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Life Cycle Greenhouse Gas Emissions From U.S. Liquefied Natural Gas Exports: Implications for End Uses

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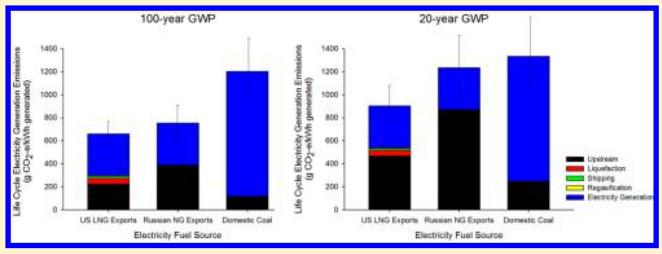
Supporting Information



ABSTRACT: This study analyzes how incremental U.S. liquefied natural gas (LNG) exports affect global greenhouse gas (GHG) emissions. We find that exported U.S. LNG has mean precombustion emissions of 37 g CO_2-equiv/MJ when regasified in Europe and Asia. Shipping emissions of LNG exported from U.S. ports to Asian and European markets account for only 3.5−5.5% of precombustion life cycle emissions, hence shipping distance is not a major driver of GHGs. A scenario-based analysis addressing how potential end uses (electricity and industrial heating) and displacement of existing fuels (coal and Russian natural gas) affect GHG emissions shows the mean emissions for electricity generation using U.S. exported LNG were 655 g CO_2-equiv/kWh (with a 90% confidence interval of 562−770), an 11% increase over U.S. natural gas electricity generation. Mean emissions from industrial heating were 104 g CO_2-equiv/MJ (90% CI: 87−123). By displacing coal, LNG saves 550 g CO2-equiv per kWh of electricity and 20 g per MJ of heat. LNG saves GHGs under upstream fugitive emissions rates up to 9% and 5% for electricity and heating, respectively. GHG reductions were found if Russian pipeline natural gas was displaced for electricity and heating use regardless of GWP, as long as U.S. fugitive emission rates remain below the estimated 5−7% rate of Russian gas. However, from a country specific carbon accounting perspective, there is an imbalance in accrued social costs and benefits. Assuming a mean social cost of carbon of $49/metric ton, mean global savings from U.S. LNG displacement of coal for electricity generation are $1.50 per thousand cubic feet (Mcf) of gaseous natural gas exported as LNG ($.028/kWh). Conversely, the U.S. carbon cost of exporting the LNG is $1.80/Mcf ($.013/kWh), or $0.50-$5.50/Mcf across the range of potential discount rates. This spatial shift in embodied carbon emissions is important to consider in national interest estimates for LNG exports.

INTRODUCTION

United States natural gas production is projected to reach 36 trillion cubic feet (Tcf) by 2040, representing an increase of 52% from 2012.[1] This abundance of domestic energy resources is seen by various stakeholders as a geopolitical advantage, an economic opportunity, and a pathway for increased environmental damages. Although use of natural gas results in greenhouse gas (GHG) emissions, life cycle emissions from the natural gas electricity generation supply chain are estimated to generally be lower than those from coal electricity generation.[2,3] Natural gas has often been discussed as a "bridge fuel" that could be used as a coal replacement until the transition to large-scale reliable renewable energy sources. The viability of natural gas as a bridge fuel depends on assumptions about stabilization objectives, emissions, and technological change.[4−7]

Prior to 2008, U.S. domestic natural gas production did not meet projected demand growth, and the national natural gas debate centered on LNG imports. As unconventional natural gas production (shale gas) became economically viable, U.S. technically recoverable natural gas reserves increased by 665 Tcf, which represents an increase in total U.S. natural gas resources of 38%.[8] As domestic natural gas production increased, supply flooded the market and wellhead prices in today's dollars in the U.S. dropped from close to $9/Mcf in 2008 to under $3/Mcf in 2012.[9] Because of higher natural gas prices in other regions, producers are hoping to sell incremental quantities of natural gas to economically attractive Asian and European markets.[10] This has prompted a debate in the United States on the policy of liquefied natural gas (LNG) exports regarding whether additional LNG exports to non-FTA countries should be approved, and if so to what capacity.

Globally, the LNG trade reached about 12 Tcf of natural gas in 2012,[11] and based on the projects worldwide currently under construction or proposed, liquefaction capacity could increase by more than 100% within the next 10 years.[12] The primary LNG importers are expected to be the rapidly developing countries in Asia and some European countries such as the UK, Spain, and France seeking to both supplement and diversify their natural gas supply.[12]

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The Natural Gas Act, as amended, requires the U.S. Department of Energy (DOE) to determine if LNG exports are in the "national interest" in order for approval. Additionally, the current regulatory framework requires exports to countries with which the U.S. has a free trade agreement (FTA) to be rapidly permitted, while applications to export to non-FTA countries must undergo additional assessments.[13] The national interest determination involves consideration of economic, international, and environmental factors. To date, the DOE has approved 37 applications to FTA countries totaling 14 Tcf of natural gas exports annually, and has issued nine final and conditional approvals of applications to non-FTA countries, totaling almost 3.8 Tcf/year.[13]

Historically, the DOE granted conditional approval prior to a full National Environmental Policy Act (NEPA) review. However, a regulatory change (effective August 2014) now requires LNG export applications from the lower 48 states to non-FTA countries pass the NEPA review process prior to the issuance of any export permits.[13] It is likely that this recent streamlining of the approval process of LNG export projects will lead to an increase in export capacity in the near future.

