MODELING OF LNG SUPPLY CHAIN GREENHOUSE GAS EMISSIONS

By
Michael Rasool Rabbani

A capstone submitted to Johns Hopkins University in conformity with the requirements for

the degree of Master of Science

Baltimore, Maryland
December 2021

Contents

Executive Summary

The projected increase of LNG trade in the next decade poses a major challenge to countries that also are planning how to meet international climate goals. Not only does the end-use of the fuel cause greenhouse gas emissions; expansive, sprawling supply chains to produce, upgrade and transport the gas emit significant but variable amounts of GHGs to the atmosphere. LNG is an appealing source of energy supply to less resource-rich countries with developing economies. Energy outlooks and projections indicate that regardless of the aggressiveness of the global response to climate change over the next few decades, natural gas usage in developing parts of the world is likely needed to support economic growth. As a result, it is important to help decision-makers by giving them tools to assess climate impact when making long-term decisions regarding energy usage.

This studied used an engineering-based LCA model to calculate emission ranges for The results of this study indicate that emissions from prolific LNG supply chains that are projected to continue producing gas for decades. The results for each field show a very large range between best-case and worst-case emissions, with individual supply chains potentially varying by up to 37 times. The discussion evaluates ways to improve emission quantification efforts for the LNG supply chain, and individual emission reduction opportunities for selected emission sources, like fugitive emissions, that substantially contributed to the modeled emissions variability.

During my five-year professional career, I have had the opportunity to work on climate change issues in the oil and gas industry from multiple vantage points; I have worked on issues relating to both the oil and gas supply chains, worked for a major international oil and gas company and a not-for-profit non-governmental organization, and taken on technical challenges in both the upstream and downstream segments of the supply chain. My current work primarily focuses on developing market-based solutions to incentivize rapid emission reductions throughout the oil and gas supply chain and increase the transparency of emissions data within these supply chains. This Capstone Project explores challenging technical and policy issues relating to the emissions footprint LNG supply chains and has allowed me to explore these challenges more in depth. Most significantly, I was able to use existing literature data along with a publicly available LCA model to evaluate the emissions impact of LNG supply chains. In my current professional work, I will continue to use the data cited in this study and the modeling framework used to further develop an understanding of the posed research question.

Introduction

Global liquefied natural gas (LNG) demand could increase almost 100% to 700 million tonnes by 2040 (Shell 2021) compared to 2020 volumes all while international efforts increase to limit the earth's warming. In many regions with little or dwindling natural gas supply, LNG can be used to increase a nation's energy supply diversity and help reduce its use of fuels, like coal, that are more toxic to human health. Increased LNG trade, however, poses serious risks to global climate goals. Like any fossil fuel, the end-use combustion of LNG emits greenhouse gases unless carbon capture and sequestration projects are employed. In addition, the processes throughout the LNG supply chain of extracting, gathering, processing, transporting, liquefying and shipping gas emit greenhouse gas emissions mostly in the form of carbon dioxide (CO_2) and methane. The GHG emissions intensity of the processes upstream of end-use combustion show wide variability. Relatively small leakage rates throughout this expansive supply chain can make the climate impacts of both pipelined gas and LNG worse than coal, making the understanding of this variability essential (Stecker 2013).

Countries that are planning on continuing and increasing LNG import volumes face significant risks to complying with their climate goals if they do not have robust, verifiable ways of knowing the emissions impact of their LNG supply chains. Satellite surveillance programs of oil and natural gas fields show immense methane plumes from infrastructure around the world that are not being detected quickly by operators or regulatory agencies and not accounted for in national greenhouse gas emission inventories (Varon, McKeever, and Jervis 2019). As a result of this and other detection campaigns, it is widely believed emissions are currently underestimated (Harvey 2020).

LNG demand is anticipated to grow primarily from developing Asian countries as growth stagnates or declines in Europe and historical Asian importers like Japan and South Korea. Since LNG infrastructure is typically a long-term, high-capital investment understanding the potential GHG emissions footprint of LNG is critical as these countries plan out how to meet international climate goals.

This study probes ***how greenhouse gas emissions across the LNG supply chain be substantively quantified and reduced for current and emerging Asian LNG import markets?*** Because these markets could install more than 50% of global LNG import capacity by the end of the decade (GlobalData 2021), the collective climate approach to these investments will play a critical role in international climate goals.

Countries that are committed to rapid greenhouse gas emission reductions to stay in line with Paris goals do not currently have the information needed to compare emissions from various LNG supply chains and how they compare to alternative sources of energy. New and improving quantification methods are consistently showing existing calculation methodologies for national inventories of oil and gas operations significantly underestimate critical sources of emissions. Technological capabilities exist both to quantify and reduce emissions but have not been reliably deployed globally.

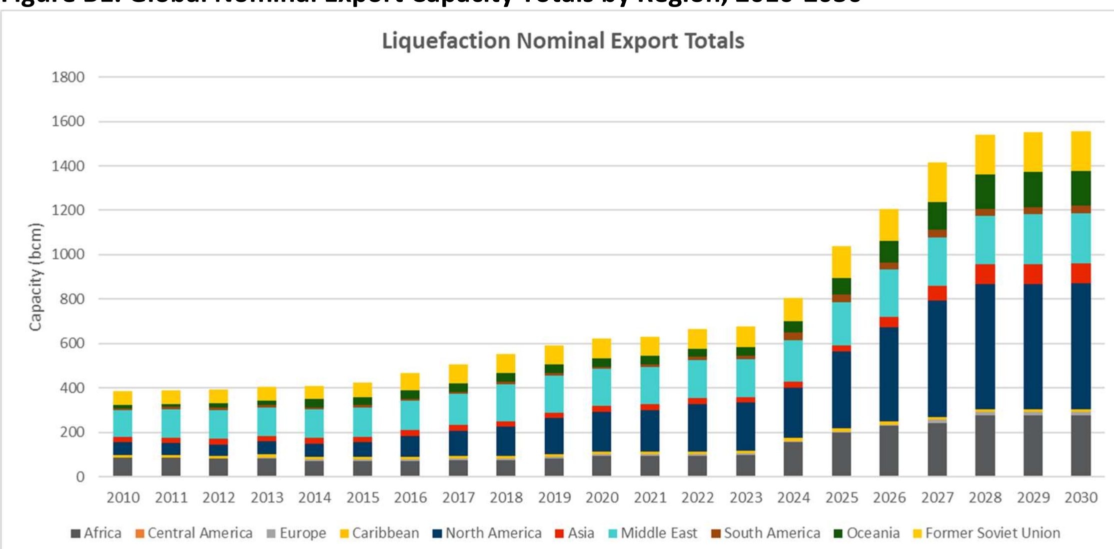
This study uses an engineering-based model and the most granular data inputs available to determine potential emission ranges for eleven prolific and geographically diverse gas supply chains that either currently supply LNG or could supply LNG in the future. The results are evaluated and compared to published LCAs of LNG supply chain. Then, it evaluates discreet parts of the supply chain and recommends areas in which emission quantification and reduction efforts should be prioritized. Finally, it draws conclusions and discusses future research efforts that could improve the results of this study.

Literature Survey

LNG Supply and Demand Trends

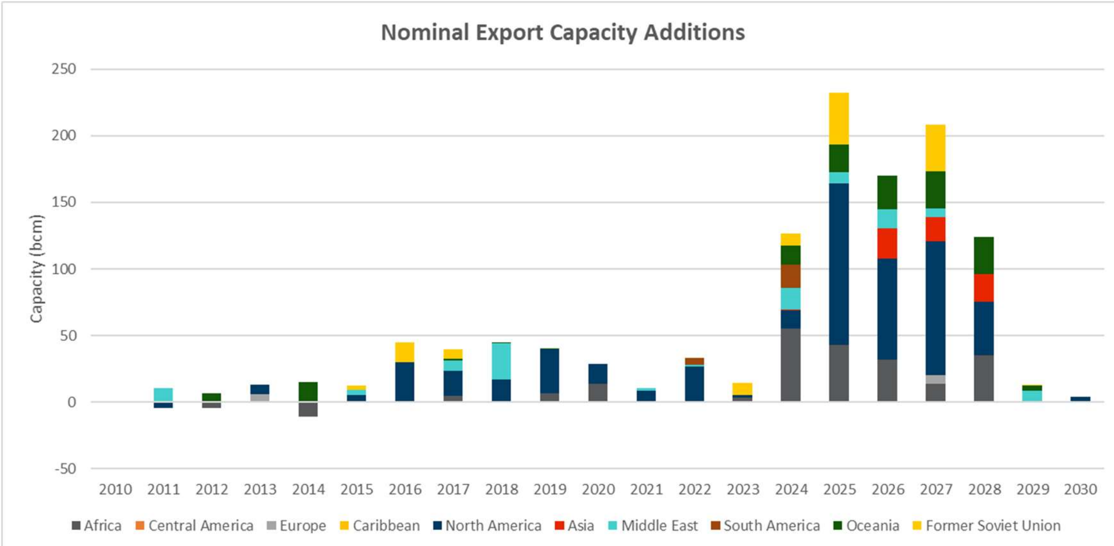
Supply
By 2027, LNG export capacity could increase 133% to over 1,400 billion m^3 gas-equivalent per year, or about 1/3 of total global natural gas demand at 2020 levels (IEA 2021). Forty-two percent of planned export capacity additions into 2030 are expected to come from the United States. The driving force behind impending North American dominance in liquefaction capacity is due to the sheer supply of natural gas resources from shale formations (EIA 2020). Other regions are expected to significantly increase liquefaction capacity during the 2020s compared to 2020 capacities, primarily Africa (20%) led by Mozambique, Oceania (13%) led by Australia, and Russia (10%). Qatar Energy has also recently announced export expansion projects totaling 60 billion m^3 gas-equivalent LNG per year by 2026 (El Gamal 2021).

Figure B1. Global Nominal Export Capacity Totals by Region, 2010-2030



Source: GlobalData 2021

Figure B2. Global Nominal Export Capacity Additions by Region, 2010-2030



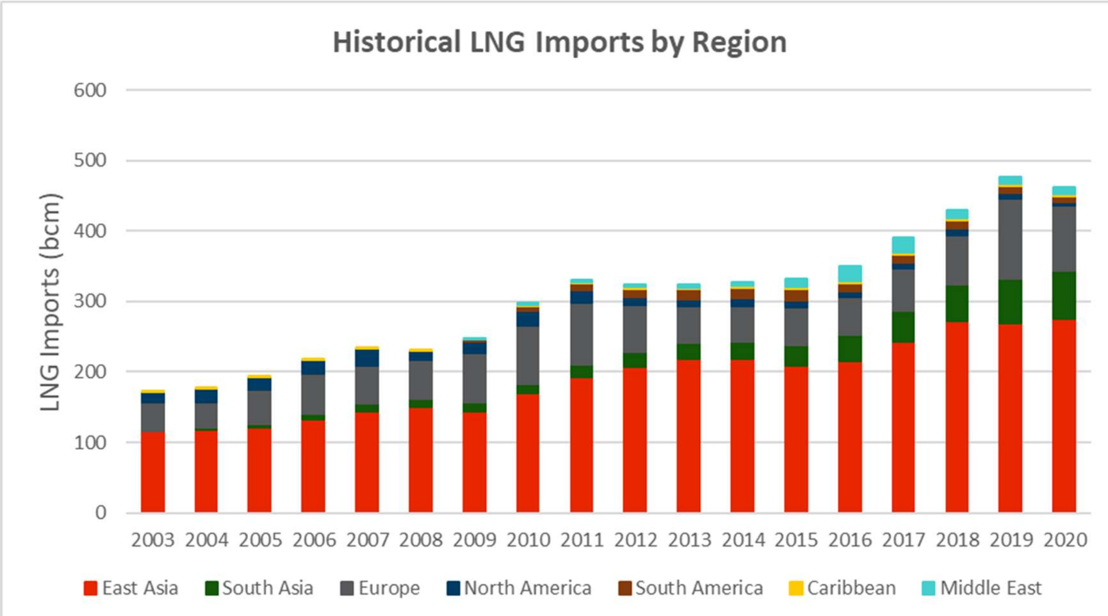
Source: GlobalData 2021

Demand

Increases in LNG demand during the 2020s are projected to come from East Asian and South Asian countries, primarily dominated by China and India. East Asia, defined for purposes of this study as Japan, China, South Korea, and Taiwan has been the dominant LNG demand hub since at least 2003. In 2020 import volumes from East Asia represented 60% of total global import volumes; contrary to stagnant European growth since 2010 East Asian import volumes by 25% from 2010 to 2020 (GlobalData 2021). While Taiwan and South Korea have modestly increased total export volumes since 2010, Chinese imports represent 75%, or 79 bcm, of the total import volume growth. As of June 2021, China has become the world's largest LNG importer (Valle 2021).

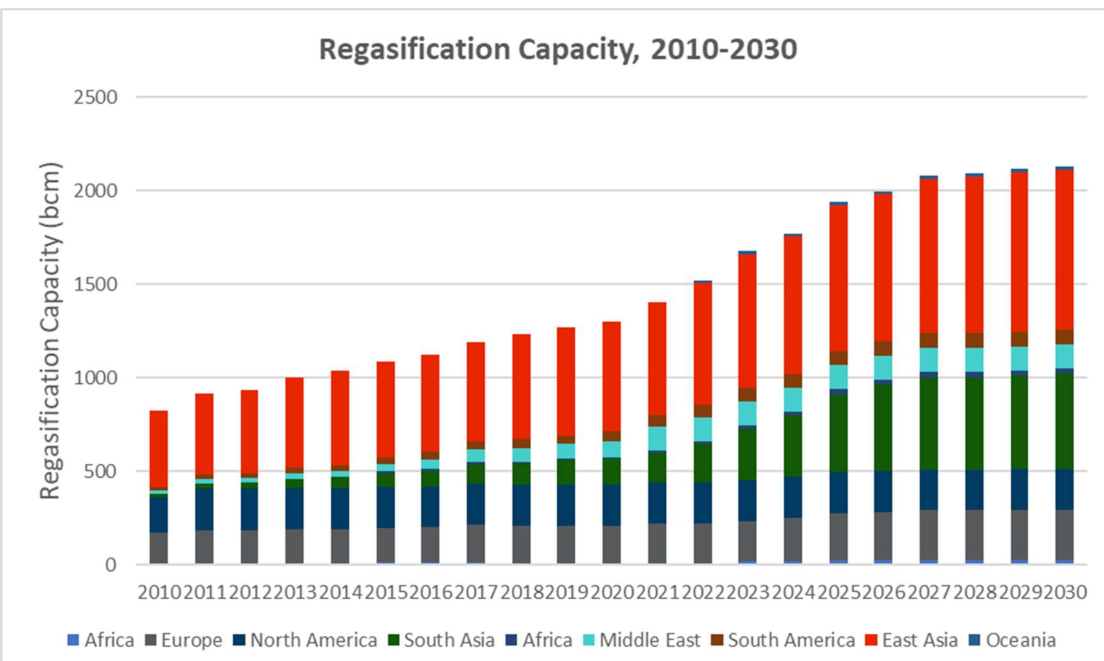
The projected regasification capacity build is used as a proxy to evaluate the extent of LNG demand growth by country. In 2020, China imported just over 90 bcm of LNG and had a total nominal import capacity of 135 bcm (GlobalData 2021). By 2030, China's nominal import capacity could increase to 365 bcm if all projects in its current project pipeline materialize (GlobalData 2021). This accounts for 86% of total projected growth in East Asia. Growth in regasification capacity for South Asian countries from 2020 to 2030 could reach 374 bcm, outpacing total East Asian capacity build by over 100 bcm (GlobalData 2021). South Asian projected demand increases span many countries; five countries represent at least 10% of the total projected build out in South Asia during the 2020s – India (30%), Philippines (18%), Vietnam (15%), Pakistan (13%), and Bangladesh (10%) (GlobalData 2021).

Figure B3. Actual LNG Imports by Region, 2003-2020



Source: Global Data 2021

Figure B4. Global Regasification Capacity, 2010-2030



Source: GlobalData 2021

Historical LNG importers are not going to dominate import volumes of future LNG markets. Table B1 lists the top 10 LNG importers in 2020 along with the top 10 regasification capacity builders from 2021-2030. Only three countries appear on both lists - China, India, and Pakistan. Even the countries overlapping on both lists, China, India and Pakistan only began ramping up LNG import capacities recently and have the largest average year-on-year growth in LNG import volumes since 2010. The historical dominant importers of LNG including Japan, South Korea, the European Union, and the United Kingdom are not projected to increase LNG import volumes.

Table B1. Top 10 Total LNG Importers in 2020 and Top 10 Regasification Capacity Adders during the 2020s

Top 10 2020 LNG Importers (bcm gas-equivalent)		Average YOY Growth, Import Volumes (2010-2020)	Top 10 Regasification Capacity Builders, 2021-2030 (bcm gas-equivalent)	
Japan	103	**1%**	**China**	231
China	92	**62%**	**India**	118
South Korea	55	**2%**	**Philippines**	67
India	36	**17%**	**Vietnam**	56
Taiwan	25	**6%**	**Pakistan**	50
Spain	21	**-2%**	**Bangladesh**	36
France	20	**4**	**Kuwait**	33
Turkey	15	**14%**	**Thailand**	24
Italy	12	**4%**	**Australia**	18
Pakistan	11	**121%***	**Brazil**	17

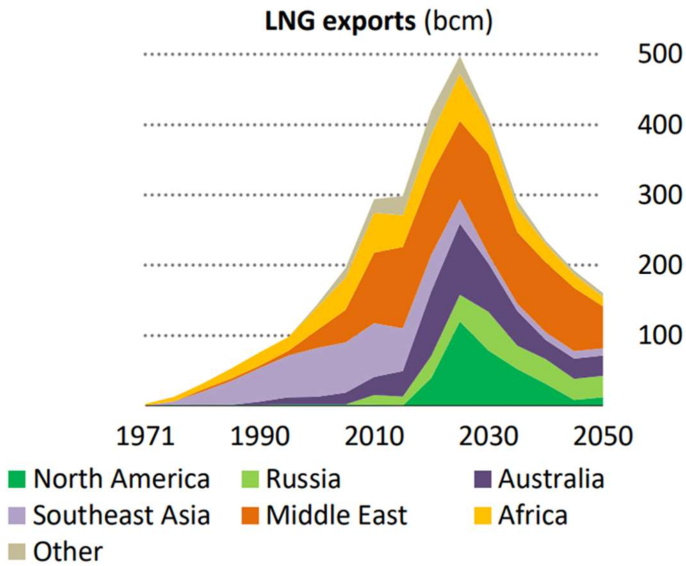
**Pakistan started importing LNG in 2015. The YOY growth represents growth from 2015-2020.*
Source: GlobalData 2021

What is LNG's Role in a 1.5C Climate-Aligned Future

According to International Energy Agency's (IEA) Net Zero by 2050 Report the current projected volumes of LNG for any end-use is incompatible with a net zero emissions pathway (IEA 2021, 175). The report models LNG export volumes peaking just below 500 bcm of gaseous -equivalent LNG in the latter half of the 2020s before precipitously dropping by over 200 bcm by 2035 and continuing a downward trend to under 200 bcm of total exports by 2050. Along with the 60% decrease in LNG trade by 2050, IEA estimates that pipeline gas trade will have to decrease by 65% by 2050 from 2020 levels (IEA 2021, 175). Much of the sustained LNG demand after 2050 stems from the increase of hydrogen production; IEA estimates that half of global natural gas use after 2050 will be as a feedstock for hydrogen production via steam methane reforming process (IEA 2021, 180).

Nearly all exports in 2050 are projected to come from the "lowest cost and lowest emission producers" (IEA 2021, 175). As a result it appears that LNG exported from the Middle East, primarily Qatar, will be lowest cost, lowest emission gas source that continues to be used while Russia and Australia constitute the next largest LNG export volume by 2050. North American and African exports will fall close to zero. Australian exports will also significantly fall while Qatari and Russian export volumes are projected to modestly decrease compared to peak export volumes projected to occur in the late 2020s.

Figure B5. Past and Projected LNG Export Volumes in a Net Zero Scenario, 1970-2050



Source: *IEA, 2021*

While the IEA Net Zero report represents one potential pathway for LNG, aligned with zero net emissions from fossil fuels by 2050, other projections exist estimating a wide range of potential demand for LNG to 2050.

