WHITE PAPER

MAY 2013

ASSESSMENT OF THE FUEL CYCLE IMPACT OF LIQUEFIED NATURAL GAS AS USED IN INTERNATIONAL SHIPPING

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ACKNOWLEDGMENTS

The International Council on Clean Transportation receives generous funding from the ClimateWorks and Hewlett Foundations. The authors are grateful for the research contributions of Thomas Balon and Thomas Curry and for reviews by Fanta Kamakaté, Rachel Muncrief, and Nigel Clark.

TABLE OF CONTENTS

LIST OF FIGURES

LIST OF TABLES

EXECUTIVE SUMMARY

Natural gas is receiving considerable attention as a plausible alternative to conventional transport fuels. Natural gas offers the inherent advantage of releasing less carbon per unit of energy than petroleum-based fuels. The fuel's recent supply boom, resulting from the development of new extraction techniques in the United States and elsewhere, has decoupled its price from that of petroleum and spurred major investments in the infrastructure for its production, storage, and distribution. As natural gas becomes more desirable for transportation, technology providers have eased its adoption by devising new engines and retrofits for cars, trucks, and ships.

Although natural gas is being used more widely for road transport, it shows particular promise for the marine transport sector. From 2015 onward, the maritime sector faces pressure from more stringent engine and fuel quality standards that will demand major emission reductions to improve air quality and mitigate climate change impacts. The use of liquefied natural gas (LNG) instead of conventional residual and distillate fuels will substantially reduce emissions of oxides of nitrogen (NO_X), sulfur dioxide (SO_2), and particulate matter (PM)—thus obviating the need to pay a price premium for new, low-sulfur marine fuels and to install after-treatment equipment to meet the upcoming standards.

Nonetheless, considerable uncertainty remains about the net effects of LNG-fueled vessels on emissions. At issue are the upstream greenhouse gas (GHG) emission impacts of LNG, including the energy required to transport, handle, and process the fuel as well as the leakage of natural gas into the atmosphere. As a result, this report seeks to analyze to what extent the associated upstream carbon dioxide (CO_2) and methane (CH_4) emissions from producing LNG offset its potential climate benefit.

The research in the following chapters presents a novel analysis of eight discrete pathways that are expected to play a role in the supply of LNG as a bunker fuel to the maritime sector. The analysis incorporates new data from a variety of sources and offers a rigorous and transparent accounting of where and how energy requirements, CO_2 emissions, CH_4 exhaust, and leakage emissions contribute to LNG's overall impact. These "well-to-propeller" pathways are diverse, so as to cover the range of fuel cycle paths by which natural gas can be distributed and processed before powering marine vessels. The pathways include a range of imported LNG and domestically produced natural gas, differences in LNG liquefaction facilities, and varying LNG distribution and storage routes.

Figure ES-1 illustrates findings from the analysis of the different LNG pathways. The pathway results are compared to various conventional distillate and residual fuels in terms of their GHG emission intensity measured in grams of CO_2-equivalent per megajoule of fuel (gCO_2e/MJ) delivered. Compared with an average of typical petroleum-based maritime fuels, this analysis suggests, taking a simple average of the LNG pathway results, that LNG would offer about an 8 percent CO_2-equivalent benefit over distillate and residual fuels. However, the findings indicate that a number of the existing and near-term pathways under consideration in the United States and the European Union involve no climate benefit at all, whereas other pathways offer GHG benefits of up to 18 percent when compared with conventional marine petroleum fuels. There is little certainty about which LNG pathways will be used, and in what proportions, at this early stage. The results here suggest that widely reported LNG GHG reductions of 20–30 percent, for which calculations tend to be based simply on the fuel's lower carbon content, overestimate the benefit.

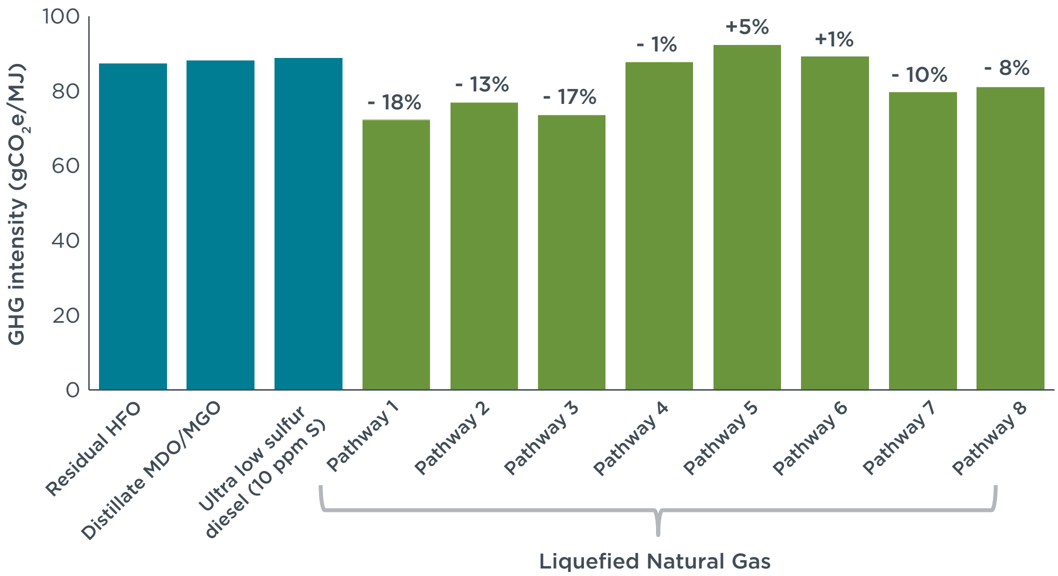

Figure ES-1: Greenhouse gas emission intensity of various conventional and liquefied natural gas fuel marine fuel pathways

The findings indicate that the pathways are associated with direct methane emissions of between 2.7 percent and 5.4 percent throughout the entire LNG fuel cycle. One major variable affecting climate benefit is the extent to which there is methane leakage within the fuel pathways. These upstream methane leakage rates are roughly consistent with the literature for natural gas emissions that are associated with on-road transport sectors. However, approximately half of the overall fuel cycle methane emissions in this analysis come directly from unregulated ship engine exhaust. Sensitivity analysis indicates that GHG intensity is most dependent upon engine efficiency, direct engine methane exhaust emissions, and upstream methane leak emissions.

This analysis also investigates the potential to improve upon life cycle natural gas processes related to upstream gas leakage, bunkering, and engine technology to offer greater climate benefits from LNG. Best practices to control direct methane emissions include the use of artificial lifts to dampen methane emissions during the unloading of liquids at producing wells; low-bleed devices to reduce fugitive methane from pneumatic valve operation during gas processing and transport; improved LNG engine design and controls; and methane-targeted oxidation catalysts in the exhaust system. Adhering to such best practices would ensure a more substantial CO_2 benefit from LNG use in the maritime fleet. The report finds that best practices would result in a 12–27 percent GHG benefit for LNG over conventional maritime fuels.

Based on this research, the report recommends that policymakers, fuel providers, and ship owners pursue LNG pathways that are the least emission intensive and, within those low-emission pathways, utilize best practices identified as limiting natural gas emissions. In addition, it suggests that relevant national and international policymakers ought to provide associated guidance to fuel providers on upstream practices to help achieve greater climate benefits from the use of natural gas in the transport sector. The findings indicate that more modest CO_2-equivalent emission benefits, on the order of perhaps 10 percent, generally should be used to estimate the benefits of LNG for ships rather than higher assumptions that underestimate or ignore upstream emissions, bunkering leakage, and energy impacts. If and when detailed pathway-specific and location-specific data are available, more precise analyses should be pursued for greater accuracy. If best practices to reduce methane leakage are embraced, greater GHG benefits will be realized. It is also recommended in the conclusion that researchers continue to study developments in this area to ensure that the purported LNG benefits are in line with the best available pathway-specific data on life cycle emissions estimates.

CHAPTER 1: INTRODUCTION

The development of liquefied natural gas (LNG) as a competitive alternative fuel in the maritime industry is exciting, yet it is at a very early stage. There are a variety of industrial, societal, and environmental reasons why LNG is widely viewed as a promising maritime fuel. The burgeoning exploitation of natural gas fields has greatly increased the supply and dramatically reduced its price in North America and in the European Union. This has heightened interest in a fuel that already has a number of attractive qualities for the shipping industry.

One of the principal reasons to explore LNG is its potential for environmental benefits. Increasing regulatory pressure to improve fuel quality and lower ship-generated emissions of sulfur oxides (SO_x), oxides of nitrogen (NO_x), and particulate matter (PM), particularly from 2015 forward, is spurring the development of more advanced vessel engine and after-treatment technology for conventional residual- and distillate-fueled ships. Emission reduction requirements increase the baseline costs of business and greatly increase the demand for alternatives. Beyond the more stringent regulations for airborne pollutants, tighter CO_2 emission standards and greater emphasis on efficiency for oceangoing vessels are helping to drive engine and design technology in new ships, as well as prompting some engine retrofits.

Even with LNG's lower price and with an ever stronger push from emission requirements, there are practical, infrastructure-related, and regulatory uncertainties that warrant consideration. As with any alternative fuel, there is the difficult question about how quickly the infrastructure can adapt to accommodate the new technologies. Even though the fuel price may be very low, the necessary infrastructure investments can be enormous. This issue is still more problematic for ships that must operate and be fueled worldwide. The necessary codes and guidelines for ships and for ports to enable LNG's use as a maritime fuel are being developed simultaneously. Central to the decision-making process about whether to proceed with such investments is the question about quantifying the actual energy and climate change mitigation benefits associated with the use of LNG in comparison with conventional maritime fuels.

CONTEXT

The use of natural gas as a transport fuel has been growing steadily over the past decade. This increased activity can be seen in many different spheres, including industrial initiatives, public investment in new infrastructure, statements by technology providers, new government policies and incentives, and emerging research projects. There have been steady developments since 2006 in the deployment of LNG-powered vessels and the construction of new LNG refueling and import infrastructure.

A critical determinant of the prospects for natural gas as a transport fuel is its long-term price relative to conventional fuels. In the past eight years, new natural gas field production has resulted in a price substantially below that of petroleum-based fuels. This dynamic has changed the cost calculations for natural gas versus energy sources like coal for the power sector as well as for transport. This has been the case in both the United States and Europe.

Figure 1 illustrates the difference in LNG and the two major bunker fuels for ocean-going vessels, conventional heavy fuel oil (HFO) and low-sulfur fuel oil (based on TSA 2013;

EIA 2013). As shown, the LNG price has generally hovered between 45 and 60 percent below conventional HFO for 2010 through 2012. More important, for Emission Control Areas (ECAs) of North America and northern Europe, where ships are required to achieve more stringent emission standards, LNG offers an approximate 55–70 percent price reduction per energy unit from low-sulfur HFO. The more stringent low-sulfur regulations (i.e., for 0.1 percent fuel sulfur content) for ECAs from 2015 to 2020 could make LNG even more cost competitive. Approximately the same price pattern for 2010–12 can be seen for LNG, HFO, and marine diesel oil (MDO) on the Rotterdam and Zeebrugge exchanges (Germanischer Lloyd and MAN 2012). What is clear is that the natural gas fuel prices have become decoupled from those of petroleum fuels. But it is not known whether this dramatic price differential in Europe and the United States will persist or will be replicated in Asia.

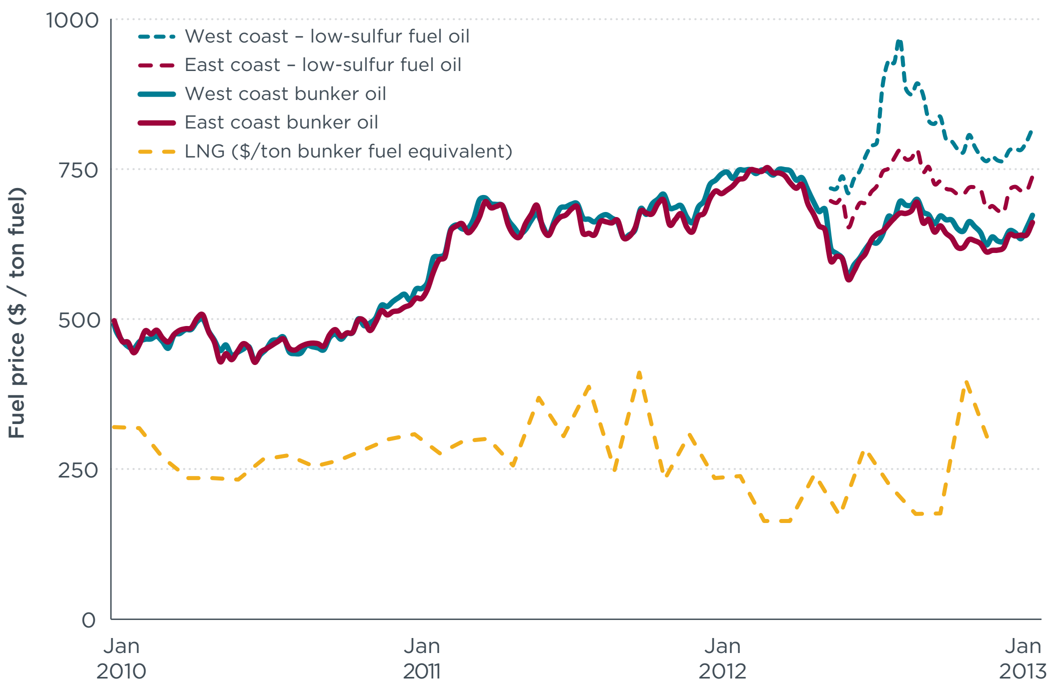

Figure 1: Average price of liquefied natural gas and petroleum-based fuel oil types in the United States, 2010–12

This steady price difference continues to be the major impulse for many major capital outlays as well as support from governments. Most of the investments to date have been in carrier ships to transport LNG globally and in import-export terminals to load and unload the fuel. In 2011, much of the LNG exported was from nations in the Middle East (most prominently, Qatar) and Asia (e.g., Indonesia and Malaysia), and most imports have been delivered to East Asia (Japan, Korea, China) or the European Union. Prices across the major LNG trading markets diverge widely owing to circumstances relating to local natural gas demand as well as long-term supply contracts and their pricing structures (IGU 2012).