In light of the recent discussions regarding the non-FTA export approval process, the DOE released studies focusing on the upstream environmental impact of increased natural gas production[14] and the global emissions impact of increased LNG exports.[15] While the Federal Energy Regulatory Commission (FERC), the lead agency for environmental review of non-FTA export applications, only formally requires a report on direct, localized environmental impacts resulting from the construction and operation of the export facility,[13] the DOE authorized these analyses as part of a broader effort to inform LNG export decisions.[16] Although the latter study models life cycle emissions of LNG exports, its specificity to the electricity sector limits its robustness as an analysis of net global changes in GHG emissions resulting from U.S. exports (see Supporting Information (SI) Section 10).

In addition to the Skone et al. (2014) analysis, previous work has been done to quantify the GHG emissions from the LNG life cycle for electricity generation,[2,17−19] as a shipping fuel,[20] and as a heavy-duty vehicle fuel.[21] However, these other studies do not account for upstream emissions from unconventional natural gas development and do not include distributions to represent uncertainties of key parameters. This study first expands upon the previous attributional life cycle analyses by considering additional uncertainties in the LNG life cycle such as GWP, fugitive emissions rate, percent methane of natural gas, shipping distances, and liquefaction emissions. This study then seeks to further inform decisions about the potential environmental impact of LNG exports through a scenario-based first order consequential analysis in which the net change in GHG emissions resulting from natural gas displacement of coal or Russian natural gas is calculated on a per kWh or per MJ basis. Finally, although all net savings in emissions benefits the global environment, this study considers trade-offs in where along the supply chain the emissions occur from a country specific carbon accounting perspective. These trade-offs are monetized using the emerging regulatory analysis metric, the social cost of carbon (SCC), as used by the U.S. federal government[22] in order to quantify country specific carbon accountability that would be relevant in the potential future scenario of an embodied carbon tax on exports. The social cost of carbon is the estimated global damages caused by an additional metric ton of CO_2 released into the atmosphere. Some of the monetized potential climate change damages considered in the SCC calculation include the impact of climate change on agriculture, water resources, air quality, human health, ecosystem services, and property damage from increased flood risk.[23]

■ MATERIALS AND METHODS

This work builds upon estimates from previous studies of upstream natural gas emissions[24,25] and LNG supply chain emissions[18,19] in order to develop an attributional life cycle assessment (LCA) of the GHG emissions of LNG exports from the United States. The assembled data was compiled into a Monte Carlo simulation to account for uncertainty in emissions from each stage in the LNG export life cycle. The results of the LCA simulation were then incorporated into a first order consequential life cycle assessment considering the impact of U.S. LNG exports displacing coal and Russian natural gas for electricity generation and industrial heating in Asia and Europe.

In this study, a "first order consequential" analysis is defined as a scenario-based comparison that serves to illustrate potential relevant impacts of a policy based on a qualitative description of conceivable market responses to the policy. For example, in this analysis, the policy being considered is an increase in U.S. LNG exports. Some potential market responses to this policy discussed in this analysis include decreased coal use for electricity and/or heat generation, decreased Russian natural gas use for electricity and/or heat generation, increased domestic natural gas production, and a shift toward increased domestic coal use. While a first order consequential analysis does not seek to quantify the degree to which these responses to a policy occur, the scenarios serve as a bounding analysis that can inform decision makers of nonintuitive potential market based consequences of a policy.

Global Warming Potential. For the upstream production and shipping stages of this LCA, both 100 and 20-year global warming potentials (GWP) for methane (fossil methane with climate carbon feedbacks) from the IPCC fifth assessment report (AR5) were used.[26] Uncertainty for both GWPs was quantified using a normal distribution based on the reported mean and 90% confidence interval. The distribution for the 100-year GWP has a mean of 36 and a standard deviation of 8.5, and the 20-year GWP has a mean of 87 and a standard deviation of 15.9. Given the wide range of uncertainty presented in AR5 and the continuing trend of increasing the GWP estimates with each assessment report, it is important to represent the complete distribution of possible values when simulating emissions. For example, with uncertainty it is possible that the 100-year GWP of methane could be double the AR4 estimate of 25. The exception to this use of the AR5 distribution in this model is for the liquefaction and regasification life cycle stages (see SI section 3).

Upstream Emissions. In this study, the upstream natural gas process included well construction, well operation, natural gas processing, and pipeline transportation to a liquefaction facility at an export terminal. Weber and Clavin (2012) assessed five previous life cycle studies and used those estimates to develop "best guess" distributions for each of these upstream stages for both shale and conventional sources of natural gas.[24] According to the Energy Information Administration (EIA), shale gas currently accounts for 40% of U.S. natural gas production.[1] The total upstream GHG emissions were therefore calculated as a weighted average of shale and conventional production emissions estimates. The inputs to

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the upstream portion of the Monte Carlo simulation, as well as a description of the validation of the upstream model can be found in SI section 2.