Table B2. Climate-Aligned Scenario Definition Comparison

	BP	IEA
Net Zero	95% GHG reduction* by 2050	100% net reduction*
Rapid / Accelerated Policy Scenario (APS)	70% GHG reduction* by 2050	NDCs, longer-term net zero targets are met
Business As Usual (BAU)/ Stated Policies Scenario (STEPS)	10% GHG reduction* by 2050	Existing climate policies are implemented

**Reductions are specifically in the energy sectors*
Source: BP 2021, IEA 2021

Table B3. LNG Annual Trade Outlook Comparison

	BP	IEA
Net Zero	N/A	2050 - 160 bcm
Rapid / APS	2035 - 1100 bcm 2050 - 1000 bcm	2050 - 575 bcm
BAU / STEPS	2035 - 900 bcm 2050 - 1000 bcm	2050 - 750 bcm

Source: BP 2021, IEA 2021

There is a role, albeit variable for natural gas through 2050 for all reviewed published scenarios. Natural gas consumption is expected to increase by 7.5% - 15% by 2030, unless Net Zero scenarios are taken which results in natural gas peaking in 2025 before sharply declining (IEA 2021, 232).

China and developing Asian economies will drive the growth of natural gas demand in the next decade. Natural gas demand is reliably projected to increase in developing economies across the wide range of future energy scenarios with LNG as a significant portion of that increased demand (IEA 2021, 233 & BP 2021).

GHG Emissions Uncertainty and Quantification in the LNG Supply Chain

As natural gas demand continues to grow in some parts of the world, it is imperative to have methodologies in place that can quantify emissions from the supply chain accurately. The increased use of natural gas creates major risks with countries developing in line with their international climate commitments. However, a growing body of literature finds emissions through the oil and gas supply chain are being significantly underestimated in official inventories, primarily due to underestimation of methane emissions (Harvey 2020). These studies have been performed across multiple, diverse basins with unique operating characteristics while also using a diverse array of quantification methodologies. The basins that have been studied include dry gas basins with unconventional gas production like the Appalachian basin and oil and gas producing basins like the Permian (Cusworth et al. 2021), San Juan (Petron et al. 2020) and the Canadian Montney basin (Tyner and Johnson. 2021). Methods used to quantify emissions include aerial infrared imaging spectrometers and optical cameras (Chen et al. 2021) as well as light detection and ranging (LiDAR) imaging (Tyner and Johnson 2021) and ground-based measurement approaches including downdwind tracer flux measurements (Omara et al. 2018). Regardless of the basin studied or the test method deployed, all studies agreed that emissions are underestimated. The amount with which emissions are underestimated, however, does vary by study.

Aerial studies in select basins in North America using advanced methane detection methods have shown emission underestimates ranging from a factor of 1.8 to 6 (Chen et al. 2021 & Tyner and Johnson 2021). Additionally, US-wide studies have also consistently shown methane emissions underreported, one concluding underestimation by about 60% (Alvarez et al. 2018). Multiple studies have also found production-specific emissions to be underestimated by around 100% (Omara et al. 2018 and Rutherford et al. 2021). Although systematic under-representation of methane emissions currently exist, solutions are rapidly developing to reduce future uncertainty and assist in better prioritization of emission reduction efforts.

New remote-sensing systems promise to reduce uncertainty in methane emissions inventories at a global, national and even asset-level. Methane emission detection programs have traditionally been carried out with handheld sensors that have a capability to detect small leaks relative to the distribution of emission rates seen in recent top-down studies (Cusworth et al. 2021)**.** Although these sensors can theoretically detect close to 100% of emissions, leak detection surveys are generally only required up to a few times per year and the requirements sometimes apply to only the newest facilities while older facilities are grandfathered (40 CFR Subchapter C, Part 60, Subpart OOOOa 2016). Additionally, technicians are prone to missing between 25-75 percent of leaks (Zimmerle, Vaughn, and Bell 2020). Currently, the most common deployments of advanced detection technologies by operators are stationary, continuous monitoring systems, flyovers with fixed-wing aircraft, or satellite inspections.

Several characteristics determine the overall effectiveness of advanced detection technologies. The minimum detection limit of a technology sets the boundary for how much of an emission rate distribution curve a technology can detect and is sensitive to environmental parameters like wind speed (Bridger Photonics 2021). The spatial coverage within a targeted geography such as an oil and gas basin defines what percentage of area that could have potential emissions is surveyed during each campaign. Because existing top-down surveys of oil and gas basins have shown a heavy-tailed distribution where a few large emissions dominate the total emissions for an area, complete spatial coverage is important to ensure that a super-emitting event is not missed in a sample size (Cusworth et al. 2021). The temporal frequency of surveys in an area affects whether a surveillance campaign can reliably catch both persistent emission sources and those sources that occur primarily due to abnormal operating conditions. Additionally, the spatial resolution of a system can be very important to an image of a methane emissions plume leading to follow-up and mitigation of the source.

Aerial flyovers to detect methane emissions have been used recently for area-wide public studies and private use by operators in the supply chain. These technologies generally have a minimum detection limit between three to 30 kg/hr (Fox, Barchyn and Risk 2019). These deployments can fly over a much larger area of interest in the same amount of time as traditional handheld methods. The temporal frequency of these surveys is currently highly dependent on the specific use case. For example, an aerial flyover used for an emissions study may fly over the same area multiple times in a month, whereas when deployed as part of an operator's leak detection and repair program deployment may be tailored to meet regulatory requirements. The spatial resolution of aerial flyovers depends primarily on the height of flight of the aircraft, but generally allows an emission source to be pinpointed to a defined site like a single wellpad, tank battery or compressor station (Tyner and Johnson 2021).

There are a handful of satellite systems currently deployed to monitor methane emissions, each of which have distinguishing performance characteristics. Generally satellites have a much higher detection limit than aerial flyover systems ranging from around 100 kg/hr to multiple thousands of kg/hr (MiQ 2021, 87-89). Satellites can operate in a variety of ways to provide different levels of spatial coverage. For example, satellites can operate like a push-broom and survey every inch of an area or be tasked to specific areas with a known potential to emit methane emissions (CarbonMapper 2021). The temporal frequency of satellites is also related to how they are chosen to be operated. Depending on the amount of satellites in orbit for a system and other operating characteristics temporal frequency can be anywhere from every couple of days to a couple of time per year (MiQ 2021, 86).

Current methane emissions research outside of North America is scant and this presents a major risk that methane emission inventories for other major LNG exporting countries are also underestimated. Other than global satellite surveillance campaigns to track extreme super-emitting methane emissions events (Elkind, Blanton and Denier 2020, 7), basin-wide studies like those described above in North America have not been published. This uncertainty presents major problems in completing high-certainty LCAs of emissions from the LNG supply chain.

LNG Supply Chain Quantification Frameworks

LNG LCA Frameworks

Accurate lifecycle assessments of LNG supply chain emissions assist consumers in quantifying their Scope 3 emissions. In addition, accurate emissions estimates provide a tool to differentiate gas resources based on climate impact allowing decision-makers to choose more assured, climate-friendly alternatives. The details of these LCAs also help assess cost-effective emission reduction measures across the entire supply chain.

Two groups have recently published frameworks for the consistent quantification of GHG emissions for LNG cargoes. The Statement of Greenhouse Gas Emissions (SGE) Methodology developed by technical specialists from Chevron, QatarEnergy, and Pavilion Energy was published in November 2021 and provides detailed guidance on the emissions calculation methodology, emissions accounting approach, and assurance steps a company should take to estimate LNG emissions from wellhead to the delivery point of the LNG cargo (Chevron 2021, 5). Additionally, the International Group of Liquefied Natural Gas Importers (GIIGNL) developed a Framework to serve as a “common source of best practice principles” in the MRV approach and reduction and offset approaches for LNG cargoes (GIIGNL 2021, 7). The GIIGNL framework goes further than the SGE Methodology by including guidance on declaring emissions reductions through supply chain improvement efforts and GHG offsets. Both methodologies discuss its expectations around the quality of data throughout the supply chain. In both methodologies primary data is preferred throughout the supply chain where the availability of such data exists (Chevron 2021, 6 and (GIIGNL 2021, 23). Primary data is defined as data relevant to emissions that is sourced from operations and specific to the value chain of the delivered LNG (GIIGNL 2021, 60). Where primary data does not exist, secondary data is able to be used although it is expected that over time more primary data will be used. Secondary data is defined as default emissions for a generalized industry or region that is not specific to the value chain of the delivered LNG (GIIGNL 2021, 60).

Emissions data transparency and availability in the oil and gas industry across the world remains a major problem and source of discrepancy between countries, increasing the difficulty for countries to announce credible climate-aligned pathways. The United States’ Greenhouse Gas Reporting Program and Greenhouse Gas Inventory (GHGRP, GHGI) compiles operator-specific and national emission estimates, respectively, and offers the most publicly available, granular data for any country in the world. Elsewhere, Annex I nations according to the United Nations Framework Convention on Climate Change (UNFCCC 2021) must submit an annual National Inventory Report with their methodologies stated, but do not consistently publish more granular data (UNFCCC 2021). Because of a lack of emissions data, it has been challenging to develop a consistent methodology to calculate emissions. However, the compilation of research primarily concentrated in the United States, that has uncovered higher than estimated methane emissions has highlighted the need for more precise methods to calculate LNG supply chain GHG emissions. Estimating lifecycle emissions is a rigorous task that requires access to the necessary information required for the calculation methodology chosen. The methods and results of two lifecycle assessments of LNG supply chains are discussed below

Existing LNG LCAs

Two influential, peer-reviewed studies examining emission across the LNG supply chain have been published since 2020 that exhibit key differences in both methodology and results. Gan developed an Excel-based model to estimate life cycle greenhouse gas emissions from natural gas extraction to the city-gate for all potential gas sources to China from 2020 to 2030, including domestically produced gas, internationally pipelined gas, and LNG (Gan, El-Houjeiri and Badahdah 2021, 3). Roman-White takes a novel approach by aggregating supplier-specific, primary emissions data to develop an annual average emissions rate for all gas sourced to Cheniere’s Sabine Pass Liquefaction plant in southwestern Louisiana (Roman-White, Littlefield and Fleury 2021, 10860). Gan modeled upstream emissions on a field-by-field basis, primarily using secondary data as defined by the recently developed LCA frameworks. The emissions intensity of the supply chain calculated in the Gan study are generally larger than the emissions calculated in Roman-White (Roman-White, Littlefield, and Fleury 2021, 10862). Gan’s use of fugitive emission models not referenced in US GHGRP methodologies for different types of basins plus significant differences in shipping emission estimates contribute to these emission estimate discrepancies.

Access to emissions data from known suppliers is an advantage to the Roman-White calculation methodology as it can assess differences in emissions performance between upstream suppliers in the same gas-producing field. However, this advantage does not cover the entire quantity of gas assessed; only 58% of gas supplied to Sabine Pass was able to be traced back to a specific supplier while 42% of gas was sourced back to gas trading entities that generally do not reveal the field or operator with which gas is sourced (Roman-White, Littlefield and Fleury 2021, 10860). Roman-White uses a US average emission intensity using EPA GHGRP data. However, as explored above the emissions inventory used in Roman-White is known to underestimate emissions throughout many US basins. For supplier specific LCAs to consistently quantify emissions more accurately than LCAs using secondary data, they must also use inventories that accurately quantify emissions.

Countries with less upstream gas suppliers and more vertically integrated entities upstream of liquefaction facilities will have less variance in emissions performance within a field. As an example, supplier-specific LCAs for US supply chains will offer considerable value if accurate emission inventories are used while supplier-specific LCAs in countries with more integrated upstream markets, like Qatar, provide less relative value because of the reduced variance.

Methods

The following methods are developed to better understand the areas of the supply chain that are currently causing the most uncertainty on the overall emissions intensity on various LNG supply chains. A range of emission results for each supply chain are developed and the contribution of each emission source is displayed. The results are used to develop recommendations for how to reduce uncertainty in the quantification of emissions throughout the natural gas supply chain, and concurrently prioritize emission reduction efforts in the supply chain.

The Oil and Petroleum Greenhouse Gas Emissions Estimator (OPGEE), version 3.0a is used to estimate emissions spanning the LNG supply chain. Due to the existing uncertainty in the variability and magnitude of emissions from LNG supply chains, this study evaluates the impact of ten variable “mitigation scenarios” by developing “best-case” (BC) and “worst-case” (WC) scenarios for each. By modeling each of the ten mitigation scenarios using BC or WC assumptions, the BC and WC emissions intensity for the entire supply chain is calculated, respectively. Appendix AIII contains waterfall charts that show the difference between BC and WC scenarios along with a quantitative estimate of the impact of each mitigation scenario.

Emissions Modeling Framework

OPGEE is the lifecycle assessment tool used in this study. Developed by Stanford University’s Environmental Assessment and Optimization Group, OPGEE is currently used by the California Air Resources Board (CARB) as the technical basis behind California’s Low Carbon Fuel Standard (LCFS) which aims to minimize lifecycle emissions of California’s transportation fuels pool. OPGEE version 3.0a was updated to calculate emissions throughout the natural gas supply chain.

This study defined both a list of primary and secondary inputs into OPGEE to distinguish each individual supply chain. An OPGEE input is considered a primary input if it has the potential to significantly affect the overall emissions profile and has variability. Secondary inputs generally either have minimal impact on emissions in the oil supply chain or are not variable. The specificity of an OPGEE model depends on the amount of relevant input data the user enters for a given model run. Field-specific primary and secondary inputs that distinguish each model run are shown in Table AII-1 of Appendix AII. OPGEE generates a “smart default” value for each primary input not specified by the user. These inputs are specified in Table AII-2 of Appendix AII.

A list of OPGEE primary and secondary inputs are also manipulated *per* supply chain to develop a BC and WC emissions scenario. The inputs are kept constant for each supply chain to maintain as much consistency as possible between model runs and are shown in Table AII-3 of Appendix AII.

Unlike Roman-White et al, this study aims to evaluate the potential variability of emissions for each selected supply chain based on transparent data inputs and assumptions to provide a baseline to prioritize emission quantification and reduction efforts. To achieve this aim, the maximum amount of specific input data is collected to properly distinguish supply chains by understanding the most relevant and potentially variable inputs that could affect the emissions intensity of these supply chains.

Selection of Supply Chains

Eleven oil and gas fields are modeled that either currently or have the potential to supply natural gas to facilities for liquefaction and eventual shipment to demand hubs. Fields were selected using two principles:

1. Select the field from the USA, Qatar, Australia, Russia, Nigeria, Algeria, Mozambique and Iran with the highest volume of recoverable gas reserves *that also* sends or will send a significant portion of gas to liquefaction.[*]
2. Add other fields in the same country with recoverable gas reserves that send a significant portion of gas to liquefaction if it differs greatly from the field already selected.

[*] *Iran does not have LNG export capacity but one field was selected for modeling due to Iran’s enormous volume of gas reserves and potential to build out LNG export capacity in the future (Argus Media, 2021).*

The Appalachian, South Tambey, Gorgon, QatarGas, Hassi R’Mel, Gbaran Ubie, Golfinho-Atum, and South Pars fields were selected based off the first principle. The Permian, Haynesville, and Daandine fields were selected based off the second principle.

Best-Case/Worst-Case Modeling

Mitigation strategies are developed to model individual pathways of emission reductions for each supply chain. Mitigation strategies are developed without assuming the exact route employed to achieve the reduction and are modeled by changing one or more of the inputs shown in Table AII-3. The BC scenario for a supply chain’s GHG emission footprint is developed by assuming that *all* mitigation strategies are achieved. The “worst-case” scenario is modeled as an accumulation of not achieving any mitigation strategies. Because mitigation strategies can affect others, each is technically modeled separately for each supply chain. For example, modeling a WC loss rate from production fugitives and gathering fugitives at the same time lowers the overall losses from gathering fugitives; due to shrinkage in throughput from the upstream production emissions the gathering throughput and absolute losses modeled are lower with a production loss rate assumed. Therefore, after the removal of each mitigation strategy is modeled separately, the resulting emissions are summed together to develop the WC scenario for each LNG supply chain.

Production Fugitives

OPGEE considers a production facility to include equipment on a well pad or tank battery associated with multiple well pads. OPGEE allows users to select emission rates from individual components at a production facility, including known high emitters like pneumatic instruments, tank hatches and vents, and more traditional components targeted in leak detection surveys such as flanges. OPGEE also allows a whole-site fugitive rate to be entered that covers all fugitives regardless of its origin. This approach is taken due to a lack of existing data setting a specific loss rate for individual components. To model the BC scenario a leak rate of zero percent is assumed. Per US regulatory reporting, the best operators of dry gas fields come close to achieving zero leak rates. With enhanced leak detection methods and state of the art facility design that will be reviewed in the discussion section, near-zero fugitive emission rates are possible.

The WC scenario modeled derives its assumptions from extensive data collected in the Delaware and Midland Basin of the Permian Basin region in Southwest Texas (Cusworth et al. 2021). The study estimates that 72,000 wells in the Permian Basin were flown over at least once during the flyover campaign. The US Greenhouse Gas Reporting program's database estimated 99,616 wells in the Permian basin throughout the year 2020 (EPA 2021). This results in a percent coverage assumption of 72% for this study. Average production of 15 bcf/d natural gas during the period of flyovers in the Permian is assumed based (EIA 2021). With methane content in the produced gas estimated to be 65% through the processing stage (EPA 2021), a loss rate based on the total production and the percent coverage of the area is derived. Since upstream flaring is not considered a fugitive emission, an adjustment is made to the loss rate to remove emissions from active and inactive flares. The effect of flaring emissions on overall supply chain emissions is evaluated under *Upstream Flaring and Flaring Efficiency.* The loss rate from well pads for the WC scenario is calculated to be 1.5% and the loss rate from tank batteries is calculated to be 1.9% for a total loss rate of 3.4%. Tank batteries are assumed to be present only in fields with a gas-to-oil ratio (GOR) of less than 100,000 scf/bbl. Therefore, the loss rate for fields with GORs greater than 100,000 scf/bbl only includes well pads and is 1.5%.

This study was chosen to model WC emissions was selected because it represents the highest emissions rate of any published basin-wide study so far, includes revisits of many emission points to establish more certainty in the persistence of an emission source and attributes emission plumes to point sources that can be entered in OPGEE to estimate site-wide fugitive loss rates from the natural gas supply chain.

This choice, however, also accentuates the problem that more top-down, basin-wide data is not available for use. The results of a near basin-wide survey to detect fugitive methane emissions was chosen in lieu of operator-reported data on equipment leaks and emissions. The observed underestimate of methane emissions from national inventories in comparison to top-down methods of wide-scale surveillance does not properly account for the WC GHG emissions rate of a supply chain. Multiple surveys have been completed to estimate methane emissions from a variety of geographies including California (Duren et al. 2019), the Four Corners region (Frankenberg et al. 2016), and the Permian Basin (Cusworth et al. 2021). Emissions distributions for individual oil and gas point sources for these three regions all show an identical, lognormal distribution with a fat-tailed distribution where most emissions came from a small portion of point sources. While the distributions follow the same pattern, the magnitude of emissions and overall gas loss rate differs.

To model the potential WC emissions, the peer-reviewed study of the Permian basin with the largest inferred loss rate was selected for use across all basins. This study, along with other top down studies, have identified the importance of super-emitting events to the overall magnitude of emissions at an oil and gas facility. As shown above, these top-down surveys have identified that super-emitting events are not well-captured in official, national emissions inventories. While the magnitude of emissions from the Permian basin may not be equal to basins with much different operations, there are no peer-reviewed studies of fugitive emissions to the level of detail of the Permian study to be used for selected basins. There are also no peer-reviewed studies currently available that attempt to identify super-emitters in the selected basins outside the United States or in the Appalachian or Haynesville. As studies are completed for these basins like the ones completed for the Permian, California and the Four Corners region, they can be added to this modeling framework.

Gathering Fugitives

The gathering and boosting segment of OPGEE is modeled as a unit process directly downstream of upstream flaring and venting and directly upstream of processing equipment starting with dehydration. For this study, gathering is defined as any pipeline downstream of a production facility and upstream of a gas processing facility, distinguishing itself from transmission which is downstream of processing. In the United States, oil and gas gathering pipelines generally operate at lower pressures than interstate transmission pipelines and are rurally located. As a result, these pipelines are not regulated as tightly as transmission pipelines. Various research has shown gathering pipelines have a propensity to leak considerable fugitive emissions.

