Global Liquefied Natural Gas Expansion Exceeds Demand for Coal-to-gas Switching in Paris Compliant Pathways

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ABSTRACT

The shift from coal to natural gas (NG) in the power sector has led to significant reductions in carbon emissions. The shale gas revolution that led to this shift is now fueling a global expansion in liquefied natural gas (LNG) export infrastructure. In this work, we assess the viability of LNG expansion to reduce global carbon emissions through coal-to-gas switching in the power sector under three temperature targets – Paris compliant 1.5ºC and 2ºC, and business-as-usual 3ºC. In the near term (pre-2038), LNG-derived coal-to-gas substitution reduces global carbon emissions across all temperature targets as there is significantly more coal power generation than the LNG required to substitute it. However, we find that long-term planned LNG expansion is not compatible with the Paris climate targets of 1.5ºC – here, the potential for emissions reductions from LNG through coal-to-gas switching is limited by the availability of coal-based generation. In a 3ºC scenario, high levels of coal-based generation through mid-century make LNG an attractive option to reduce emissions. Thus, expanding LNG infrastructure can be considered as insurance against the potential lack of global climate action to limit temperatures to 1.5ºC or 2ºC. In all scenarios analyzed, low upstream methane leakage and high coal-to-gas substitution are critical to realizing near-term climate benefits. Investors and governments should consider stranded risk assets associated with potentially shorter lifetimes of LNG infrastructure in a Paris-compatible world.

Keywords: LNG, life cycle emissions, coal-to-gas switching, Paris Agreement, climate policy

1 Introduction

Natural gas (NG) accounted for about a quarter of global primary energy demand in 2017 [1]. The rise of NG as a major fuel source in electricity generation has led to significant reductions in carbon emissions by displacing generation from high-emitting coal plants [2-10]. For every unit of electricity generated, NG power plants emit roughly half as much carbon dioxide (CO_2) as coal [11]. The U.S. Energy Information Administration (EIA) in its international energy outlook projects that global demand for NG will increase by over 40%

between 2018 and 2040, with a majority of the growth in developing economies [1]. NG consumption for electricity generation in non-Organization for Economic Co-operation and Development (OECD) countries will increase more than 60%, at 1.5% per year, compared to a rate of 0.9% per year in OECD countries [1]. Growth in global demand is driven by several factors including the closures of nuclear power plants in Europe and Asia that have further increased imports of NG to substitute for the loss of carbon-free power [12-14]. Growing NG demand from these two regions, coupled with the favorable economics of shale gas, has led to an expansion in global liquefied natural gas (LNG) trade [15-17] that is outpacing domestic growth – the share of LNG in the global NG market increased from roughly 5.8 % in 2001 to over 10.7% in 2017 [18, 19].

The arguments for expanding LNG use are relatively straightforward. When used to generate power, NG produces lower carbon emissions and fewer criteria pollutants compared to coal. Thus, coal-to-gas switching can help address climate change and improve local air quality [20]. It has the potential to deliver economic and job growth in exporting countries, potentially offsetting job losses and declining revenues in other fossil resource sectors. LNG also offers greater trade flexibility and allows cargoes of NG to be delivered over large distances. Finally, the availability of LNG from several geologically distinct resource basins in North America, Middle East, and Australia can potentially improve energy security in importing nations by providing diverse supply options that are resilient to local supply disruptions [21-23].

The Paris Agreement signed in 2015 codified a global commitment to keep global temperatures ‘well below’ 2ºC above pre-industrial level and to ‘pursue efforts to limit the temperature increase even further to 1.5ºC [24]. Achieving these targets will require significant reductions in global CO_2 and non-CO_2 greenhouse gas (GHG) emissions, compared to 2019 levels. Several scenarios developed by the Intergovernmental Panel on Climate Change (IPCC) in line with these temperature targets estimate significant reductions in the consumption of coal, oil, and NG [25, 26]. The rate of reduction in GHG emissions and therefore fossil-fuel consumption varies based on the emissions budget available in each scenario. Although not predictive, these scenarios illustrate the trajectory of global emissions required to achieve temperature-based climate action goals. Exploring the evolution of fossil fuels and energy infrastructure in these scenarios can provide critical insights into the viability of new fossil fuel projects around the world [27-29].

The climate benefit of LNG expansion through coal-to-gas substitution is threatened by two factors – methane leakage across the NG supply chain [30-32], and the degree to which LNG-derived NG is used to reduce emissions from coal. Methane is a short-lived and potent GHG whose warming potential is 34 times that of carbon dioxide over a 100-year time frame [33]. Recent field measurements of methane leakage across the U.S. have shown a significant underestimation in official EPA inventories [34-37]. Furthermore, the difference in methane leakage rates globally increases disparity in the emissions impact of LNG based on its source [38]. Thus, the emissions advantage of a coal-to-gas transition will be a function of the life cycle emissions associated with the LNG supply chain. Recent life cycle assessment (LCA) studies on global LNG trade have demonstrated a wide range of emissions intensity for power generation, ranging from about 427 g CO_2e/kWh to over 740 g CO_2e/kWh [8, 39-42]. The high uncertainty in these estimates can be attributed to differences in system boundaries, methane leakage, and various assumptions related to LNG liquefaction and regasification. In addition, the argument for climate benefits from increasing LNG use relies on coal-to-gas substitution, as NG that displaces new renewable energy will lead to an increase in carbon emissions [43].

In this work, we analyze the central claim in contemporary debates around LNG infrastructure expansion – that LNG can reduce global carbon emissions by coal-to-gas switching in the power sector. Although LNG as a commodity can be used in non-power sectors such as industry and transportation, the key claim to the climate benefits of LNG has been to replicate US' power sector carbon emission reductions through coal-to-gas switching around the world. Therefore, the analysis presented here specifically focuses on the use of LNG in the power sector and the potential impact of LNG infrastructure expansion on global climate targets.

First, we compile a comprehensive and up-to-date database of all existing, under-construction, approved, and proposed LNG projects around the world. We then evaluate the life cycle emissions intensity of the LNG value chain and discuss the impact of cumulative LNG-related emissions on global carbon budgets. Next, we quantify the coal-to-gas substitution potential and explore the role of LNG as a decarbonization tool for the electricity sector within the context of IPCC scenarios that limit global warming to three temperature targets – 1.5ºC and 2ºC as enshrined in the Paris Agreement, and 3ºC representing a business-as-usual scenario. We show that long-term use of LNG at the levels enabled by existing and planned terminals is fundamentally incompatible with the 1.5ºC Paris temperature target and increases annual emissions after 2038 compared to a 1.5 ºC compatible pathway. However, LNG can play a limited role in reducing global GHG emissions through 2038 by substituting for the existing coal-based generation. Finally, we conclude with a discussion of the stranded asset risk for exporting countries from stringent climate policy and limitations to coal-to-gas substitution in the power sector in importing countries.

2 Methods

2.1 Global LNG Facility Database

We build a comprehensive database of global LNG projects by compiling and integrating data from government agencies, international industry-affiliated trade unions (e.g., international gas union (IGU), International Group of Liquefied Natural Gas Importers (GIIGNL)), non-profit organizations, and public LNG project announcements [44-46]. All LNG projects in this database were compiled under three general categories: existing, under-construction/approved, and proposed projects. Whenever possible, proposed projects were verified using secondary sources such as news releases or other publicly available documents. LNG projects that have been canceled or on hold (as of November 2020) are not included in the analysis. The start year of each project in the database is based on operational status – we use the year of the first LNG shipment for existing projects and the expected year of the first shipment for other categories (see SI section S1). Although the designed operational life of an LNG terminal is around 25 to 35 years, several LNG facilities have been operating for more than 40 years, with the earliest in-service LNG facility in operation for 51 years [46]. The sensitivity of cumulative emissions to assumptions on project lifetimes is discussed in section 3.2. This new, up-to-date database of LNG infrastructure will serve as a fundamental resource to help understand the future of the industry.

2.2 Life cycle emission intensity of LNG supply chain

We evaluate the life cycle emission intensity of the LNG supply chain based on peer-reviewed literature and publicly available data across five stages – upstream, liquefaction, transportation and shipping, regasification, and end-use. Prior LCA studies of LNG exhibit large variation in emissions based on differences in system boundaries, modeling approaches, and data sources [40]. In addition to CO_2-related combustion emissions, methane emissions from NG production, processing, and transportation are also included. Here, we conduct a systematic literature review of peer-reviewed LCA studies of LNG projects to identify the most likely parameter estimates in the base-case emission scenario. In addition, we also conduct a sensitivity analysis by constructing a low- and high-emission scenario based on variability in critical parameters. Details of the LCA parametrization for the low-emission, base-case, and high-emission scenarios are presented in SI section S2.