LNG use in the shipping industry to date has predominantly been to fuel carriers that transport LNG from its production sources to various global markets. The sheer scale of international LNG transport is enormous. International LNG shipments of 330 billion cubic meters (vapor equivalent) account for about 10 percent of all global natural gas consumption, and natural gas accounts for about a quarter of global energy use overall (BP 2012). This LNG trade is done by about 350 tankers, which tend to be large ships, powered by 25–40 megawatt engines, that carry 120,000–180,000 cubic meters of LNG each (IGU 2012; Colton 2013). These tankers can boil off a portion of the LNG cargo for propulsion, or they can use marine distillate or residual fuel, or some combination. LNG carriers represented 3 percent of all maritime activity fuel consumption according to the 2009 International Maritime Organization inventory based on 2007 data (Buhaug et al. 2009), when there were about 240 of these LNG carriers. The fleet has since expanded in order to handle the growing natural gas supply worldwide.

Beyond these tanker ships, LNG is making more incremental inroads into the maritime sector in a variety of ways. As projected in the IMO's 2009 greenhouse gas (GHG) study, increased LNG adoption for fuel beyond tankers is most likely to be seen in regional or coastal shipping applications, where regulatory emission reduction requirements are high and refueling infrastructure shortcomings are minimal. Most of the newer LNG-powered ships have been on the smaller side, in the North and Baltic seas and plying shorter-distance, regional routes. The largest LNG powered ship outside of LNG carriers is the *Bit Viking*, a 25,000 metric-ton product tanker that is in use in Norway. The largest such LNG fleet operation is the 12-ship Fjord 1 ferry fleet in Norway that transports passengers and vehicles. Also mostly found in Norway are a number of oil and gas platform supply and patrol vessels.

In 2012, there were about 29 LNG ships in operation and about as many slated for delivery through 2014 (Mohn 2012). Among those to be delivered are several LNG-powered general cargo ships and roll-on/roll-off cargo hauling vessels for use in the Baltic Sea and the North Sea (by Eidsvaag, Norlines, Nordnorsk Shipping, Sea-Cargo). Also, in North America, there are commitments that will put two to five LNG container ships in operation by Totem Ocean Trailer Express (TOTE) for shipping on two separate routes (between Florida and Puerto Rico and between Washington and Alaska). These TOTE ships, with a capacity of about 3,000 twenty-foot equivalent units each, will be the first LNG-powered container ships when they are ready to go in 2015 and 2016.

Three manufacturers—Rolls-Royce, Wärtsilä, and MAN—have developed different LNG engine technologies for marine applications. Spark-ignited, lean-burn engines allow the gas to be mixed with an excess of air before passing through the intake valves, more completely combusting the fuel and reducing efficiency losses. Rolls-Royce has sold more than 500 LNG engines; 400 were in operation in 2011. The company indicates that its spark-ignition, Miller-cycle, lean-burn engines have 48 percent peak efficiency and 3.5 percent lower efficiency than comparable diesel engines (Rolls-Royce 2011).

Dual-fuel diesel engines, which can run on LNG or distillates, are gaining traction. These engines use a small amount of fuel oil as a pilot fuel to support ignition for these engines to primarily utilize fuel injection of natural gas. These engines are able to transfer from gas mode to fuel oil operation mode quickly and automatically. The use of a dual-fuel engine can help solve issues of limited gas supply while taking advantage of lower LNG prices where available. Wärtsilä has delivered more than 330 dual-fuel engines for 90 ships and specifies that its engines consume about 0.6 percent more energy than marine diesel oil engines and 5 percent less than residual fuel oil engines with scrubber after-treatment (Levander, 2011). MAN states that its dual-fuel LNG engine achieves 50 percent peak thermal efficiency, the same as its comparable conventional diesel engines, with lower fuel consumption (Germanischer Lloyd and MAN 2011; Laursen 2012).

The infrastructure for LNG has been ramped up to meet the demand for these ships. There are almost two hundred terminals for LNG import-export globally. As of early 2012, there were about 89 receiving, or regasification, terminals in 29 countries around the world. Japan, the United States, South Korea, the United Kingdom, and Spain are the largest importers by LNG volume. There are almost 100 exporting terminals, mostly in the Middle East and Asia. These facilities are set up to transport LNG itself, not as bunkering facilities to fuel shipping vessels. In contrast, there are small-scale LNG production and storage facilities that supply the above-mentioned ferries and other working ships in and around Norway. Each of the new LNG ship contracts is aligned with some installation of bunkering facilities to provide the fuel. For example, the plans for the new LNG-powered TOTE Washington-Alaska line includes port infrastructure development in Puget Sound that would seek to power LNG demand on a smaller scale for other, port-related activities. The port of Rotterdam has announced that it, too, will develop an LNG bunkering facility around 2014. In addition, China has been retrofitting LNG-powered ships that operate along the Yangtze River and the Grand Canal.

Over the longer term, several governments have bigger plans for LNG in the maritime sector. For example, an ambitious plan was launched by the European Commission to have 139 LNG refueling facilities for seagoing and inland vessels by the 2020–25 time frame (EC 2013). China's central government, in late 2012, issued guidance on how the development of "green ports" would be part of its strategy in pursuit of improved air quality within its 12th five-year plan. As part of the objective, ports will accelerate the use of natural gas to replace heavy fuel oil by ships.

Table 1 summarizes the current state of LNG ship and fueling developments. Taken as a whole, these suggest there has been a lot of activity engaged in transporting LNG globally, but, to date, measures to make LNG a significant maritime shipping fuel are in their early stages. There are in excess of three hundred large oceangoing vessels that transport LNG all over the world, but there are about one-tenth as many smaller vessels that utilize LNG as an energy source for hauling goods or people. Similarly, in terms of infrastructure development, there are, as mentioned, more than a hundred import and export terminals to facilitate the shipping of LNG around the world but just a scattering of small-scale LNG bunkering and storage facilities where ships can refuel.

Table 1: Examples of maritime industry LNG technology installations

	State of development [a]
LNG-powered vessels	• About 350 operating LNG carriers; 50–100 additional planned for 2013–16 • About 30 ferries, platform supply vessels, merchant ships, coast patrol, etc., in operation (mostly in Norway); about 25 on order (including in Canada, Finland, Norway, Sweden, the United States) • 1 chemical product tanker operating (Norway) • 2–5 container ships in 2015–16 (in the United States)
LNG import-export terminals [b]	• 89 import terminals 29 countries (approximately 27 terminals in Japan, 23 in Europe, 15 in North America, 6 in China) • 96 liquefaction facilities in 18 countries (48 percent in Qatar, Malaysia, Indonesia) • Many dozens of import and export facilities planned and in construction
LNG port refueling bunkers [b]	• Small-scale bunkering facilities available in Norway, Sweden • Small-scale facilities planned for Finland, Netherlands, Canada, the United States for 2013–15 • EU plan for 139 bunkering facilities at major maritime and inland ports by 2020–25

a All numbers are approximate owing to conflicting reports on completed projects/deliveries and uncertainties about planned and in-construction projects and deliveries.
b In addition, there are hundreds of fueling facilities that provide LNG for on-road vehicles and other nonmarine uses.

The potential air pollution benefits of natural gas versus conventional higher-sulfur and higher-carbon fossil fuels reinforce the inclination to increase the use of LNG. The establishment of ECAs in North America, the North Sea, and the Baltic Sea requires sharp declines in fuel sulfur (or equivalent after-treatment scrubber technologies to reduce SO_X) for oceangoing vessels in 2012 and 2015, respectively. The ECA in North America, in particular, has NO_X requirements starting in 2016 that will induce after-treatment technologies like selective catalytic reduction. Studies widely report that LNG offers the potential for 85–100 percent emission reductions of SO_X, PM, and NO_X (see, e.g., Germanischer Lloyd and MAN 2012; Buhaug et al. 2009; Rolls-Royce 2011; Bengtsson, Andersson, and Fridell 2011; Van Tassel 2010). As a result, the fuel switch to LNG, though not without costs and technical hurdles, could effectively allow ships to sidestep the need for low-sulfur marine fuel and after-treatment.

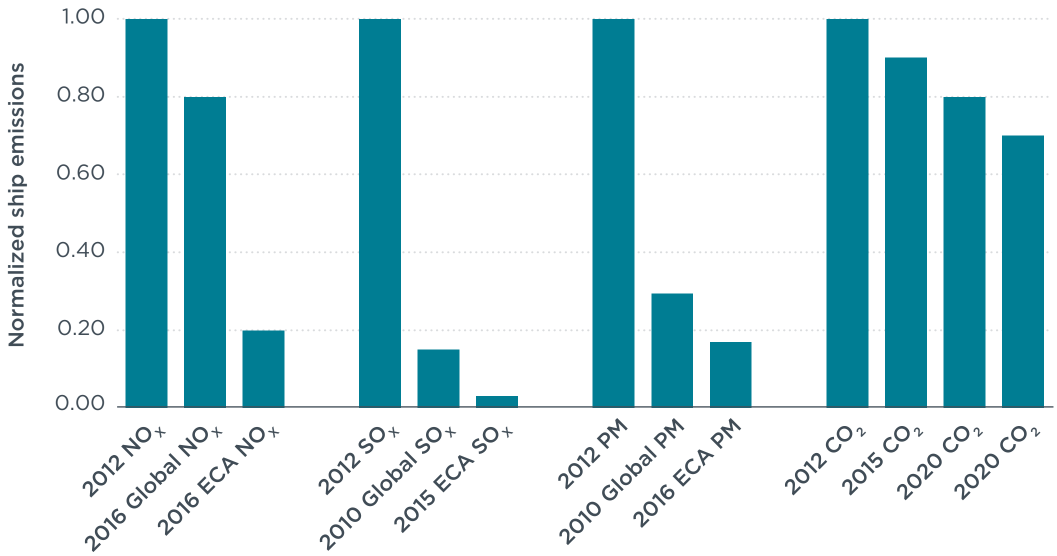

Figure 2: Required NO_X, SOx, PM, and CO_2 emission reductions to meet new shipping vessel engine and fuel requirements in the 2015–25 time frame

More recent climate mitigation policies provide further motivation for the use of LNG. The Energy Efficiency Design Index (EEDI) standards for ships will curtail ship CO_2 emissions. The standards require that new ships reduce their CO_2 per dry-weight tonnage capacity by 10 percent by 2015, 20 percent by 2020, and 30 percent by 2025 (see ICCT 2011). The rules, by and large, promote reduced CO_2 emissions through increased vessel efficiency (e.g., engine, hull, propeller modifications). Alternative-fuel ships, like those powered by LNG, would be able to comply with lower at-vessel (independent of their upstream emissions) CO_2 emissions.

There are additional climate and fuel policies that might have some bearing on marine fuels and their associated carbon footprint. In particular, the European Union and the state of California have regulations that would bind fuel providers to reducing the average carbon intensity of all fuels sold over time. The EU Fuel Quality Directive would reduce GHG intensity by 6 percent from 2010 to 2020, whereas the California Low Carbon Fuel Standard (LCFS) would reduce GHG intensity by 10 percent over the same period. Both policies put default values on fuels, from which fuel providers can demonstrate improved upstream practices to earn superior GHG ratings. But both are focused on road transport and expressly exclude marine fuels. Nonetheless, the LCFS program does rate LNG fuel pathways at 72–93 grams of carbon dioxide–equivalent per megajoule fuel (gCO_2e/MJ), which would amount to a 5–26 percent GHG reduction from the California Air Resources Board's road transport diesel baseline.