WC scenario estimates leakage from gathering pipelines at 1.7% of total gas production while BC assumes 0% leakage. Some studies pinpoint the root cause of the high leakage rate from the Permian as undercapacity (Cusworth et al. 2021). Another reason for high leakage can be lax regulation on gathering pipelines, compressor stations and treating equipment that do not require frequent monitoring (Murphy and Holstein 2021). Since upstream flaring is not considered a fugitive emission, an adjustment is made to the loss rate to remove emissions from active and inactive flares. The 72% coverage assumption for production is used for gathering as well, as is the 65% methane content assumption of gas lost to the atmosphere.

Processing Fugitives

Gas processing plants in OPGEE consist of gas treating and fractionation units including dehydration, acid gas removal and natural gas liquid (NGL) fractionation. These processing plants treat gas to set pipeline or LNG cargo specifications and separate NGLs. Using data from Cusworth et al. it is estimated that 0.3% of gas is lost from processing plants in the Permian basin after accounting for the overlap in flaring emissions as described above in the production and gathering fugitives section. The same coverage and methane content assumptions are used for processing as are used for production and gathering. For the BC scenario, processing fugitives are set to 0. For the WC scenario, fugitive emissions are set to 0.3%.

Transmission Fugitives

Gan completed a literature survey of studies relating to pipeline leakage both in and outside of the United States to determine a data-backed distribution to run its emission models. The study with the largest leak rate either in or outside the US is chosen in this study to model the WC scenario for each supply chain, which attributed a pipeline leak rate of 6E-5 kg/kg-km to transmission pipelines (Logan, Heath and Macknick 2012). Due to a lack of peer-reviewed primary data on the leak rate of transmission compressor stations, the derived leak rate from Cusworth et al. of 1.3% of total gas throughput for compressor stations in the gathering segment is used for transmission compressor stations as well. Transmission compressor stations operate at higher pressures so are likely more stringently regulated

(PHMSA 2018). As studies on transmission compressor station emissions are completed in different regions, the results can be included in this modeling framework.

Upstream Flaring and Flaring Efficiency

Upstream flaring volumes and efficiencies for the production operations of each individual supply chain are modeled. Flaring from gas processing plants or liquefaction facilities are not included in this mitigation scenario and are modeled separately in OPGEE. For the BC scenario, flaring volumes for the field are set to zero. This means that there is no impact from changing flaring efficiency and so efficiency is not considered a variable to adjust for best case scenario modeling. For WC scenario modeling, gas flaring location and volumetric data collected by NASA and NOAA's jointly owned Visible Infrared Imaging Radiometer Suite (VIIRS) are used to estimate actual flaring volumes for each field (Colorado School of Mines 2019 & 2020).

An empirical calculation developed the Water Environment Research Foundation was used to model the flare efficiency of a normally operating non-assisted flare commonly found in production fields (Willis, Checkel and Handford 2013, 4-2). This study uses windspeed data from the Global Wind Atlas in each production field as a critical input to the efficiency estimate (Global Wind Atlas). In addition, the study assumes for the WC scenario that the flare is completely unlit and providing 0% combustion through 20% of the year.

A literature review was conducted on the geographical boundaries of each field. Then, VIIRS flaring volumetric data from 2019 and 2020 are collected and filtered to cover flares associated with upstream production operations. Individual field boundaries are unable to be identified for some modeled fields. In these cases, the flaring rate from the field is assumed to match the average flaring rate from a larger area with an easier defined boundary. For example, the geographic location of the offshore production assets associated with the QatarGas 2 project were unable to be distinguished from the overall North Dome field region. Therefore, the flaring rate in scf/bbl oil/condensate produced is used as a proxy. The 2019 and 2020 gas flaring volumes from each region are averaged to develop an average flaring rate. 2020 flaring volume is not used alone to avoid the effects that the Coronavirus pandemic may have had on a field's oil and gas production volume or practices. A decrease in production may have also resulted in a decrease in baseline flaring volume. Alternatively, a lack of operational staffing or delays in maintenance activities due to the pandemic may have caused an increase in flaring above known baseline rates.

Table M1. Flaring-to-Oil Ratio and Average Windspeed per Field

Input	Units	OPGEE v3.0a Excel Cell Reference	Greater Gorgon	Permian	Appalachian	Gbaran Ubie Phase 2	Hassi R'Mel	South Tambey
Flaring-to-Oil Ratio	scf/bbl oil	Inputs!I86	21.0	4.7	0.8	30.1	32.1	5.2
Average wind speed	m/s	Flaring!M317	6.5	6.5	4.5	2.5	6	7

Input	Units	OPGEE v3.0a Excel Cell Reference	Daandine	Haynesville	Qatargas 2	South Pars (Phase 4-24)	Golfinho Atum
Flaring-to-Oil Ratio	scf/bbl oil	Inputs!I86	27359.8	1.9	18.0	14.1	0.0
Average wind speed	m/s	Flaring!M317	5	4.5	5.5	5.5	6

Table M2. Flaring Data per Modeled Field

Field	2020 Volume (bcf)	2019 Volume (bcf)	Latitude Range*	Longitude Range*
South Pars	1.23	4.48	25-28	51-61
North Dome**	0.73	0.72	25-27	50-53
Gorgon	0.14	0.09	-21-(-19)	115-116
Daandine	0.01	0.01	-28-(-26)	149-151
Permian	5.06	7.82	30-33	-105-(-101)
Appalachian	0.01	0.04	38-42	-83-(-76)
Haynesville	0.01	0.03	31-33	-96-(-93)
Hassi R'Mel	0.93	0.87	27-34	2-5
South Tambey	0.03	0.06	71-72	71-72
Gbaran Ubie Phase 2	0.24	0.27	4.6-5.1	6.15-6.8
Golfinho Atum Complex	0.00	0.00	40.75-41.25***	10.5-12***

** Northward latitude and eastward longitude are associated with positive values*
*** North Dome field used as a proxy for QatarGas 2 production*
**** Footprint of all offshore production off of eastern Mozambique coast used because Golfinho-Atum Complex has not yet began gas production*

Liquefaction Carbon Capture and Sequestration

OPGEE models energy-related combustion emissions from liquefaction on a site-level basis; thus, emission reductions from carbon capture at a liquefaction plant must be modeled via a reduction in energy usage. OPGEE also assumes only electrical load is required and none from the form of process heat. Compression, refrigeration and ancillary loads are inputs in MW per mmtpa of LNG production. As secondary inputs, OPGEE has a built-in assumption of the loads required but allows the user to update these inputs with better available data. Without better available data, the OPGEE assumptions of 29.1 MW per mmtpa for compression/refrigeration and 17.7 MW per mmtpa are used as the base energy requirement for each field.

While there is no carbon capture modeling option in OPGEE for liquefaction plants, a reduction in energy demand from the plant lead to a reduction in assumed emissions as well. A limitation of this approach is that the parasitic energy loss associated with carbon capture facilities is not discreetly modeled. Because of the assumption that electricity is generated onsite using feed natural gas, this means that liquefied, shipped, and delivered volumes of natural gas may be slightly higher than modeled.

The BC scenario assumes through a proxied 90% reduction in energy demand from the liquefaction facility that 90% of total energy-related emissions from liquefaction plants are captured and sequestered. The BC scenario for modeling assumes that 90% of baseline emissions associated with energy-related emissions is reduced. The WC scenario assumes the OPGEE default electrical load for liquefaction facilities with no carbon capture and sequestration. As a result, for all supply chains the BC scenario, is a 90% reduction of energy-related combustion emissions for liquefaction compared to the WC scenario.

LNG Cargo Methane Slip

Most LNG cargoes use a mixture of fuel to meet the energy demand requirements to move the cargo. The three most common fuels are ultra-low sulfur diesel (ULSD), low-sulfur fuel oil (LSFO) and boil-off gas (BOG) from the LNG (Roman-White, Littlefield, and Fleury 2021). BOG consists mainly of the lighter components of the LNG cargo, so is primarily nitrogen and methane regardless of the starting composition of the LNG. For each scenario and field, a BOG boil-off rate of 0.1% per travel day is used with no LNG being regasified. Effectively, all the BOG ends up being used for fuel and the total amount of BOG is positively, linearly correlated with the distance of LNG cargo travel. For fuel use, this study takes an approach consistent with the approach in Roman-White; the remainder of the fuel requirement after BOG is made up by LSFO (84%) and ULSD (16%) based on proprietary shipping log data (Roman-White, Littlefield, and Fleury 2021). Maximizing the use of BOG also helps maximize the differentiation potential for choosing engines with lower methane slip. Methane slip from the BOG of different engines on LNG cargoes is variable. Roman-White et al. summarizes the methane slip associated with each type of commercially available engine. For the BC scenario a steam turbine internal combustion engine is modeled with a methane slip of 0.1%, per EPA. A tri-fuel diesel electric (TFDE) engine with a methane slip of 3.13% is used for the WC scenario for all fields (Balcombe, Staffell, and Kerdan 2021).

The OPGEE model was slightly updated to take account of the loss of boil-off-gas in the LNG stream arriving at the regasification facility. Additionally, the energy requirement per ton of LNG shipped and per voyage mile was updated from the OPGEE default to 145 btu per ton per mile. (Le Fevre 2018).

Reservoir CO_2 Sequestration

For BC scenario modeling, the capture and reinjection of CO_2 from reservoir gas is assumed for fields with a known reservoir gas CO_2 concentration of at least 2 volume percent. For the fields modeled, only three (Gorgon-15%, QatarGas 2-2.3%, and South Pars-2.3%) had this mitigation modeled in their BC scenario. For all other fields, CO_2 is vented through the acid gas removal unit (AGRU) in the processing segment of the supply chain. The WC scenario assumes that these fields do not reinject CO2 and all CO2 is lost either through fugitive emissions or normal venting via the AGRU.

Engine Electrification on a Primarily Renewable Grid

OPGEE models all engines associated with production, gathering or processing operations as natural gas-fired engines. Natural gas-fired engines are the industry norm because the intended product can conveniently be used as the fuel source as well, thereby limiting the facilities required for other types of energy, like electricity. However, depending on the type of engine uncontrolled natural gas-fired engines generate high quantities of nitrogen oxides (NO_x) and greenhouse gases, including methane due to high levels of combustion slip. As a comparison, engines are generally less efficient as well than natural gas turbines and may generate more CO_2 as well per unit of energy created.

The WC scenario modeled in OPGEE assumes that all engines are natural gas-fired, 4-stroke lean burn engines with a methane slip rate consistent with most recent literature of 1.15 lb/mmbtu (Vaughn, Luck and Williams 2021). Additionally, minimal offsite electricity requirement is modeled to negate any unintended effects of the grid. The BC scenario is modeled by changing each engine type for engines upstream of the liquefaction plant to electric. This increases the amount of offsite electricity needed. To model a heavily decarbonized grid, 75% of the grid electricity is assumed to come from renewables on an annual average while the remaining 25% comes from natural gas-fed power plants meant to balance the grid. It is assumed that electricity coming from natural gas is from highly efficient turbines that have negligible methane slip, so methane slip is not included as an upstream emission to be accounted for in the BC scenario. A list of engines is shown below and with more detail in Table AII-3.

Table M3. List of Compressors and Pumps in which Prime Mover Type is Switched Between Natural Gas-Fired and Electric

Modelled Units with Engines
Well and downhole pump
Separation compressor
Water injection pump
Acid gas removal compressor
Demethanizer compressor
CO_2 separation membrane compressor
Gas lifting compressor
Gas reinjection compressor
CO_2 injection compressor
Sour gas reinjection compressor
VRU compressor
Pre-membrane compressor
Gas transmission compressor

Import Country Pipeline Distance

The distance of high-pressure transmission pipeline required to pipe regasified LNG from a port to the intended end-user can have an impact on the emission footprint of the supply chain. Pipeline distance affects the number of compressor stations needed and affects the potential for fugitive emission events to occur. The import destination modeled for each supply chain is a regasification terminal near the port area in Guangdong. For the BC scenario the end user is assumed to be downtown Guangdong. As a result, zero miles of additional transmission pipeline are modeled because it is assumed that the gas distribution network, which is out of scope of this modeling, begins immediately after the regasification terminal. For the WC scenario, 500 miles of transmission pipeline are assumed from Guangdong to neighboring Hunan Province which has heavy industry that uses natural gas both as a feedstock and as an energy source (Lundquist 2021). Hunan Province is assumed to be located far enough away from large sources of Chinese domestic gas production and close enough to LNG regasification terminals to be a reasonable long-distance LNG demand hub. The emissions rate assumed for transmission fugitives is used for this mitigation strategy as well. Fugitive compressor station emissions are not doubled for this strategy from transmission. However, combustion emissions including CO_2 and methane for combustion slip are included in the results for this mitigation strategy.

Emissions Allocation and Emissions Intensity

Emissions Allocation

Most fields modeled in this study produce oil, condensate and/or NGL co-products. To strictly model the LNG supply chain, an emissions allocation method was developed to disassociate a fraction of emissions from natural gas from segments of the supply chain that produce co-products. This allocation of emissions to products is done on an energy basis and use built-in OPGEE calculations and assumptions of a product's energy density to account for emissions. As described above, OPGEE presents results of each individual process unit, but also defines several stages related to the supply chain. The energy allocation methodology for each stage and the boundary of each stage is described in Table M6. Stream number refers to the process stream in OPGEE and can be found in the 'Flow Sheet' tab. The quantity of product leaving each OPGEE stage is chosen for the emissions allocation.

Table M4. Energy Allocation Methodology

Stage	Boundary	Energy-Allocation Streams	Stream Numbers
Exploration	Exploration-related activities for oil/condensate and gas	**Oil/Condensate:** Volume after three-phase separation **Gas:** Gas volume after flaring/venting + Stabilizer gas + VRU gas	**Oil/Condensate:** 7 **Gas:** 31-33
Drilling and Development	Well-site preparation for oil/condensate and gas wells	**Oil/Condensate:** Volume after three-phase separation **Gas:** Gas volume after flaring/venting + Stabilizer gas + VRU gas	**Oil/Condensate:** 7 **Gas:** 31-33
Production and Extraction*	**Gas:** Production operations from gas extraction to gas gathering post-separation (includes venting and flaring) **Oil/Condensate:** Production operations from oil/condensate extraction to crude oil stabilization and dewatering	**Oil/Condensate:** Volume after three-phase separation **Gas:** Gas volume after flaring/venting + Stabilizer gas + VRU gas	**Oil/Condensate:** 7 **Gas:** 31-33
Surface Processing	**Gas:** Includes gathering and gas processing unit processes upstream of transportation and/or gas liquefaction **Oil/Condensate:** Includes oil upgrading and dilution upstream of storage or pipeline transportation **NGLs:** Includes all separation processes from gas stream in separation units at processing plants upstream of transportation and further treatment	**NGLs:** Heavy product exiting demethanizer **Gas:** Light product exiting demethanizer	**NGLs:** 39 **Gas:** 38
Liquefied Natural Gas	**Gas**: Includes liquefaction, shipping and regasification of LNG	No energy allocation needed as the only product is gas	N/A
Gas Transport and Storage	**Gas**: Includes transportation of gas through high-pressure transmission lines after the gas processing plant in the export country and after the regasification facility in the import country	No energy allocation needed as the only product is gas	N/A

**Oil surface processing operations are turned off for these OPGEE runs. Therefore, no energy allocation is required for oil/condensate streams because no emissions are modeled for oil upgrading or dilution processes.*

Emissions Intensity Metric

The metric utilized to compare LNG supply chains is total GHG intensity, in tons CO_2 equivalent, per ton of LNG that enters the distribution grid for the BC scenarios or a high-pressure transmission pipeline for the WC scenarios. To create a consistent denominator in the emission intensity for each supply chain, the regasified LNG associated with the BC scenario is used as the denominator to calculate the intensity of each mitigation scenario and the overall WC scenario. This has the effect of slightly underestimating the *real* intensity of the WC scenario because less gas would be delivered.

LNG delivered to the end customer is the preferred metric because the amount of gas lost through the import country's transmission pipeline is not removed. However, this value would have required an extensive update of the existing OPGEE model and is thus not chosen. Emissions and internal usage of natural gas throughout a supply chain can affect the total amount of gas that ends up at the end user. For each model iteration that removes an emission mitigation scenario, total regasified natural gas will likely increase.

Climate Metric and Time Horizon

The climate metric selected for use in modeling is global warming potential (GWP). A GWP of 84 is used to characterize methane, consistent with the 20-year time horizon GWP of methane in IPCC's AR5 report, excluding climate feedbacks (IPCC 2014). GWP is used to compare the relative radiative forcing impact of different GHGs and converts each GHG emitted into CO_2 equivalence. A GWP can be selected for multiple time horizons. Methane emissions contribute largely to the GHG emissions in the oil and gas supply chain, in different magnitudes for each operating basin. A single molecule of methane has 120 times the warming potential of carbon dioxide immediately after it is released into the atmosphere. However, methane does not last in the atmosphere for as long as CO_2 as it readily reacts with hydroxyl radicals to form non-GHGs. Thus, the GWP of methane 20 years after emission into the atmosphere is estimated to be 84-86 times that of CO_2 and between 28-34 times that of CO_2 after 100 years. Because global action is being taken to evaluate and implement the best ways to reduce methane emissions from the oil and gas sector within the next 10-30 years, the 20-year time horizon for GWP was selected for calculation of CO_2 equivalence from the modeled LNG supply chains. This modeling approach further accentuates the warming potential of emission sources consisting mainly of methane as compared to using the 100-year time horizon of methane to calculate CO_2 equivalence.

Results

This study quantifies ranges around the total emissions for major LNG supply chains and showcases:

1. The results of the emission quantification strategies described in the Methods section for each of the 11 LNG supply chains selected, and
2. The relative impact of different emission sources over a best-case scenario to a worst-case scenario.

Eleven LNG supply chains were estimated using OPGEE to determine the range of emissions and potential magnitude of emission reductions that could be expected through mitigation strategies in the supply chain. The results of this study show that WC scenario emissions from each supply chain range between 10-37 times higher than the modeled BC scenario. The non-weighted average GHG emissions mitigated between the BC and the WC scenario is 7.5 tons CO_2eq per ton regasified LNG, and ranges from 3.8 to 9.1 tons CO_2eq per ton regasified LNG. For the fields modeled between 82 to 95% of the difference between BC and WC emission scenarios come from total fugitive emissions in the production, gathering, processing and transmission segments of the supply chain. The impact of each modeled emission source varies by supply chain and indicates that each supply chain may require different mitigation strategies.

