significant direct and inverse correlations can be identified over select 6-month and 12-month periods.

But the key point is that there has been no significant and sustained relationship where U.S. LNG exports have driven higher domestic natural gas prices. In fact, a selective focus on correlation analysis over periods within the data could support opposite inferences. We will avoid such an error and present in Section II a valid model that is suitable for testing hypotheses about the relationship between U.S. LNG net exports and domestic natural gas prices.

II. Econometrically forecasting natural gas prices

Intuition

Let's discuss economic intuition as to why increased U.S. LNG exports could contribute to higher natural gas prices in a static sense but not necessarily in a dynamic sense.

Some domestic industrial consumers (for example, see here) have asserted that the growth of U.S. LNG exports has driven higher domestic natural gas prices. In a static view of LNG exports, shipping domestic gas production internationally could lower domestic supply, all else being equal. By economic fundamentals, less supply generally corresponds with higher prices *if all other things remain equal*. The main counterpoint to this view, however, is that the natural gas market is not static.

The growth of U.S. LNG exports, which enables those with U.S. liquefaction capacity to access premium global markets, has motivated new incremental natural gas production in the United States. For example, natural gas marketed production among the Lower 48 (L48) states increased from 74.1 bcf/d in Dec. 2015 up by 37.1 bcf/d or 50.1% over the period (per EIA).[6] By comparison, U.S. LNG net exports rose by 4.1 bcf/d or 12.5% of the L48 production increase over the same period. With the dynamic growth of U.S. natural gas production, investments in new process and technologies raised U.S. drilling productivity, improved the recovery of natural resources, and raised the estimated amounts of U.S. proved and probable natural gas reserves.[7]

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[6] While access to international natural gas markets at premia above U.S. levels economically motivates LNG export project development, an economic issue for domestic natural gas supply curve has either shifted to the right or simply remained flat, such that developing more domestic resources has not materially lowered productivity or added cost per se. The evidence from EIA and other sources (e.g., FactSet/BTU Analytics and petronerds) show drilling productivity that exceeds its pre-pandemic levels even if one excludes any contributions from previously drilled but uncompleted wells.

[7] EIA's Drilling Productivity Report (DPR) shows that, despite some decreases over the past year, natural gas rig productivity in Jan. 2024 was estimated to be more than double what it was in Dec. 2015 in the Haynesville production region (E. Texas and Louisiana) and increased by 121% in Appalachia over the same period. Natural gas proved reserves nearly doubled between 2015 and 2021 (latest) per EIA.

Additionally, as LNG exports require dry natural gas with the extraction of natural gas liquids (NGLs) like ethane, propane, butane, and pentanes-plus, another dynamic market feature has been to advantage the primary feedstocks for U.S. petrochemical production. U.S. NGL production grew by nearly 91.6% between Dec. 2015 and November 2023 (latest per EIA) while domestic NGL consumption increased by 35.2% over the same period. So, U.S. natural gas market fundamentals have positively evolved, and we must account for broad market conditions to assess the potential impact of LNG net exports on prices.

Variables to Explain U.S. Natural Gas Prices

With domestic natural gas prices and U.S. LNG exports, we have at this point analyzed two variables of interest but done so in isolation. Other economic measures that should influence natural gas prices include:

- **Price expectations** (the price level and whether it is expected to increase or decrease over time).
- **Working gas storage** (the amount in storage and its position relative to its historical 5-year range).
- **Pipeline natural gas net exports (imports).**
- **Total U.S. natural gas production and consumption.**
- **Seasonality/weather** (degree days) and an indicator for the **2020 COVID-19 pandemic**.

We also considered domestic oil prices since much natural gas production is associated with oil production.[8] Table 1 describes the measures employed here, their units, source, transformation (if any) by which they enter the model, and the sample mean and range for our monthly data spanning Jan. 2016 to Jan. 2024.

Table 1. Variables and Descriptive Statistics

Variable	Units	Transformation	Source	Mean	Min	Max
Natural gas spot prices at Henry Hub	$/mmBtu	first difference	EIA	3.393	1.695	9.143
Nymex natural gas month 1 futures prices	$/mmBtu	first difference	CME Group	0.007	-2.350	1.730
Futures price expectations (ratio of month 1 to month 4)	ratio	n/a	CME Group	0.957	0.687	1.354
Natural Gas Net Withdrawals from Inventory	billion cubic feet, end-of-period	n/a	EIA	0.377	-15.493	32.083
Nat. Gas Storage Position (ratio of current to 5-yr avg.)	ratio	n/a	EIA	1.015	0.911	1.214
LNG net exports	bcf/d	first difference	EIA	0.023	-1.930	1.309
Pipeline nat. gas exports	bcf/d	first difference	EIA	0.023	-1.849	3.002
Natural Gas Lower 48 States (excl GOM) Marketed Production	bcf/d	n/a	EIA	92.742	71.199	107.000
U.S. Natural Gas Consumption	bcf/d	n/a	EIA	83.103	61.033	115.861
Heating Degree Days, U.S. average	degree days	n/a	EIA	341.348	3.547	912.734
Pandemic indicator	binary	n/a	derived	0.227	0.000	1.000

Most of these variables are interrelated, so we employ a vector autoregression (VAR) framework that is appropriate for interrelated or endogenous variables. Each of them except weather and the pandemic indicator are assumed to be endogenous, so their own past values and past values of each of the other variables can influence the estimation. The weather/heating degree days and pandemic indicator variable are taken to be exogenous, so they are independent of the other variables.