2.3 Emission pathways and LNG-related climate impact

We use emission trajectories from the IPCC's shared socioeconomic pathways (SSPs) to explore the impact of LNG-related emissions. The socioeconomic assumptions of the SSPs were translated by six different integrated assessment models (IAMs) into estimates of future energy use characteristics and emissions. Based on publicly available data, we identified 13, 18, and 48 SSPs that provide pathways to limit peak warming to below 1.5ºC, 2ºC, and 3ºC, respectively [47-49] (see SI Table S6 for details). We then estimate the average global annual GHG emissions and net electricity production from NG and coal across the selected scenarios for each temperature target. These average values for emissions and electricity production are used as reference inputs to understand the impact of new LNG infrastructure.

Since SSPs were developed and established in 2016, LNG projects that come online after 2016 were treated as new contributions to the emission budgets in the SSPs. The cumulative emissions from new LNG export projects between 2017 and 2050 were calculated to analyze the impact of LNG expansion on global emission budgets and temperature targets.

We quantify the coal-to-gas substitution potential and discuss the role of LNG as a decarbonization tool in the electricity sector. To evaluate impacts from structural changes in the power sector, we calculate net GHG emissions associated with the use of LNG under different coal-to-gas substitution scenarios ranging from no fuel switching (all LNG is used for additional power generation, or 0% substituting for coal) to full fuel switching (all LNG is used to displace coal use in power sector, or 100% substitution). For comparison, we also analyze the case where coal-based power generation is replaced by zero-carbon energy sources. Figure 1 depicts the whole process flow of the methodology of this study.

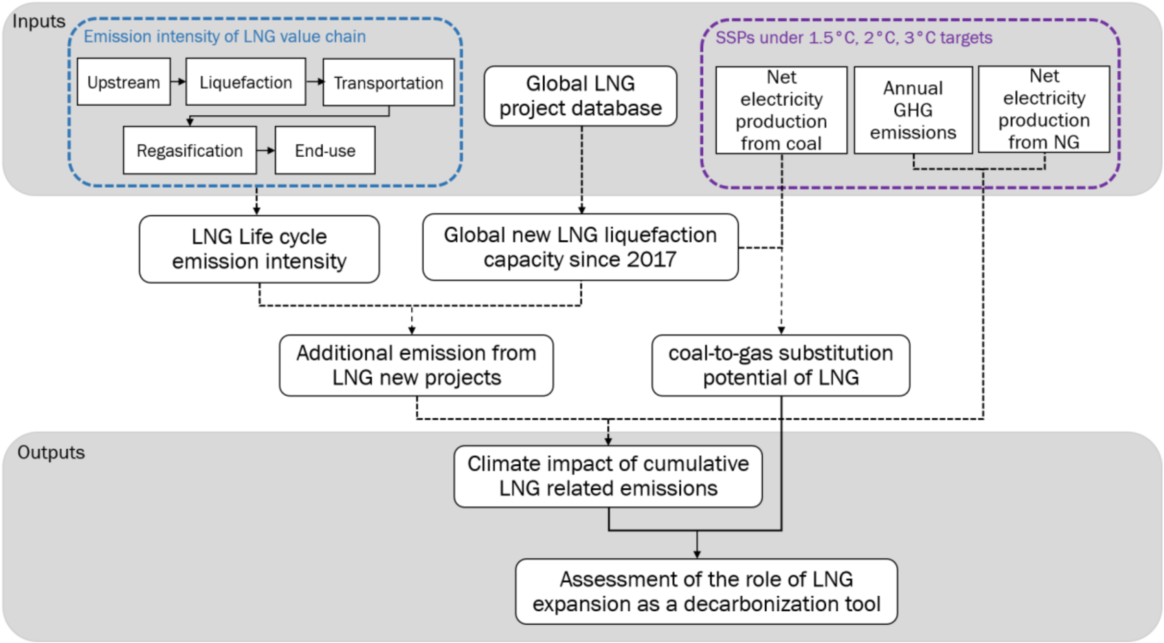

Figure 1. Schematic diagram of the study model used to evaluate the climate impacts of new LNG infrastructure.

3 Results

3.1 Global LNG export/import capacity

Figure 2 shows the annual nameplate LNG import and export capacity through 2050, up to date as of November 2020. Only terminals that have not announced future retirements are included in this figure, and thus their capacity extends through 2050. The average capacity weighted age of all existing LNG export and import terminals is 12 and 20 years, respectively. Of the 439 million metric tons per annum (MTPA) of LNG export capacity operating in 2020, 216 MTPA or 49% are younger than 10 years. In general, existing import capacities are older than export capacities with an average age of 14.4 years old compared with that of export capacities of 12.6 years.

As of November 2020, 134 MTPA of new liquefaction capacity is under-construction, 203 MTPA is approved, and 303 MTPA is proposed or awaiting final investment decision (FID) as shown in Figure 2(a). Together, these projects would increase global liquefaction capacity by 146% from 439 MTPA in 2020 to 1079 MTPA in 2030. The growth in regasification terminals continues to lag growth in liquefaction terminals. Between 2021 and 2050, 362 MTPA of new import capacity is expected to come online, compared to 640 MTPA of export capacity. Global annual import capacity will also reach a peak of 1194 MTPA by 2030 (Figure 2(b)). The expected growth in LNG import terminal capacity suggests that the availability of regasification infrastructure is not likely to be a bottleneck for growth in LNG trade. However, on average, operating LNG import terminals are older than operating export terminals – long-term demand for LNG will be incumbent on new LNG import infrastructure being developed to match recent growth in export capacity.

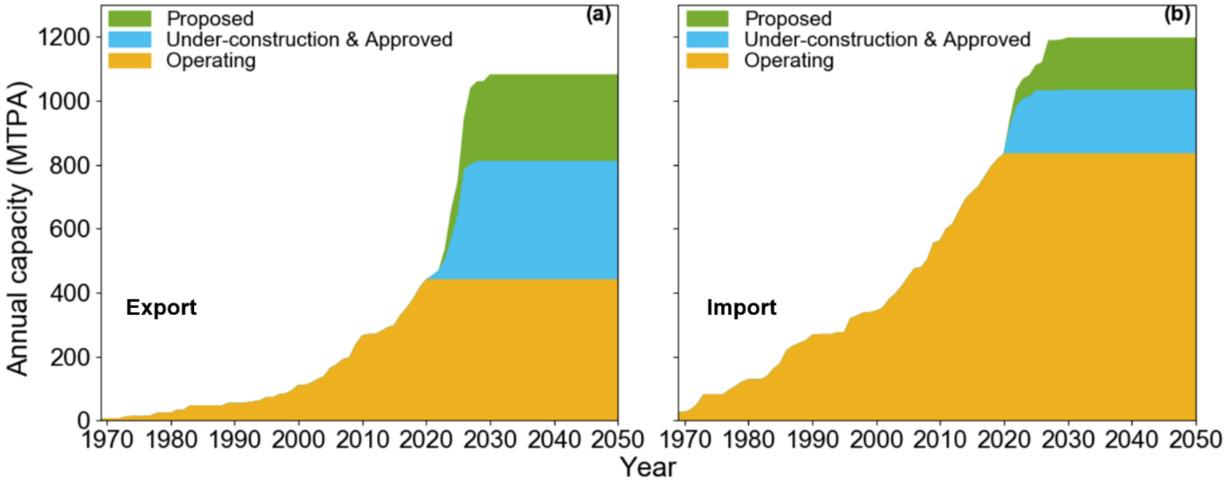

Figure 2. Global annual nameplate (a) LNG export capacity and (b) LNG import capacity by project status- proposed (green), under-construction and approved (blue), and operating (yellow) – from 1969 to 2050. All the LNG terminals are up to date of November 2020.

Figure 3 shows the country-level age distribution of existing, under-construction, and proposed LNG export and import capacity, with 2020 as the base year. We see an emergence of new dominant exporters and importers – the United States and Canada account for 48% and 26% of all in-development growth of global export capacity, respectively, becoming the two largest exporters followed by Qatar, Australia, and Russia. This growth in export capacity is accompanied by consolidation in export markets, potentially making NG prices vulnerable to supply shocks. For example, the share of LNG trade from the top three exporters, as indicated by available export capacity, increases from 50% (Australia, Qatar, and the US) in 2018 to over 65% (US, Canada, and Qatar) in 2030. Furthermore, recent COVID-19 pandemic-induced disruptions to the supply chain of critical goods and supplies are likely to increase pressure on governments to reduce reliance on imports [50]. On the import side, although LNG imports have been dominated by Japan and South Korea because of a decline in nuclear power generation capacity, developing countries in Asia and the European Union are poised to become major demand centers. About 63% of under-construction and proposed regasification capacity will be built across developing nations in Asia. Among these countries, China is likely to be the largest demand center for LNG and accounts for about 50% of the global planned import capacity.