Table R1. Best-Case and Worst-Case Emission Intensity Results for each Modeled Supply Chain

Field	Best-Case Scenario (t CO2eq/t LNG regasified)	Worst-Case Scenario (t CO2eq/t LNG regasified)
Haynesville	0.4	4.2
South Pars	0.3	5.6
Permian	0.6	6.3
Daandine	0.2	6.5
South Tambey	0.4	7.1
Appalachian	0.5	7.3
Golfinho-Atum	0.2	7.5
Gorgon	0.4	8.5
Hassi R'Mel	0.5	8.8
QatarGas 2	0.3	9.1
Gbaran Ubie	0.5	9.6

Figure R1. Example LNG Supply Chain Emission Results: Permian

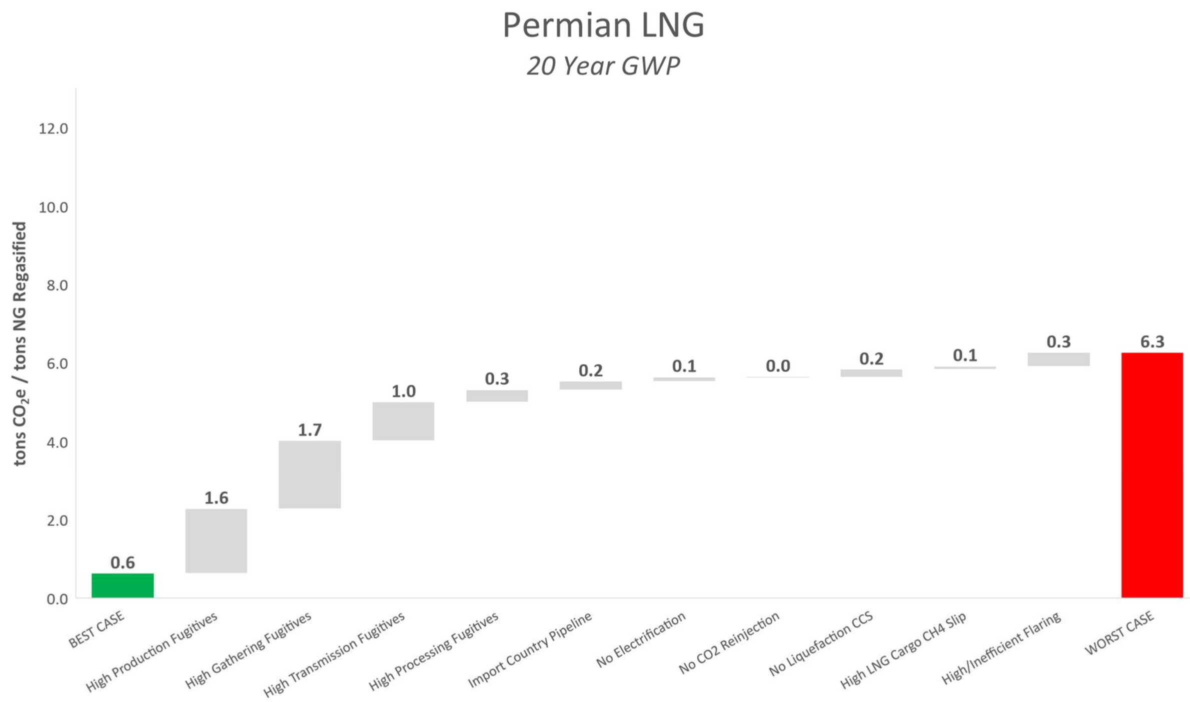


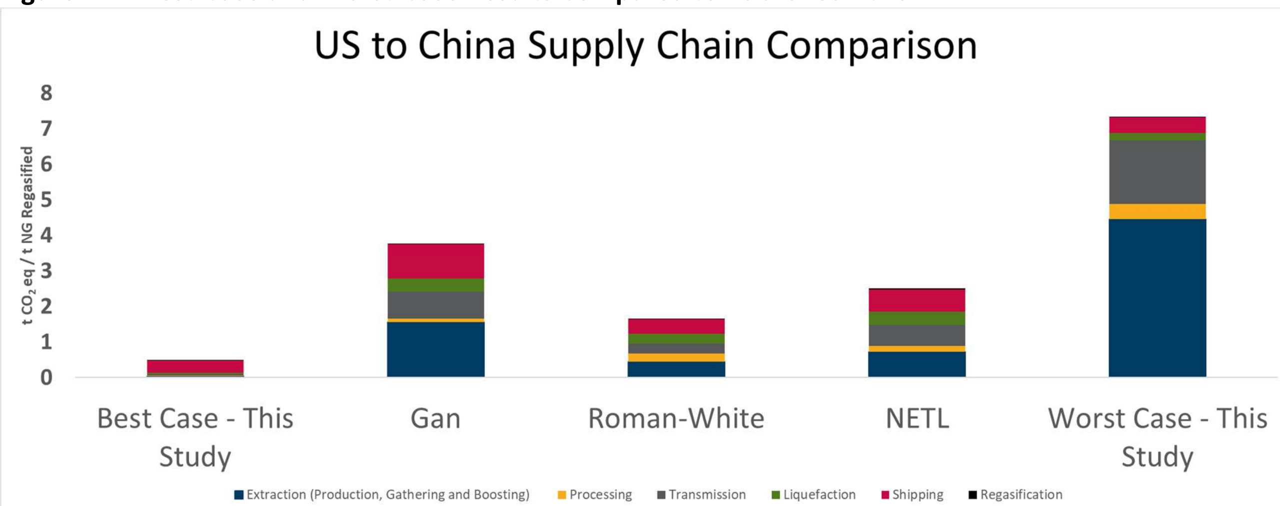
Table R2. Range of Impact per Mitigation Scenario

Mitigation Scenario	Smallest Emissions Impact (t CO2eq/t LNG regasified)	Largest Emissions Impact (t CO2eq/t LNG regasified)
High Production Fugitives	1.0	4.5
High Gathering Fugitives	1.1	2.6
High Transmission Fugitives	0.9	1.0
High Processing Fugitives	0.2	0.5
Import Country Pipeline	0.2	0.2
No Electrification	0.0	0.3
No CO2 Reinjection	0.0	1.0
No Liquefaction CCS	0.2	0.2
High LNG Cargo CH_4 Slip	0.0	0.1
High/Inefficient Flaring	0.0	0.4

Variation to Published Results

A comparison of this study's results to previously published LCA results show that BC scenarios are well under published results while WC scenarios are well over published results. The case used from this study to compare is the Appalachian basin, since gas from the Appalachian makes up about 1/3 of total US gas supply (EIA 2021). First, the best and worst case runs of this study for the Appalachian basin fall at the bounds of each of the three compared studies. The emissions intensity of the BC scenario is between 3.3 to 7.5 times lower, while the WC scenario is between 2 to 4.5 times higher than the compared studies. The results of this study also indicate that if bottom-up emission estimates, especially with regards to fugitive emissions from production, gathering, processing and pipeline transmission, are replaced with the results of recent top-down emission source identification and quantification studies that the overall total supply chain GHG emissions can increase up to an order of magnitude. The Roman-White and NETL results do not provide a direct comparison because those studies sourced gas from multiple upstream North American locations to develop average results. However, emissions shown from Gan et al. are directly from Appalachian-shale gas. The extraction, processing and transmission segments are directly affected by the sourced gas basin while liquefaction, shipping and regasification emissions are not a function of the sourced gas basin.

Figure R2 – Best-Case and Worst-Case Results Compared to Published LCAs



Variations of differing magnitude exist between each of the compared segments as well. Tables R2-R3 shows variations in emissions from the three published studies compared to the BC scenario for the Appalachian Basin-sourced supply chain.

In the BC scenario of this study,

- Extraction emission reductions are between 91% to 97% lower,
- Processing emissions are between 86 to 93 percent lower,
- Transmission emissions are 83% to 94% lower,
- Shipping emissions are 15% to 64% lower, and
- Regasification emissions are 16% lower to 152% higher.

In the WC scenario of this study,

- Extraction emission reductions are between 186% to 900% higher,
- Processing emissions are between 90% to 307% higher,
- Transmission emissions are 136% to 556% higher
- Shipping emissions are between 55% lower and 7% higher, and
- Regasification emissions are 16% lower to 152% higher.

Based on Table R2's ranges of emissions impact from each mitigation scenario, the fugitive emissions from the production, gathering, processing and transmission segments and the electrification of all compressor drivers throughout the supply chain on a 75% renewable grid are likely drive the differences between the published results and the BC scenario. For the WC scenario, fugitive emissions are the primary driver behind the absolute differences in GHG intensity estimates.

Table R3 - Best-Case Appalachian Supply Chain Comparison

Segment	Best Case vs. Gan	Best Case vs. Roman-White	Best Case vs. NETL
Extraction (Production, Gathering and Boosting)	-97%	-91%	-94%
Processing	-86%	-93%	-91%
Transmission	-94%	-83%	-92%
Liquefaction	-92%	-90%	-92%
Shipping	-64%	-15%	-45%
Regasification	88%	152%	-16%
Total	**-87%**	**-70%**	**-80%**

Table R4 - Worst-Case Appalachian Supply Chain Comparison

Segment	Worst Case vs. Gan	Worst Case vs. Roman-White	Worst Case vs. NETL
Extraction (Production, Gathering and Boosting)	186%	889%	518%
Processing	307%	90%	157%
Transmission*	136%	556%	200%
Liquefaction	-41%	-22%	-41%
Shipping	-55%	7%	-31%
Regasification	88%	152%	-16%
Total	**95%**	**345%**	**193%**

**Worst-case transmission emissions for this study also include pipeline and compressor emissions in the importing country*

This study's results indicate that fugitive emissions in all segments upstream of liquefaction pose the greatest emissions risk on each of the supply chains modeled. For example, this study calculates that fugitive emissions from extraction for the Appalachian Basin-sourced model can be up to 60% of *entire supply chain* GHG emissions using a 20-year GWP.

A critical and currently understudied aspect of emissions in the LNG supply chain is the geographical variation of upstream fugitive emissions. The Cusworth et al. emissions dataset to estimate WC emissions was taken from a detection campaign conducted over a wide swath of the Permian Basin, specifically. However, the Permian Basin and Appalachian Basin have very different operational realities that can affect the magnitude of fugitive emissions, the relative importance of individual emission sources, and the emission rate distribution of an entire segment. For example, gas produced from the Permian basin is associated with simultaneous oil production. Because of the presence of oil, the footprint of production is much more complicated than in most areas of the Appalachian, which produces mainly dry gas.

While field-by-field process variations were taken into account, differing underlying reasons for fugitive emissions per field may be underrepresented in this study's results and should be a major area of future focus for both supplier-specific and more generic LCAs. Many large potential fugitive emission sources like oil and condensate tanks and vapor recovery units do not exist in dry gas basins, thus removing the potential emission sources from these basins. In addition, the Permian Basin has historically been unable to process and transport the quantities of gas being produced because of undersized infrastructure. Because oil is the more valuable product to extract, many well pads with associated gas started production once oil-handling infrastructure was complete while neglecting to build sufficient gas-handling infrastructure, which has led to unprecedented flaring emissions and is believed to have contributed to the amount of fugitive emissions observed. As gas is the main product for operators in the Appalachian Basin, there is a much larger economic incentive to operate in a manner that generally minimizes emissions of natural gas to the atmosphere.

As discussed in the methods section, process variations per field were taken account of. For example, tank battery emissions were removed from basins with a gas-oil-ratio of greater than 100,000 scf per bbl of oil/condensate production as an attempt. However, other variables such as capacity adequacy of infrastructure and national regulatory standards may also influence a basin's actual fugitive emissions footprint and these factors were not modeled.

Discussion

This study quantifies GHG emission ranges around for major LNG supply chains using a mix of data sources to evaluate:

1. Areas of each supply chain that quantification needs to improve most dramatically to increase the assurance of emissions estimates, and
2. Emission reduction opportunities for areas of each supply chain that are either already known to significantly contribute emissions or have the potential to contribute significant emissions based on information from other supply chains.

The results indicate that supply chain emissions can be extremely variable due primarily to different operating characteristics and a lack of available data to represent different operating characteristics for many supply chains. Data input into this modeling effort was as specific as possible to the region being studied. In cases where region-specific data was not available, assumptions were made that contribute to the ranges seen between BC and WC scenarios. It is currently unfeasible for a third-party to differentiate global supply chains with a GHG LCA using emissions data sourced from each individual supply chain. Instead, as this study does, significant assumptions must be made using potentially unrepresentative data from other regions. As a result, LNG importing nations that are keen on differentiating LNG based on emissions need a suite of solutions that increase their confidence in tracking emissions directly from the supply chains that they receive the resource from. The range of emissions found highlight the need for decision-makers to gain access to the most granular data possible and for more emission studies across all the regions modeled. The results of these efforts, especially with regards to fugitive emissions studies, could be directly input into a similar framework as this study to differentiate emissions more granularly from individual supply chains.

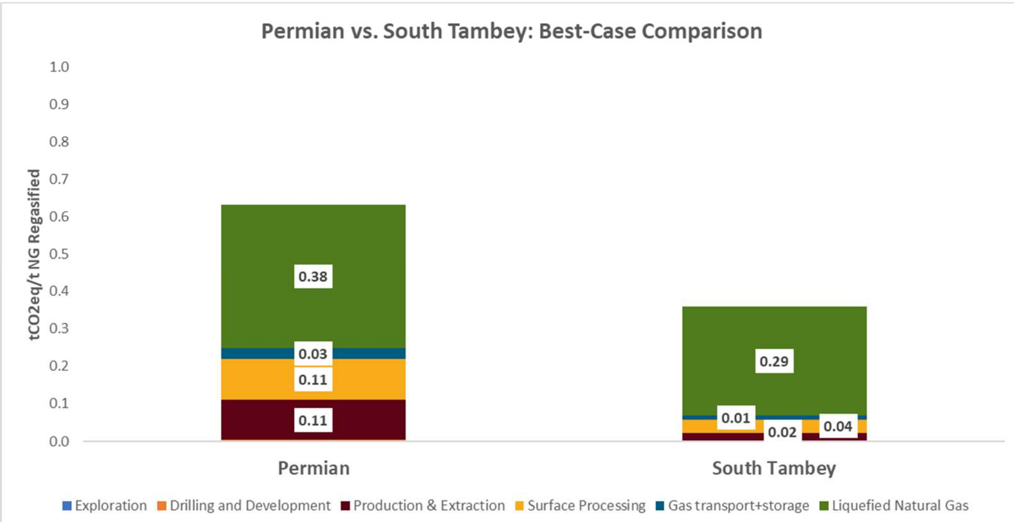
The following case study highlights some opportunities that can be done to improve differentiation of fields and build on the results of this work.

Case Study: Permian and South Tambey Supply Chain Emissions

There are vastly different geographical and operating considerations with the LNG supply chains supplied by the Permian basin and South Tambey. Geographically, the Permian basin is remote, spread out and relatively far away from liquefaction facilities (Chevron 2021). While also remote the South Tambey's production operations cover a fraction of the Permian footprint and located directly next to the Yamal LNG facility (Hydrocarbons Technology 2018). Operationally, the Permian Basin is modeled with a GOR of 0.40 while South Tambey is modeled as a very dry gas field with a GOR of 0.96.

The distribution of emissions for the BC scenario of each field is shown in Figure D1**.** Emissions intensity from production and processing in Permian operations is larger than South Tambey because of the additional processes to handle crude oil, even though emissions are allocated on an energy basis. Onshore gas transport emissions in the Permian are higher because of the longer pipeline mileage required to ship gas to LNG facilities on the Gulf Coast. Shipping distances for Permian-sourced gas to China are also 37% longer than South Tambey. As a result, BC emissions allocated to the LNG supply chain for the Permian Basin are 75% higher than South Tambey's BC scenario.

Figure D1. Permian and South Tambey Supply Chain Comparison: Best-Case Scenario



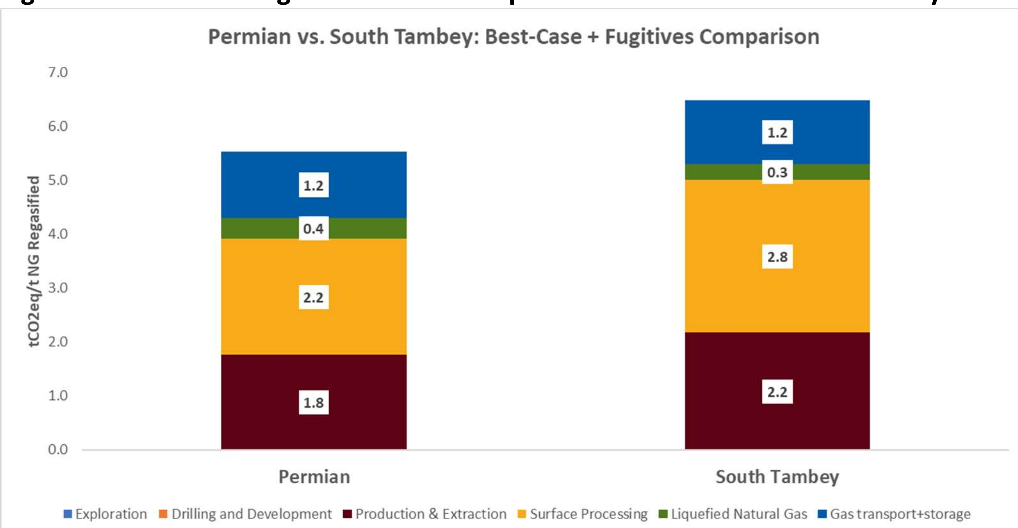
Curiously, the study's modeling shows South Tambey's total supply chain to have a higher intensity than the Permian when the WC inputs for fugitives are added, as shown in Figure D2. As discussed in the Methods section, the South Tambey model does not include losses from tank batteries because it is a dry gas field with a GOR greater than 100,000 scf/bbl. However, South Tambey's WC fugitive emissions drives its intensity higher than the Permian in the production and extraction stage because of the methane content of the South Tambey gas, which as shown in Appendix AIII**,** is higher than the Permian's.

Since the WC fugitive loss rates used in this study primarily come from a study specifically surveying the Permian basin, the confidence in the range of results for the Permian basin are much higher than South Tambey's. Unfortunately, there is no public third-party or operator data available for fugitive emissions in the South Tambey field that could be added to this study, so this study assumes that WC emissions can reach levels seen in the Permian Basin. However, operational and geographic characteristics of South Tambey's operations suggest otherwise.

The type of products transported, and the sheer asset footprint are two major variables. There are less emission sources in a dry gas field, like the South Tambey, due to its relative simplicity. Also, the Permian gathering system is an extensive network of pipelines and compressor stations that transport oil and gas to downstream processing and storage facilities across long distances. Because loss rates per unit of a source (i.e. loss rate per mile of gathering pipeline, or loss rate per compressor station) were unable to be calculated from the reviewed study datasets the total loss rate observed in the Permian was modeled for South Tambey as well. However, assuming reasonably responsible operation of assets total fugitives' loss rate in South Tambey's production and gathering assets would be *significantly* lower than in the Permian largely because of the smaller footprint of assets, like the number of well pads, compressor stations and miles of gathering and transmission pipeline to the liquefaction facility.

More specific, published emissions data from the South Tambey and other understudied regions will better quantify emissions and increase the competitiveness of the field as emissions footprints of LNG supply chains become more important to the bottom line. If an identical study to that of Cusworth et. al was completed on the South Tambey field to quantify total emissions and classify emissions to specific sources, then those results could be added to an OPGEE model like the one used in this study to assess more representative emissions ranges for South Tambey. In addition, if South Tambey is shown to be a field with relatively low fugitive emissions, a robust study would help the competitiveness of the field's supply in the LNG market by differentiating it from a known high-emitting basin such as the Permian.

Figure D2. Potential Fugitive Emissions Impact on Permian and South Tambey Basin Supply Chains



Improving Quantification in Future LCA Frameworks

LNG will likely continue growing as an important energy source to many countries without domestic supply or that need to diversify their energy supplies to support resilience plans, illustrated by the aggressive buildout of import terminals in the 2020s to increase the export capacity of many Asian countries. While LNG trade must dramatically decline by 2050 for the world to stay aligned with net zero scenarios, the importance of minimizing emissions through the supply chain remains a critical strategy to limit the rate of warming (UNEP 2021). Supply chains in LNG-exporting countries will react to pressure from their consumers regarding their emissions footprint.

While decisions regarding long-term LNG contracts are influenced primarily by financial factors geopolitical consequences affecting both the exporter and importer, environmental factors continue to increase in importance (Zhang and Bai 2020). LNG contracts to European buyers have been nixed or stalled due in part to LNG being sourced from high-emitting supply chains. Methods to accurately quantify emissions from LNG supply chains are needed to responsibly facilitate the inclusion of environmental factors into decision-making regarding both short and long-term LNG supply decisions. Sixty percent of LNG was traded in 2020 via long or medium-term contracts between a certain exporter and a certain buyer, while 40% was sold through the spot market (GIIGNL 2021). Any framework should also be available for consideration in spot market transactions as well, especially considering that the average length of medium and long-term contracts has steadily declined (GIIGNL 2021).

The variations of emissions in this study's results show the dire need for a common calculation methodology that is globally applicable. Recently, the concept of providing tags to each LNG cargo stating the emissions performance of the supply chain has gained popularity. Cheniere Energy has volunteered to begin providing cargo emission tags to importers starting in 2022 (Cheniere 2021). The SGE and GIIGNL frameworks allow both primary data directly from the actual supply chain and secondary data meant to represent emissions from a specific region, with SGE directly stating that third-party verifiers are responsible for evaluating the emission assertions by an operator in the supply chain to determine if the quality of data presented is the best available information to the operator (Chevron 2021. 10).

Primary data specific to operators in the supply chain may still significantly underestimate emissions and pose problems with accurate quantification. For example, if all gas was sourced directly from the Permian Basin for a Gulf Coast liquefaction facility, using GHGRP data from the operators would likely underestimate emissions associated with the production, gathering and processing segments due in large part to the studied discrepancies between the GHGRP and top-down emission quantification studies (Chen et al. 2021). These methodologies should consider non-operator specific information for LCAs over primary data if the data may be more indicative of actual operations. Lumping in multiple operator's performance based on basin or region-wide data will pose tremendous difficulty in differentiating operations within the same basin. However, region-wide studies with large sample sizes may be more efficient to execute than operator-specific studies over much smaller areas.