Empirical results

Before estimation, we conducted tests for unit roots, stationarity, and cointegration, and we found that it is appropriate to apply VAR estimation to the data set. Natural gas (spot) prices and futures prices are expressed as first differences, which ensures stationarity. Based on the results of lag exclusion testing, we employ six monthly lags in the regression.[9] Each estimated equation is highly significant, and the one of prime interest that explains U.S. natural gas prices at the Henry Hub is a strong fit with the data.[10] Granger causality testing shows that natural

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[8] We developed specifications including domestic oil prices but found the variables presented herein were superior in their ability to forecast domestic natural gas prices.

[9] VAR lag exclusion Wald Tests show jointly that the first six monthly lags are significant with more than 99% confidence.

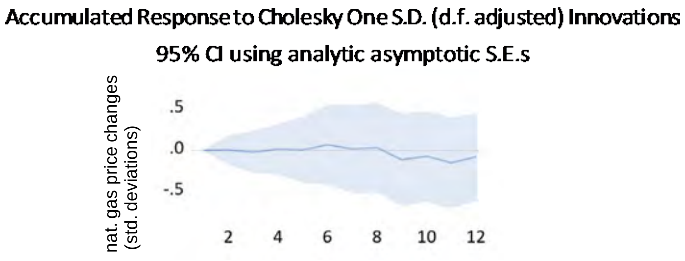
[10] Adjusted R-squared 0.907, F-statistic 3.842, Log likelihood -1.533, AIC 1.487.

gas prices are not Granger-caused by changes in U.S. LNG exports, so one cannot accurately project natural gas prices based on U.S. LNG net exports.[11]

As is typical for a VAR framework, we present outputs as follows:

1. Impulse response function (IRF) (i.e., how any given variable responds to shocks in another variable) and quantification of the cumulative sensitivity;
2. VAR variance decomposition (to identify how much a given variable contributes); and
3. Comparisons of actual data versus dynamic forecasts from the model.

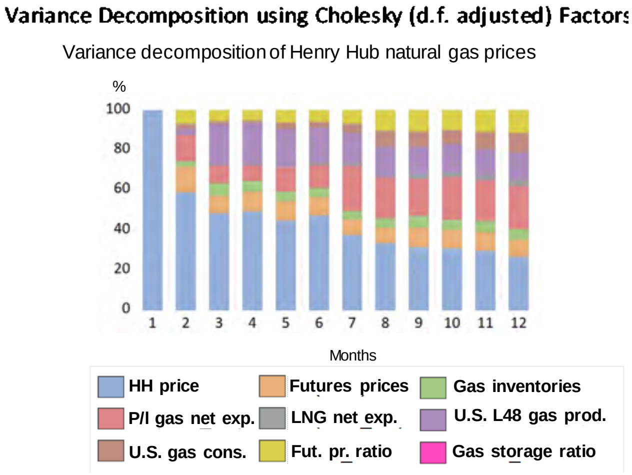
1. IRF for natural gas prices at Henry Hub, showing the accumulated response over 12 months of natural gas prices at Henry Hub to a standard deviation innovation in LNG net exports.


Accumulated Response to Cholesky One S.D. (d.f. adjusted) Innovations

95% CI using analytic asymptotic S.E.s

An IRF shows the responsiveness over time of one variable to an innovation in another in terms of standard deviations. This chart shows the cumulative effect on Henry Hub natural gas prices up to 12 months following a standard deviation increase in LNG net exports. The line in the middle of the shaded region shows the estimated impact on natural gas prices at Henry Hub, which statistically is not significantly different from zero. The shaded region shows a 95% confidence interval that also encompasses and is not significantly different than zero. Consistent with the correlation analysis in Section I, the IRF shows at five and six months a short-lived positive response of domestic natural gas prices to a shock in LNG exports, but it dissipates by month seven and corresponds with lower prices, but not significantly so, in months nine through 12. Consequently, one would not conclude that LNG net exports have a significant and sustained impact on domestic natural gas prices.