Much of the environmental and technology literature simply takes the differences in carbon content between natural gas and distillates or residual fuels to claim a 25–30 percent GHG benefit of natural gas over conventional petroleum fuels. Although these differences are genuine, the real-world effect on emissions of substituting natural gas as an alternative fuel is more complicated than that. For example, LNG processing requires upstream energy for liquefaction. Another reason that natural gas falls short of its full potential GHG benefit is the upstream leakage of natural gas. Methane, the dominant component of natural gas, has 25 times the global warming potential (GWP) of carbon dioxide within 100 years.[1] Each CH_4 molecule that leaks results in lost energy and increased fuel cycle emissions. Finally, any difference in natural gas engine efficiency versus conventional engines also affects real-world life cycle emissions.

Several recent studies highlight the importance of the methane leakage problem. Two recent analyses studied the question of natural gas in the on-road transportation sector as an alternative for vehicles. Howarth, Santoro, and Ingraffea (2011) found that upstream gas leak rates range from 1.7 percent to 6 percent for conventional natural gas and that leak rates for new shale gas developments can be as high as 9 percent. These leak rates result in GHG intensities for conventional natural gas of 74 to 99 gCO_2e/MJ, suggesting somewhere between a 0 and 28 percent GHG reduction from baseline gasoline. Another study, by Burnham et al. (2012), deemed a 2.8 percent leak rate to be more plausible, yielding a GHG intensity of 76 gCO_2e/MJ, and found a 23 percent overall natural gas benefit as an alternative to gasoline. The issue of upstream natural gas emissions continues to be intensely investigated in order better to inform overall energy and climate policies related to natural gas. This study investigates similar questions for natural gas use in the transport sector—but as a maritime shipping fuel with very different handling and transport processes—and utilizes up-to-date technical assumptions for diverse LNG pathways.

REPORT OVERVIEW

This report focuses on providing a rigorous quantification of the potential greenhouse gas emission benefits of LNG as a maritime fuel. The analysis estimates the life cycle greenhouse gas emissions associated with LNG based on state-of-the-art technical knowledge about the most likely means of its delivery to power ships. The research incorporates new data on natural gas leakage, or "slip", and energy expenditures that occur through the LNG chain, from gas field extraction to transmission and distribution pipelines, to liquefaction processes, to bunkering, to on-vessel fuel combustion. The multitude of options for LNG upstream processing and delivery is acknowledged through the investigation of eight discrete pathways. Finally, after investigation of the GHG characteristics of the eight pathways, for each case best practices are highlighted to prioritize and reduce LNG emissions throughout the fuel chain.

The following chapter describes the analysis that was undertaken for the various LNG pathways and the related data sources and assumptions. Chapter 3 is devoted to reporting on the findings from the analysis. Finally, Chapter 4 provides conclusions and considers implications from the research.

1 Methane has a disproportionately short-lived warming impact as compared to CO_2. This report adopts the convention of 100-year time horizon and GWP of 25; however, note that methane's global warming potential versus CO_2 is much greater, at 72, when a 20-year time horizon is applied.

CHAPTER 2: ANALYSIS OF LNG PATHWAYS

The analysis presented here evaluates the total greenhouse gas (GHG) emissions associated with liquefied natural gas use as a marine fuel on a “well-to-water” basis. It includes emissions from natural gas recovery and processing, liquefaction, transport, bunkering activities, and marine vessel exhaust emissions. For each separate delivery pathway considered, the analysis projects methane leak emissions from current or expected bunkering practices, given current market conditions and regulations, as well as methane emissions if “best available practices” for minimizing methane leakage were practiced throughout the supply chain. This chapter provides an overview of the various pathways investigated, describes the analytical steps, and summarizes the major data sources and assumptions involved in the analysis.

OVERVIEW OF PATHWAYS

The report identifies eight discrete bunkering pathways for producing LNG and delivering it to marine vessels. The different pathways vary in three fundamental characteristics: (1) the source, either imported or domestic, of the natural gas used to create LNG; (2) whether LNG is processed through an existing or new liquefaction plant; and (3) the location and method of vessel bunkering.

These eight bunkering pathways are summarized in Figure 3 and illustrated in Figure 4. Because of the nuanced differences in describing the eight pathways, these two figures in essence sketch out a “guide” for the pathways that are analyzed throughout this report. Pathways 1 through 3 comprise imported LNG that has been produced overseas using large-scale liquefaction facilities and transported via carrier to an LNG import terminal. In Pathway 1, the import terminal has facilities for directly fueling marine vessels from on-site LNG storage via a dedicated pipeline. In Pathways 2 and 3, LNG is loaded onto a truck or barge at the import terminal for delivery to a remote location for vessel fueling.

For Pathway 2, the bunkering site has dedicated LNG storage, so that the LNG from the import terminal will be off-loaded from the truck or barge to a land-side storage tank, and at some later date vessels will be fueled from the storage container using a dedicated pipeline. Pathway 3 has a remote fueling location but does not have on-site LNG storage; in this scenario, trucks or barges would be loaded with LNG at the import terminal and would travel to the remote site for rendezvous with a vessel, and the fuel would be off-loaded from the trucks or barges directly onto the vessel.

Pathways 4 through 8 use domestically sourced and liquefied natural gas. Pathways 4 through 6 are analogous to Pathways 1 through 3 but with the LNG procured from an existing large domestic liquefaction plant (or satellite storage facility) rather than an LNG import terminal. For Pathways 7 and 8, there is a smaller-scale liquefaction plant created specifically to produce LNG fuel for one or more vessels. For Pathway 7, fueling is via a dedicated pipeline from on-site LNG.

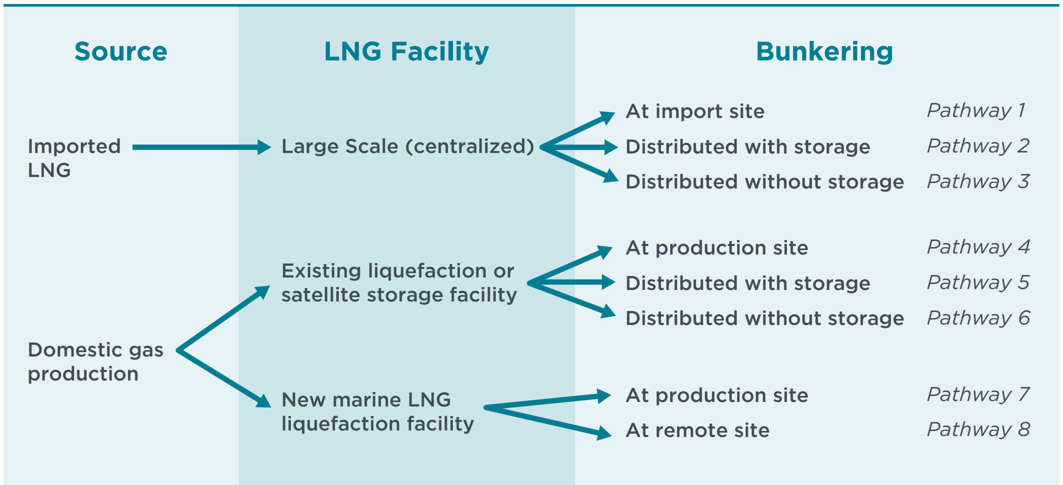

Figure 3: Analyzed LNG marine vessel bunkering pathways

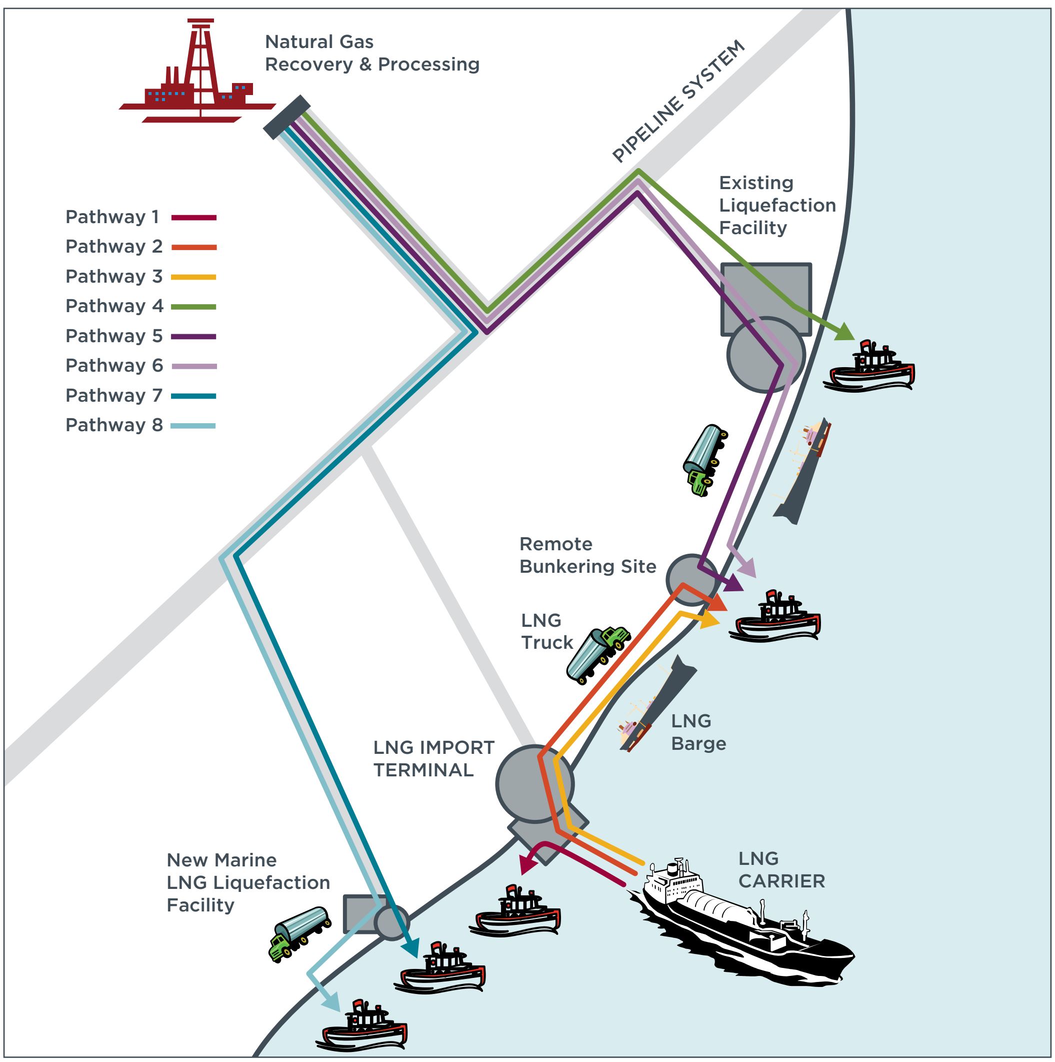

Figure 4: Illustration of LNG marine vessel bunkering pathways

Storage tanks, while Pathway 8 involves fuel loaded onto trucks at the plant for conveyance to relatively nearby vessels. For the purpose of the analysis, these eight bunkering pathways are generally available as options so long as the infrastructure is there to accommodate them. However, in any particular case, a number of the pathways would likely be impractical or cost-prohibitive for a variety of reasons. For any vessel, fleet, or port, the actual choice of bunkering pathway would depend on a host of considerations including vessel size, preferred fueling frequency, the total number of LNG vessels to be fueled in the local port, proximity to existing LNG storage locations, and pre-existing LNG distribution networks.

For most smaller vessels the easiest pathways in the short term will be Pathways 3 and 6: direct truck-to-ship fueling at remote sites (e.g., the vessel's home port), with LNG trucked from the nearest import terminal or liquefaction plant that has truck loading capability. While likely the easiest to implement, they might not be the most cost-effective. In the long run, LNG providers or vessel owners may make infrastructure investments to open up one or more of the other pathways, including direct ship-to-ship transfers and in isolated cases rail. For larger vessels direct truck-to-ship fueling may not be practical because of the amount of fuel that must be transferred and the time constraint inherent in the fuel transfer rate. For these vessels an expenditure on land-side LNG storage at the vessel's home port (e.g., in Pathways 2 and 5) will likely be required in the short term. In the long term the development of infrastructure for direct ship-to-ship or barge-to-ship fueling may allow larger vessels to be supplied without the need for local storage.

Several other LNG bunkering pathways are not analyzed because they are judged to be impractical or not economically rational. For example, one could import LNG, vaporize it into the natural gas grid, and then reliquefy it at an LNG facility for delivery to marine vessels. However, owing to the 10–20 percent energy penalty incurred in liquefying, a double-liquefaction pathway would suffer a significant jump in GHG emissions on a well-to-propeller basis and would not provide economic or environmental advantages relative to the other pathways. In addition, where truck LNG transport is not established and where direct ship-to-ship fueling is infeasible, pathways that utilize rail LNG transport could potentially develop.