There is significant debate in the literature over the fugitive emissions rate for the upstream natural gas life cycle stages. As such, in this analysis the fugitive emissions rate is presented in three ways: (1) a "most likely" range commonly cited in literature.[27−32] This uncertainty is represented as a triangular distribution with a minimum of 2%, maximum of 4% and most likely value of 3%, (2) a sensitivity analysis showing the effects of fugitive emissions rates across a range encompassing most values discussed in the literature[33,34] (1−9%, see SI Figure S4), and (3) a discussion of the break-even fugitive emissions rate that would change the result of the analysis.

Liquefaction Emissions. After the natural gas is produced, processed, and transported to the export location, it must be liquefied. Emissions from liquefaction derive from fuel combustion for electricity, natural gas venting, and fugitive methane leaks. There are several cooling technologies that may be used in a liquefaction terminal, each with unique energy requirements and energy efficiencies. Additionally, the capacity of the facility and the ambient temperature of the environment affect the efficiency and energy consumption. As a result, there is a wide range of estimated liquefaction GHG emissions in both peer-reviewed literature and in publicly available environmental impact assessments from the private sector. The literature is generally not transparent in the specific technology analyzed, either for proprietary reasons or because it was not considered important. To account for this variability, a distribution was fit to these point estimates. Using the upper or lower bound did not significantly alter the overall life cycle emissions (SI Figure S1).

Shipping Emissions. LNG is transported on large ocean going vessels with capacities ranging from 75 000 to 265 000 m^3 of LNG.[36] Traditionally, LNG tankers run on steam engines powered by boil off gas (BOG). On average, BOG generated is approximately 0.15% by volume per day.[35] Tankers may have regasification facilities on board to supplement the BOG volume. However, in construction of new very large capacity tankers, there has been a transition to dual-powered diesel engines. These tankers are powered by diesel and reliquify the BOG onboard the vessel.[36] This technology is economically preferable for large cargos over long distances because the engines are more efficient and the full cargo of profitable LNG remains available for sale at the destination port. To quantify the impact the tanker technology has on the life cycle LNG emissions, the simulation was run under two different cases: a 140 000 m^3 capacity tanker powered by BOG generated steam supplemented with regasification technology, and a 265 000 m^3 capacity tanker powered by diesel, reliquefying all of the BOG. These cases were chosen to bound the emissions because they represent the traditional and modern typical capacities and engine technologies. In both cases, port turn-around time was assumed to be 3 days, and the return trip was assumed to be of equal distance (returning to the port of origin) and fueled by diesel. In reality, a tanker fueled by BOG would likely retain enough LNG in its tanks to fuel the return voyage. Additionally, because there is a network of tankers, rather than being commissioned at its original port of origin, the tanker would likely be sent to the nearest port for its next LNG cargo. Therefore, these last two assumptions result in conservative estimates of the shipping emissions, which are likely to result in an upper bound shipping emissions estimate. For both cases the percentage of the journey spent in each engine mode was calculated according to Corbett (2008).[37] Finally, steam and diesel engine efficiencies and associated combustion factors were represented by triangular distributions to capture the uncertainty (SI Table S8). In accordance with the assumption in the literature,[15,18] this simulation presumes that there are no fugitive emissions released during shipping.

One parameter that could be expected to influence the environmental impact of LNG exports is the shipping distance. This shipping distance is determined as the most efficient trade route between the port of origin and the importing country. For this study, we chose three export terminals in the U.S.: Sabine Pass, TX, Coos Bay, OR, and Cove Point, MD. These three were chosen because they are either already approved to export LNG or have applied for DOE approval to export, and for their geographic diversity; the locations represent the maximum and minimum distance traveled from the U.S. to any one of the importing countries. For the import terminals, we selected ports in six countries: China, India, South Korea, Japan, UK, and The Netherlands. These countries were chosen because they are in the two key economically attractive markets (Asia and Europe) that either traditionally have imported large quantities of LNG or are expected to do so in the future. The distances traveled from each port of origin to destination were calculated using a port distance calculator,[38] assuming that the Panama Canal upgrades were complete and therefore the canal was able to accommodate the large LNG tankers. The motivation behind this analysis is to understand if the origin and destination of the LNG impact life cycle emissions such that the DOE should consider contracted destinations of the LNG as part of the permitting approval process.