2. VAR Variance Decomposition


Variance Decomposition using Cholesky (d.f. adjusted) Factors

Variance decomposition of Henry Hub natural gas prices

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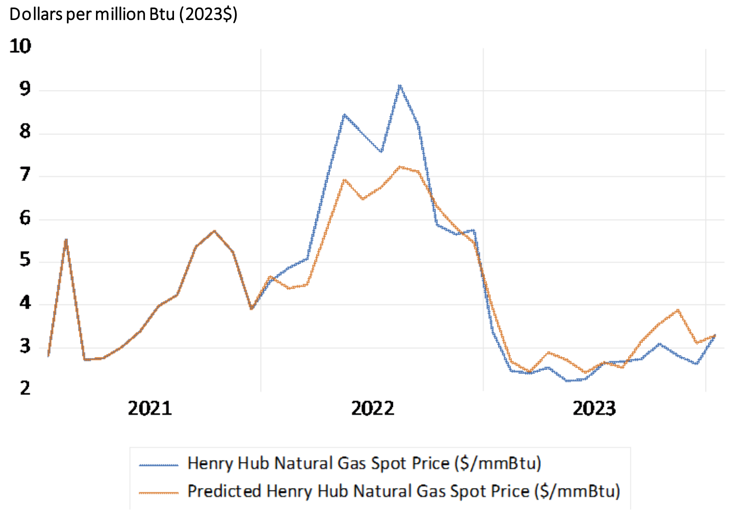
[11] Jointly, the specification Granger-causes prices with 99% confidence, but the Chi-square statistic of 11.2 for LNG net exports is not statistically with levels of confidence of 95% or greater.

Contributions to variance in the VAR model are shown and suggest that the past prices and futures price expectations account for over half of the variation in natural gas prices at Henry Hub. U.S. LNG net exports (grey) contributed negligibly to the variance in natural gas prices over a period up to 12 months.

3. Actual vs. predicted natural gas prices at the Henry Hub



A litmus for any model is whether it can forecast accurately out of sample, and this chart shows dynamic forecasts from the specification produced a mean error of +/- $0.29 per mmBtu (+/- 8.1%). This is a valid econometric specification and an appropriate framework by which to gauge relative contributions of the fundamental drivers, and it shows that U.S. LNG net exports are not a statistically significant driver of natural gas prices at Henry Hub.[12]

Implications and Conclusions

Based on correlation analysis as well as VAR analysis, we have demonstrated that U.S. LNG exports are not a significant driver of monthly domestic natural gas prices. This is mainly because LNG exports beget incremental new U.S. natural gas production. These findings are consistent with the commercial development of LNG export projects, which require billions of dollars for each project and where investors require reasonable certainty about the source of natural gas supply.

Until a new LNG export train begins operation, natural gas production and storage must place the new incremental gas production domestically, so it is reasonable to see brief periods when terminals are starting that directly correspond with prices. After operations begin and LNG exports continue at high-capacity utilization rates — almost regardless of domestic market conditions — LNG exports have supported steady gas production growth, drilling productivity, and reserve additions in areas like the Haynesville, Eagle Ford, and Permian basins, which are well positioned to support LNG exports in terms of their geography, infrastructure, and state business climates.

The VAR analysis also reinforces the well-established facts that natural gas prices tend to be correlated with one another over time and that future price expectations, which are economically linked to prices through the trading of natural gas price futures and options, also play an important role in establishing market-based prices. Distinguishing between changes in U.S. LNG exports that could have "surprised" markets, as opposed to those which are expected based on anticipated start-ups would be an additional wrinkle that could be modeled. Unintended events, such as the outage at Freeport LNG beginning in Jun. 2022, tend to increase domestic supplies, while the growth of LNG exports has been anticipated based on long-term planning for the export capacity, which must run at high capacity utilization rates to economically justify the investments.

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[12] The t-statistic on the accumulated response of LNG net exports on Henry Hub prices is 0.27, which is statistically insignificant.

In conclusion, our research demonstrates that U.S. LNG exports have not exerted any significant or sustained impact on domestic prices. Whether examining correlation analyses between domestic natural gas prices and U.S. LNG exports or employing robust modeling based on fundamental market drivers, it becomes evident that attributing higher U.S. natural gas prices to LNG exports would be inaccurate. On the contrary, LNG exports have spurred production and fostered productivity gains, thus contributing to sustained downward pressure on prices.

Armed with a clear understanding of these findings, U.S. natural gas producers and industrial consumers can forge more cohesive commercial arrangements that mutually benefit all parties involved. This alignment can also facilitate support for domestic production and infrastructure initiatives, thereby enhancing the resilience of the entire value chain.

Nevertheless, it is crucial to recognize the potential risks posed by short-sighted energy policies. Failure to acknowledge the positive role of natural gas in driving human and environmental progress, particularly in displacing biomass and coal consumption worldwide, could undermine the United States' growth and leadership in natural gas markets. Therefore, it is imperative to adopt forward-thinking policies that prioritize the interests of American consumers while fostering global sustainability and progress.