These frameworks should be accepted by the industry as a whole and begun to be used immediately to help the industry begin reporting emissions in a consistent manner, globally. They will become more robust and challenge-tested over time as they are used and, in the short-term, help increase the transparency and consistency of emissions reporting. In the longer term, demand must increase for robust scientific studies to better quantify actual emissions and actual emission reductions over time.

While these methodologies will not *directly* help better quantify emissions from the supply chain, they will likely support organized sharing of emissions data to meet existing requirements of the methodology. The US benefits greatly from public reporting of emissions so that operators such as Cheniere can calculate emissions specific to their upstream sources of gas if they have receipts of gas source. An operator of a liquefaction facility in any other country does not have supplier-specific information publicly available to recreate Roman-White et al.'s study. However, the supply chains of other countries generally do not include as many upstream operators so data collection may be much simpler than in the US.

Most importantly, quantification frameworks will give LNG importing countries with a necessary tool to be able to require LNG shippers to provide an emission cargo tag with details calculated by consistent, transparent methodologies. Countries should also begin considering the specific requirements of emissions performance, including the emissions intensity and the methods in which emissions are calculated. For example, fugitive emissions may be extremely underreported in many fields. Basin-wide direct measurement studies of these basins can be funded and supported by these importing nations to understand where to source LNG from to minimize their GHG emissions footprint. Aside from helping to differentiate fields, the results of these studies could be used by importing nations to develop specific requirements, such as fugitive monitoring plans, that LNG suppliers must comply with to continuously reduce uncertainty further and assure that a country is not importing product from a poorly performing supply chain.

Improving Quantification by Verification Efforts

Different types of frameworks are needed to ensure consistency in emission quantification and reconciliation efforts, with special attention placed on methane emissions. For example, Veritas is a newly formed initiative spearheaded by the Gas Technology Institute that attempts to develop a consistent framework to quantify whole-site emission rates and then reconcile those measurements effectively with company reported data to come up with the best possible estimate (GTI 2021). Emission calculation methodology frameworks should adopt these protocols eventually to increase the certainty of emissions quantification throughout the supply chain. Voluntary supply chain emission certification programs are also beginning to emerge such as the MiQ certification program (MiQ 2021) and the Oil and Gas Methane Partnership methodology (OGMP 2020). These programs aim to improve the credibility of claims made by individual operators on the methane emissions performance of their assets through either requirements or recommended best practices. If these performance verification standards end up being followed by a large fraction of gas supply chains globally, they will also stimulate demand for more direct methods of detection and quantification of emissions.

While fugitive methane emissions have the potential to emit such a large fraction of emissions supply chains should also be differentiated based on CO_2 emissions and other sources of methane emissions to strive for the BC scenarios outlined for each of the 11 modeled fields. The inclusion of CO_2 performance in these verification programs will help holistically shape emission reduction efforts that are undertaken. The results of this study could be used by these programs to weight the importance of certain practices to incentivize the most impactful opportunities. Importing LNG nations can use these verification programs to further assure the performance of gas from supply chains they are electing to import from. Accepting certification programs that are independent of the natural gas market that it is certifying, and the emission reduction solutions used for certification is critical to ensuring the lasting credibility of these initiatives.

Prioritizing Emission Reduction Efforts

The vast modeled variability in emissions across global supply chains presented by this study indicates a need to improve and standardize quantification methods for methane emissions across the supply chain to improve overall accuracy and improve the differentiation of different resources so that LNG importing nations can help make informed decisions to drive emissions reductions. The following section expands on ways to achieve emission reductions for fugitive emissions, gas-driven instruments, and other equipment in the LNG supply chain. Importing nations can use the strategies presented here to assess countries based on their operating practices related to emissions reductions.

Reduce Upstream Fugitives

Upstream and midstream fugitives can emit up to 8 tons of CO_2eq. per ton of regasified LNG, which for reference is at least twice the emissions estimated for the heaviest emitting supply chain in Gan et al. Regardless of the time horizon used to assess methane emissions, fugitive methane emissions can be the vast majority of GHG emissions for a given supply chain. This depends on several factors including the age of facilities and the maintenance and monitoring practices of the infrastructure. Leak Detection and Repair (LDAR) programs are the primary means of managing fugitive emissions from oil and gas operations. However, as described above, the emissions captured from non-regulatory top-down surveys show large differences in observed emissions versus reported emissions from operations. As discussed in the case study, top-down direct measurement campaigns have not extended to all basins globally and minimal basin-wide published work has even been completed outside the United States. Therefore, it is unclear whether all basins are underreporting fugitive methane emissions and to what magnitude. Regardless of this existing uncertainty, effective LDAR programs serve two purposes; they help detect and quantify observed emissions across a wide operating area and provide certainty and assurance about the emissions performance of the area surveyed.

Update Leak Detection and Repair Programs

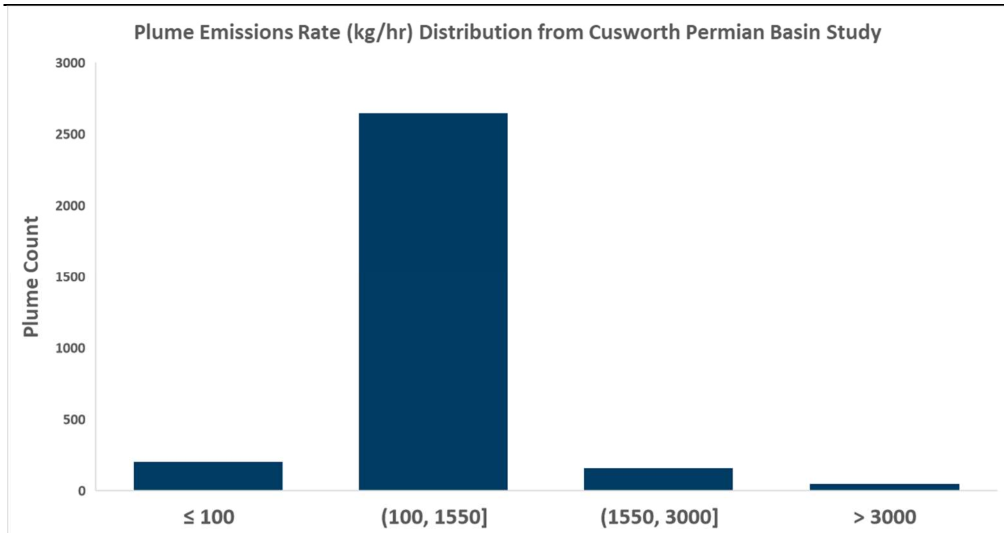
The effectiveness of current leak detection and repair programs have come under intense scrutiny, especially in the United States and Canada where recent regulatory updates have been proposed. Both country's existing LDAR programs state the type of detection technology allowed. Under Canada's regulatory LDAR program a portable monitoring instrument meeting the specifications, operation and calibration requirements of EPA Method 21 and an optical gas imaging instrument capable of detecting leaks well under 1 kg/h are allowed for use (Government of Canada 2020). US EPA's regulatory LDAR programs allow the same technologies. Numerous studies have shown that methane emissions exhibit a heavy-tailed distribution across many different basins, where most emissions usually come from a small sample of heavy emitters. These regulatory approved monitoring technologies and methods can detect the smallest individual emission sources in emission distributions but also require extensive time and labor to survey large areas. While OGI, the more common of the two detection technologies in upstream operations, has an extremely low minimum detection limit it is still subject to human error. In fact, only a fraction of total emissions is detected from OGI screenings, with the percentage of emissions detected most significantly dependent on time spent at a piece of equipment and the overall experience of the operator (Zimmerle 2020). With about one million producing gas wells in the United States, hundreds of thousands of miles of pipeline and other infrastructure like compressor stations and processing plants, complementary technology solutions that can survey large areas in less time should be explored for use to improve the overall effectiveness and completeness of LDAR surveys.

Use Advanced Monitoring Technologies

Alternative monitoring technologies and deployment methods currently exist that can be deployed in a manner that leads to higher emission reductions. Commercially available technologies currently include continuous methane fence line monitors, various types of imaging cameras attached to aircraft that can fly over large swaths of operations per flight, and a growing number of satellite constellations. Aircraft-based detection programs have proven the ability to detect super emitting events reliably and at a higher rate than current work practices. Depending on many environmental and operational factors like wind speed, flight altitude and imaging camera type, these deployments can have minimum detection limits between around 3 to 30 kg/h, about 2 to 3 orders of magnitude higher than OGI. As an example, the instrument used in the Permian leakage study used for this study was able to cumulatively detect almost 2,000 tons per hour of emissions during the Permian study sourced with a source detection limit of around 20 kg/h. Other basins, like South Tambey or other dry gas fields or fields with higher rates of supervision will likely exhibit a smaller magnitude of emissions and unique emission distributions. Having a technology that can frequently, reliably detects super-emitting events as part of an LDAR program would further increase assurance to an LNG importer that the largest emissions in a distribution are quickly detected, mitigated, and prevented from occurring again. A high detection limit of 100 kg/hr would catch over 80% of emission sources detected by the flyover campaign and about 99%

of the total mass of emissions detected. For other basins, the capability of detection solutions will likely differ.

Figure D3. Permian Basin Emissions Rate Distribution of Detected Plumes



Source: Cusworth et al. 2021

Implement Flexible Regulatory Policy

Regulatory policy that allows or mandates the use of these types of technologies with higher detection limits and larger spatial coverage capabilities will likely assist in achieving greater emissions reductions. In Canada, an alternative leak detection and repair program is allowed to be used if it demonstrates that it results in equivalent of better emission reduction quantities. While this allows use of alternative technologies, it also puts a significant burden of proof and risk on an individual operator to prove the equivalency of its own program (Lavoie, Risk and O'Connell 2021). This is especially harder in an understudied basin or geographical area where emission distribution rates are not well known.

To establish alternative monitoring technologies as regulatory-approved monitoring methods, some agencies require that equivalency in emission reductions is proven (Government of Canada 2020). Equivalency models such as LDAR-Sim (Fox, Gao and Barchyn 2020) or the Fugitive Emissions Abatement Simulation Toolkit (FEAST) (Ravikumar 2021) can be used to simulate equivalency. However, due to uncertainty about critical inputs that these models are extremely sensitive to equivalency determinations are still based on considerably important assumptions. While many unknowns still exist, advanced LDAR technologies have shown a unique ability to determine fugitive emission rates for the gas supply chain and exceed equivalency of emission reductions for the large fugitive emissions rates distributions that have been recently published in regions including the Permian basin. As this is currently the most rigorous and technically robust way to evaluate the effectiveness of LDAR programs, LNG importing nations should require some form of equivalency determination or fugitive emission reductions target to be put in place. To help gain assurance of emissions performance, importing authorities can use the results of these models to back up the requirement of use of advanced detection technologies to minimize the risk of fugitive emissions.

Pursue Electrification via a Primarily Renewable Grid

Upstream electrification can save between 0.04 to 0.33 tons of CO_2eq. per ton of regasified LNG. Installing electric motors in place gas-fired reciprocating engines can save a significant amount of both fuel burned and fuel lost to the atmosphere from combustion slip. Electrification throughout the LNG supply chain is likely the highest capital-intensive mitigation solution proposed in this study affecting the gathering, processing, and transmission segments most significantly. Along with changing out gas-driven drivers for compressors, pumps and other gas-powered equipment, electrical facilities must be significantly expanded in remote areas to provide electricity to a site. While capital-intensive, this solution likely reduces both CO_2 *and* methane emissions per unit of energy requirement for reciprocating compressors and has been shown to be cost effective with short payback periods in some instances (EPA 2016). According to the 2019 US GHGI, 25% and 61% of methane emissions in the gathering and processing segment are methane emissions from gas exhaust. Assuming similar methane slip quantities elsewhere in the world, this source of methane emissions would be extremely relevant to rapid methane emission reduction efforts. Unlike fugitive emissions, this source of emissions is constant when a compressor is operating increasing its overall magnitude. Electrification is the biggest opportunity to reduce overall GHG footprint for many supply chains, after low fugitive emitting basins implement solutions that verify a low fugitive emissions footprint through equivalency based LDAR programs and those that include long-distance gathering and transmission footprints. Even if electricity is sourced from natural gas-fired sources the methane slip from engines would be effectively mitigated as gas turbines operate with a methane slip close to zero.

Conclusion

As climate goals tighten over time, it is important for LNG exporters and importers to adjust their decision-making based on rapidly evolving information surrounding the greenhouse gas footprint of LNG supply chains. The variability of emissions from the LNG supply chain poses a challenge to countries importing the product that also have pledges to reduce their greenhouse gas emissions. This study addresses what it will take to substantively quantify emissions throughout supply chains and how to prioritize emission reductions opportunities.

In it, I quantify the potential variability and the impact that certain emission reduction efforts can have on the overall supply chain. The methodology compiles a mixture of secondary data sources and uses the recently developed capability of the OPGEE LCA model to quantify the potential variation of GHG emissions in prolific LNG supply chains around the world. The results establish a best-case and worst-case scenario for emissions from each modeled supply chain. These cases are modeled to have variability as high as 37x between the WC emissions scenario and BC emissions scenario. The results suggest that significant further efforts are needed to better quantify emissions from existing supply chains that produce and import LNG, especially those outside of the United States. Significant progress has been made in certain regions including many western US basins to quantify emissions in the gas supply chain. These efforts have illuminated the need to develop new quantification methodologies to estimate emissions more accurately. This will help buyers of LNG differentiate their supply options to make decisions more in line with climate agreements. Likewise exporters of gas with more accurately quantified and lower emissions should gain a market advantage especially with emissions-strict importing markets.

The increasing importance of the GHG emissions footprint of LNG cargoes among many importing nations suggests rapid movement in quantification and reductions can reap significant rewards. For example, a group of Japanese LNG buyers have begun a carbon-neutral LNG buyers alliance to increase the procurement of “carbon-neutral” LNG (Cocklin 2021). Without consistent quantification methods to assess the amount of offsets needed to claim carbon-neutrality, these claims simply amount to greenwashing.

To achieve consistent quantification, methodologies have recently been released that should be used to provide more consistent quantification methods for emissions while accuracy continues to improve. As the use of these methodologies expand, movements in improving quantification methods for the most uncertain parts of the supply chain, such as fugitive methane emissions, will continue to increase. Additionally, if global regulation efforts increase, including Europe’s proposed Carbon Border Adjustment Mechanism, it will be critical for emission studies and assurance activities be taken to preserve the credibility and increase the effectiveness of these policy tools to reduce global emissions and minimize leakage risks (Columbia University 2021).

More consistent and accurate quantification will be critical to guide prioritization of emission reduction activities and verify total reductions over time for an individual supply chain. The results of this study clearly indicate that a better understanding of the fugitive emission rates and source distributions of the supply chains modeled in this study is needed to increase the accuracy of emissions totals and provide more assurance. For confirmed high leakage regions like the Permian Basin, fugitive emissions monitoring programs will likely be the most impactful emission short-term reduction measure considering the magnitude of leaks and the relative importance of methane when evaluating total emissions with a shorter time horizon. Basins that are verified to be lower fugitive emitting areas with multi-tiered LDAR campaigns will be able to explore additional emission reduction pathways while having increased assurances that their gas is not near the top-range of the emissions intensities modeled in this study.

While carbon-neutral LNG and other environmental product declarations related to LNG may include the purchase of carbon credits, the verifiable reduction of emissions supply chains is the only way to directly reduce emissions and should be prioritized over the purchase of carbon credits. Additionally, the total volume of carbon credits purchased for individual cargoes will continue to have major credibility issues until better assurance can be given on a supply chain’s intensity. With the release of robust calculation frameworks, importing countries can now discontinue inaccurate methods of calculating the GHG intensity of the supply chains it is sourcing LNG from and demand exporters to provide more granular data, verified by third-party audit. In the meantime, exporters need to continually pursue methods to reduce their GHG footprint in a verified way both as a competitive advantage, but also to maintain their existing markets.

The results of this study confirm that OPGEE can be used with reliable inputs to generate ranges of supply chain emissions that agree with existing LCAs and developing supply chain emissions research. The limitations in data access for extremely sensitive parameters limit the field-specificity of the results of this study. Future research on less-studied supply chains from countries outside of North America should substantially assist a user in completing a LCA of a LNG supply chain using OPGEE. The use of emerging frameworks to estimate LNG emissions should also be studied to determine how the usability and impact of the frameworks can improve over time.

Appendices

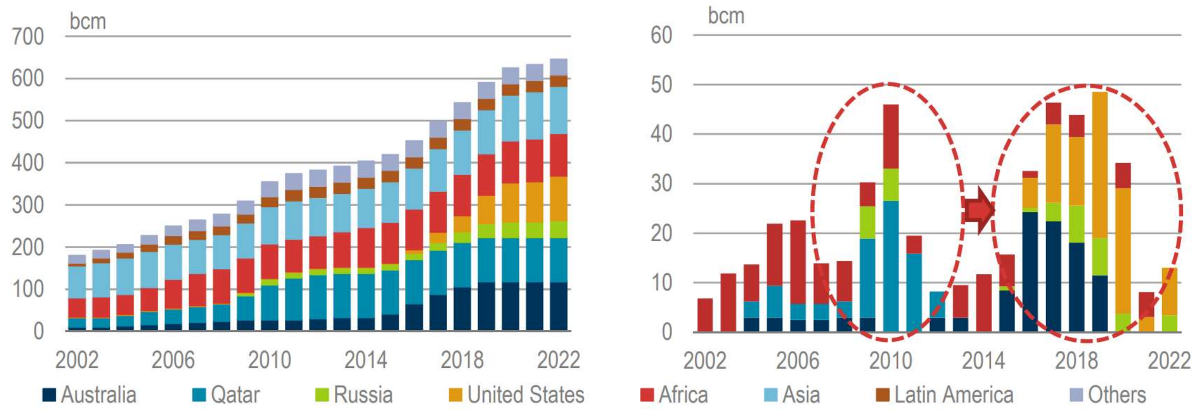
Appendix I: LNG Market Details

Liquefying natural gas for either storage or transport reduces its volume by a factor of 600. A series of refrigeration steps are required to liquefy natural gas at around -162 degrees Celsius. After the liquefaction process, liquefied natural gas (LNG) can be stored at atmospheric pressure for months at a time prior to either being gasified and introduced to the natural gas distribution grid to meet local demand needs or loaded on a carbo ship to be transported and imported overseas. Liquefying natural gas has been a solution employed since the 1940s. The first liquefaction plant in Cleveland, Ohio was an energy storage solution that liquefied and stored gas to meet heating demand increases during winter months. The plant was destroyed in 1944 when a storage tank ruptured, initiating an explosion and fire that killed over 100 people in the surrounding area (Case Western, “East Ohio Gas Co. Explosion and Fire”). Research and development of better cryogenic handling materials enabled the industry to revive itself, and in the late 1950s the first LNG cargo ship was developed carrying LNG from the United States of America to Great Britain to help with an energy demand shortage (Ship Technology 2014). These voyages also helped prove the overall feasibility of transoceanic LNG transport enabling others to begin to develop supply chains from resource-rich gas supply areas to areas overseas with high demand. The *Methane Princess,* the world’s first purpose-built LNG carrier entered service in 1964 and primarily carried LNG from liquefaction plants in Algeria to nearby European demand hubs like Great Britain and France. The *Methane Princess* was able to ship approximately 16 million m^3 of gaseous-equivalent LNG per voyage.

In the 21st century, the total size and number of market participants in the LNG trade has increased. Many projections indicate these areas of growth to continue. Total LNG export capacity in 2002 approached 200 billion m^3 per year (IEA 2019). Since then, export capacity has increased over 250% to over 500 billion m^3 per year. Capacity additions in the 21st century have come from Africa, Australia, the United States, Qatar, the United States and, to a smaller extent, Russia. Two primary waves of gas liquefaction build out in the 21st century have led to the significant increase in export capacity. Between 2002 to 2012 the nameplate capacity of LNG exports more than doubled from 180 to 382 billion m^3, dominated by Nigeria, Egypt, Equatorial Guinea and Qatar.