Regasification Emissions. The regasification stage of the LNG life cycle is the least discussed topic related to LNG in existing literature. There is a wide variation in energy required for regasification due to differences in ambient air temperatures and availability of resources such as seawater for heating, which can displace some of the energy requirements. Furthermore, regasification facilities can be colocated near power plants or other manufacturing facilities that require cooling. This colocation minimizes direct emissions from energy required to regasify the LNG.[36] For this study, a triangular distribution as described by Venkatesh (2011) was used to represent the uncertainty in emissions from the regasification component of the LNG process.[2] Total life cycle emissions through the regasification stage (including upstream, liquefaction, shipping, and regasification) are precombustion emissions. In this study, these emissions will be referred to as "landed emissions" since they represent the total GHGs emitted through the process of getting the natural gas on shore (i.e., to land) for use at the destination port. SI Table S10 provides estimates of landed LNG emissions for export origins and import destinations.

First Order Consequential Analysis. The results of the LCA were then used to conduct a first order consequential analysis of net GHG impacts resulting from U.S. exports, which considered the net change in emissions based on how the global market might respond to increased natural gas availability. As previous studies have discussed,[15] one possible outcome of U.S. LNG exports is that the natural gas could be used to replace existing fuel sources for electricity generation. For example, a country might choose to increase electricity production in natural gas combined cycle (NGCC) power plants, thereby reducing their reliance on coal power plants. Additionally, due to either price differentials or geopolitical

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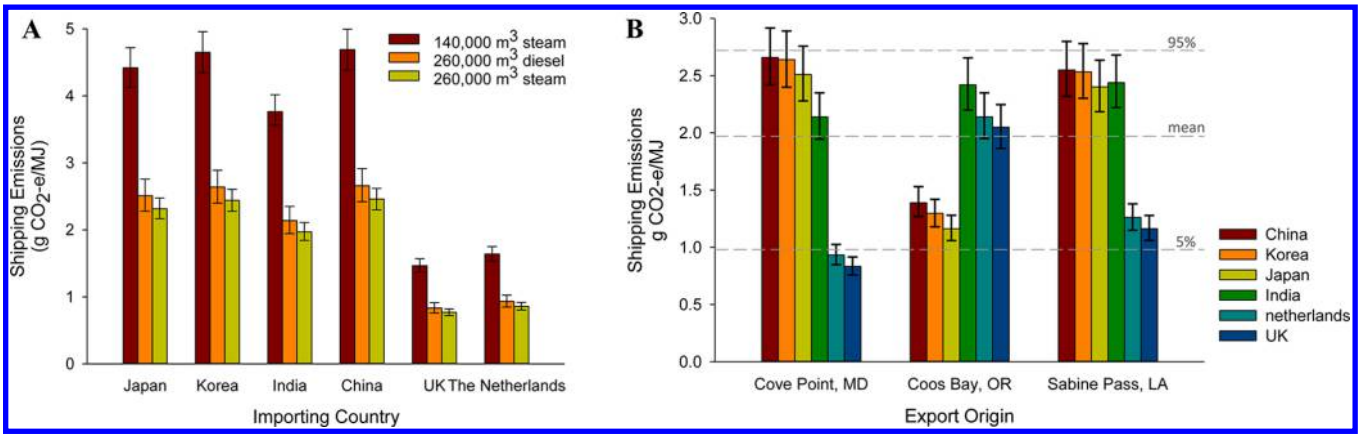

Figure 1. (A) The shipping GHG emissions from Cove Point, MD to six import countries assuming a 140 000 m^3 steam tanker equipped with on board regasification (brown), a 260 000 m^3 diesel tanker equipped with reliquifaction (orange), or a 260 000 m^3 steam tanker equipped with on board regasification (green), and B) Shipping emissions from U.S. ports to six import countries, assuming 260 000 m^3 diesel vessel, and the mean and 90% confidence interval from the distribution fit to all 18 voyage distances (dashed gray lines). Note: a 260 000 m^3 tanker equates to a capacity of about 5.5 Bcf in gaseous form and a 140 000 m^3 tanker equates to a capacity of about 3 Bcf in gaseous form.

reasons, a country may chose to use U.S. LNG as a replacement for natural gas previously imported from Russia or the Middle East. For this study, upstream coal life cycle emissions were obtained from Venkatesh et al. (2012)[39] and adjusted to the AR5 GWP, and coal power plant combustion emissions were obtained from a distribution fit to the data from Steinmann et al. (2014) (see SI section 6).[40] Emissions from Russian natural gas transported via pipeline were estimated using the same upstream and combustion emissions as the LNG exports. To account for the increase in pipeline transport distance associated with exporting natural gas from Russia, 3% was added to the U.S. fugitive emissions rate distribution. For example, where the average fugitive emission rate used to represent U.S. upstream production and transport was 3%, the average was assumed to be 6% for Russian upstream production and transport. This follows the Skone et al. (2014)[15] method to account for the extended pipeline transport distance required for Russian exports. This is likely to be a conservative estimate, as operational differences between U.S. and Russian natural gas production could further increase the Russian fugitive emissions rate (See SI Section 6).

While electricity generation is the most common end use, natural gas is also regularly used as a source of thermal energy. Therefore, in order to depict broader representation of potential end use pathways, fossil fuel combustion for industrial heating was also included in this first-order consequential analysis. For this study, a range of efficiencies and combustion factors were used for both natural gas and coal fired industrial boilers in order to capture the uncertainty in emissions (See SI Section 7).