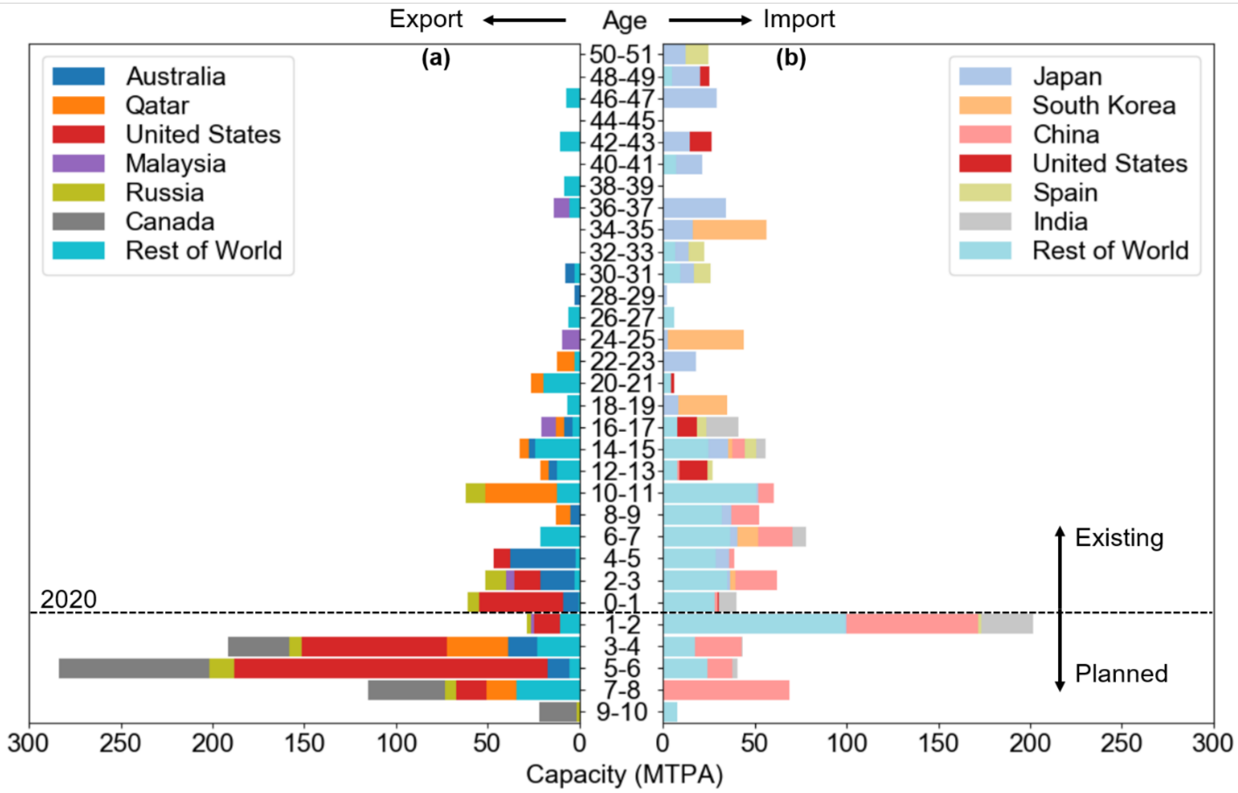

Figure 3. Country-level age distribution of global (a) LNG liquefaction (export) capacity and (b) LNG regasification (import) capacity. The dotted line represents the base year 2020. The youngest existing terminals are shown at the bottom of the 'existing' section. The bars in the "planned" section show under-construction, approved, and proposed capacities based on the year (from 2020) that they are expected to be commissioned. 0 years old refers to a terminal that came online in 2020.

3.2 Climate impact of cumulative emissions from LNG infrastructure

Figure 4 shows the cumulative climate impact of operating, under-construction/approved (Figure 4(a)) and proposed (Figure 4(b)) LNG infrastructure through 2050 as a function of life cycle methane leakage and infrastructure lifetime. Critically, we describe this impact within the context of international climate policy by showing LNG-related emissions as a fraction of the global GHG emission budgets under different temperature targets. Cumulative LNG emission is calculated based on 100% utilization rate of facilities. The global average utilization rate for import terminals in 2019 was only 43%, while that of export terminals was over 80% [46]. For example, U.S. liquefaction facilities averaged a 93% capacity utilization rate in 2019 [51]. The impact of utilization rate on global cumulative LNG emissions calculation is discussed in SI section S3. We make two important observations.

First, cumulative emissions increase as methane leakage and infrastructure lifetime increases. Overall, cumulative LNG emissions from "committed" capacity (existing and under-construction projects) vary from around 30 to 80 Gt CO_2e, with a median estimate of 51 Gt CO_2e based on a

2.3% methane leakage rate and a 35-year project lifetime. In comparison, the cumulative emissions from all “potential” LNG capacity including proposed projects range from about 50 Gt CO_2e to over 120 Gt CO_2e with a median estimate of 78 Gt CO_2e. Thus, proposed LNG infrastructure around the world increases cumulative GHG emissions from LNG by 76%, compared to committed emissions from existing and under-construction projects. Based on a designed infrastructure lifetime of 35 years, cumulative emissions increase by 90% as upstream fugitive emission increases from 0.1% to 10%. By contrast, at a median global methane leakage of 2.3%, cumulative emissions only increase by 33% (57 – 76 Gt CO_2e) as infrastructure lifetime increases from 20 to 50 years. Thus, the growth in cumulative life cycle emissions is significantly higher as a function of methane leakage compared to that of infrastructure lifetime. Given that existing LNG terminals are relatively new with an average age of 13 years, reducing the life cycle impact of LNG strongly relies on addressing upstream methane emissions.

Second, life cycle emissions from LNG take up significant fractions of the global GHG emission budgets under various IPCC emissions scenarios. Achieving the goal of 1.5°C temperature target requires a median reduction in NG use of 3% and 25% by 2030 and 2050, respectively, compared to 2010 levels [52]. However, the expansion of LNG liquefaction and regasification capacity from under-construction and proposed projects will increase global NG use and put increased pressure on reducing coal and oil use beyond those estimated in the IPCC scenarios. Under the most stringent temperature target of 1.5ºC, cumulative life cycle LNG emissions from committed and potential capacity take up around 8% and 13% of the emission budget through 2050, respectively. These reduce to around 7% and 12% of emission budgets for mean global warming of 2ºC, and 4% and 7% for mean global warming of 3ºC, respectively. These contributions to the total carbon budget are in addition to emissions from direct NG use that are transported by pipelines. By comparison, emissions associated with electricity production from NG in the IPCC scenarios take up 10%, 11%, and 8% in the GHG emission budgets for 1.5°C, 2°C, and 3°C pathways, respectively. Thus, the carbon budget associated with all LNG infrastructure in the 1.5°C and 2°C scenarios – 13% and 12%, respectively – is greater than the carbon budget associated with power sector NG use in the median IPCC 1.5°C and 2°C scenarios – 10% and 11%, respectively. Even with a conservative and unrealistic assumption that LNG represents all NG use in future electricity generation, “potential” LNG-related emissions still exceed the emission budgets associated with NG in the 1.5°C and 2°C scenarios. More critically, the median emissions pathways that limit global warming to 1.5ºC suggests that global emissions should reach near-zero by about 2050, with significant negative emissions thereafter. In this scenario, any emissions associated with LNG in 2050 will be fundamentally incompatible with the 1.5ºC target without significant deployment of negative emissions technologies. A 1.5ºC compatible world will increase the risk of stranded LNG assets, particularly in exporting countries that have proposed new terminals far beyond 2020.

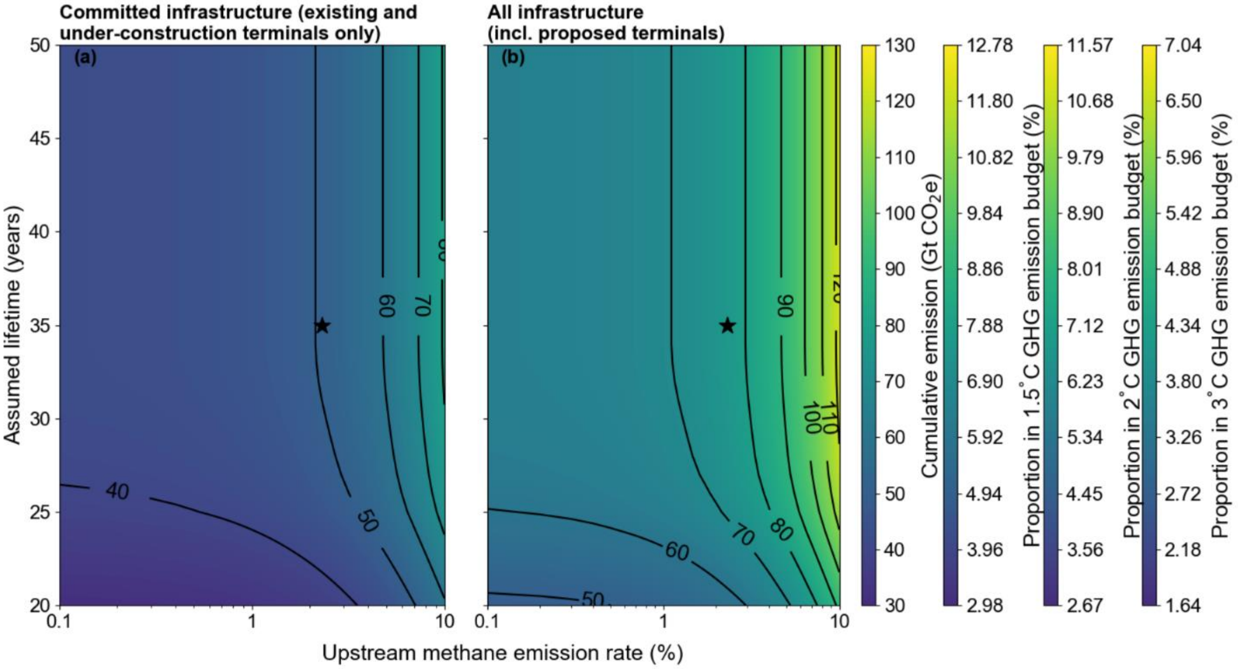

Figure 4. Cumulative life cycle LNG emissions (Gt CO_2e) and proportion in total emissions budgets under 1.5ºC, 2ºC, and 3ºC scenarios as a function of infrastructure lifetime (y-axis, years) and upstream methane emission rate (x-axis, %). (a) Cumulative LNG emissions from existing and under-construction capacities; (b) Cumulative LNG emissions from all existing, under-construction, and proposed capacities. The star shows the projected cumulative LNG emission with a 2.3% upstream emission rate and a 35-year infrastructure lifetime.