Of the smaller LNG ships in the European fleets that were mentioned in Chapter 1, most are currently fueled via the equivalent of Pathways 5 or 6—where LNG is produced from within the region; trucked to the vessels' home port; and is either directly loaded onto the vessel (Pathway 6, truck-to-ship) or off-loaded to an on-site, land-side LNG storage tank for later use (Pathway 5).

EMISSIONS THROUGHOUT THE FUEL SUPPLY CHAIN

The LNG supply chain has numerous steps and processes that consume energy and therefore produce emissions of carbon dioxide and other GHGs. Many of these processes also involve methane leakage into the atmosphere. Per unit of delivered LNG, the most significant source of GHGs from the use of natural gas by marine vessels is engine combustion, which produces carbon dioxide.

Other than operation of the vessel itself, the processes in the LNG supply chain that use the most energy, resulting in the greatest amount of associated carbon dioxide, are initial natural gas recovery and processing as well as liquefaction. Lesser amounts of energy are used in transporting the gaseous fuel (in pipelines) to the liquefaction plant and in transporting LNG (in LNG carriers, barges, and trucks) from the liquefaction plant to the end user.

Based on analysis by the U.S. Department of Energy's National Energy Technology Laboratory (NETL) using U.S. Environmental Protection Agency (EPA) estimates, the majority of methane released from the LNG supply chain is emitted during natural gas recovery and processing (upstream or wellhead activities). Lesser amounts of methane are emitted during pipeline transport of natural gas and from storage, transport, and handling of LNG (bunkering activities).

Bunkering activities include four different types of methane losses: (1) losses due to heat absorption and venting from storage tanks over time; (2) venting of displaced vapor when filling a storage tank; (3) LNG liquid and vapor purged from hoses and lines after fueling a vessel; and (4) flash losses created from precooling lines and storage tanks or from transferring LNG from a high-pressure to a low-pressure tank. In addition, the vessel itself allows instances of leakage of methane to the atmosphere, from its fuel system and the engine's exhaust during operation. Effective control of boil-off gas, as will be described below, is the key to minimizing methane emissions from storage and transport of LNG throughout the marine bunkering supply chain.

The different bunkering pathways analyzed entail different steps and processes and accordingly offer distinct opportunities for reducing energy use and methane leakage. The processes examined in the analysis for each pathway are summarized in Table 2. The eight options, described above, can be grouped as Pathways 1–3 for imported LNG, Pathways 4–6 for domestic existing liquefaction facilities, and Pathways 7–8 for domestic new liquefaction facilities.

MANAGEMENT OF BOIL-OFF GAS

A critical aspect of controlling methane leak emissions is the management of boil-off gas (BOG) from the cryogenically cooled liquefied natural gas. At atmospheric pressure, natural gas must be maintained at a temperature below –162°C in order to stay in a liquid state. It is therefore stored and transported throughout the supply chain in specially designed, well-insulated containers. No matter how well insulated, however, some heat will continually seep into the container. As heat is absorbed, the head space pressure inside the container rises as LNG evaporates. The rate at which LNG evaporates depends on the size of the tank and the materials and methods of construction. For very large tanks the evaporation rate may be as low as 0.1 percent of stored LNG per day; for smaller tanks it may be as high as 0.25 percent per day (Chart Inc. 2012; Van Tassel 2010).

LNG storage tanks are designed to vent some of the vaporized gas when the internal tank pressure rises above a set threshold. This venting not only relieves pressure but also removes some of the absorbed heat. Many LNG storage tanks are designed to function in range close to atmospheric pressure, and they generally vent when the internal tank pressure rises above approximately 10 pounds per square inch gauge, or psig (0.7 bar). If LNG must be stored for long periods, a pressurized Type C tank may be used to extend the amount of time without resorting to venting. The use of a pressurized tank does not, by itself, reduce the LNG evaporation rate, but it increases the time between venting events because it can withstand a higher internal pressure. For example, one manufacturer offers intermodal LNG storage containers with maximum operating pressures from 148 to 345 psig. Both the 148-psig tank and the 345-psig tank have an advertised LNG evaporation rate of 0.25 percent per day, but the former can hold LNG for 52 days without venting, while the latter can do so for 75 days (Chart Inc. 2012).

Table 2: Processes for each LNG marine vessel bunkering pathway

		PATHWAY 1	PATHWAY 2	PATHWAY 3	PATHWAY 4	PATHWAY 5	PATHWAY 6	PATHWAY 7	PATHWAY 8
	LNG Source →	Imported	Imported	Imported	Domestic	Domestic	Domestic	Domestic	Domestic
	LNG Production →	Large Scale	Large Scale	Large Scale	Existing	Existing	Existing	New	New
	LNG Bunkering →	At Import Terminal	Distributed with Storage	Distributed without Storage	At Production Site	Distributed with Storage	Distributed without Storage	At Production Site	Distributed Without Storage
FOREIGN	**NG Recovery**	X	X	X					
	NG Processing	X	X	X					
	NG Liquefaction	X	X	X					
	LNG Carrier Loading	X	X	X					
	LNG Carrier Transport	X	X	X					
DOMESTIC	**NG Recovery**				X	X	X	X	X
	NG Processing				X	X	X	X	X
	NG Transport (pipeline)				X	X	X	X	X
	NG Liquefaction				X	X	X	X	X
	LNG Receiving at Import Terminal	X	X	X					
	LNG Storage at Import Terminal or Production Site	X	X	X	X	X	X	X	X
	LNG Truck/Barge Loading		X	X		X	X		X
	LNG Truck/Barge Transport		X	X		X	X		X
	LNG Truck/barge Off-Loading		X	X		X	X		X
	LNG Tank Filling at Bunker Site		X			X			
	LNG Storage at Bunker Site		X			X			
	LNG Vessel Fueling	X	X	X	X	X	X	X	X
	LNG Vessel Boil Off	X	X	X	X	X	X	X	X
	LNG Engine Emissions	X	X	X	X	X	X	X	X

The use of pressurized tanks does not necessarily reduce the total amount of BOG vented as LNG is moved through the supply chain; they may in fact only affect when and how the gas is ultimately vented. As heat is absorbed into a pressurized LNG tank and the internal pressure rises, so does the temperature of the fluid. If the LNG is then off-loaded into another atmospheric pressure tank (at lower temperature), its excess heat will cause some of the LNG in the receiving tank to evaporate and be vented—this is generally referred to as a flash loss.

BOG is also created when transferring LNG from one storage tank to another, as vapor in the empty tank is displaced by liquid, and when filling empty tanks since the pipelines and equipment used for the transfer, even the receiving tanks, must be precooled by flowing or spraying LNG into them—as heat is absorbed the LNG evaporates and must be vented. After the transfer is completed all lines must be also be purged of both liquid and gas that did not reach the receiving tank.

In the complete LNG cycle for marine bunkering, the amount of BOG created is a function of how long the LNG is held in the supply chain, the size and construction details of the containers used, and the number and methods of transfers of LNG from one storage container to another. The longer LNG is bunkered before being used, and the more times it is transferred from one storage vessel to another, the more BOG is created.

There are four main methods for dealing with the BOG created during LNG storage and handling: (1) releasing it to the atmosphere; (2) flaring it; (3) capturing it for use as gaseous fuel, or (4) capturing and reliquefying it. Capture of BOG can take a number of forms. For marine vessels that store LNG onboard for their own propulsion, BOG is continually being created in the fuel tanks as heat is absorbed, but liquid and vapors are also steadily being withdrawn from the tank to power the engines. For vessels that are used every day, the internal pressure of the fuel tanks can generally be kept below the venting threshold, so no BOG is actually released from the tank. BOG will generally only be vented from the fuel system if the vessels are idle for an extended period.

Similarly, some oceangoing LNG carriers that transport bulk LNG across the globe use the BOG created in the cargo tanks to power the ships' steam turbine propulsion engines. Since the total fuel requirement for propulsion is typically greater than the rate of BOG creation, these vessels can usually operate for an entire voyage without releasing any BOG into the atmosphere. Recently, new LNG carriers have been built with diesel heavy-fuel propulsion engines, in order to maximize LNG product delivery volumes. In order to avoid BOG venting, these vessels are equipped with reliquefaction plants that collect the gas, cool it to below –162°C so that the vapors condense, and inject the LNG that forms back into the cargo tanks.

LNG import terminals must handle a lot of BOG created during carrier vessel unloading as well as during long-term storage of LNG on site. Since the main purpose of these terminals is to provide natural gas to grid, their normal procedure is to collect and compress the BOG vapors and inject them into a natural gas pipeline. In some cases they might reliquefy a portion of the BOG and put it back into storage rather than injecting the vapors into the gas grid, if economic conditions warrant. Import terminals also typically maintain a flare in their BOG handling system in the event that instantaneous BOG volume (i.e., flash losses) exceeds the compression or liquefaction capacity of the system.

Similarly, the BOG created during loading and unloading of trucks (primarily displaced vapor) that transport LNG from an import terminal or liquefaction facility to satellite storage facilities is typically directed to a low-pressure pipeline at the facility, for distribution to customers, rather than being vented to the atmosphere.

LNG liquefaction plants can also collect BOG, compress it, and redirect it into the liquefaction process to limit the amount of methane ultimately released into the atmosphere or flared. BOG handling at remote marine bunkering sites is potentially more problematic. These sites are unlikely to be connected to a natural gas pipeline that could be used to siphon the BOG created during tank filling, long-term storage, or vessel fueling. Reliquefaction could be considered to handle BOG at these sites. However, the low average volume and intermittent nature of BOG generation would likely make this method unattractive economically. For such locations, flaring might be the most practical method to ensure that methane is not vented into the atmosphere.

Another option might be to co-locate LNG bunkering sites with compressed natural gas fueling sites for on-road vehicles as well as stationary power. Under such a scenario, BOG created from LNG storage and fueling operations could be compressed into on-site storage tanks for later delivery to vehicles that run on compressed natural gas. BOG generated in LNG storage tanks and during vessel fueling could theoretically be used as well to satisfy on-site process heat or space heating needs, but the practicality of such an approach would vary significantly from location to location.

MAJOR DATA SOURCES AND ASSUMPTIONS

Many of the assumptions for this analysis are based primarily on U.S. data sources related to natural gas handling, leakage, and processing. The reasons for this are the wide availability of U.S.-related data and the relatively intense scrutiny given to natural gas processes by the Department of Energy and the EPA. These public sources utilize state-of-the-art primary data and provide this assessment with the highest possible level of rigor, detail, and transparency. In addition, the reliance on these sources provides great consistency throughout the various natural gas processes, ensuring consistent control volumes, context, and fuel specifications (e.g., rather than relying on disparate, unrelated data sources from multiple countries). The assumptions about the upstream processes are based on best available technical data and can continue to be updated as new data, or more location-specific data, become available.

For each marine LNG bunkering pathway, this analysis considers both GHG emissions from energy use (grams of CO_2-equivalent per megajoule of delivered natural gas, gCO_2e/MJ) and methane “leakage” to the atmosphere (grams CH_4 per MJ delivered natural gas, gCH_4/MJ). Leaked methane is converted to CO_2-equivalent emissions (gCO_2e/MJ) using a global warming potential (GWP) of 25 for methane over a 100-year time frame (as per IPCC 2007), meaning that each gram of methane leaked has 25 times the atmospheric warming effect of a gram of carbon dioxide emitted.

Values for current upstream emissions from natural gas recovery, processing, pipeline transport, liquefaction, and imported LNG transport are taken from a 2012 analysis by the National Energy Technology Laboratory (NETL) (Skone 2012). That analysis was modeled on LNG imported from offshore wells in Trinidad and Tobago and transported to the United States in large carrier ships. Data from the NETL study provide the basis for the assumptions for Pathways 1–3 here.

It is important to point out that LNG produced and imported from other regions of the world may have somewhat different upstream GHG emissions than those reported here. Methane and GHG emissions from "upstream" operations (i.e., natural gas recovery and processing) can differ according to regulations and operational practices for natural gas recovery and processing in Europe compared with the United States. However, for existing European LNG vessels, current methane and GHG emissions from bunkering and from vessel operation would be similar to emissions from North American activity for given non-import LNG pathways investigated due to the highly similar upstream processes.

For domestically produced natural gas (Pathways 4–8), upstream GHG emissions from recovery, processing, and transport vary significantly depending on the location of the producing wells (onshore or offshore), as well as on whether the gas is from conventional or unconventional (shale gas) wells. For this analysis, assumptions are based on U.S. natural gas that comes from onshore, conventional wells. This is considered a conservative assumption since NETL estimates that both upstream methane emissions and total upstream GHG emissions are lower from conventional offshore wells (total GHG 53 percent lower) and from unconventional onshore wells (total GHG 10 percent lower), than from conventional onshore wells.[2]

Note that the NETL analysis finds that total upstream GHG emissions from recovery and processing are much lower for imported LNG than for U.S.-produced natural gas. There are two primary reasons for this. First, the high production rates for offshore wells in Trinidad and Tobago, compared with US onshore wells, mean that their emissions per unit of energy (g/MJ) are lower. Second, the analysis assumes that, for safety reasons, operators of offshore drilling platforms pay much greater attention to minimizing methane leaks than do operators of onshore wells (Marriot and Littlefield 2013).