Another important component of a first order consequential analysis is to identify domestic opportunity costs of exporting natural gas rather than consuming it through domestic combustion. The end use and fuel displacement consequences described above all implicitly assume that U.S. demand would remain relatively flat, and in the absence of U.S. exports, there would be no additional natural gas produced for domestic use. While this study does not attempt to quantify the level of displacement through a global energy market model, it serves as a first step toward understanding potential consequences of displacement through bounding scenario-based assumptions. For example, this study explores the potential that given current U.S. natural gas electricity generation capacity, U.S. natural gas demand could increase such that all of the presumed export volume could be combusted domestically and displace U.S. coal baseload electricity generation. As a basis for this scenario, combustion emissions of U.S. coal power plants were compared to regional and global coal power plant average emissions. Data for this comparison were drawn from the EPA eGRID database[41] and from Steinmann et al. (2014) that used regression models to predict coal power plant emissions factors.[40] Coal plants from eGRID were limited to those with a nameplate capacity of over 100 MW with no combined heat and power generation. Furthermore, the plants were limited to those that were fueled by coal for over 95% of the electricity generated annually. It is important to note that this is a bounding analysis; in reality the electricity sector is complex and direct substitution occurring linearly in the short term based on cost differential is a simplifying assumption. Additionally, a decreased domestic demand for coal could increase the competitiveness of steam coal exports, which may either reduce some of the GHG benefits of increased domestic natural gas consumption[42] or contribute to further reducing global GHG emissions, such as in the case where U.S. PRB coal replaces other coal sources in new high efficiency coal-fired power plants in South Korea.[43]

■ RESULTS

This study quantifies the GHG emissions from the production, liquefaction, shipping, and regasification phases of the supply chain, as well as the end use of the fuel in both the electricity and industrial heating sectors. These life cycle GHG emission results are discussed in the context of replacing alternative fuel sources, including locally produced coal and natural gas transported via pipeline from Russia.

Attributional Life Cycle Emissions. Mean landed (precombustion) life cycle GHGs for exported U.S. LNG after regasification at the importing country were found to be 37 g CO_2-equiv/MJ with a range of 27 to 50 (SI Figure S2). Of these landed emissions, the shipping stage of the life cycle contributes an average of 5%. Tanker capacity, rather than shipping distance or fuel type, is the most significant factor in determining shipping GHG emissions (Figure 1A). An analysis of the impact of origin and destination on shipping emissions is

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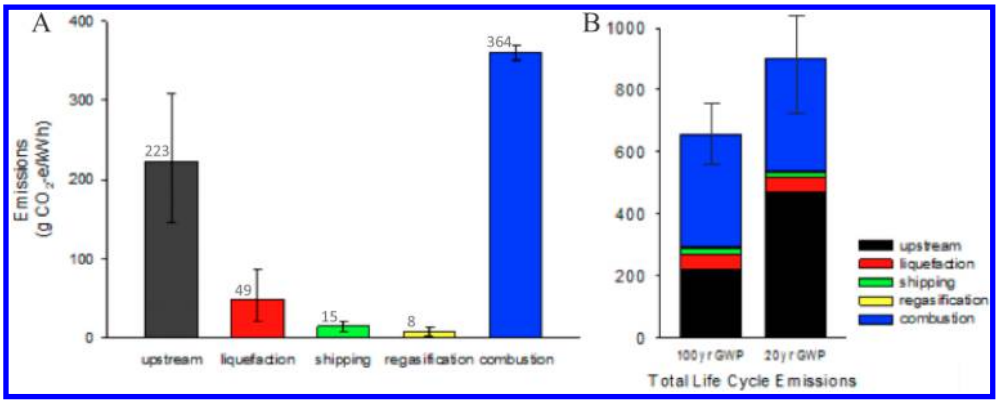

Figure 2. Life cycle emissions for electricity generation from natural gas exports (A) by life cycle stage for a 100-year GWP, and (B) for the complete life cycle for both a 100-year and 20-year GWP.