3.3 Potential for LNG as a decarbonization tool through coal-to-gas substitution

Because the main argument for expanding LNG capacity has been to reduce global carbon emissions through a coal-to-gas transition, we quantify the impact of LNG-related emissions within the power sector under 1.5°C, 2°C, and 3°C pathways. Figure 5a-c shows global annual emissions associated with electricity from coal and NG under three temperature targets as a function of various LNG end-use scenarios: baseline IPCC trajectory, 0% coal-to-gas substitution (no displacement of new or existing coal), 100% coal-to-gas substitution (all LNG is used to replace new or existing coal) and a coal-to-clean energy transition. Here, the baseline corresponds to the mean emissions pathways of the various temperature-compatible SSPs (see Methods and SI section S4). We note several critical insights.

First, in the near term until around 2038, 100% coal-to-gas substitution reduces global carbon emissions across all scenarios for the three temperature pathways. This implies that **LNG can reduce emissions as a viable near-term solution to reducing coal-based power generation through a coal-to-gas substitution**. Coal-dependent countries that have significant dormant NG power plant capacity such as India could potentially use LNG as a bridge to transition to a cleaner, lower-carbon power sector.

Second, there is no scenario where LNG use reduces global carbon emissions in the power sector that excludes coal-to-gas substitution – that is, an increase in LNG exports must be coupled with a substitution of LNG for coal to reduce emissions. When all LNG capacity is used for new electricity generation to meet growing demand with 0% coal-to-gas switching, global carbon emissions will be higher compared to the baseline scenario. Net emissions benefits can be achieved if at least 59% of LNG capacity is used for coal-to-gas substitution in the power sector. Emission reduction as a function of various coal-to-gas switching rates is discussed and shown in Figure 6.

Third, substituting coal-based power generation with carbon-free sources results in emissions reductions significantly higher than coal-to-gas substitution in all scenarios. While not surprising, this illustrates a critical source of uncertainty for LNG demand that relies on climate and energy policies in importing countries. Growing concern over climate change in Asia and Europe, coupled with a desire for domestic fuel security or control can result in policies that increase zero-carbon sources in the power sector and reduce demand for LNG, leading to an increased stranded asset risk for LNG exporters or increased use of LNG in other sectors with a corresponding increase in emissions. Thus, while LNG can help reduce emissions from the power sector globally, long-term planning for new import and export infrastructure should be based on an eventual transition away from fossil sources.

Fourth, long-term LNG expansion for use in the power sector is not compatible with 1.5ºC pathways even under 100% coal-to-gas substitution. This is because coal use around the world declines rapidly between 2020 and 2040 in all 1.5ºC scenarios such that there is not enough coal for LNG to substitute to counteract the emissions from additional LNG. That is, a 1.5°C pathway is one where coal use declines independent of the need for additional LNG. Figure 5(d) shows the annual surplus coal-based power generation after 100% coal-to-gas substitution under 1.5°C, 2°C, and 3°C pathways. For 1.5°C pathway in the base-case scenario, 2030 is the threshold year when the climate benefits of coal-to-gas switching start eroding from additional LNG emissions. Before 2030, the potential for emissions reductions is limited by LNG availability – there is sufficient global coal-based power generation to be substituted by all LNG to offset the impact of LNG expansion (surplus coal-based power generation > 0). Beyond 2030, the potential for emissions reduction is limited by the availability of coal-based power generation – the declining share of coal use in the 1.5°C pathways reduces the climate benefits of coal-to gas-switching (surplus coal-based power generation < 0). Here, available global LNG volumes exceed those required to substitute all remaining coal and the excess LNG will generate additional emissions. For 2ºC pathway, the corresponding threshold year is 2038. However, this constraint does not apply in 3ºC pathway – throughout the 2017 - 2050 study period, coal-to-gas substitution has the potential to reduce global carbon emissions. Thus, the current LNG infrastructure build-up can be considered as potential insurance against a world on a 3ºC trajectory with significant coal-based power generation through 2050.

It is also worth noting that the availability of coal capacity to be substituted by gas is estimated under a best-case scenario where all coal plants are assumed to be able to be substituted by gas. Several factors such as the availability of pipeline infrastructure, technical constraints, and the age of the coal plants will limit the realistic potential for substitution. Using

IPCC estimates of coal use in the 3ºC pathway, we find that 47% and 65% of total coal-based generation must be substituted by LNG to achieve net-zero change in total emissions in 2030 and 2050, respectively. Thus, **a 3ºC pathway world will continue to be limited by LNG availability in reducing global carbon emissions through 2050.**

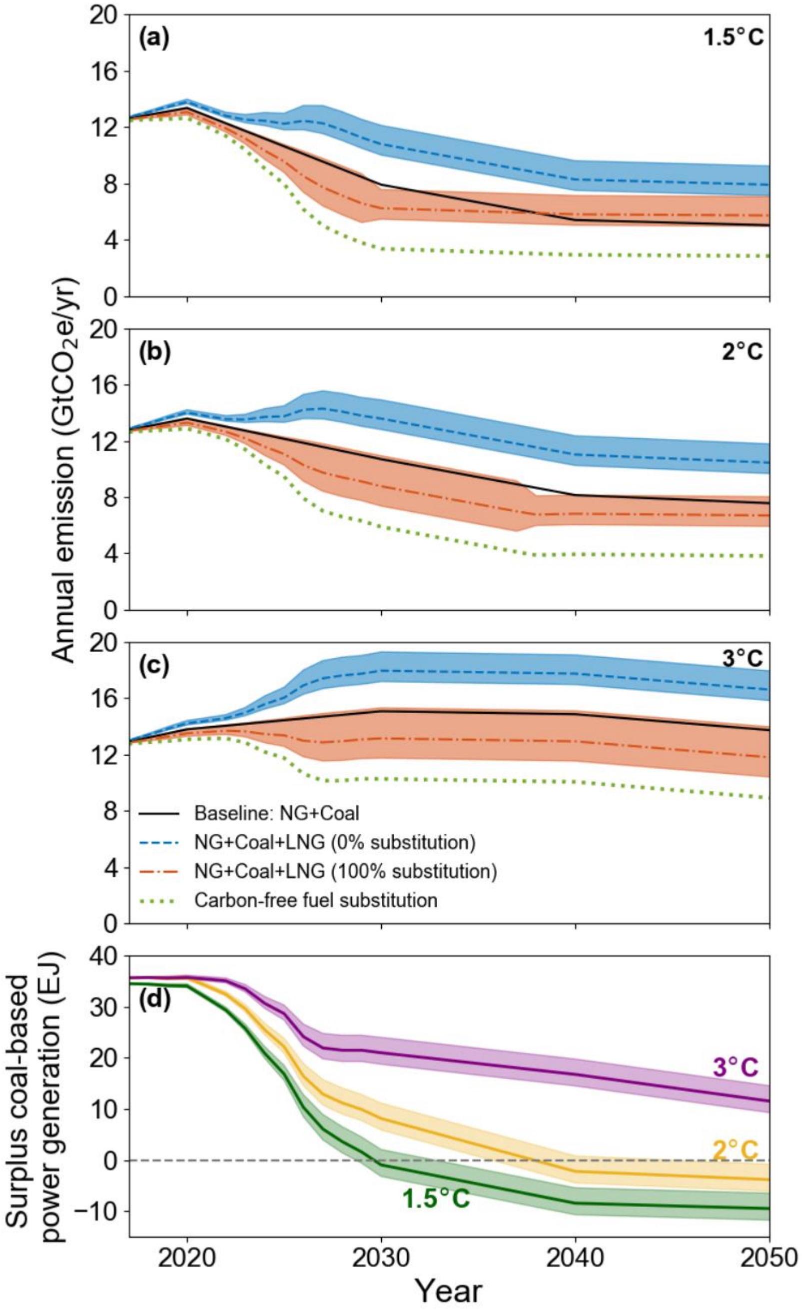

Figure 5. (a-c) Power sector CO_2 emissions from coal and NG, as a function of different LNG use cases in 1.5ºC, 2ºC, and 3ºC pathways. Total emissions from NG and coal electricity generation in the IPCC baseline are shown in black lines. Blue dashed line represents emissions in scenarios with 0% coal-to-gas switching and the red dashed line represents emissions in

scenarios with 100% coal-to-gas switching. Shaded regions represent the lower and upper bound of emissions when considering the lowest (low-emission scenario) and highest (high-emission scenario) emissions from each stage of the LNG supply chain, respectively. Green dotted line represents the scenario where coal is substituted by the same amount of carbon-free fuel as LNG with a 100% switching rate. (d) Surplus coal-based power generation after 100% coal-to-gas switching rate in 1.5ºC (green line), 2ºC (yellow line), and 3ºC (purple line) pathways. Shaded regions indicate the lower and upper bound in low-emission scenario and high-emission scenario, respectively.