To evaluate the potential to reduce upstream methane emissions from following best practices in the recovery and processing of U.S. natural gas, this report assumed implementation of technologies and procedures discussed in the 2012 Natural Gas STAR Annual Implementation Workshop for liquids unloading[3] (Robinson 2012) and requirements in the New Source Performance Standards for well completions and work-overs finalized by the EPA in August 2012 (EPA 2012). These requirements primarily involve the use of artificial lifts to reduce methane emissions during liquids unloading activities for producing wells, as well as low-bleed devices to reduce fugitive methane from pneumatic valve operation during gas processing and transport. The low upstream emissions in the NETL study suggests that producers of imported LNG are already more or less following best practices to reduce methane leakage during recovery and processing, so no additional measures were assessed.

Of all of the processes needed to produce and deliver LNG, the largest energy consumer is liquefaction. The energy required to liquefy natural gas ranges from 10 to 20 percent of the energy content of the gas being liquefied. Historically, the larger the liquefaction facility, the more efficient it was, though this is changing with the development of new liquefaction technologies. The NETL study assumes that imported LNG (Pathways 1–3)

2 Note that there is continuing uncertainty about the level of methane emissions from natural gas recovery and processing in the United States (and elsewhere). The NETL analysis indicates that the largest source of methane emissions from conventional onshore wells over their lifetime is gas released during activities to clear fluid from the well bore and increase the flow rate from older producing wells. For unconventional wells, the largest source of methane emissions is gas released during the initial well completion and hydraulic fracturing (fracking) operations. The NETL analysis, which bases its assumptions on the EPA's 2012 Greenhouse Gas Emissions Inventory, may overstate some emissions and understate others.

3 Liquids unloading refers to the removal of water and other liquids from the wellbore to improve gas flow

will be produced in large, highly efficient liquefaction facilities with approximately a 10 percent energy penalty. For the analysis presented here, assumptions about energy use and GHG emissions from existing U.S. liquefaction facilities (Pathways 4–6) were taken from a survey by the California Air Resources Board (ARB 2009), which assumes smaller and less efficient facilities (i.e., approximately a 20 percent energy penalty), resulting in higher GHG emissions from liquefaction of domestically produced LNG than for imported LNG. In recognition of current advances in technology, this analysis assumes that new U.S. liquefaction facilities (Pathways 7–8) would have the same efficiency as those used to produce imported LNG.

The major energy expenditure during domestically produced marine LNG bunkering activities is for transport of LNG by heavy-duty vehicle or barge from an import terminal or production facility to a remote vessel-fueling location in some of the specified bunkering pathways. This analysis assumes that all LNG transport is by heavy-duty vehicles rather than barge. That is a conservative case since waterborne transport is generally more efficient than truck transport.[4] For all pathways involving heavy-duty vehicle transport (Pathways 2, 3, 5, 6, and 8), this report assumed the use of a standard heavy-duty vehicle pulling an LNG tank trailer with a 26,000-liter effective capacity. Transport distance between the LNG import terminal or production facility and remote fueling location is assumed to be 100 miles (62.5 km),[5] and average heavy-duty vehicle fuel economy is assumed to be 2.1 kilometers per liter diesel. Off-loading time is assumed to be two hours, during which the truck engine would be idling and would consume approximately four liters of fuel per hour (Watkins 2013).

Relevant to these assumptions for the pathways where LNG is transported on heavy-duty vehicles, note that Denmark and other northern EU countries have expressed interest in the development of dedicated ships and barges to allow for direct ship-to-ship bunkering of LNG fuel, especially for larger vessels (e.g., DMA 2012; SMTF undated). For the largest vessels, direct vehicle-to-ship fueling may not be practical because of the amount of fuel that must be transferred, considering the fuel transfer rate. Such vessels may require multiple vehicles per filling, or vehicle-to-ship fueling may take longer than the available fueling window, causing delays in ship schedules. For these vessels, larger-capacity bunker vessels or barges will be required, or else on-site LNG storage must be instituted at the vessel's home port.

Of the four potential sources of methane emissions from marine LNG bunkering activities, mentioned earlier in the chapter, this analysis only deals with three. Flash losses are more difficult to quantify and were not included for two reasons. First, the analysis is intended to assess "steady-state" emissions from LNG bunkering, whereas it is assumed that throughout the supply chain storage vessels (including fuel tanks on marine vessels) would not normally be completely emptied of LNG and allowed to warm up. Second, the bunkering pathways specified involve LNG stored and transported in atmospheric tanks, which would minimize the possibility of flash losses during transfer of LNG from one tank to another, rather than pressurized tanks.

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4 Assuming that barges would produce only about one-quarter of the CO_2 emissions of a truck per ton-mile of LNG moved, this analysis indicates that the use of barges rather than trucks could reduce total GHGemissions for pathways 2, 3, 5, 6, and 8 by approximately 0.24 gCO_2e/MJ; this is approximately 0.3 percent of total well-to-water GHG emissions for these pathways.

5 For every additional 100 miles (62.5 km) that LNG needs to be transported by truck from the production/import facility to the bunkering site, total well-to-water GHG emissions would increase by approximately 0.45 percent.

In this analysis, both LNG import facilities and production facilities are equipped with boil-off gas handling systems that can collect and use BOG from all three of the quantified sources of methane leakage. The displaced vapor from filling LNG tank trucks, or from directly fueling marine vessels at an import terminal or production facility, would be captured by the facilities' BOG handling system. Likewise, BOG generated during long-term storage of LNG at these sites would be recycled.

It is assumed that for LNG production sites the handling system would capture 100 percent of BOG created, so that none would be released into the atmosphere. For LNG import terminals, the working assumption is that the BOG handling system would capture 95 percent of BOG and that 5 percent would be released. The reason for the difference is that BOG volume is more variable at an import facility thanks to the need to handle LNG carrier deliveries; this might on occasion result in instantaneous BOG volume greater than the capacity of the handing system.[6]

The analysis assumes that remote marine bunkering sites would not typically be equipped with BOG handing/reuse systems because, in most cases, the bunkering sites would not be connected to a natural gas pipeline. As such, standard practice would be to release the resulting methane from vapor displaced during filling of on-site LNG storage tanks and vessel fueling, as well as BOG created during on-site storage of LNG. Consistent with the literature (Van Tassel 2010), the analysis assumes that on-site LNG storage tanks at remote bunkering sites have a boil-off rate of 0.15 percent of tank volume per day. It postulates that the best practice would involve flaring this methane rather than releasing it to the atmosphere since that would generally be the least expensive control option.

The last source of methane leakage from bunkering operations is the purging of liquid and vapor from the fueling hoses of LNG delivery trucks after filling on-site storage tanks or directly fueling vessels at remote bunkering sites. For current LNG tankers, the maximum volume of purged methane would be about 8.5 liters for a 26,000-liter capacity, approximately a 0.03 percent loss (Watkins 2013).[7] It is surmised that there is no effective way to eliminate this purging loss, so the current practice is the best practice.

This analysis also considers emissions of both carbon dioxide and methane from operation of marine engines. EPA new marine engine standards do not specify limits on tailpipe methane emissions. According to Rolls-Royce, one of three global suppliers, methane emissions from new EPA-certified natural gas marine engines are assumed to be 4 grams per kilowatt-hour (g/kWh) of engine output (based on Trent 2012; Horgen 2012; Czajkowski 2011)[8]. This equates to about 1–2 percent of fuel input to the engine, emitted to the atmosphere unburned through the exhaust stack. "Best practice" is presumed to involve improved engine design and controls and perhaps installation of methane-targeted oxidation catalysts in the exhaust system of natural gas marine engines to reduce methane exhaust emissions by approximately 80 percent.

6 It is likely that actual capture efficiency would vary by facility based on investment decisions, operating procedures, duration and frequency of LNG deliveries, and local permitting requirements.

7 This assumes a 5-cm-diameter by 4.3-m-long fill hose, which would allow for off-loading approximately 26,000 liters of LNG in two hours. Faster off-loading would require a larger-diameter hose and would increase the loss rate for hose purging.

8 Note that this level of tailpipe methane emissions is also consistent with a large body of test data from heavy-duty on-road natural gas vehicles equipped with lean-burn natural gas engines.

It is also possible for methane to be released from the LNG fuel storage systems aboard marine vessels, as heat is absorbed into the LNG tank, creating boil-off gas. LNG tanks on marine vessels are expected to have a boil-off rate of 0.15 percent of tank volume per day (Van Tassel 2010), identical to that premised for land-side tanks. However, vessels will generally be engaged in continuous operation, so that most boil-off gas will be drawn from the tank and burned in the vessel engines. The analysis assumes that only 2 percent of BOG will be released to the atmosphere, primarily during infrequent periods of extended vessel inactivity.

CHAPTER 3: FINDINGS

This chapter summarizes the high-level findings from the analysis. The findings are shown first for existing practices for the eight liquefied natural gas bunkering pathways identified and second for best practices for those eight pathways. The options, as described in the previous chapter, are Pathways 1–3 for imported LNG, Pathways 4–6 for domestic existing liquefaction facilities, and Pathways 7–8 for domestic new liquefaction facilities.

The upstream processes that the analysis encompasses are natural gas recovery and processing, liquefaction (overseas or domestic), transport of LNG, storage and handling at an import terminal, transport of natural gas by pipeline, and storage and handling of LNG at the production facility, as applicable for each pathway. Also included are emissions released during the delivery of the fuel to the marine vessel, emanating from the vessels' fuel storage system, and originating from vessel tailpipes (both CO_2 and CH_4 emissions) as a result of the operation of the engines. For each case, the results are shown in terms of the total CO_2-equivalent emissions, broken down through the various parts of the fuel cycle. Detailed data findings for CO_2 and CH_4 emissions from each of the eight potential marine LNG bunkering pathways are included in the Appendix.

EMISSIONS FROM EXISTING PRACTICES

Summary emissions results of the analysis are shown in Table 3 for natural gas processing in current practice throughout the LNG fuel cycle. As shown in the table, the total projected greenhouse gas (GHG) emissions to supply LNG as a marine fuel vary significantly depending on the bunkering pathway—from a low of 72 grams of CO_2-equivalent per megajoule to a high of 92 gCO_2e/MJ. The highest emissions occur along Pathway 5, which involves LNG produced in an already existing large liquefaction plant and then delivered via heavy-duty vehicle to a remote bunkering facility where there is on-site LNG storage. The option with the lowest emissions is Pathway 1, for which imported fuel is directly bunkered to a vessel at an LNG import terminal. GHG emissions from Pathway 5 are 28 percent higher than those from Pathway 1.

Table 3: Summary of well-to-water GHG emissions from eight liquefied natural gas marine fuel bunkering pathways under existing practices

	GHG emissions (gCO_2e/MJ) by bunkering pathway							
	1	2	3	4	5	6	7	8
CO_2 from vessel operation	48.4	48.4	48.4	48.4	48.4	48.4	48.4	48.4
CO_2 from energy upstream	11.5	11.8	11.8	19.2	19.5	19.5	11.0	11.4
CH_4 from vessel operation	10.6	10.6	10.6	10.6	10.6	10.6	10.6	10.6
CH_4 leakage from bunkering	0.0	4.5	1.1	0.0	4.3	1.1	0.0	1.1
CH_4 leakage from upstream	1.6	1.6	1.6	9.5	9.5	9.5	9.5	9.5
Total GHG emissions	**72.1**	**76.9**	**73.5**	**87.7**	**92.3**	**89.1**	**79.5**	**81.0**
Percentage of GHG from CH_4 emissions	17	22	18	23	26	24	25	26
Overall CH_4 emission rate (percentage of delivered natural gas)	2.7	3.7	3.0	4.5	5.4	4.7	4.5	4.7
GHG percentage change from conventional distillate and residual marine fuels	-18	-13	-17	-0.5	4.8	1.1	-9.8	-8.1

The variability in GHG emissions by pathway has two primary sources: (1) lower upstream GHG and methane emissions from imported LNG compared to LNG produced from domestically extracted natural gas; and (2) higher methane emissions at remote bunkering sites, especially those with on-site storage, than at LNG import or production facilities equipped with boil-off gas (BOG) handling systems. The direct CH_4 emission rate—as percentage of total natural gas delivered to the vessel—from upstream, bunkering, and vessel processes is also shown for each pathway in Table 3.