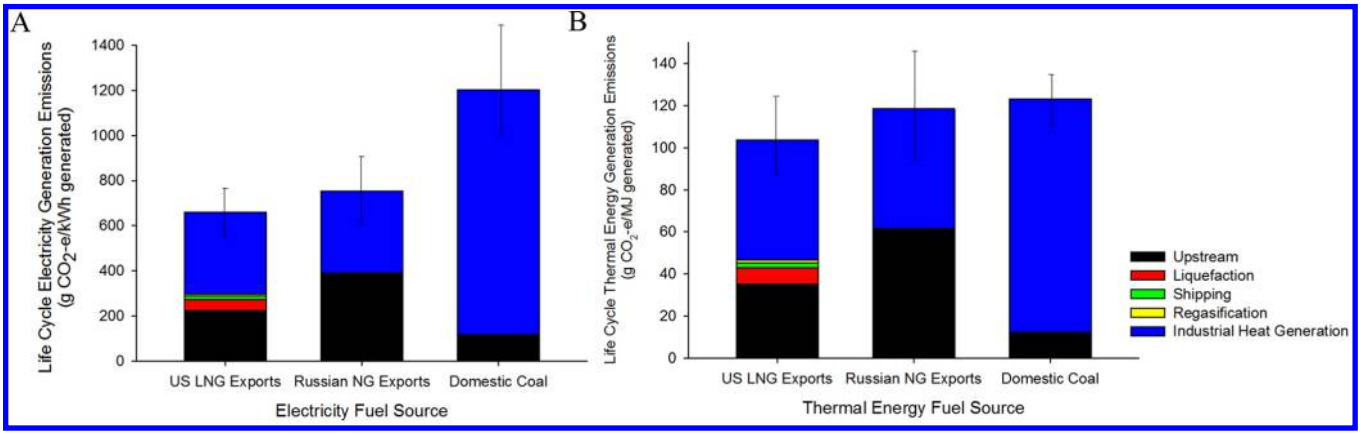

Figure 3. Comparison of emissions from U.S. LNG exports, Russian natural gas, and coal using a 100 year GWP for (A) electricity generation and (B) industrial heating.

shown in Figure 1B. Both the average shipping and average landed life cycle emissions and 90% confidence intervals from each port of origin to each importing country can be found in SI (Tables S9 and S10).

Life cycle emissions from exported LNG were found on average to be 655 g CO_2-equiv/kWh for electricity generation and 104 g CO_2-equiv/MJ for thermal energy generation. These emissions primarily result from upstream production and downstream combustion. The liquefaction, shipping, and regasification components of the life cycle contribute an additional 72 g CO_2-equiv/kWh over the domestic natural gas electricity generation life cycle emissions from production and combustion (Figure 2). Therefore, exporting natural gas instead of combusting it domestically increases emissions from natural gas electricity generation by an average of 11%.

The life cycle emissions from LNG exports are most sensitive to the GWP and fugitive emissions rate (SI Figure S9). This implies that increases in efficiency in these processes, such as colocating regasification facilities with power plants to use waste heat to regasify the LNG, would have a nominal impact on life cycle emissions. While still beneficial from an economic and absolute emissions perspective, the discussion of future efficiency increases related to the LNG process is not relevant to decisions based on life cycle emissions. A summary of the key parameters and their impact on the total life cycle emissions for electricity generation (based on the Spearman correlation coefficient) is outlined in SI Section 8.

First Order Consequential Analysis. When considering the global benefits of LNG exports, the life cycle LNG emissions must be compared to emissions from alternative sources of fuel that U.S. exports would displace. The two most likely candidates for replacement would be coal and Russian natural gas.[15] The results of a Monte Carlo simulation show that the benefit of displacing either of these two sources of fuel depends on the GWP metric chosen and is highly sensitive to the upstream fugitive emissions rate from natural gas production and pipeline transport. When considering a 100-year GWP, mean life cycle emissions from exported U.S. LNG are 13% lower than those from Russian natural gas exports, and result in about 45% fewer emissions than coal electricity generation (Figure 3A). When considering a 20-year GWP, exported U.S. LNG would reduce emissions from electricity production via Russian gas by 27% and cut emissions from electricity production from coal by 32% (SI Figure S3B). The higher emissions from Russian natural gas are due to the higher leakage rate assumed to account for the longer pipeline transport distance. This further emphasizes the fact that emissions from liquefying, shipping, and regasifying natural gas are marginal relative to the production and combustion emissions, and that the life cycle emissions of natural gas production are highly dependent on the fugitive emissions rate.

In addition to electricity generation, natural gas is often used for industrial heating. Both coal and natural gas-fueled industrial boilers have higher efficiencies than power plants. As a result, coal use for industrial heating is more competitive

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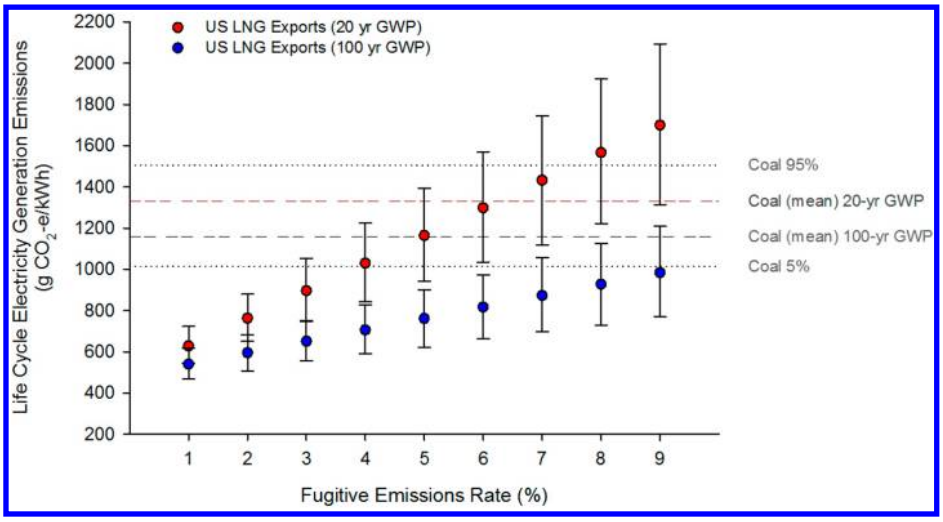