Figure 6 shows the annual (Figure 6(a)) and cumulative (Figure 6(b)) impact of different coal-to-gas substitution fractions on power sector GHG emissions in the 1.5ºC pathway. Substituting at least 59% of coal-based power generation with LNG results in a net annual reduction (net emission <0) in global carbon emissions in the power sector prior to 2038. Beyond 2038, no amount of coal-to-gas substitution results in a net reduction in carbon emissions – this is because of a lack of available coal-based power generation. The cumulative reduction in emissions gets slowly eroded after 2038 as more LNG comes online even as remaining coal generation declines. Even though there is a net climate benefit (cumulative net emission <0) through 2050, it is smaller than that realized in 2038 when emission reduction from coal-to-gas substitution is maximized.

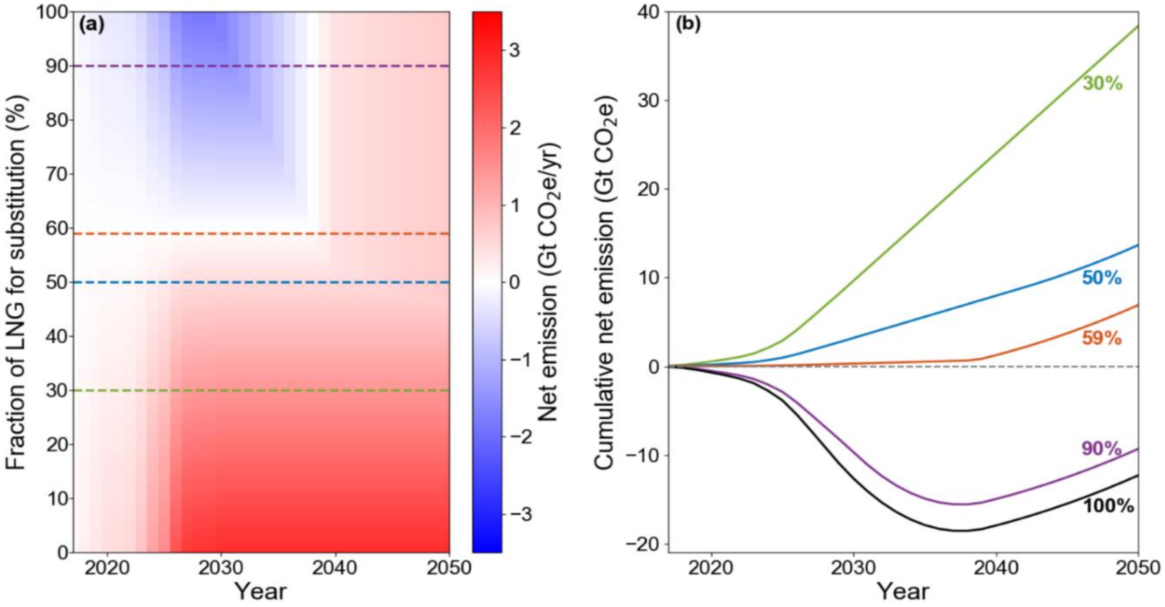

Figure 6. (a) Annual net emission after coal-to-gas switching as a function of coal-to-gas substitution fraction of LNG in the 1.5ºC pathway. Net negative emissions indicate positive climate benefits resulting from coal-to-gas switching. (b) Cumulative net emission through 2050 at coal-to-gas substitution rates of 30% (green), 50% (blue), 59% (orange), 90% (purple), and 100% (black).

4 Discussion and Implication

In this study, we analyze the climate impact of expected cumulative carbon emissions from currently operating and planned LNG export facilities for use in the power sector. We find that the expansion of the LNG industry as planned in the context of coal-to-gas switching is incompatible with the 1.5ºC temperature target of the Paris Agreement by 2050. This incompatibility derives from the significant reduction in coal-based power generation in all IPCC 1.5ºC scenarios leaving little room for emissions reductions through coal-to-gas substitution. Thus, the ability of LNG to reduce global emissions in the 1.5ºC pathway is limited by the availability of coal-based power generation. Beyond 2030, LNG-derived coal-to-gas substitution starts eroding from the emissions reductions made prior to 2030 as the reduction in coal-related emissions is lower than the additional emissions from LNG that are not used to substitute coal. In the 2°C pathway, coal-to-gas substitution provides maximum emission reduction benefits until 2038 when the volume of LNG available is larger than that required to substitute all coal-fired generation. In both the 1.5°C and 2°C scenarios, domestic policies in importing countries to move to carbon-free generation or increase reliance on domestic fuel sources create significant uncertainty in the long-term viability of LNG export projects.

In a scenario where the global temperature is on a 3°C pathway, the power sector is limited by the availability of LNG through 2050 – there is enough coal-fired generation around the world to substitute with LNG and reduce global emissions. In this way, the recent growth in LNG could be considered as insurance against a potential lack of global climate action to limit temperatures to 1.5°C or 2°C. This has several implications for our approach to LNG expansion including the need to plan for the potential for stranded assets and avoid carbon lock-in. For example, project economics could be evaluated under shortened time frames, and regulatory approvals could prioritize projects that are viable under shortened lifetimes. Where public support for projects is desirable, it could be structured in a way that reflects and considers the risk of stranded assets. Where a decision is made to pursue projects as an "insurance" for a 3ºC or higher temperature pathway, the project could be explicitly structured as a cost for this insurance with near-term profits shared/allocated/used accordingly. Similarly, the risk of creating carbon lock-in should be carefully managed to ensure an LNG build-out does not create pressure to extend the lifetime of gas power plants.

Moreover, it is also important to consider the limited benefit of coal-to-gas switching on the 2050-time horizon, even on a 3°C pathway, in evaluating the cost of such an "insurance". Future work should compare the cost and feasibility of the emission reductions that can be achieved through LNG growth coupled with coal-to-gas switching with that of a switch to non-fossil power sector alternatives. With the recent global momentum against the development and financing of new coal plants, this work demonstrates the sensitivity of climate benefits of LNG to the availability of coal plants presents significant uncertainty to the long-term viability of LNG export facilities.

In all cases, methane leakage plays an important role in the climate impact of LNG consumption. The contribution from exporting countries to global emission reductions through

LNG is limited by upstream actions to reduce methane leakage. The variation in leakage rates across global gas basins suggests that countries that effectively address methane emissions could have an emissions advantage in LNG exports in a climate-conscious world. Our study highlights the importance of future technological developments in methane monitoring in helping regulatory agencies and large customers to directly verify methane leakage across the NG supply chain. Unlike methane leakage, any emissions reductions from coal-to-gas substitution are clearly taking place within the importing country as a result of the decision to make this substitution and are attributable only to the actions of the importing country. It is imperative that any reduction in global emissions arising from a coal-to-gas substitution is not claimed by both the importing and exporting country in GHG emissions accounting.

This study focused on electricity generation given the importance of NG in the power sector and the current interest in the potential for LNG to reduce emissions through coal-to-gas switching. However, LNG can also be used in transportation, residential heating and cooking, and petrochemical production. The existence of these additional potential end uses further complicates the emissions savings from fuel-switching, but some general conclusions can be drawn from the findings as our results on total emissions from LNG apply to any combustion end-use. Future studies on the cumulative emissions impact of LNG can explore the potential for emissions reductions through the substitution of non-gas fuels in the heating and transportation sectors.

The findings of this study may help investors and regulators to consider stranded asset risks associated with the expanding LNG industry in the context of global climate action. While we show that LNG can play a limited role in the near to medium term in addressing global carbon emissions within the power sector, there are several risks for its long-term viability. These risks, including the stringency of global climate action, should be carefully weighed against the long lifetimes of LNG infrastructure when making investment decisions. This is particularly important for countries such as the US and Canada that are poised to become two of the largest exporters and are considering significant government support for new development such that stranded assets will have significant implications for public finances. For major importers, the simple model presented here can help policymakers understand the potential for carbon lock-in before greenlighting an expansion of NG power plants or import terminals.