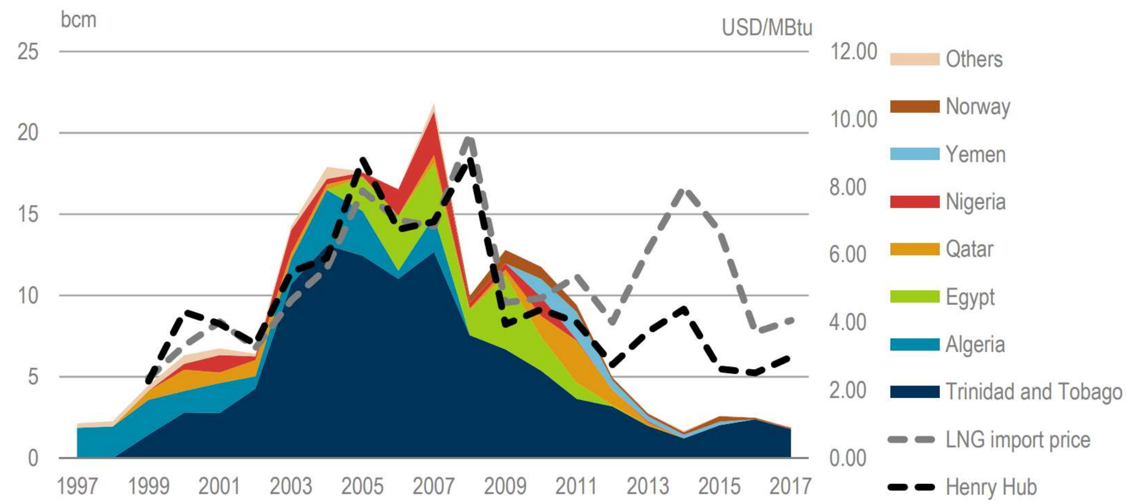
Rapidly growing US LNG demand had proven itself out and demand seemed like it would only continue increasing, prompting those African countries and Qatar, each with access to Atlantic shipping routes, to begin rapidly building out LNG export capacity. US-based multinational oil companies and foreign investment firms were intimately involved in many of the African and Qatari projects (IEA 2019). Dwindling US gas reserves signaled an increase in the market price for natural gas. The Henry Hub price tripled from 2202 to 2005 to $9 per MMBtu, with prices persisting above $7 per MMBtu until late 2008. Concurrently, LNG imports increased by a factor of 3 with LNG and Henry Hub prices maintaining relative parity.

Figure AI-1. LNG Export Capacity Trends and Incremental Capacity (2002 to 2018)



Source: International Energy Agency (IEA) 2019

Figure AI-2. US LNG Imports and Natural Gas Spot Market Prices



Source: Energy Information Administration (EIA) 2019

Advances in hydraulic fracturing began the “Shale Gas Revolution” in the late 2000s (Strauss Center, “The US Shale Revolution”). This development flipped flows in the US natural gas market, resulting in an immediate decrease in LNG imports and a steady increase in domestic natural gas production that equaled US natural gas consumption by 2014.

LNG demand projections in many non-US markets forecasted continued growth in global LNG trade. LNG demand steadily increased in the East Asian countries of Japan and China, as well as Europe, enough for most of the export capacity buildout between 2002 to 2012 to be met by increasing demand. Total imports rose by 85% of the total LNG export capacity built out by 2012.

East Asian LNG Imports and Regasification Capacity

Figure AI-3. East Asian LNG Import Volumes, 2003-2020

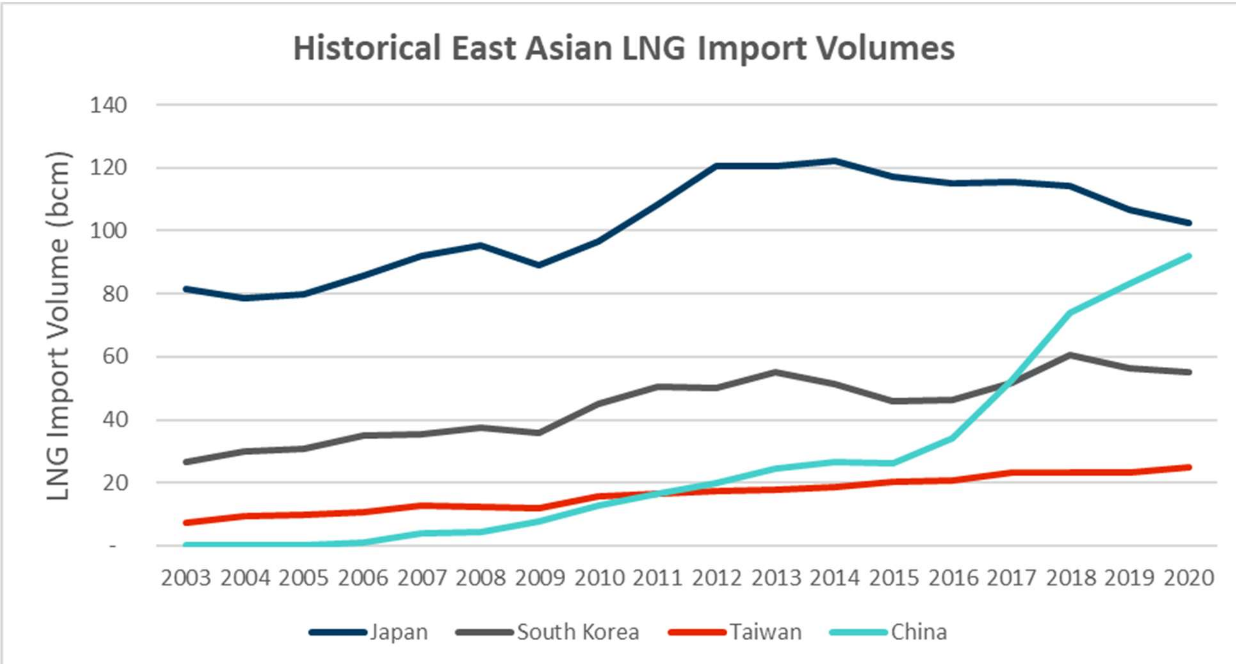
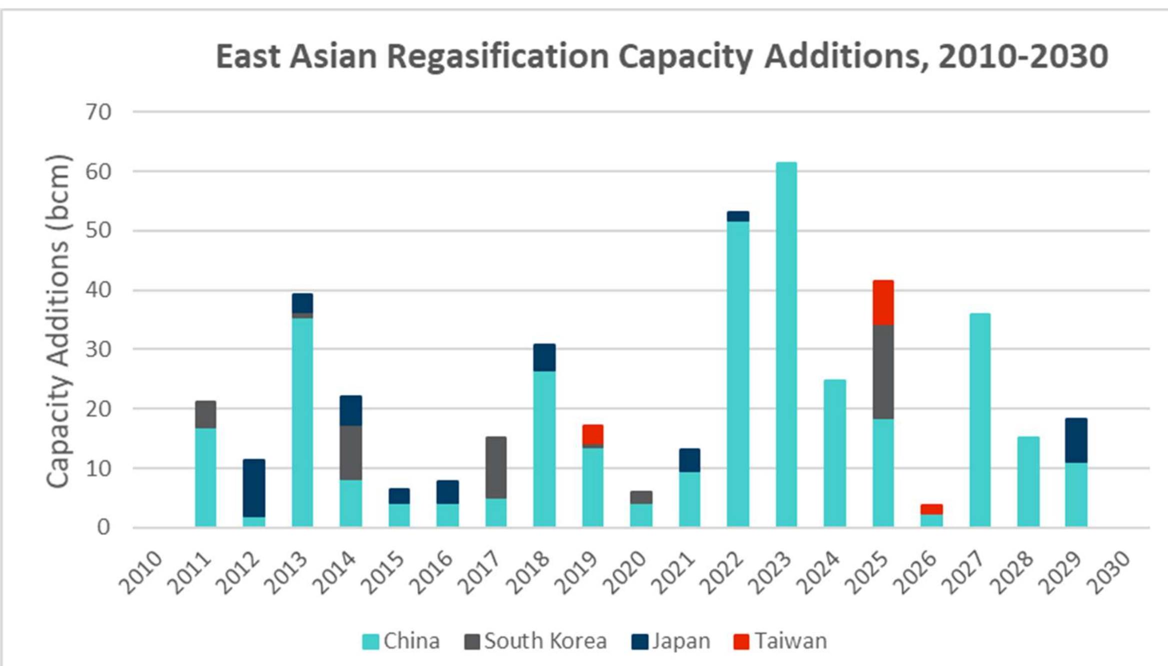
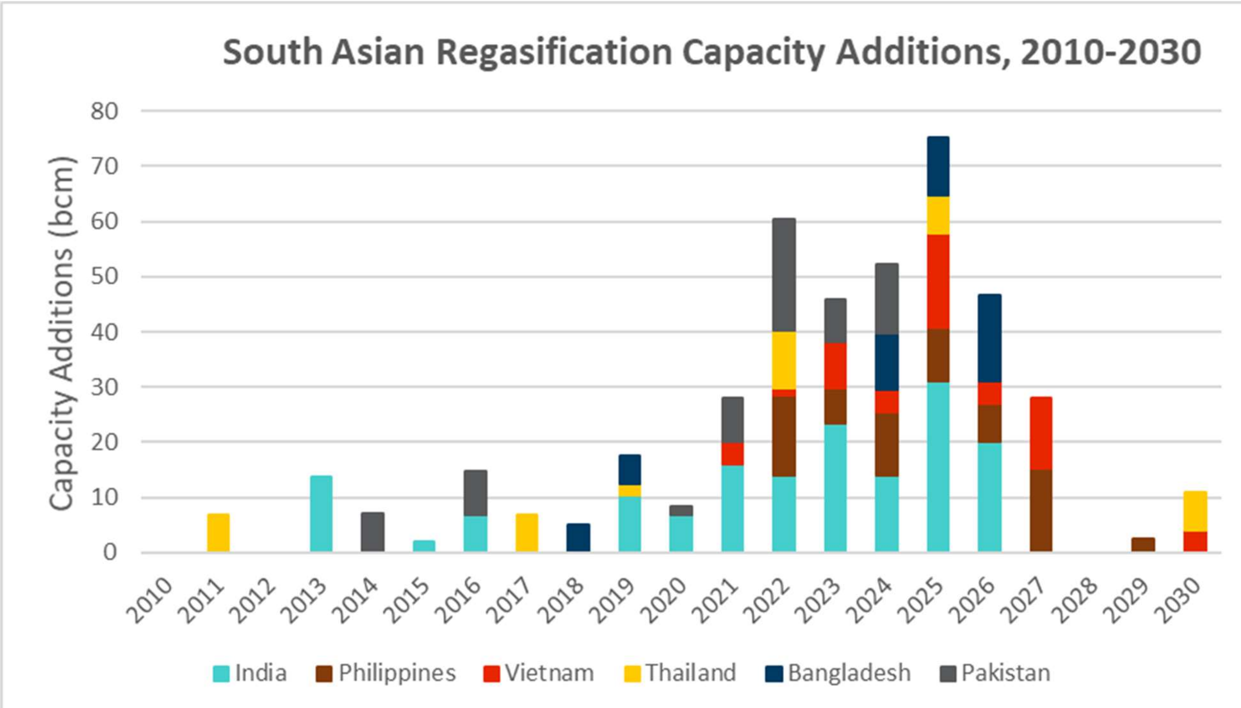


Figure AI-4. East Asian Regasification Capacity Additions, 2010-2030



Source: GlobalData

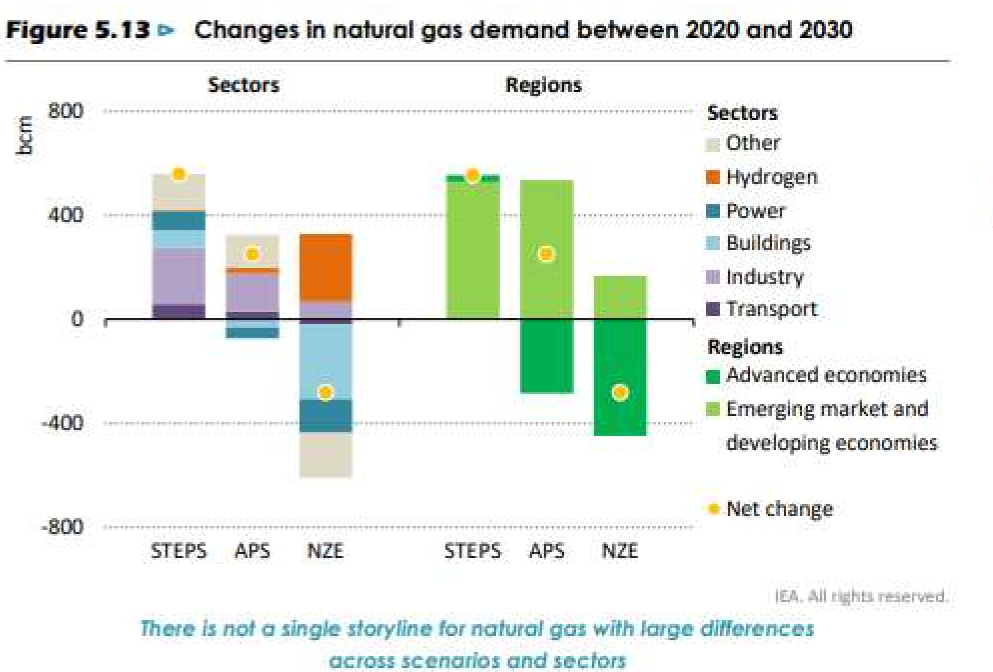
Figure AI-5. South Asian Regasification Capacity Additions, 2010-2030



Source: GlobalData

Future Natural Gas Projections

Figure A1-6. Changes in Natural Gas Demand by Sector, Region and IEA Climate Pathway



Appendix II: OPGEE Detailed Inputs

Table AII-1. Field-Specific OPGEE User Inputs

Primary Input	Units	OPGEE v3.0a Excel Cell Reference	Greater Gorgon	Permian	Appalachian	Gbaran Ubie Phase 2	Hassi R'Mel	South Tambey
Field location (Country)	NA	Inputs!I21	Australia	USA	USA	Nigeria	Algeria	Russia
Downhole pump	NA	Inputs!I9	Yes	Yes	Yes	Yes	Yes	Yes
Water reinjection	NA	Inputs!I10	Yes	Yes	Yes	Yes	Yes	Yes
Natural gas reinjection	NA	Inputs!I11	Yes	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Field age	yr.	Inputs!I22	4	12	12	38	64	11
Field depth	ft	Inputs!I23	14408	10917	1650	12098	7169	6150
Oil production volume	bbl/d	Inputs!I24	15000	3754106	90850	23196	76771	23588
Reservoir pressure	psi	Inputs!I29	5925	7642	3000	5928	3003	5143
Reservoir temperature	°F	Inputs!I30	310	267	130	[redacted]	[redacted]	300
Offshore?	0-1	Inputs!I31	1	0	0	0	0	0
API gravity	deg. API	Inputs!I34	[redacted]	[redacted]	[redacted]	[redacted]	44	[redacted]
Gas composition	NA							
CO_2	mol%	Inputs!I37	15.0	1.0	0.1	0.3	0.2	0.3
C_1	mol%	Inputs!I38	76.1	70.0	87.0	[redacted]	81.1	90.0
C_2	mol%	Inputs!I39	[redacted]	[redacted]	[redacted]	[redacted]	7.2	[redacted]
C_3	mol%	Inputs!I40	[redacted]	[redacted]	[redacted]	[redacted]	2.4	[redacted]
C_4+	mol%	Inputs!I41	[redacted]	[redacted]	[redacted]	[redacted]	0.8	[redacted]
H_2S	mol%	Inputs!I42	0.0	[redacted]	0.0	3.5	2.8	[redacted]
Gas-to-oil ratio (GOR)	scf/bbl oil	Inputs!I46	143,915	3,441	3,404,835	36,109	38,087	116,773
Fraction of CO2 breaking through to producers	%	Inputs!I58	0.00					
Source of CO2	NA	Inputs!I59	Anthropogenic					
Percentage of sequestration credit assigned to the oilfield	%	Inputs!I62	0.00					
Fraction of required electricity generated onsite	-	Inputs!I64	0.00	0.00	0.00	0	0	0
Associated Gas Processing Path	NA	Inputs!I77	Dehydrator + Ryan-Holmes Process	Dehydrator + AGRU + DeC1	Dehydrator + AGRU	Dehydrator + AGRU + DeC1	Dehydrator + AGRU + DeC1	Dehydrator + AGRU + DeC1
Flaring-to-oil ratio	scf/bbl oil	Inputs!I86	20.98	4.69	0.75	30.08	32.07	5.22
Venting-to-oil ratio	scf/bbl oil	Inputs!I87	0.00	0.00	0.00	0	0	0
Ocean tanker size, if applicable	Ton	Inputs!I113	78750.00	78750.00	78750.00	78750	78750	78750
Small sources emissions	gCO_2eq/MJ	Inputs!I115	0.00	0.00	0.00	0	0	0
Import Country gas transmission distance	gCO_2eq/MJ	Secondary Inputs!N524	137.00	675.00	1100.00	80	300	15
Ocean tanker transport distance	gCO_2eq/MJ	Secondary Inputs!N561	4000.00	15090.00	15090.00	10800	12260	11000

Primary Input	Units	OPGEE v3.0a Excel Cell Reference	Daandine	Haynesville	Qatargas 2	South Pars (Phase 4-24)	Golfinho Atum
Field location (Country)	NA	Inputs!I21	Australia	USA	Qatar	Iran	Mozambique
Downhole pump	NA	Inputs!I9	Yes	No	Yes	Yes	Yes
Water reinjection	NA	Inputs!I10	Yes	Yes	Yes	Yes	Yes
Natural gas reinjection	NA	Inputs!I11	[redacted]	[redacted]	Yes	Yes	[redacted]
Field age	yr.	Inputs!I22	14	6	6	21	1
Field depth	ft	Inputs!I23	1936	12000	7000	10173	13189
Oil production volume	bbl/d	Inputs!I24	1	28254	110476	553577	7000
Reservoir pressure	psi	Inputs!I29	[redacted]	12500	[redacted]	4951	[redacted]
Reservoir temperature	˚F	Inputs!I30	[redacted]	286	196	213	[redacted]
Offshore?	0-1	Inputs!I31	0	0	1	1	1
API gravity	deg. API	Inputs!I34	[redacted]	[redacted]	[redacted]	47	[redacted]
Gas composition	NA						
CO_2	mol%	Inputs!I37	[redacted]	0.0	2.3	2.2	[redacted]
C_1	mol%	Inputs!I38	[redacted]	88.0	[redacted]	86.5	90.0
C_2	mol%	Inputs!I39	[redacted]	[redacted]	[redacted]	5.1	[redacted]
C_3	mol%	Inputs!I40	[redacted]	[redacted]	[redacted]	1.9	[redacted]
C_4+	mol%	Inputs!I41	[redacted]	[redacted]	[redacted]	0.4	[redacted]
H_2S	mol%	Inputs!I42	[redacted]	0.0	0.9	0.6	[redacted]
Gas-to-oil ratio (GOR)	scf/bbl oil	Inputs!I46	98,000,000	416,835	19,468	32,591	278,562
Fraction of CO2 breaking through to producers	%	Inputs!I58			0	0	
Source of CO2	NA	Inputs!I59			Anthropogenic	Anthropogenic	
Percentage of sequestration credit assigned to the oilfield	%	Inputs!I62			0	0	
Fraction of required electricity generated onsite	-	Inputs!I64	0	0	0	0	0
Associated Gas Processing Path	NA	Inputs!I77	Dehydrator + AGRU	Dehydrator + AGRU	Dehydrator + Ryan-Holmes Process	Dehydrator + Ryan-Holmes Process	Dehydrator + AGRU + DeC1
Flaring-to-oil ratio	scf/bbl oil	Inputs!I86	27359.78	1.94	17.95	14.11	0.00
Venting-to-oil ratio	scf/bbl oil	Inputs!I87	0	0	0	0	0
Ocean tanker size, if applicable	Ton	Inputs!I113	78750	78750	78750	78750	78750
Small sources emissions	gCO_2eq/MJ	Inputs!I115	0	0	0	0	0
Import Country gas transmission distance	gCO_2eq/MJ	Secondary Inputs!N524	200	150	65	100	100
Ocean tanker transport distance	gCO_2eq/MJ	Secondary Inputs!N561	4300	15090.00	6100	6100	6700