As shown, the bunkering option with the best GHG emissions results, Pathway 1, has the lowest CH_4 emission rate at 2.7 percent, whereas the least favorable option, Pathway 5, has the highest overall CH_4 emission rate, 5.4 percent. The upstream leak rates appear to be similar to the range of methane emission rates seen in the research literature for upstream leakage associated with on-road transport using natural gas (see, e.g., Burnham et al. 2012; Howarth, Santoro, and Ingraffea 2011). However, marine engine exhaust CH_4 emissions, at greater than 50 percent of the overall fuel cycle CH_4 in most pathways, are considerably higher than on-road CH_4 exhaust, which tends to be more tightly controlled.

These LNG fuel pathway findings are represented graphically in Figure 5. As shown, under any pathway, the majority of GHG emissions associated with the use of LNG as a marine fuel come from vessel operations (burning fuel for propulsion). Vessel tailpipe CO_2 exhaust accounts for 52–67 percent of overall GHG emissions. Upstream energy use related to the handling, processing, transporting, and bunkering of natural gas represents 15–22 percent of the fuel cycle GHG emissions across the eight pathways. CH_4 leakage throughout the fuel production processes amounts to 17–26 percent of the total emissions. Pathways 4–6 are revealed to have the highest GHG emissions—on account of steeper upstream energy processing requirements and greater upstream CH_4 leakage.

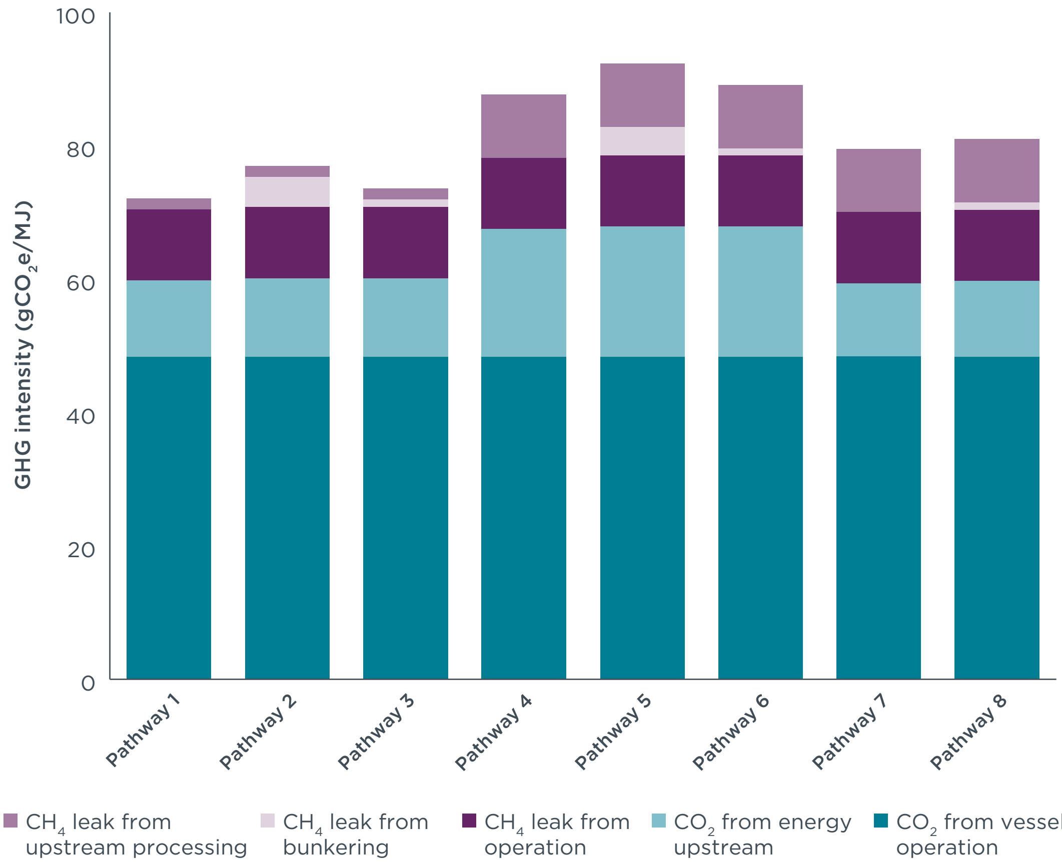

Figure 5: Fuel cycle GHG emissions for eight LNG marine vessel bunkering pathways

Overall, the results are reasonably similar to those that others have obtained. A 2011 study by the Netherlands Organisation for Applied Scientific Research (TNO) found GHG intensities of 78–93 gCO_2e/MJ for three LNG pathways in Europe (Verbeek et al. 2011). Several studies focused on road transport offer comparable results. The technical findings used for the regulatory development of California's Low Carbon Fuel Standard indicate that using LNG for vehicles would amount to 72–93 gCO_2e/MJ for the various fossil fuel LNG pathways (ARB 2011). A major well-to-tank study for the EU specifically isolated the upstream processes for various natural gas pathways, and generally it shows results of about 15–20 gCO_2e/MJ (Edwards, Larivé, and Beziat 2011), which also echo the results from this analysis.

Methane leakage can be broken down into upstream activities, bunkering, and vessel operations. The findings indicate a lower level of upstream CH_4 leakage from imported LNG than from domestically sourced natural gas. As discussed in the prior chapter, a reason for lower methane emissions from imported gas is the presumed higher production rates, resulting in lower emissions per unit of gas, and the greater attention paid to reducing methane leaks because of higher safety risks at offshore gas platforms compared with onshore U.S. gas wells. However, there continues to be uncertainty about the actual level of methane emissions from recovery and processing of onshore U.S. natural gas. As a result, sensitivity analysis is incorporated (its methodology summarized in the Appendix) to examine the effects of upstream CH_4 leakage, liquefaction energy, direct engine CH_4 exhaust emissions, and LNG engine efficiency on the overall findings.

The vast majority of CH_4 emissions from vessel operation are unburned fuel emitted through the ship's exhaust stack. Under normal circumstances emissions from the vessel's onboard LNG storage are projected to be comparatively minor thanks to fuel management systems that minimize and recycle boiled-off natural gas.

Projected GHG emissions from marine LNG bunkering vary from essentially zero for methane for Pathways 1, 4, and 7 to a high of 4.5 gCO_2eMJ (0.3 gCH_4e/MJ) for Pathway 2. The options with the lowest estimated methane emissions from bunkering all involve direct fueling of vessels at an LNG import terminal or production plant. The reason methane emissions from these pathways are low is that any vapor created during vessel fueling can be collected and reused by the import or production facility's BOG handling system, so it is not expelled into the atmosphere.

The options with the highest estimated methane emissions specifically from bunkering operations, Pathways 2 and 5, both involve transport of LNG by heavy-duty vehicle from an import or production facility to a remote fueling location, where it is piped into an on-site land-side storage tank for later transfer to marine vessels. Pathways 3, 6, and 8 also involve remote fueling but not on-site LNG storage at the remote bunkering site; under these scenarios vessels are fueled directly from the LNG delivery vehicle.[9]

The findings are evaluated against an average of conventional fuels used in the shipping industry. Specifically, they are compared with the GHG emission intensity of residual heavy-fuel oils, distillate marine gas oil (MGO) and marine diesel oil (MDO), and ultralow-sulfur diesel. Research indicates that these various conventional fuels have average GHG intensities of 87–89 gCO_2e/MJ (Corbett and Winebrake 2008; Verbeek et al. 2011). Both studies cited here cover upstream fuel cycle emissions for the handling and processing for petroleum[10] and are therefore used as the basis for this comparative analysis.

Figure 6 shows the average conventional marine fuel GHG intensity for comparison with the LNG pathway results as reproduced from Figure 5. The LNG fuel cycle GHG emission results are between 5 percent higher and 18 percent lower than the average of conventional marine distillate and residual fuels.

9 In the future, if direct ship-to-ship or barge-to-ship fueling is developed, methane emissions from this type of marine bunkering will be similar to those from truck-to-ship fueling.

10 Note that Corbett and Winebrake (2008) do not include CH_4 emissions within the residual and distillate analysis; however, as Verbeek et al. (2011) illustrate, CH_4 is an insignificant contributor to overall fuel cycle emissions, so the two studies' results are similar.

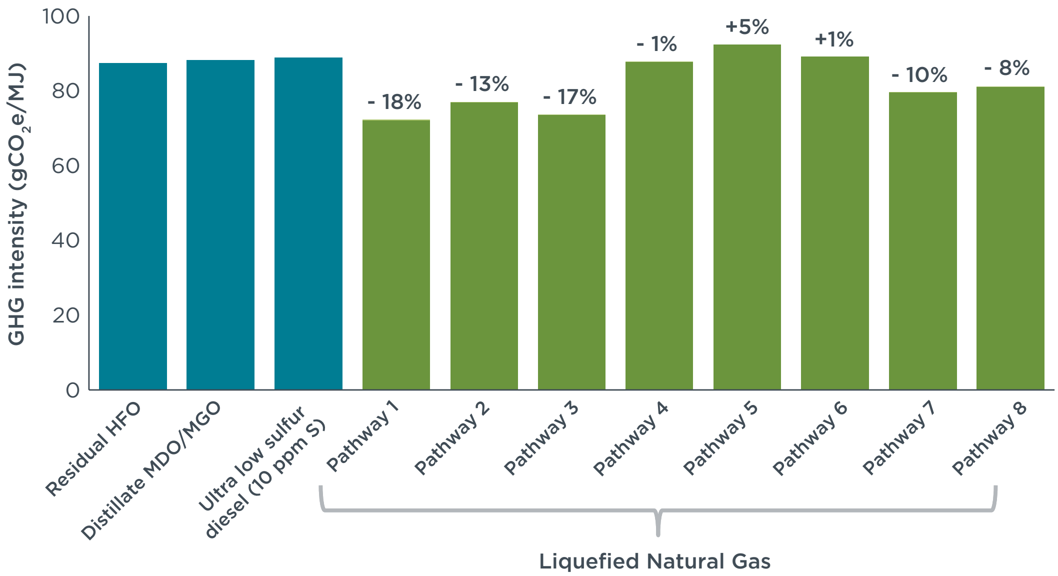

Figure 6: Fuel cycle GHG emissions for eight LNG marine vessel bunkering pathways, compared with conventional distillate and residual fuels.

EMISSIONS FROM BEST PRACTICES

Table 4 shows the findings from this analysis regarding the extent to which methane emissions can be minimized by following best practices throughout the entire LNG supply chain for the eight pathways. They indicate that, if best practices are followed, methane emissions from the use of LNG fuel for marine vessels can be reduced by approximately 60–75 percent for each bunkering pathway. As was the case with the results above taken from actual practice, there is still considerable variation across the pathways' fuel cycle GHG emission results, although the range is somewhat narrower. The best practice LNG pathways range from a low of 65 to a high of 78 gCO_2e/MJ.

Table 4: Summary of well-to-water GHG emissions from eight liquefied natural gas marine fuel bunkering pathways under best practices

	GHG emissions (gCO_2e/MJ) by bunkering pathway							
	1	2	3	4	5	6	7	8
CO_2 from vessel operation	48.4	48.4	48.4	48.4	48.4	48.4	48.4	48.4
CO_2 from energy upstream	12.4	13.2	12.8	20.1	20.9	20.6	12.0	12.4
CH_4 emissions from operation	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2
CH_4 leakage from bunkering	0.0	0.5	0.2	0.0	0.3	0.2	0.0	0.2
CH_4 leakage from upstream	1.6	1.6	1.6	6.0	6.0	6.0	6.0	6.0
Total GHG emissions	**64.6**	**65.8**	**65.2**	**76.6**	**77.8**	**77.3**	**68.5**	**69.1**
Percentage of GHG from CH_4 emissions	6	6	6	11	11	11	12	12
Overall CH_4 emission rate (percentage of delivered natural gas)	0.9	1.0	0.9	1.8	1.9	1.9	1.8	1.9
Percentage decline in GHG, best practices versus existing practices	10	14	11	13	16	13	14	15
Percentage decline in GHG, best practices versus conventional distillate and residual marine fuels	27	25	26	13	12	12	22	22

Overall, the findings indicate that LNG fuel pathways' GHG intensities can be reduced by between 10 percent and 16 percent by implementing best practices in controlling methane leaks throughout the fuel cycle. The results of adopting best practices in the handling and processing of natural gas throughout the fuel cycle are illustrated in Figure 7. Evidently, the highest GHG emission pathways (Pathways 4–6) can offer substantial GHG benefits over conventional fuels with adoption of best practices; these pathways' improvement in GHG emissions increases from near zero under existing practices to about 12–13 percent when methane leakage is minimized.