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Author contributions

A.P.R. and S.H.S. conceived the study. S.Y. compiled and verified the data underlying this study and developed the technical analyzes. S.Y., A.P.R., and S.H.S. discussed and interpreted the results. All authors contributed to writing the paper.

Additional information

Supplementary dataset to this article is available online: https://doi.org/10.7910/DVN/TDYYLN.

Competing interests

The authors declare no competing interests.

Supporting Information

S1. Assignment of LNG terminals' start year

For some approved and proposed projects that are in the initial stages and the start year of operation has not been announced, we make assumptions based on the average time between approval and operation for existing projects [53]. First, we add five additional years to projects that are ready for construction and six years to those that are waiting for a final investment decision by 2020 under normal circumstances. Second, one and three year(s) are added to projects that only involve adding new trains or expanding existing terminal infrastructure, respectively.

S2. Calculation of life cycle emissions from LNG operational chain

Life cycle assessment (LCA) of liquefied natural gas (LNG) was conducted by quantifying the GHG emissions associated with each stage of the LNG operational chain: upstream (exploration and production), liquefaction, transportation, regasification, and end-use. We estimate parameter values based on a systematic literature survey of publicly available, peer-reviewed LCA studies. For parameters with multiple published values, we use the median estimate for base-case scenario analysis and the range for the low- and high-emission scenarios.

To convert methane leakage estimates from natural gas (NG) production and transportation to CO_2 equivalent estimates, we use 100-year global warming potential (GWP) (fossil methane with climate-carbon feedback) from the Intergovernmental Panel on Climate Change (IPCC) Fifth Assessment Report (AR5) [54]. The exception to the use of AR5 GWP is for the emissions estimates in the literature for liquefaction and regasification life cycle stages that used GWP values from the IPCC second or fourth assessment report. However, because the majority of liquefaction and regasification emissions originate from fuel combustion rather than from CH_4 leakage or venting [55], it is likely that these estimates would not change the overall LNG life cycle emission. The estimates for each stage are shown in Table S1.

Table S1 *Summary of estimated emissions intensity of each LNG stage. The units are g CO_2e/MJ unless otherwise noted.*

Parameter	Type	Value		
		Low	Base-case	High
Upstream	Assumed parameter	3.1	17.2	44.5
Liquefaction	Adapted from literature	3.9	5.8	7.4
Transportation	Calculated	0.19	2.1	6.2
Regasification	Adapted from literature	0.36	1	1.6
End-use (g CO_2e/kWh)	Calculated	343	402	455
Life cycle emission intensity (g CO_2e/kWh)	Calculated	400	632	1052

S2.1 Upstream

The complexity and scale of upstream operations, as well as the level of control over operations that producers have, make upstream emissions a prime target for reduction efforts. The upstream stage of the LNG supply chain includes exploration, production, and pipeline transmission of NG to the liquefaction facility. Emissions are mainly associated with fugitive methane leaks, venting, and fuel combustion. Prior studies across US shale basins have estimated fugitive emissions rates between 1 and 9% and a recent model suggests that the most likely value is 2−4% since 2000 [37]. In this study, we take 2.3% as our central assumption of CH_4 emission rate, based on a recent meta-analysis of published methane emissions studies across several US basins [30]. In addition, we also explore the impact of differences in methane leakage across US shale basins and globally on the life cycle emissions of LNG. Global methane leakage rates are derived from the International Energy Agency (IEA) Global Methane Tracker and supplemented with data from peer-reviewed studies [38, 56-59]. The methane leakage rates considered in this analysis range from 0.1% in Qatar to 6.4% in Russia. Estimates of non-methane fugitive emissions from the upstream stage (e.g., lease and plant energy emission and operational transmission emissions (compression combustion)) were adapted from Weber et al. (2012) [60]. Non-operational emissions associated with the transmission (e.g., steel use in pipelines and land-use changes) are not considered in this case. Detailed calculations of upstream emissions are shown in Table S2.

Table S2 *Parameters and assumptions used to estimate upstream methane emissions.*

Parameter	Unit	Assumption		
		Low	Base-case	High
Upstream methane emission rate [30, 32, 61-65]	%	0.1	2.3	6.4
Upstream production and transportation emissions [60]	g CO_2e/MJ	2.64	5.56	10.71
Average CH_4 content in NG	vol%		90	
CH_4 density	kg/m³		0.657	

S2.2 Liquefaction

In the liquefaction stage, emissions are associated with fuel consumption at plants, flare combustion, and vented emissions. Inputs of liquefaction emissions are obtained from simulation results suggested by Abrahams et. al (2015) [41], which were derived from a constructed distribution built upon estimates of prior studies and industry reports. In the base-case scenario, we use an emissions intensity estimate of 5.8 g CO_2e/MJ, with low and high sensitivity cases of 3.9 g CO_2e/MJ and 7.4 g CO_2e/MJ, respectively.

S2.3 Transportation

Transportation emission is primarily from the combustion of fossil fuels in main engines, auxiliary engines, and boilers of LNG shipping vessels, which are highly dependent on the carbon content of fuel and fuel consumption. In our simplified case scenario, we make several assumptions:

(1) LNG tankers return to the origin port. Because there is a network of tankers, in reality, 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.

(2) Tankers are fueled by diesel for the entire trip. Total transportation emission of LNG export is determined by shipping distance (D), tanker speed (s), rated power of engine (r), emission factor of shipping fuel (EF), cargo capacity (C_c), and the export capacity of each year (C_e). For any given year, transportation emission of LNG export is estimated using an emissions factor (emissions per cargo) and an activity factor (number of cargos). Thus, transportation emission is calculated as follows:

$$Emission = \frac{2\mathrm{D}}{\mathrm{s}} \times r \times EF \times \frac{C_e}{C_c}$$

The corresponding parameters are shown in Table S3. Global average shipping distance is estimated as the average sea distances between 41 global major LNG flows as shown in Figure S1 [44]. The average LNG shipping distance in the base-case scenario is assumed to be 8000 km.

Table S3 *Parameters and assumptions used to estimate LNG shipping and transportation emissions.*

Parameter	Unit	Assumption		
		Low	Base-case	High
Weighted LNG cargo capacity [44]	m^3		137600	
Shipping distance [44, 66]	km	750 (Algeria-France)	8000	23800 (Russia (Archangel)-Japan (Aboshi))
Average carrier speed [67]	km/h		35.2	
Emission factor (diesel) [11]	g CO_2e/MJ		70	
Engine rated power (diesel) [41]	MW/hr		60	
LNG density [68]	kg/m^3		450	

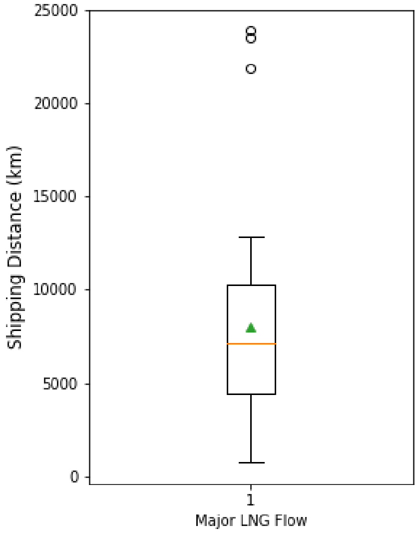

Figure S1. *Estimates of shipping distance of 41 global major flows of LNG cargo.*

Global averaged cargo capacity is calculated using a weighted average based on LNG fleet statistics in 2018 [44], as shown in Table S4.

Table S4 *LNG cargo capacity and fleet statistics in 2018.*

Cargo capacity (m^3)	Number of fleets
< 25000	33
25000-50000	11
50000-90000	7
90000-150000	219
150000-170000	127
170000-210000	120

S2.4 Regasification

We take 0.36 and 1.6 g CO_2e/MJ as the lower and upper bounds of the possible range of regasification emissions – this assumes that 0.15 – 3% of gas is used on-site at the regasification terminal [55, 69]. The base case estimate for regasification emission is 1 g CO_2e/MJ [41].

S2.5 End-use

The end-use emission from combustion in NG power plants was calculated based on the parameters and assumptions outlined in Table S5.

Table S5 *Parameters and assumptions used to estimate end-use emissions associated with LNG use in NG power plants.*

Parameter	Unit	Assumption		
		Low-Emissions	Base-case	High-Emissions

LNG Calorific value (energy content) [68]	MJ/kg		53.6	
NG emission factor [70]	g CO_2e/ft^3		53.1	
Heat content of NG [71, 72]	Btu/ft^3	1074	1038	966
NG plant heat rate [73, 74]	Btu/kWh	6935	7732	8281

S3. Sensitivity analysis

S3.1 Attributional life cycle emission intensity of LNG

The benefit of using LNG to replace coal-fired power plants stems from the lower carbon intensity of NG compared to coal. In recent years, several groups have undertaken detailed life cycle assessment studies to estimate the net emissions impact of LNG use in power generation and district heating applications. These studies have concluded that in addition to air quality benefits, LNG provides net GHG reductions as long as methane leakage is below 3.2% [34]. Because NG basins around the world exhibit significant variation in methane leakage, the emissions impact of resulting LNG will also vary. Methane leakage rates for exporting countries and 5 U.S. shale basins are derived from the International Energy Agency (IEA) methane tracker database [38].