Table AII-2. "Smart-Default" Field-Specific OPGEE Inputs

Primary Input	Units	Greater Gorgon	Permian	Appalachian	Gbaran Ubie Phase 2	Hassi R'Mel	South Tambey
Field location (Country)	NA	Australia	USA	USA	Nigeria	Algeria	Russia
Natural gas reinjection	NA	Yes	Yes	Yes	Yes	Yes	Yes
Water flooding	NA	No	No	No	No	No	No
Gas lifting	NA	No	No	No	No	No	No
Gas flooding	NA	No	No	No	No	No	No
Steam flooding	NA	No	No	No	No	No	No
Oil sands mine (integrated with upgrader)	NA	No	No	No	No	No	No
Oil sands mine (non-integrated with upgrader)	NA	No	No	No	No	No	No
Number of producing wells	-	8	42,905	1,039	266	160	270
Number of water injecting wells	-	7	35,569	862	221	133	224
Production tubing diameter	in	7.7	2.8	1.5	2.8	2.8	2.8
Productivity index	bbl/psi-d	6.8	6.8	6.8	6.8	6.8	6.8
Reservoir pressure	psi	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Reservoir temperature	°F	[redacted]	[redacted]	[redacted]	288	202	[redacted]
API gravity	deg. API	47	33	47	47	[redacted]	47
Gas composition		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
N_2	mol%	2.4	7.6	3.5	2.8	5.7	2.6
CO_2	mol%	[redacted]	[redacted]	[redacted]	0.3	0.2	[redacted]
C_1	mol%	76.1	70.0	87.0	86.1	81.1	90.0
C_2	mol%	4.5	14.1	6.5	5.1	[redacted]	4.9
C_3	mol%	1.4	4.3	2.0	1.6	[redacted]	1.5
C_4+	mol%	0.6	1.9	0.9	0.7	[redacted]	0.7
H_2S	mol%	[redacted]	1.0	[redacted]	[redacted]	[redacted]	0.0
Water-to-oil ratio (WOR)	water/bbl	0.4	1.3	1.3	6.0	14.7	1.2
Water injection ratio	water/bbl	1.4	2.3	2.3	7.0	15.7	2.2
Gas lifting injection ratio	f/bbl liqui	364	364	364	364	364	364
Gas flooding injection ratio	scf/bbl oil	215,873	5,162	5,107,253	54,164	57,131	175,160
Flood gas	NA	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas
Steam-to-oil ratio (SOR)	steam/bb	0.0	0.0	0.0	0.0	0.0	0.0
Fraction of remaining natural gas reinjected	-	0.5	0.5	0.5	0.5	0.5	0.5
Fraction of steam generation via cogeneration	-	0.0	0.0	0.0	0.0	0.0	0.0
Fraction of steam generation via solar thermal	-	0.0	0.0	0.0	0.0	0.0	0.0
Heater/treater	NA	No	No	No	No	No	No
Stabilizer column	NA	No	Yes	No	No	Yes	Yes
Upgrader type		None	None	None	None	None	None
Volume fraction of diluent	-	0.0	0.0	0.0	0.0	0.0	0.0
Low carbon richness (semi-arid grasslands)	NA	Yes	Yes	Yes	Yes	Yes	Yes
Moderate carbon richness (mixed)	NA	No	No	No	No	No	No
High carbon richness (forested)	NA	No	No	No	No	No	No
Low intensity development and low oxidation	NA	Yes	Yes	Yes	Yes	Yes	Yes
Moderate intensity development and moderate oxidation	NA	No	No	No	No	No	No
High intensity development and high oxidation	NA	No	No	No	No	No	No

Primary Input	Units	Daandine	Haynesville	Qatargas 2	South Pars (Phase 4-24)	Golfinho Atum
Field location (Country)	NA	Australia	USA	Qatar	Iran	Mozambique
Natural gas reinjection	NA	Yes	No	Yes	No	Yes
Water flooding	NA	No	No	No	No	No
Gas lifting	NA	No	No	No	No	No
Gas flooding	NA	No	No	No	No	No
Steam flooding	NA	No	No	No	No	No
Oil sands mine (integrated with upgrader)	NA	No	No	No	No	No
Oil sands mine (non-integrated with upgrader)	NA	No	No	No	No	No
Number of producing wells	-	1	323	1,263	126	80
Number of water injecting wells	-	1	268	1,048	105	67
Production tubing diameter	in	2.8	2.8	2.8	3.8	2.8
Productivity index	bbl/psi-d	6.8	6.8	6.8	6.8	6.8
Reservoir pressure	psi	416	[redacted]	1505	[redacted]	2836
Reservoir temperature	°F	105	[redacted]	[redacted]	[redacted]	307
API gravity	deg. API	47	47	47	[redacted]	47
Gas composition		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
N_2	mol%	2.9	3.3	2.8	3.3	2.6
CO_2	mol%	0.3	[redacted]	[redacted]	[redacted]	0.3
C_1	mol%	89.2	88.0	86.6	86.5	90.0
C_2	mol%	5.3	6.1	5.1	[redacted]	4.9
C_3	mol%	1.6	1.9	1.6	[redacted]	1.5
C_4+	mol%	0.7	0.8	0.7	[redacted]	0.7
H_2S	mol%	0.0	0.0	[redacted]	[redacted]	0.0
Water-to-oil ratio (WOR)	water/bbl	1.6	0.6	0.6	2.6	0.1
Water injection ratio	water/bbl	2.6	1.6	1.6	3.6	1.1
Gas lifting injection ratio	cf/bbl liqui	364	364	364	364	364
Gas flooding injection ratio	scf/bbl oil	147,000,000	625,103	29,202	48,887	417,843
Flood gas	NA	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas
Steam-to-oil ratio (SOR)	steam/bb	0.0	0.0	0.0	0.0	0.0
Fraction of remaining natural gas reinjected	-	0.5	0.5	0.5	0.5	0.5
Fraction of steam generation via cogeneration	-	0.0	0.0	0.0	0.0	0.0
Fraction of steam generation via solar thermal	-	0.0	0.0	0.0	0.0	0.0
Heater/treater	NA	No	No	No	No	No
Stabilizer column	NA	No	No	No	Yes	No
Upgrader type		None	None	None	None	None
Volume fraction of diluent	-	0.0	0.0	0.0	0.0	0.0
Low carbon richness (semi-arid grasslands)	NA	Yes	Yes	Yes	Yes	Yes
Moderate carbon richness (mixed)	NA	No	No	No	No	No
High carbon richness (forested)	NA	No	No	No	No	No
Low intensity development and low oxidation	NA	Yes	Yes	Yes	Yes	Yes
Moderate intensity development and moderate oxidation	NA	No	No	No	No	No
High intensity development and high oxidation	NA	No	No	No	No	No

Table AII-3. Best-Case/Worst-Case OPGEE Inputs

Inputs	OPGEE v3.0a Excel Cell Reference	Units	Best-Case model input	Worst-Case model input	Mitigation Strategy Affected
Well and downhole pump prime mover type	Secondary Inputs!N103	N/A	Electric motor (2)	NG Engine (1)	Electrification
Separation prime mover type	Secondary Inputs!N129	N/A	Electric motor (2)	NG Engine (1)	Electrification
Water injection prime mover type	Secondary Inputs!N256	N/A	Electric motor (2)	NG Engine (1)	Electrification
Acid gas removal prime mover type	Secondary Inputs!N380	N/A	Electric motor (1)	NG Engine (2)	Electrification
Demethanizer prime mover type	Secondary Inputs!N392	N/A	Electric motor (1)	NG Engine (2)	Electrification
CO_2 separation membrane prime mover type	Secondary Inputs!N434	N/A	Electric motor (1)	NG Engine (2)	Electrification
Gas lifting compressor prime mover type	Secondary Inputs!N490	N/A	Electric motor (1)	NG Engine (2)	Electrification
Gas reinjection compressor prime mover type	Secondary Inputs!N496	N/A	Electric motor (1)	NG Engine (2)	Electrification
CO_2 injection compressor prime mover type	Secondary Inputs!N502	N/A	Electric motor (1)	NG Engine (2)	Electrification
Sour gas reinjection compressor prime mover type	Secondary Inputs!N508	N/A	Electric motor (1)	NG Engine (2)	Electrification
VRU compressor prime mover type	Secondary Inputs!N514	N/A	Electric motor (1)	NG Engine (2)	Electrification
Pre-membrane compressor prime mover type	Secondary Inputs!N520	N/A	Electric motor (1)	NG Engine (2)	Electrification
Transmission compressor prime mover type	Secondary Inputs!N530	N/A	Electric motor (1)	NG Engine (2)	Electrification
Liquefaction compression/refrigeration load	Secondary Inputs!N546	MW/mmtpa	2.91	29.1	Liquefaction CCS
Ancillary loads	Secondary Inputs!N547	MW/mmtpa	1.77	17.7	Liquefaction CCS
Production fugitives loss rate	VF - Site - onsite!D37	%	0%	1.5% (+ 1.9% if GOR<100,000 scf/bbl)	Production Fugitives
Gathering fugitives loss rate	VF - Site - offsite!M44	%	0%	1.70%	Gathering Fugitives
Processing fugitives loss rate	VF - Site - offsite!M57	%	0%	0.30%	Processing Fugitives
Transmission fugitives loss rate	VF - Site - offsite!M57	%	0%	0.0006%*(Gas Transmission Distance) + 1.3%	Export/Import Country Transmission Fugitives
Export country transmission distance	Secondary Inputs!N524	miles	0	500	Import Country Transmission Pipeline Length
Unlit flare	Flaring!M63	% time	0%	20%	Flaring
Flaring-to-Oil ratio	Primary Inputs!I86	scf/bbl oil	0	Supply chain-specific	Flaring
Fraction of CO2 breaking through to producers	Inputs!I58	%	0%	N/A	CO_2 Reinjection
Source of CO2	Inputs!I59	N/A	Anthropogenic	N/A	CO_2 Reinjection
Percentage of sequestration credit assigned to the oilfield	Inputs!I62	%	0%	N/A	CO_2 Reinjection
Associated gas processing path	Inputs!I77	N/A	Dehydrator + Ryan-Holmes Process (**7**)	Dehydrator + AGRU + DeC1 (**5**)	CO_2 Reinjection
Ocean tanker CH_4 slip from natural gas combustion	Emissions Factors!B6	% CH_4	0.10%	3.13%	LNG Cargo Methane Slip

Appendix III: Supply Chain GHG Emission Results

Figure AIII-1. Gorgon

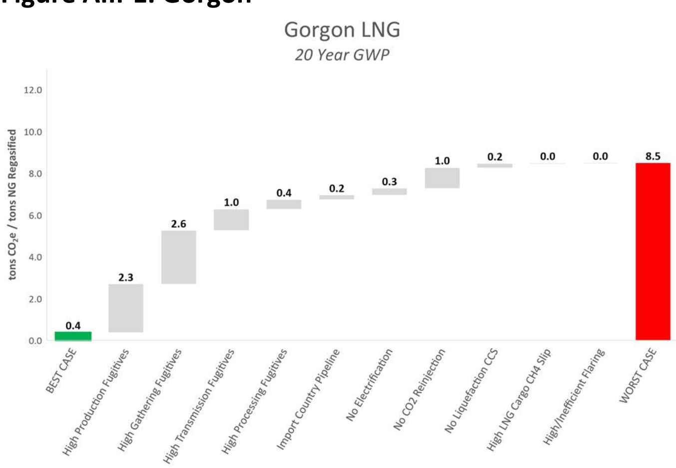


Figure AIII-2. Permian

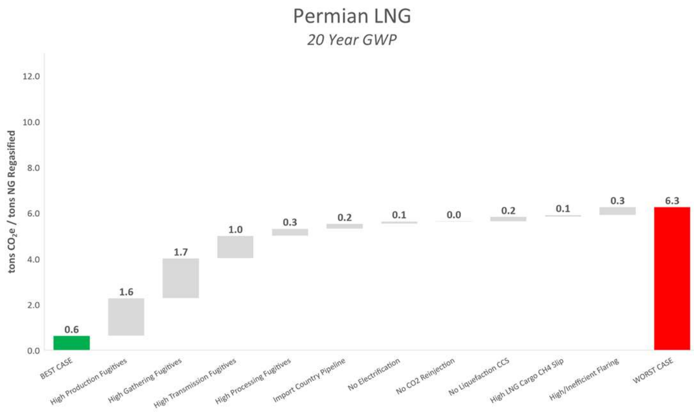


Figure AIII-3. Appalachian

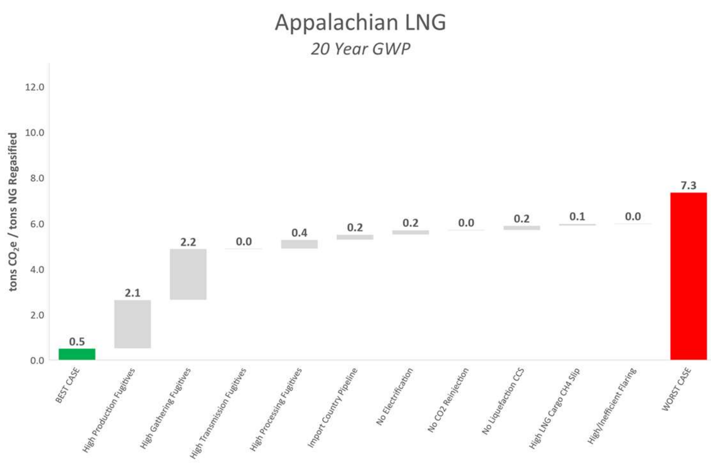


Figure AIII-4. Gbaran Ubie

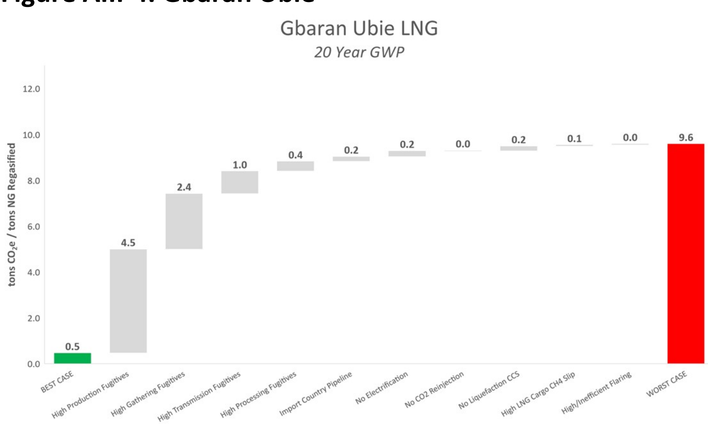


Figure AIII-5. Hassi R'Mel

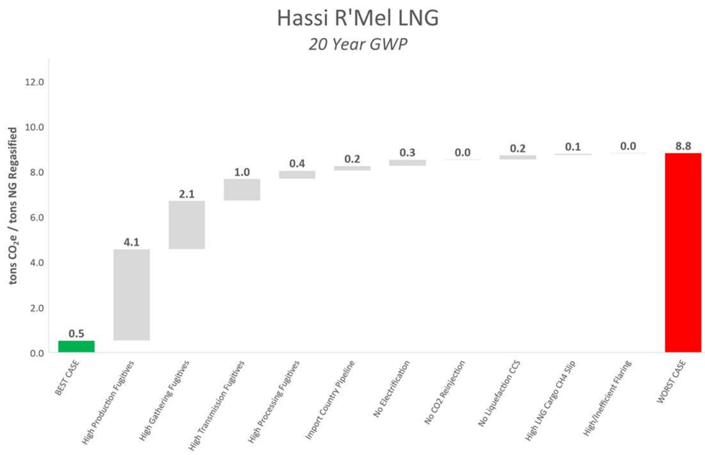


Figure AIII-6. South Tambey

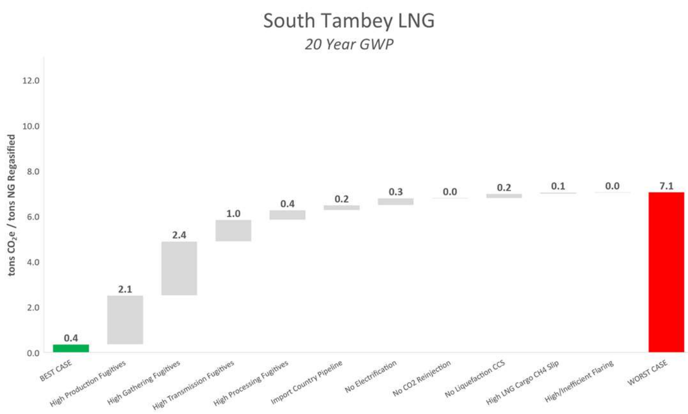


Figure AIII-7. Daandine

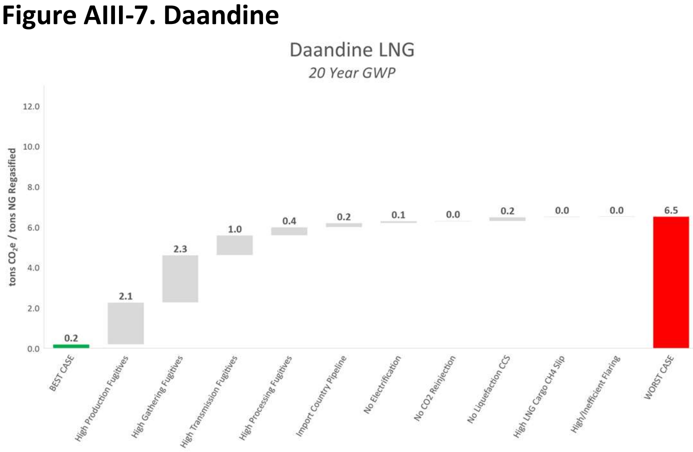


Figure AIII-8. Haynesville

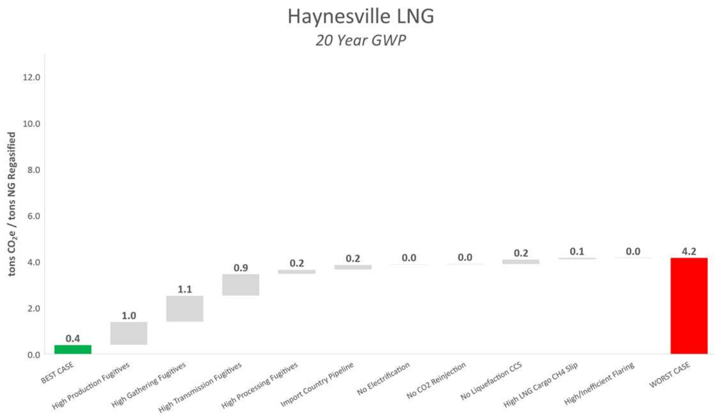


Figure AIII-9. QatarGas 2

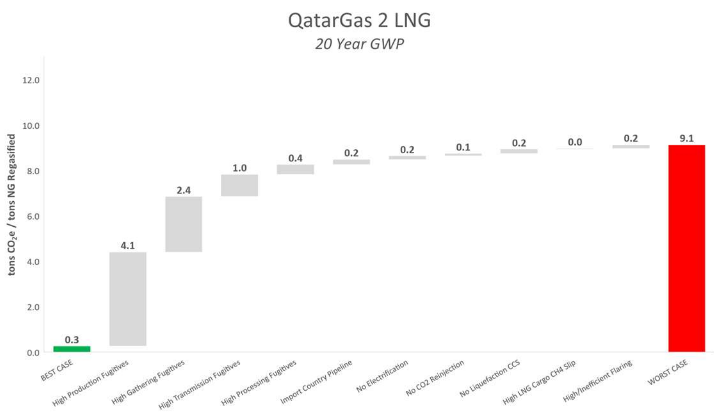


Figure AIII-10. South Pars (Phase 4-24)