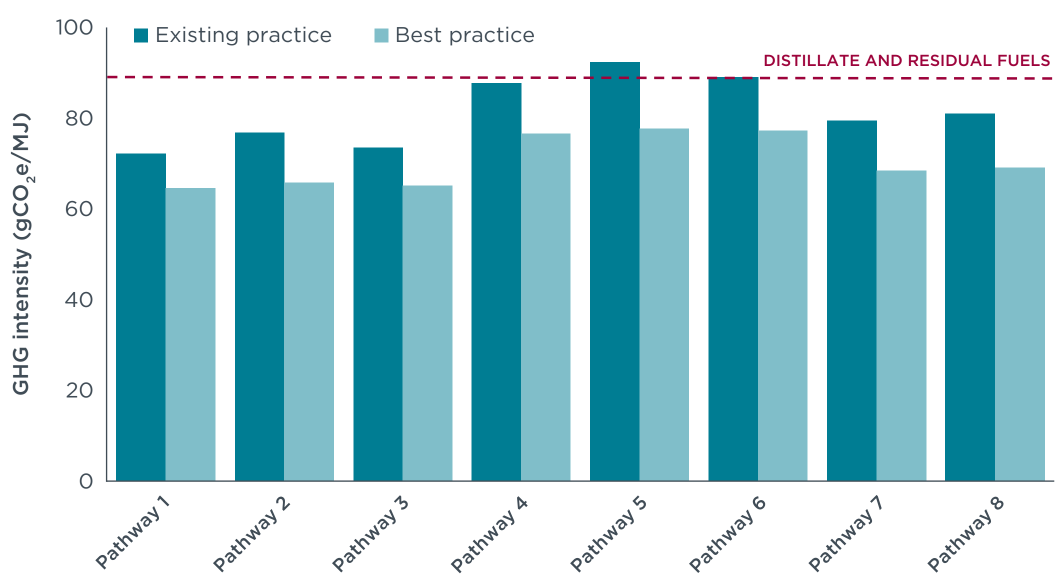

Figure 7: Fuel cycle GHG emissions for eight LNG marine vessel bunkering pathways, with adoption of best practices to reduce methane leakage

Best practices for each LNG pathway are multifarious and concern more than simply limiting leakage. Significant methane reductions of 8.4 gCO_2e/MJ (0.34 gCH_4/MJ) can be achieved by equipping natural gas marine engines with improved engine design and control or with methane-targeted oxidation catalysts. For domestically produced LNG (Pathways 4–8), a lesser-scale of methane reduction of 3.5 gCO_2e/MJ (0.14 gCH_4/MJ) can be achieved by implementing best practices in the upstream recovery and processing of natural gas, primarily by controlling methane emissions during new well completions and during liquids unloading operations for producing wells. For pathways that involve remote bunkering with on-site LNG storage, a reduction of an additional 4 gCO_2e/MJ (0.16 gCH_4/MJ) is attainable by implementing effective controls for boil-off gas during the filling of bunker tanks and during vessel fueling.

The impact of the shift from existing to best practices on fuel cycle leakage of CH_4 and fuel cycle GHG emissions overall is shown in Figure 8. The methane emissions throughout the full cycle of LNG production for the existing pathways, as described above, range from 2.7 to 5.4 percent of the total natural gas delivered to the vessel as fuel. Five of the pathways exhibit emissions greater than 4 percent of the total volume supplied. However, best practices in reducing direct methane emissions for all the pathways would bring each below 2 percent and several below 1 percent. Figure 8 makes clear that the overall methane emission rate is a critical determinant in delivering low-GHG LNG fuel. With improved control practices for methane emissions, all of the LNG pathways exhibit more substantial differences between their own GHG intensity (at 78 gCO_2e/MJ or lower) and those of conventional marine fuels (at 87–89 gCO_2e/MJ).

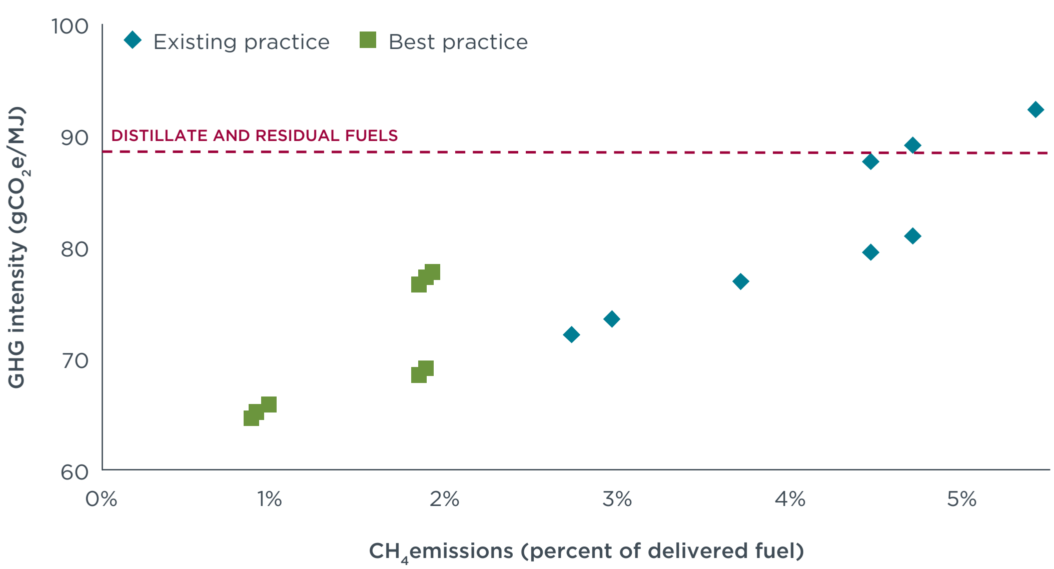

Figure 8: Fuel cycle natural gas emissions and GHG intensity for eight LNG marine bunkering pathways, existing and best practices.

CHAPTER 4: IMPLICATIONS AND RECOMMENDATIONS

This report evaluates the methane (CH_4), carbon dioxide (CO_2), and total greenhouse gas (GHG) emissions resulting from the use of liquefied natural gas (LNG) as a marine fuel. Energy use and emissions are evaluated over the entire "well-to-water" supply chain, from recovery and processing of natural gas through vessel bunkering to use of the fuel in natural gas engines for ship propulsion. A range of results is presented, based on eight different potential bunkering pathways.

These bunkering pathways vary based on the source of the natural gas imported or domestic), the type of LNG production facility (existing or new liquefaction plants), and the location and method of vessel bunkering (at an import terminal, LNG production site, or remote locations). For remote bunkering, the analysis presented here also investigates differences between locations with on-site storage, at which fueling would be via a fixed pipeline from a land-side LNG storage tank to the vessel, and those without on-site storage, where direct truck-to-ship or barge-to-ship fueling would be used. These pathways represent the range of plausible methods for supplying marine vessels with LNG fuel. Not every pathway would be practical at every port location, but at least one pathway could work for most vessels over the long term. At specific ports some pathways might be practicable without major new investments, while others would require installation of new infrastructure for LNG storage and handling.

The analysis indicates that total GHG emissions from the use of LNG as a marine fuel, expressed as grams of carbon dioxide-equivalent per million megajoules (gCO_2e/MJ) of LNG fuel delivered vary by 30 percent depending on the bunkering pathway, ranging from a low of 72 gCO_2e/MJ to a high of 92 gCO_2e/MJ. The pathway with the highest emissions involves the use of LNG produced in existing facilities and delivered via heavy-duty vehicle tanker to remote bunkering sites with on-site storage. The pathway with the lowest emissions uses imported LNG that is directly transferred to a vessel at an import terminal.

Variability in total GHG emissions among the different bunkering pathways springs from two primary sources: (1) lower upstream emissions during recovery and processing for imported LNG compared to domestically produced gas; and (2) higher methane emissions from bunkering operations. Direct fueling of marine vessels at an LNG import terminal or production plant offers the lowest potential for fugitive and vented methane emissions because these facilities typically have boil-off-gas handling systems that can collect methane vapors created during vessel fueling. On the other hand, remote marine bunkering sites—particularly those with on-site LNG storage—will likely have much higher methane emissions because they are unlikely to be equipped with effective vapor recapture controls. It must be emphasized that these results are driven by U.S.-specific data on imported and domestic natural gas sources.

In the short term, marine vessels will likely be fueled by some combination of imported LNG and LNG produced from domestic natural gas sources. This is the case in the United States as well as in many other places around the world. The choice will depend on economic considerations and existing supply infrastructure in the vicinity of the vessel home port. In the long term, shipping may move toward greater use of locally produced LNG as the markets develop.

It is likely that practical opportunities for direct vessel fuel transfers at LNG import or production facilities will remain limited; most marine vessels will use remote bunkering, both in the short and long term. Small vessels may be able to use direct truck-to-ship fueling, but, in the short term, larger vessels will likely require on-site LNG storage at their home port location, which will increase methane emissions during fueling operations. In the longer term, the development of infrastructure for direct barge-to-ship fueling of larger vessels will reduce the opportunity for methane emissions from bunkering operations at remote locations.

The analysis indicates that application of best practices for methane control throughout the LNG supply chain has the potential to cut total GHG emissions by 10–16 percent from existing practices for the eight LNG pathways. By following these model practices, the eight LNG pathways would yield a 12–27 percent GHG reduction for marine LNG fuel as compared with conventional fuels. To achieve these levels of reduction, best practices would have to be observed in three main areas: (1) recovery and processing of natural gas upstream, primarily controlling methane released during well completions and during liquids unloading activities at developed wells; (2) bunkering procedures, specifically controlling or flaring methane vapors at remote marine bunkering sites; and (3) onboard vessel operations, utilizing improved engine design and controls and possibly installing exhaust emission controls to oxidize methane normally emitted through the exhaust stack of natural gas engines. These improved practices represent the larger means, based on available data, for realizing significant climate benefits. In addition, there are many more smaller opportunities for reduced methane emissions related to improved pneumatic valves, better detection-and-repair programs, tighter seals for compressor leaks in pipeline systems, and emission controls for gas-powered compressor engines.

Reduced methane emissions will mean greater GHG benefits for LNG-powered ships. Existing practices in treating liquefied natural gas manifest a wide range of GHG impacts, from a 5 percent emission increase to an 18 percent decline as compared with conventional distillate and residual fuels for ships. Fundamentally, this is a result of differences in methane leakage throughout the fuel cycle and the degree to which exhaust emissions are controlled. Moving from existing practices to best practices would effectively cut overall fuel cycle methane emissions from the currently estimated 3–5 percent as a percentage of the total delivered LNG down to 1–2 percent.

The research conducted for this study demonstrates that, in addition to LNG being a promising environmental solution to various air pollution problems for ships, its desirability would be enhanced by a number of improvements to diminish its direct methane emissions. Policymakers and fuel providers ought to pursue those LNG pathways that are the least emission intensive and implement best practices to limit natural gas leakage. This study suggests that policymakers could provide guidance, or consider new regulatory policy, for fuel providers to improve upstream practices in the interest of greater climate benefits from the use of natural gas in the transportation sector. In addition, ship manufacturers, engine manufacturers, and fuel providers could strive to improve practices within their control and document these improvements with transparent data collection and reporting.

The findings suggest that more modest CO_2-equivalent emission benefits, perhaps in a range of 5–10 percent, generally should be used to gauge the benefits of LNG use by ships rather than higher values that tend to underplay or ignore some of the upstream emission and energy impacts. If and when detailed pathway-specific, location-specific data become available, more precise analyses should be pursued for greater accuracy. If best practices to reduce methane leakage are more widely embraced, greater GHG benefits will be realized, and the climate benefits are likely to be higher than those suggested by current methods of extraction, processing, transport, storage, and combustion. Researchers should be encouraged to continue studying developments in this area to ensure that the purported LNG benefits are in line with the best available data on life cycle emissions estimates.

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APPENDIX

This Appendix has two components: (1) Data documentation for the analytical assumptions for each LNG fuel cycle pathway; and (2) Presentation of sensitivity analysis for the variation in fuel cycle assumptions on the GHG intensity of LNG as a marine fuel.