Figure S2 shows the attributional life cycle emission intensity of LNG for power generation across major LNG exporting nations and US NG basins. Emissions are divided across five stages – upstream, liquefaction, shipping, re-gasification, and end-use. The life cycle emissions intensity of LNG use in power generation varies from about 520 g CO_2e/kWh for gas sourced in Qatar to over 810 g CO_2e/kWh for gas sourced from the Uintah Basin in the US. These figures correspond to methane leakage rates of 0.1% and 6.6%, respectively. Thus, depending on the source of NG, the contribution of upstream methane leakage to life cycle emissions can vary from 10% of total life cycle emissions at low leakage rates to over 40%. This has potential international implications in a climate-constrained world. NG from Russia, with a leakage rate of 6.3%, results in a life cycle emissions intensity of 802 g CO_2e/kWh. By contrast, the life cycle emissions intensity from gas sourced from the US Marcellus shale basin with a leakage rate of 0.4% is 531 g CO_2e/kWh, 34% lower than that of Russian gas. Even comparing Russian pipeline exports by removing the contribution of the liquefaction, transportation, and re-gasification stages, the life cycle emissions intensity only reduces to 725 g CO_2e/kWh, over a third higher than life cycle emissions from Marcellus shale LNG.

Life cycle emissions associated with LNG exports from the US vary considerably. In the base-case scenario with a methane leakage rate of 2.3%, the life cycle emission used in power generation is estimated to be about 610 g CO_2e/kWh, similar to several recent LCA studies [8, 39-42]. This estimate is about 39% lower than the life cycle emissions from coal-fired electricity at 1001 g CO_2e/kWh. However, depending on the US source basin for NG, the life cycle emissions impacts can vary from 531 g CO_2e/kWh in the Marcellus basin to 811 g CO_2e/kWh in the Uintah Basin. The differences in methane leakage rates across basins have been documented in prior studies and are likely attributable to differences in basin and production characteristics, state-level emissions reduction policies, and operator maintenance practices [30]. In general, NG sourced from oil-rich, associated gas basins such as the San Juan, Bakken, and Permian have higher methane leakage rates than dry gas basins such as the Marcellus, Barnett, and Fayetteville. Thus, the emissions impact of US LNG exports should be estimated at the individual supplier level and weighted based on the volumes of NG from different basins. A scientifically robust measurement and monitoring protocol would be required to verify the upstream emissions intensity of US-sourced NG and its role in reducing global carbon emissions.

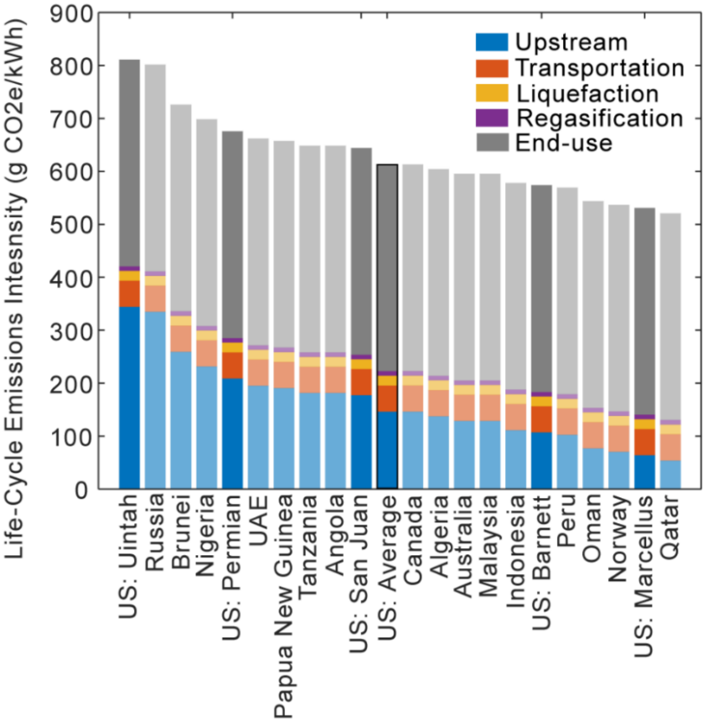

Figure S2. *Attributional life cycle emission intensity of LNG from different NG supplying countries across the upstream (blue), liquefaction (orange), transportation (yellow), regasification (purple), and end-use (gray) stages. Emissions from US basins are shaded darker, compared to emissions associated with non-US basins. Life cycle emission with a national averaged methane leakage rate of 2.3% across U.S. basins is shown in an enclosed black box.*

S3.2 Impact of utilization rate on global cumulative LNG emissions

Cumulative life cycle LNG emission is calculated based on the liquefaction capacity of export terminals. Since the global utilization rate was on average 81.4% in 2019 based on prorated capacity basis (depending on when the plants are commissioned) [46], we analyzed the impact of utilization rate on the calculation of cumulative LNG emissions of all infrastructures under 70%, 80%, 90%, and 100% utilization rate as shown in Figure S3. Cumulative LNG emissions can change from less than 30 Gt CO$_2$e with short lifetime and low methane emission rate under 70% utilization rate to more than 120 Gt CO$_2$e with long lifetime and high methane emission rate under 100% utilization rate. The results of the most possible case with a 2.3% upstream emission rate and a 35-year designed infrastructure lifetime are 37 Gt CO$_2$e, 41 Gt

CO_2e, 46 Gt CO_2e, and 77 Gt CO_2e under 70%, 80%, 90%, and 100% utilization rate, respectively.

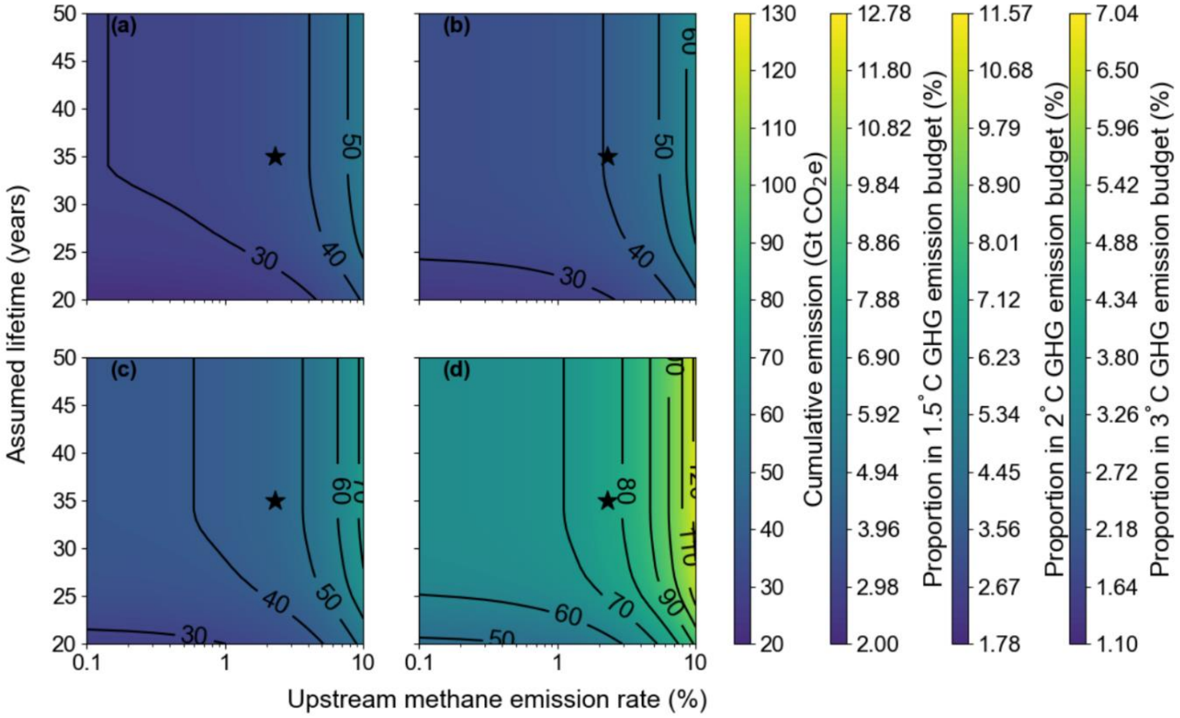

Figure S3. *Cumulative life cycle LNG emissions of all infrastructures and the proportion in total carbon budgets under 1.5ºC, 2ºC, and 3ºC scenarios as a function of infrastructure lifetime (y-axis, years) and upstream methane emission rate (x-axis, %) with various utilization rate: (a) 70%, (b) 80%, (c) 90%, (d) 100%. The star shows the result with a 2.3% upstream emission rate and a 35-year infrastructure lifetime.*

S3.3 Sensitivity analysis of GWP on cumulative LNG export emission

Between 2017 and 2050, the cumulative emission of LNG export is calculated in three emission scenarios: low-emission, base-case, and high-emission scenarios. For the upstream emission estimates, both 100 and 20-year GWP for methane (fossil methane with climate carbon feedbacks) from the IPCC AR5 were used and estimated cumulative emissions are shown in Figure S4. The difference in estimates is negligible in the low-emission scenario because of the low methane leakage across the LNG supply chain. Cumulative emission increases by around 22% and 30% in base-case and high-emission scenarios, respectively when using 20-year GWP compared to 100-year GWP values.