Figure 4. Sensitivity of life cycle emissions of LNG exports for electricity generation to fugitive emissions rates. The mean 100-yr and 20-yr GWP coal life cycle emissions and the 100-yr GWP 90% confidence interval are included for reference. Similar graphs are available comparing LNG exports to Russian natural gas exports for electricity generation (SI Section 6) and comparing LNG exports to both coal and Russian natural gas for heating (SI Section 7).

with LNG on a life cycle GHG emissions basis. When considering a 100 yr GWP, mean GHG emissions from U.S. LNG exports would be 16% and 13% lower than industrial heating fueled by Russian natural gas exports and coal, respectively. However, when using a 20-year GWP, mean GHG emissions from U.S. exports would be 4% higher than coal (SI Figure S6B). Despite this increase in emissions, it is important to note that if LNG were to displace Russian natural gas, it would reduce emissions by 27% (SI Figure S6B). This is illustrative of the complexity of quantifying net impact of LNG exports; there are numerous first-order consequential pathways influenced by the emergence of a U.S. natural gas export market, and the specific end use and resulting fuel displacement is outside the domain of control of U.S. policymakers who need to approve LNG projects.

Domestic Opportunity Cost. When comparing average coal power plant combustion emissions, there is no significant regional variation (SI Figure S10).[40] Therefore, all else being equal there are no marginal benefits of displacing coal emissions in Asia or the EU versus domestically in the United States. As a result, displacing U.S. coal generation by combusting U.S. natural gas is more efficient in reducing global GHGs than exporting it abroad; an equivalent reduction in combustion emissions can be obtained without the additional supply chain emissions required by the liquefaction, shipping, and regasification steps for export. Again, however, it is important to note that there is not a linear relationship between natural gas price and coal substitution,[42] and therefore the potential for this domestic absorption of excess supply would likely be both market and policy driven. Additionally, there would be market changes resulting from this shift in U.S. natural gas consumption. For example, there could be an increase in U.S. coal exports which may serve to either increase or decrease net GHG emissions depending on where it is combusted and what fuel it displaces.[43] This wide range of possible market consequences makes the net impact of increased domestic natural gas use uncertain.

■ DISCUSSION

The current environmental component of the national interest calculation considers only localized environmental impacts directly related to the liquefaction project under review.[13] However, as the DOE and NEPA processes have begun to recognize,[16,44] it is also important to consider both the upstream emissions of increased natural gas production and the downstream life cycle emissions from these LNG export projects in order to ensure the U.S. is contributing to the minimization of global net GHG emissions. This analysis can then serve as a basis for determining the social cost of carbon embodied in these U.S. exports, which affects both country-level GHG emissions inventories and the potential for future domestic GHG reductions.

This study found that the emissions from the liquefaction, shipping, and regasification segments of the LNG life cycle are fewer than 11% of the total life cycle emissions of LNG exports for electricity generation based on a 100-year GWP and 3% average fugitive emission rate. This percentage would continue to decrease as a result of increased methane leakage rates and/or a 20-year GWP assumption (Figure 4). Based on a sensitivity analysis of these results (SI Figure S9), the key model parameters that can have a significant impact on the LNG life cycle emissions are the end use efficiency, the GWP (both time horizon used, and value within a given time horizon probability distribution), and the fugitive emissions rate. Other uncertain parameters, however, such as liquefaction plant efficiency, tanker capacity, tanker fuel, and shipping distance can vary widely without materially affecting the overall life cycle emissions.

From a first order consequential perspective, we found that mean global GHG savings from U.S. LNG exports are likely associated with coal displacement for electricity generation. The break-even point for GHGs from U.S. LNG and coal electricity would be over a 9% fugitive emissions rate using a 100-year GWP, and a 6% fugitive emissions rate using a 20-year GWP (Figure 4). Additionally, GHG savings from U.S. LNG exports can be achieved through displacing coal for industrial heating. Using a 100 yr GWP, the break-even point for heating is a 5% leakage rate. However, on a 20-year GWP basis, U.S. natural gas

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displacement of coal for heating would be advantageous only up to about a 3% fugitive emissions rate (SI Figure S7). Finally, GHG savings are also associated with displacement of Russian pipeline natural gas for both electricity generation and industrial heating regardless of GWP, as long as the U.S. fugitive emission rate remains below the estimated 5−7% rate of Russian natural gas (See SI Sections 6 and 7).

While this study focused on electricity generation and industrial heating as two important end uses of natural gas, there are several additional end uses, including transportation, residential heating and cooking, and petrochemical production. The existence of these additional potential end uses further complicates the uncertainty in the emissions savings from U.S. LNG exports. Rather than outline all possible end use permutations and potential fuel displacement, the implication for the U.S. is that in order to ensure maximum GHG benefits of LNG exports, fugitive emissions rates from upstream production and pipeline transmission must be reduced as much as possible. This is important because while the U.S. cannot designate a specific end use of the LNG, the U.S. fugitive emission rate is within the U.S. regulatory domain. The government has recognized the importance of minimizing methane leakage as a step toward reducing the U.S. contribution to climate change.[45] As regulation progresses and the domestic fugitive emissions rate decreases, it will become more likely that LNG exports will result in global emissions savings.