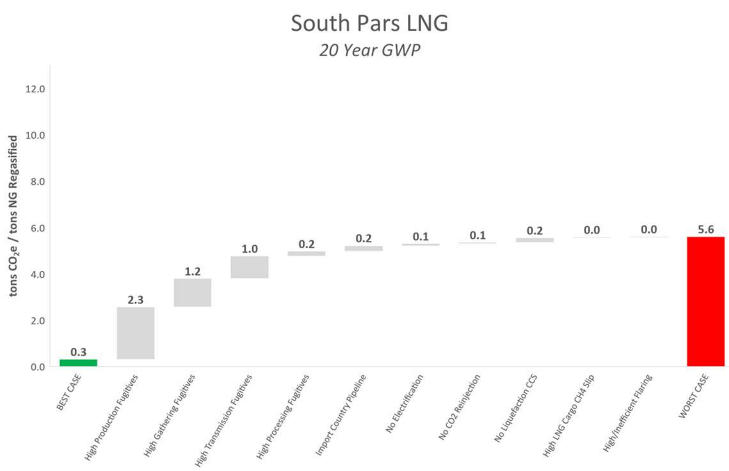
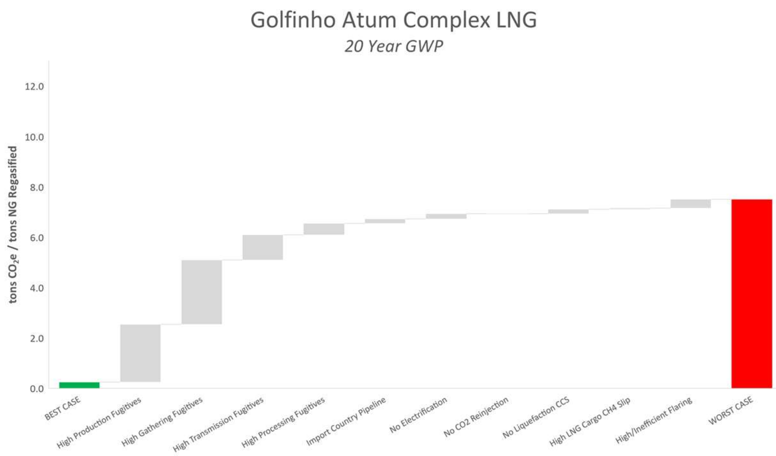


Figure AIII-11. Golfinho-Atum Complex



References

Argus Media. 2021. "Iran special: Could Tehran revive LNG export ambitions?" Accessed on November 1, 2021. https://www.argusmedia.com/en/news/2224178-iran-special-could-tehran-revive-lng-export-ambitions

Alvarez, Ramon A, Daniel Zavala-Araiza, David Lyon, David Allen, Zachary Barkley, Adam Brandt, Kenneth Davis et al. 2018. "Assessment of methane emissions from the U.S. oil and gas supply chain." 361 (6398) 186-888. https://doi.org/10.1126/science.aar7204

BP Energy Outlook: *Fuels-Gas. London:* BP, 2021. Accessed November 1, 2021. https://www.bp.com/en/global/corporate/energy-economics/energy-outlook/demand-by-fuel/natural-gas.html

Balcombe, Paul, Iain Staffell, Ivan Garcia Kerdan, Jamie F. Speirs, Nigel P. Brandon, and Adam D. Hawkes. 2021. "How can LNG-fuelled ships meet decarbonisation targets? An environmental and economic analysis." *Energy.* 227. Accessed November 1, 2021. https://doi.org/10.1016/j.energy.2021.120462

Bridger Photonics. 2021. "5 Questions to Ask When Evaluating Methane Emissions Detection Technologies". Technology. Accessed November 15, 2021. https://www.bridgerphotonics.com/blog/5-questions-ask-when-evaluating-methane-emissions-detection-technologies

CarbonMapper. 2021. "Technology." Accessed November 15, 2021. https://carbonmapper.org/our-mission/technology/

Case Western University. "EAST OHIO GAS CO. EXPLOSION AND FIRE." Accessed October 16, 2021. https://case.edu/ech/articles/e/east-ohio-gas-co-explosion-and-fire

Chen, Yuanlei, Evan David Sherwin, Elena Berman, Brian Jones, Matthew Gordon, Erin Wetherley, Eric Kort et al. 2021. "Comprehensive aerial survey quantifies high methane emissions from the New Mexico Permian Basin." *EarthArxiv*. https://doi.org/10.31223/X56D0D

Cheniere. 2021. "Cheniere to Provide Cargo Emissions Data to LNG Customers." Accessed November 15, 2021. https://lngir.cheniere.com/news-events/press-releases/detail/214/cheniere-to-provide-cargo-emissions-data-to-lng-customers

Chevron. 2021. *The Permian Basin.* Accessed November 20, 2021. https://www.chevron.com/projects/permian

Cocklin, Jamison. 2021. "Japanese Alliance Formed to Buy, Promote Carbon-Neutral LNG." Natural Gas Intel. Accessed December 4, 2021. https://www.naturalgasintel.com/japanese-alliance-formed-to-buy-promote-carbon-neutral-lng/

Colorado School of Mines. 2019. Global Gas Flaring Database. Accessed November 5, 2021. https://eogdata.mines.edu/download_global_flare.html

Colorado School of Mines. 2020. Global Gas Flaring Database. Accessed November 5, 2021. https://eogdata.mines.edu/download_global_flare.html

Columbia University. 2021. “Benefits and Risks of Border Carbon Adjustments: Q&A with Julio Friedmann.” Center on Global Energy Policy. Accessed December 1, 2021. https://www.energypolicy.columbia.edu/research/interview/benefits-and-risks-border-carbon-adjustments-qa-julio-friedmann

Cusworth, Daniel H., Riley Duren, Andrew Thorpe, Winston Olson-Duvall, Joseph Heckler, John Chapman, Michael Eastwood. 2021. “Intermittency of Large Methane Emitters in the Permian Basin.” *Environmental Science & Technology Letters.* 8 (7) 567-573. https://doi.org/ 10.1021/acs.estlett.1c00173

Duren, Riley M., Andrew K. Thorpe, Kelsey T. Foster, Talha Rafiq, Francesca M. Hopkins, Vineet Yadav, Brain D. Bue, et al. 2019. “California’s methane super-emitters.” *Nature.* 575. 180-184. https://doi.org/10.1038/s41586-019-1720-3

EIA. 2021. “How much shale gas is produced in the United States?” Frequently Asked Questions. Accessed October 2, 2021. https://www.eia.gov/tools/faqs/faq.php?id=907&t=8

EIA. 2021. “Natural gas explained: Where our natural gas comes from.” Energy Explained. Accessed on September 29, 2021. https://www.eia.gov/energyexplained/natural-gas/where-our-natural-gas-comes-from.php

El Gamal, Rania. 2021. “Qatar Petroleum signs deal for mega-LNG expansion.” Accessed November 1, 2021. https://www.reuters.com/article/qatar-petroleum-lng-int/qatar-petroleum-signs-deal-for-mega-lng-expansion-idUSKBN2A81ST

EPA. 2000. Section 3.1: Stationary Gas Turbines. Stationary Internal Combustion Sources. AP-42 Fifth Edition, Vol. 1. Accessed November 15, 2021. https://www.epa.gov/sites/default/files/2020-10/documents/c03s01.pdf

EPA. 2016. “Install Electric Compressors.“ NaturalGas Star. Accessed October 25, 2021. https://www.epa.gov/sites/default/files/2016-06/documents/installelectriccompressors.pdf

EPA. 2021. Greenhouse Gas Subpart W Model. EPA Envirofacts. Accessed October 1, 2021. https://www.epa.gov/enviro/greenhouse-gas-subpart-w-model-all-tables

Elkind, Jonathan, Erin Blanton, Hugo Denier van der Gon, Robert L. Kleinberg and Anton Leemhuis. 2020. “Nowhere To Hide: The Implications of Satellite-Based Methane Detection for Policy, Industry, and Finance.“ Columbia Center on Global Energy Policy. Accessed on November 15, 2021. https://www.energypolicy.columbia.edu/sites/default/files/file-uploads/Methane_CGEP_Commentary_v3.pdf

Fox, Thomas, Mozhou Gao, Thomas E. Barchyn, Yorwearth L. Jamin and Chris H. Hugenholtz. 2020. "An agent-based model for estimating emissions reduction equivalence among leak detection and repair programs." *Journal of Cleaner Production. 282.* Accessed November 1, 2021. https://doi.org/10.1016/j.jclepro.2020.125237

Fox, Thomas, Thomas E. Barchyn, David Risk, Arvind P. Ravikumar, and Chris H Hugenholtz. 2019. "A review of close-range and screening technologies for mitigating fugitive methane emissions in upstream oil and gas." *Environmental Research Letters.* 14 (5). Accessed November 1, 2021. https://doi.org/10.1088/1748-9326/ab0cc3

Frankenberg, Christian, Andrew K. Thorpe, David R. Thompson, Glynn Hulley, Eric Adam Kort, Nick Vance, Jakob Borchardt, et al. 2016. " Airborne methane remote measurements reveal heavy-tail flux distribution in Four Corners region." PNAS. 113 (35). 9734-9739. https://doi.org/10.1073/pnas.1605617113

Gan, Yu, Hassan M. El-Houjeiri, Alhassan Badahdah, Zifeng Lu, Hao Cai, Steven Przesmitzki and Michael Wang. 2020. "Carbon footprint of global natural gas supplies to China." *Nature Communications.* 11 (824) 1-9. https://doi.org/10.1038/s41467-020-14606-4

Gas Technology Institute. 2021. "GTI Launches Veritas, an Initiative to Measure and Verify Companies' Methane Emissions Reductions." Accessed November 1, 2021. https://www.gti.energy/gti-launches-veritas-an-initiative-to-measure-and-verify-companies-methane-emissions-reductions/

GIIGNL. 2021. *GIIGNL Annual Report*. Accessed November 1, 2021. https://giignl.org/wp-content/uploads/2021/11/GIIGNL_Annual_Report_November2021.pdf

GlobalData. 2021. LNG Liquefaction Database. Accessed September 15, 2021. https://oilgas.globaldata.com/sector/LngLiquifactionData/2100003

GlobalData. 2021. LNG Regasification Database. Accessed September 15, 2021. https://oilgas.globaldata.com/sector/LngRegasificationData/2100003

GlobalData. 2021. LNG Imports Database. Accessed September 15, 2021. https://oilgas.globaldata.com/sector/LngImportsData/2100003

Global Wind Atlas. 2021. Accessed on November 15, 2021. https://globalwindatlas.info/

Gordon, Deborah and Reuland, Frances. 2021. "Climate TRACE Lifts the Veil on Oil and Gas Emissions." Climate Intelligence. Accessed November 26, 2021. https://rmi.org/climate-trace-lifts-the-veil-on-oil-and-gas-emissions/

Government of Canada. 2020. "Alberta equivalency with federal methane regulations: emissions reduction estimation." Accessed October 29. 2021. https://www.canada.ca/en/environment-climate-change/services/canadian-environmental-protection-act-registry/agreements/equivalency/consultation-canada-alberta-methane-oil-gas/emissions-reduction-estimation.html

Harvey, Chelsea. 2020. "Methane Emissions from Oil and Gas May Be Significantly Underestimated.“ Scientific American via E&E News. https://www.scientificamerican.com/article/methane-emissions-from-oil-and-gas-may-be-significantly-underestimated/

Hydrocarbons Technology. 2018. *Yamal LNG Project, Sabetta.* Accessed November 20, 2021. https://www.hydrocarbons-technology.com/projects/yamal-lng-project-russia/

IEA. 2021. "Detailed and comprehensive annual data on natural gas supply, demand and trade." Natural Gas Information: Overview. Accessed October 2, 2021. https://www.iea.org/reports/natural-gas-information-overview

IPCC. 2014. Climate Change 2014 Synthesis Report. Accessed November 10, 2021. https://ar5-syr.ipcc.ch/ipcc/ipcc/resources/pdf/IPCC_SynthesisReport.pdf

Lavoie, Martin, David Risk, Elizabeth O'Connell, Emmaline Atherton, Jan Gorski and Jack Johnson. 2021. "Evaluating the benefits of alternative leak detection programs." Accessed November 1, 2021. https://doi.org/10.31223/X5F628

Le Fevre, Chris N. 2018. "A review of demand prospects for LNG as a marine transport fuel." The Oxford Institute for Energy Studies. Accessed December 1, 2021. https://www.oxfordenergy.org/wpcms/wp-content/uploads/2018/07/A-review-of-demand-prospects-for-LNG-as-a-marine-fuel-NG-133.pdf

LNG Market Trends and Their Implications: Structures, drivers and developments of major Asian importers. 2019. Paris: International Energy Agency. Accessed October 15, 2021. https://iea.blob.core.windows.net/assets/a916b9f9-4a74-4136-ad72-e05c0f466627/LNG_Market_Trends_and_Their_Implications.pdf

Logan, Jeffrey, Garvin Heath, Jordan Macknick, Elizabeth Paranhos, William Boyd, and Ken Carlson. 2012. "Natural Gas and the Transformation of the US Energy Sector: Electricity." National Renewable Energy Laboratory. University of Colorado Law School. Colorado State University. Accessed November 15, 2021. https://www.nrel.gov/docs/fy13osti/55538.pdf

Lundquist, Zachary. 2021. "The Rise of Hunan." China Today. Accessed November 21, 2021. http://www.chinatoday.com.cn/ctenglish/2018/et/202110/t20211009_800259959.html

MiQ Standard for Methane Emissions Performance: Subsidiary Document 3 – Monitoring Technology Deployment – Onshore. Rocky Mountain Institute and SYSTEMIQ Ltd. Accessed November 15, 2021. https://miq.org/wp-content/uploads/2021/09/MiQ_Standard_Onshore_v0.9_COMBINED.pdf

MRV and GHG Neutral LNG Framework. 2021. GIIGNL. Accessed December 1, 2021. https://giignl.org/wp-content/uploads/2021/11/MRV-and-GHG-Neutral-Framework.pdf

Murphy, Erin and Holstein, Frances. 2021. "Federal pipeline agency has essential opportunity to reduce methane emissions." Energy Exchange. Accessed November 1, 2021. https://blogs.edf.org/energyexchange/2021/07/06/federal-pipeline-agency-has-essential-opportunity-to-reduce-methane-emissions/

Net Zero by 2050: *A Roadmap for the Global Energy Sector.* Paris: International Energy Agency. 2021. Accessed October 15, 2021. https://iea.blob.core.windows.net/assets/deebef5d-0c34-4539-9d0c-10b13d840027/NetZeroby2050-ARoadmapfortheGlobalEnergySector_CORR.pdf

Nissimov. 2021. "France's Engie Scraps Proposed Rio Grande LNG Deal Amid Environmental Concerns." Accessed November 20, 2021. Natural Gas Intel. Accessed November 28, 2021. https://www.naturalgasintel.com/frances-engie-scraps-proposed-rio-grande-lng-deal-amid-environmental-concerns/

Oil and Gas Methane Partnership (OGMP) 2.0 Framework. 2020. Oil and Gas Methane Partnership. Accessed November 21, 2021. https://www.ccacoalition.org/en/resources/oil-and-gas-methane-partnership-ogmp-20-framework

Omara, Mark, Naomi Zimmerman, Melissa R. Sullivan, Xiang Li, Aja Ellis, Rebecca Cesa, R. Subramanian et al. 2018. "Methane Emissions from Natural Gas Production Sites in the United States: Data Synthesis and National Estimate." *Environmental Science & Technology.* 52 (21), 12915-12925. https://doi.org/ 10.1021/acs.est.8b03535

Pipeline and Hazardous Materials Safety Administration. 2018 "Gathering Pipelines FAQs." Accessed November 10, 2021. https://www.phmsa.dot.gov/faqs/gathering-pipelines-faqs

Stanford University. 2021. "OPGEE: The Oil Production Greenhouse gas Emissions Estimator." Accessed on September 29, 2021. https://eao.stanford.edu/opgee-oil-production-greenhouse-gas-emissions-estimator

Petron, Gabrielle, Benjamin Miller, Bruce Vaughn, Eryka Thorley, Jonathan Kofler, Ingrid Mielke-Maday, Owen Sherwood, et al. 2020. "Investigating large methane enhancements in the U.S. San Juan Basin." *Elementa: Science of the Anthropocene* 8 (1): 038. https://doi.org/10.1525/elementa.038

Regulations Respecting Reduction in the Release of Methane and Certain Volatile Organic Compounds (Upstream Oil and Gas Sector). 2020. *Statutory Orders and Regulations. https://laws-lois.justice.gc.ca/eng/regulations/SOR-2018-66/index.html*

Roman-White, Selina, James A. Littlefield, Kaitlyn G. Fleury, David T. Allen, Paul Balcombe, Katherine E. Konschnik, Jackson Ewing, Gregory B. Ross, and Fiji George. 2021. "LNG Supply Chains: A Supplier-Specific Life-Cycle Assessment for Improved Emission Accounting." *ACS Sustainable Chemical Engineering.* 9 (32) 10857-10867. https://doi.org/10.1021/acssuschemeng.1c03307

Rutherford, J.S, Evan David Sherwin, Arvind Ravikumar, Garvin Heath, Jacob Englander, Daniel Cooley, David Lyon et al. 2021. "Closing the methane gap in US oil and natural gas production emissions inventories." *Nature Communications. 12 (4715).* https://doi.org/10.1038/s41467-021-25017-4

The SGE Methodology: *GHG Methodolgoy for Delivered LNG Cargoes.* 2021. Chevron, QatarEnergy and Pavilion Energy. Accessed on December 1, 2021. https://www.chevron.com/-/media/chevron/sustainability/documents/SGE-methodology.pdf

Shell. 2021. *Shell LNG Outlook.* Accessed on December 1, 2021. https://www.shell.com/energy-and-innovation/natural-gas/liquefied-natural-gas-lng/lng-outlook-2021

Ship Technology. 2014. "Methane Princess LNG Carrier." Accessed October 15, 2021. https://www.ship-technology.com/projects/methane-princess-lng-carrier/

Stecker, Tiffany. 2013. "EPA Should Address Natural Gas Leaks." Scientific American via ClimateWire. Accessed December 1, 2021. https://www.scientificamerican.com/article/epa-should-address-natural-gas-leaks/

Strauss Center. "The U.S Shale Revolution." Energy and Security. Accessed October 1, 2021. https://www.strausscenter.org/energy-and-security-project/the-u-s-shale-revolution/

Subpart OOOOa - Standards of Performance for Crude Oil and Natural Gas Facilities for which Construction, Modification or Reconstruction Commenced After September 18, 2015. 2016. *Code of Federal Regulations. https://www.ecfr.gov/current/title-40/chapter-I/subchapter-C/part-60/subpart-OOOOa*

Tyner, David R and Matthew R. Johnson. 2021. *Environmental Science & Technology.* 55 (14), 9773-9783. https://doi.org/ 10.1021/acs.est.1c01572

UN Environment Programme. 2021. "New global methane pledge aims to tackle climate change." Accessed November 1, 2021. https://www.unep.org/news-and-stories/story/new-global-methane-pledge-aims-tackle-climate-change

University of Texas at Austin. 2021. "Fugitive Emissions Abatement Simulation Tool." Sustainable Energy Transition Lab. Accessed October 15, 2021. https://arvindravikumar.com/feast/

UNFCCC. 2021. "Reporting requirements." Accessed on November 20, 2021. https://unfccc.int/process-and-meetings/transparency-and-reporting/reporting-and-review-under-the-convention/greenhouse-gas-inventories-annex-i-parties/reporting-requirements

UNFCCC. 2015. "The Paris Agreement." Accessed November 1, 2021. https://unfccc.int/process-and-meetings/the-paris-agreement/the-paris-agreement

Willis, John, David Checkel, Dan Handford, Anup Shah and Matt Joiner. 2013. "Flare Efficiency Estimator and Case Studies" Water Environment Research Fund. Brown and Caldwell. Checkel Engineering, Inc. University of Alberta.

World Energy Outlook 2021. Paris: International Energy Agency, 2021. Accessed October 15, 2021. https://iea.blob.core.windows.net/assets/4ed140c1-c3f3-4fd9-acae-789a4e14a23c/WorldEnergyOutlook2021.pdf

Varon, D.J., J. McKeever, D. Jervis, J.D. Maasakkers, S. Pandey, S. Houweling, I. Aben, et al. 2019. "Satellite Discovery of Anomalously Large Methane Point Sources From Oil/Gas Production." *Geophysical Research Letters.* 46 (22). 13507-13516. Accessed November 15, 2021. https://doi.org/10.1029/2019GL083798

Valle. 2021. “China to overtake Japan as world's top LNG buyer in weeks, ICIS says.” Accessed November 5, 2021 https://www.reuters.com/article/us-china-lng-japan/china-to-overtake-japan-as-worlds-top-lng-buyer-in-weeks-icis-says-idUSKCN2DL2UB

Vaughn, Timothy, Benjamin Luck. Laurie Williams. Anthony J. Marchese and Daniel Zimmerle. 2021. “Methane Exhaust Measurements at Gathering Compressor Stations in the United States ” *Environmental Science and Technology.* 55 (2). 1190-1196. Accessed November 1, 2021. https://doi.org/ 10.1021/acs.est.0c05492

Zhang, Long and Bai, Wuliyasu. 2020. “Risk Assessment of China’s Natural Gas Importation: A Supply Chain Perspective.” *Sage.* 10(3). Accessed October 15, 2021. https://journals.sagepub.com/doi/10.1177/2158244020939912