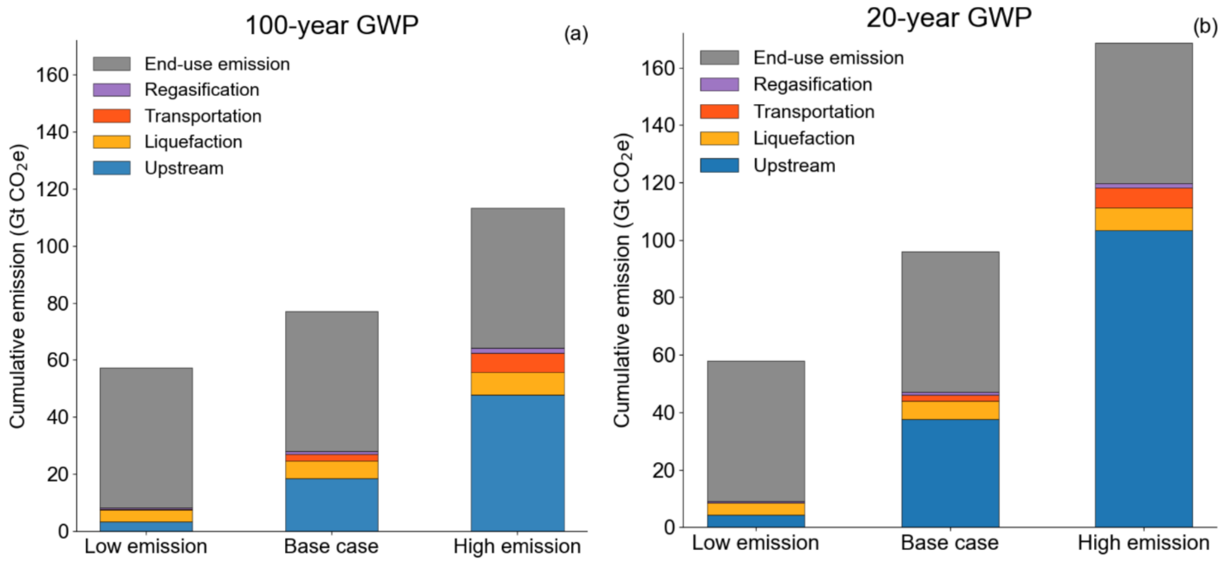

Figure S4. *Cumulative lifecycle LNG emission between 2017 to 2050 based on (a) 100-year GWP, and (b) 20-year GWP, in the low-emission, base-case, and high emission scenarios.*

S4. Viability of LNG expansion

S4.1 Selection of emission pathways

This study follows the framework of IPCC's "Shared Socioeconomic Pathways" (SSPs), which is an important input to the upcoming sixth assessment report investigating five different ways to explore how societal choices will affect GHG emissions and, therefore, how the climate goals of the Paris Agreement could be met. Given current policies, we chose the SSPs that reflect temperature trajectories aiming to limit peak warming to below 1.5°C, 2°C, and 3°C. Corresponding scenarios are selected using Integrated Assessment Modeling Consortium (IAMC) 1.5°C Scenario Explorer and detailed criteria used for filtering data are shown in Table S6 [75].

Table S6 *Criteria applied for selecting scenarios using IAMC 1.5°C Scenario Explorer.*

Temperature Target	Category	Project contributing the scenario	Numbers of scenarios
1.5°C	1.5°C high overshoot 1.5°C low overshoot Below 1.5°C	SSP/SSP (1.9Wm2)	13
2°C	Higher 2°C Lower 2°C	SSP	18
3°C	Above 2°C (with additional filter: median warming at peak (MAGICC6): 2.1~3.1°C	SSP	48

S4.2 Climate benefit from coal-to-gas switching

The emissions reduction potential for LNG is a function of coal-to-gas substitution rates in the power sector. The efficiency of the NG power plant, heat content of NG, and NG emissions factor are important parameters required for determining end-use emissions of the LNG life-cycle assessment. The approximate heat rate of NG-fueled plants for electricity net generation in the United States is 7732 Btu/kWh (44.1% efficiency) in 2019 [76], which is derived from electric power plants in the utility and electricity-only independent power producer sectors. Combined heat and power plants, and all plants in the commercial and industrial sectors are excluded from the calculations. In our analysis, we take this number as the power plant efficiency in the base-case scenario. The efficiency range of 41.2% ~ 49.2% is designed to be representative of NG-fueled power plants in the destination [77]. Policies that specify acceptable NG composition and heat rates vary by region – typical limits include a maximum of 4% of inert gases (nitrogen, argon, and CO_2) and a heat rate in the 966~1074 Btu/ft^3 range [72]. We use the average heat content of NG deliveries to electric power consumers in the US as the central input in the base-case scenario. Our study does not include transmission emissions in the end-use stage because we assume power plants at the destination are local nearby regasification facilities. Parameters used to estimate LNG related climate benefit from coal-to-gas switching are shown in Table S7.

Table S7 *Parameters used to estimate climate benefit from coal-to-gas switching.*

Parameters	Unit	Values
Coal-to-gas switching rate	%	0-100
NG lifecycle emission (carbon) intensity[78]	g CO_2e/kWh	469
Coal lifecycle emission (carbon) intensity[78]	g CO_2e/kWh	1001

In the low-emission scenario of 1.5ºC pathway, a 39% substitution rate of LNG achieves net-zero additional emissions (Figure S5). In contrast, net-zero additional emission cannot be achieved in the high-emission scenario under 1.5ºC pathway for all coal-to-gas substitution rates. The breakeven point in the base-case scenario is 59%. In 2ºC and 3ºC pathways with sufficient coal budgets, positive emission reduction can be always achieved in three emission scenarios.

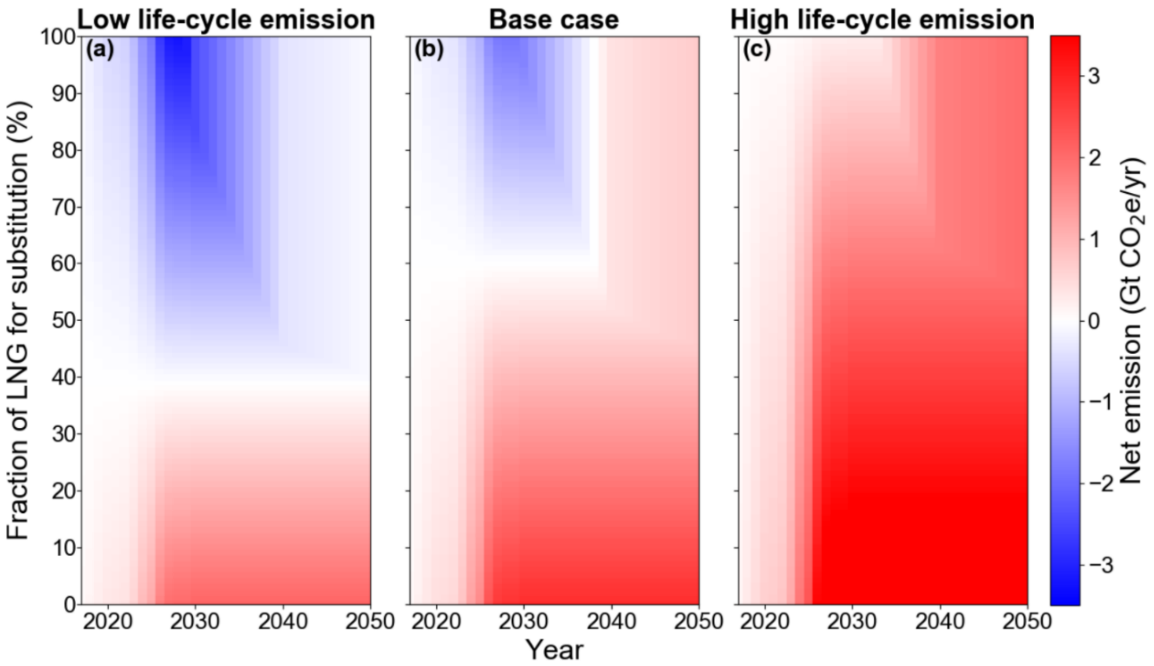

Figure S5. *Net emissions from coal and gas-fired electricity production as a function of coal-to-gas substitution rates in the (a) low life-cycle emissions, (b) base-case, and (c) high life-cycle emissions scenario.*

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