An additional consideration in the evaluation of the U.S. national interest of LNG exports beyond the first order absolute net global emission savings is the GHGs embodied in trade.[46,47] The embodied CO_2 equivalent emissions in the exported LNG have implications for social impacts along the LNG supply chain that are not captured through a life cycle analysis. This affects both country-level GHG emissions inventories and the potential for future reductions. Because approximately 41% (58% using a 20-year GWP) of life cycle LNG export emissions would arise from domestic extraction, pipeline transport, and liquefaction, increased extraction of natural gas without the domestic benefits of reduced combustion emissions would likely not be advantageous for the U.S. from a country-based carbon accounting perspective. Our mean estimates are that each thousand cubic feet (Mcf) of natural gas loaded onto a ship in liquefied form at a U.S. port represents about 0.037 t of GHGs (for 100 yr GWP from production, transmission and liquefaction). Using the 2020 social cost of carbon ($2014) from the U.S. Interagency Working Group[22] for a 3% discount rate of $49/metric ton GHG, this means each Mcf of natural gas converted to LNG and exported from the U.S. for electricity generation potentially could cost the U.S. about $1.80 of social cost for embodied GHGs, or $0.50 to $5.50/Mcf across the full range of estimates for the 2020 social costs of carbon. Assuming a natural gas price of $4/Mcf, exporting LNG could have a social cost of between 12.5% to 137% of the market price. Because climate change damages are global, potential GHG reductions in other countries also benefit the U.S. As an illustrative example, using $49/ton GHG as a social cost, 1 kWh of electricity generated by coal in the United Kingdom (UK) has a social cost of carbon of about $0.06. In contrast, 1 kWh of natural gas generation using LNG imported from the U.S. has a total social cost of about $0.032/kWh, with $0.013 of this cost comprised of U.S. production, transmission and liquefaction. Therefore, while U.S. LNG displacing coal in the UK results in a net global social cost savings of about $0.028/kWh ($0.06-$0.032), from a country-level accounting perspective, the U.S. incurs more costs than benefit; the U.S. incurs the aforementioned cost of $0.013 while the UK sees a cost savings of about $0.04 composed of the difference in social cost resulting from coal production and combustion versus the social cost attributed to LNG shipping, regasification, and combustion. Both the monetized global savings from LNG exports and the domestic cost of the embodied carbon are likely underestimates, as new evidence suggests the social cost of carbon may be several times larger than previously estimated.[48] This is an important consideration because increased international fossil fuel trade has prompted the discussion for new climate policies that recognize the responsibility of embodied carbon contributions at all points in the supply chain of goods and services, including mechanisms to account for carbon emissions at the point of fossil fuel extraction.[49,50] The economic benefits of natural gas development explicitly for export needs to be analyzed against the monetized domestic social costs. These include environmental and public health risks, and potentially the expected increase in costs for domestic emissions reductions. This social cost differential may be important to consider as a component of the national interest determination, among other regional social costs of shale gas production such as air, water, and road impacts.[51−53]

This study raises important policy implications for consideration in evaluating the national interest of LNG exports. From a global emissions perspective, this study has shown that exporting LNG can help to reduce life cycle GHG emissions from electricity generation and industrial heating. However, the extent to which this net reduction is realized depends on the end use of the fuel, the upstream methane leakage rate, the fuel displaced by the natural gas use, and the downstream consequences of the displaced fuel source. The downstream consequences of the fuel displacement, such as cheaper coal, can induce a rebound effect of additional fossil fuel consumption. While this may in fact increase net GHG emissions, it is important to also consider the economic benefits and accrued social benefits from the increased access to energy services. This demonstrates the complex interaction between environmental, social, and economic consequences that extend beyond what is captured through life cycle assessment and the current national interest determination. However, by quantifying both the direct GHG emissions from the LNG life cycle and the first order net impacts of fuel substitution and alternative end uses, the bounding scenarios in this study provide an important perspective in further informing the environmental component of the national interest discussion. In order to reduce the uncertainty of whether exports would result in a net global benefit, it would be most productive for U.S. policy to focus on incentivizing reductions in domestic fugitive emissions rates, including conducting more accurate and consistent leakage monitoring and indicting penalties for infractions, rather than prioritizing increased liquefaction, shipping, or regasification efficiency. Additionally, when discussing the national interest of LNG exports, it may be important for the U.S. to consider embodied carbon emissions in trade and identify the social cost accrued by the U.S. on behalf of global net GHG savings.

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■ ASSOCIATED CONTENT

Supporting Information

Additional information on methods, detailed calculations, supplementary results, and references is included. This material is available free of charge via the Internet at http://pubs.acs.org/

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Notes

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