DATA DOCUMENTATION FOR LNG FUEL PATHWAYS

Table A1. Process data for Pathway 1

PATHWAY 1: IMPORTED LNG – BUNKER AT IMPORT TERMINAL								
PROCESS	Major Leakage Assumptions			GHG from Energy use [g CO_2e/ mmBtu]	NG Leakage		GHG Emissions	
		Current	Best Practice		Current [g/mmBtu]	Best Practice [g/mmBtu]	Current [g CO_2e/mmBtu]	Best Practice [g CO_2e/mmBtu]
Non-US NG Recovery	Liquid Unloading				5.2		130.5	
	Other Point Source Emissions (Extract)				0.5		11.5	
	Well Completion				0.0		0.3	
	Workovers				0.0		0.0	
	Valve Fugitive Emissions (Extract)				0.0		0.9	
	Other Fugitive Emissions (Extract)				4.5		112.4	
	Offshore Crew Transport				0.0		0.2	
	Well Construction				0.0		0.2	
	Total			**34.5**	**10.2**	**10.2**	**290.5**	**290.5**
Non-US NG Processing	Acid Gas Removal				19.0		474.3	
	Valve Fugitive Emissions (Process)				0.1		2.8	
	Dehydration				0.0		0.0	
	Other Fugitive Emissions (Process)				14.7		367.3	
	Centrifugal Compressor Operation				0.2		4.1	
	Dehydration				0.0		0.0	
	Gas Centrifugal Compression				0.1		3.4	
	Other Point Source Emissions (Process)				0.2		4.0	
	Total			**2,399.3**	**34.2**	**34.2**	**3,255.3**	**3,255.3**
Non-US NG Liquefaction	NG Liquefaction, Storage, Loading			8,063.0	0.0		8,063.0	
	Liquefaction Const./ Instal./Deinstal.			25.5	18.7		493.5	
	Total			**8,088.4**	**18.7**	**18.7**	**8,556.4**	**8,556.4**
LNG Carrier Loading	Vapor Displaced [% of LNG fill mass]	0.13%	Current practice is best practice – BOG handling system captures BOG	0.0	1.2	1.2	30.2	30.2
	Recovery rate [%]:	95%						
LNG Carrier Transport	Boil-off rate [%/day]:	0.15%	Current practice is best practice – BOG used for vessel propulsion	1,561.0	0.0	0.0	1,561.0	1,561.0
	Duration [day]:	20						
	Recovery Rate [%]:	100%						
LNG Receiving at Import Terminal	Vapor Displaced [% of LNG fill mass]	0.13%	Current practice is best practice – BOG handling system captures vapors	0.0	1.2	1.2	30.2	30.2
	Recovery rate [%]:	95%						
LNG Storage at ImportTerminal	Boil-off rate [%/day]:	0.05%	Current practice is best practice – BOG handling system captures BOG	0.0	2.3	2.3	58.0	58.0
	Duration [day]:	5						
	Recovery Rate [%]:	95%						
LNG Vessel Fueling	Vapor Displaced [% of LNG fill mass]	0.22%	Current practice is best practice – BOG handling system captures vapors	0.0	2.0	2.0	51.1	51.1
	Recovery rate [%]:	95%						
LNG Vessel Boil Off	Boil-off rate [%/day]:	0.15%	Current practice is best practice – boil off used for vessel propulsion unless vessel is idle	0.0	2.2	2.2	55.7	55.7
	Duration [day]:	4						
	Recovery Rate [%]:	98%						
LNG Engine Emissions	Exhaust CH_4 Emissions [g/KWh]:	4.0	80% reduction using methane-targeted DOC	51,058.4	445.5	89.1	62,195.1	54,265.8
TOTAL				**63,141.7**	**517.7**	**161.3**	**76,083.5**	**68,154.1**

Table A2. Process data for Pathway 2

PATHWAY 2: IMPORTED LNG – DISTRIBUTED BUNKERING WITH STORAGE								
	Major Leakage Assumptions			GHG from Energy use [g CO_2e/ mmBtu]	NG Leakage		GHG Emissions	
PROCESS		Current	Best Practice		Current [g/mmBtu]	Best Practice [g/mmBtu]	Current [g CO_2e/mmBtu]	Best Practice [g CO_2e/mmBtu]
Non-US NG Recovery	Liquid Unloading				5.2		130.5	
	Other Point Source Emissions (Extract)				0.5		11.5	
	Well Completion				0.0		0.3	
	Workovers				0.0		0.0	
	Valve Fugitive Emissions (Extract)				0.0		0.9	
	Other Fugitive Emissions (Extract)				4.5		112.4	
	Offshore Crew Transport				0.0		0.2	
	Well Construction				0.0		0.2	
			Total	**34.5**	**10.2**	**10.2**	**290.5**	**290.5**
Non-US NG Processing	Acid Gas Removal				19.0		474.3	
	Valve Fugitive Emissions (Process)				0.1		2.8	
	Dehydration				0.0		0.0	
	Other Fugitive Emissions (Process)				14.7		367.3	
	Centrifugal Compressor Operation				0.2		4.1	
	Dehydration				0.0		0.0	
	Gas Centrifugal Compression				0.1		3.4	
	Other Point Source Emissions (Process)				0.2		4.0	
	Total			**2,399.3**	**34.2**	**34.2**	**3,255.3**	**3,255.3**
Non-US NG Liquefaction	NG Liquefaction, Storage, Loading			8,063.0	0.0		8,063.0	
	Liquefaction Const./Instal./Deinstal.			25.5	18.7		493.5	
			Total	**8,088.4**	**18.7**	**18.7**	**8,556.4**	**8,556.4**
LNG Carrier Loading	Vapor Displaced [% of LNG fill mass]	0.13%	Current practice is best practice – BOG handling system captures BOG	0.0	1.2	1.2	30.2	30.2
	Recovery rate [%]:	95%						
LNG Carrier Transport	Boil-off rate [%/day]:	0.15%	Current practice is best practice – BOG used for vessel propulsion	1,561.0	0.0	0.0	1,561.0	1,561.0
	Duration [day]:	20						
	Recovery Rate [%]:	100%						
LNG Receiving at Import Terminal	Vapor Displaced [% of LNG fill mass]	0.13%	Current practice is best practice – BOG handling system captures vapors	0.0	1.2	1.2	30.2	30.2
	Recovery rate [%]:	95%						
LNG Storage at Import Terminal	Boil-off rate [%/day]:	0.05%	Current practice is best practice – BOG handling system captures BOG	0.0	2.3	2.3	58.0	58.0
	Duration [day]:	5						
	Recovery Rate [%]:	95%						
LNG Truck Loading	Vapor Displaced [% of LNG fill mass]	0.74%	Current practice is best practice; BOG handing system at import terminal captures and re-uses displaced vapor	0.0	6.9	6.9	171.7	171.7
	Vapor Captured by BOG Handling	95%						
LNG Truck Transport*	Boil-off rate [%/day]:	0.25%	Current practice is best practice; use of 70 psi transport tanks allows retention of BOG on truck	0.0	0.0	0.0	0.0	0.0
	Duration [day]:	1						
	Retention Rate [%]:	100%						
LNG Truck Off-Loading**	LNG loss to hose purging [% of load]	0.03%	Current practice is best practice; there is no practical method to capture or flare gas from hose purging	0.0	5.6	5.6	0.0	0.0
	% vented	100%						
LNG Tank Filling at Bunker Site	Vapor Displaced [% of LNG fill mass]	0.13%	Best practice assumed to be flaring, with efficiency of 95%	0.0	24.1	1.2	603.4	93.2
	Vapor Vented	100%						
LNG Storage at Bunker Site	Boil-off rate [%/day]:	0.15%	Best practive assumed to be flaring with efficiency of 95%	0.0	111.4	5.6	2,785.0	430.3
	Duration [day]:	4						
	Recovery Rate [%]:	0%						
LNG Vessel Fueling	Vapor Displaced [% of LNG fill mass]	0.22%	Best practice assumed to be flaring, with efficiency of 95%	0.0	40.8	2.0	1,021.2	157.8
	Vapor Vented	100%						
LNG Vessel Boil Off	Boil-off rate [%/day]:	0.15%	Current practice is best practice – boil off used for vessel propulsion unless vessel is idle	0.0	2.2	2.2	55.7	55.7
	Duration [day]:	4						
	Recovery Rate [%]:	98%						
LNG Engine Emissions	Exhaust CH4 Emissions [g/KWh]:	4.0	80% reduction using methane-targeted DOC	51,058.4	445.5	89.1	62,195.1	54,265.8
TOTAL				**0.0**	**704.5**	**180.5**	**0.0**	**0.0**

* GHG from truck energy use assumes: 5 MPG and 100 mile trip and 7,000 gal tanker
** GHG from energy use assumes truck idle fuel use of 1 gal/hr and 2 hour off-load time

Table A3. Process data for Pathway 3

PATHWAY 3: IMPORTED LNG – DISTRIBUTED BUNKERING WITHOUT STORAGE								
	Major Leakage Assumptions			GHG from Energy use	NG Leakage		GHG Emissions	
PROCESS		Current	Best Practice	[g CO_2e/mmBtu]	Current [g/mmBtu]	Best Practice [g/mmBtu]	Current [g CO_2e/mmBtu]	Best Practice [g CO_2e/mmBtu]
Non-US NG Recovery	Liquid Unloading				5.2		130.5	
	Other Point Source Emissions (Extract)				0.5		11.5	
	Well Completion				0.0		0.3	
	Workovers				0.0		0.0	
	Valve Fugitive Emissions (Extract)				0.0		0.9	
	Other Fugitive Emissions (Extract)				4.5		112.4	
	Offshore Crew Transport				0.0		0.2	
	Well Construction				0.0		0.2	
			Total	**34.5**	**10.2**	**10.2**	**290.5**	**290.5**
Non-US NG Processing	Acid Gas Removal				19.0		474.3	
	Valve Fugitive Emissions (Process)				0.1		2.8	
	Dehydration				0.0		0.0	
	Other Fugitive Emissions (Process)				14.7		367.3	
	Centrifugal Compressor Operation				0.2		4.1	
	Dehydration				0.0		0.0	
	Gas Centrifugal Compression				0.1		3.4	
	Other Point Source Emissions (Process)				0.2		4.0	
			Total	**2,399.3**	**34.2**	**34.2**	**3,255.3**	**3,255.3**
Non-US NG Liquefaction	NG Liquefaction, Storage, Loading			8,063.0	0.0		8,063.0	
	Liquefaction Const./Instal./ Deinstal.			25.5	18.7		493.5	
			Total	**8,088.4**	**18.7**	**18.7**	**8,556.4**	**8,556.4**
LNG Carrier Loading	Vapor Displaced [% of LNG fill mass]	0.13%	Current practice is best practice – BOG handling system captures BOG	0.0	1.2	1.2	30.2	30.2
	Recovery rate [%]:	95%						
LNG Carrier Transport	Boil-off rate [%/day]:	0.15%	Current practice is best practice – BOG used for vessel propulsion	1,561.0	0.0	0.0	1,561.0	1,561.0
	Duration [day]:	20						
	Recovery Rate [%]:	100%						
LNG Receiving at Import Terminal	Vapor Displaced [% of LNG fill mass]	0.13%	Current practice is best practice – BOG handling system captures vapors	0.0	1.2	1.2	30.2	30.2
	Recovery rate [%]:	95%						
LNG Storage at ImportTerminal	Boil-off rate [%/day]:	0.05%	Current practice is best practice – BOG handling system captures BOG	0.0	2.3	2.3	58.0	58.0
	Duration [day]:	5						
	Recovery Rate [%]:	95%						
LNG Truck Loading	Vapor Displaced [% of LNG fill mass]	0.68%	Current practice is best practice; BOG handing system at production site captures and re-uses displaced vapor	0.0	0.0	0.0	0.0	0.0
	Vapor Captured by BOG Handling	100%						
LNG Truck Transport*	Boil-off rate [%/day]:	0.25%	Current practice is best practice; use of 70 psi transport tanks allows retention of BOG on truck	336.6	0.0	0.0	336.6	336.6
	Duration [day]:	1						
	Retention Rate [%]:	100%						
LNG Truck Off-Loading**	LNG loss to hose purging [% of load]	0.03%	Current practice is best practice; there is no practical method to capture or flare gas from hose purging	33.7	5.6	5.6	172.9	172.9
	% vented	100%						
LNG Vessel Fueling	Vapor Displaced [% of LNG fill mass]	0.22%	Best practice assumed to be flaring, with efficiency of 95%	0.0	40.8	2.0	1,021.2	157.8
	Vapor Vented	100%						
LNG Vessel Boil Off	Boil-off rate [%/day]:	0.15%	Current practice is best practice – boil off used for vessel propulsion unless vessel is idle	0.0	2.2	2.2	55.7	55.7
	Duration [day]:	4						
	Recovery Rate [%]:	98%						
LNG Engine Emissions	Exhaust CH4 Emissions [g/KWh]:	4.0	80% reduction using methane-targeted DOC	51,058.4	445.5	89.1	62,195.1	54,265.8
TOTAL				**63,512.0**	**562.0**	**166.9**	**77,563.1**	**68,770.4**

* GHG from truck energy use assumes: 5 MPG and 100 mile trip and 7,000 gal tanker
** GHG from energy use assumes truck idle fuel use of 1 gal/hr and 2 hour off-load time

Table A4. Process data for Pathway 4

PATHWAY 4: EXISTING DOMESTIC LIQUEFACTION FACILITY – BUNKER AT PRODUCTION SITE								
	Major Leakage Assumptions			GHG from Energy use [g CO_2e/mmBtu]	NG Leakage		Total GHG Emissions	
PROCESS		Current	Best Practice		Current [g/mmBtu]	Best Practice [g/mmBtu]	Current [g CO_2e/mmBtu]	Best Practice [g CO_2e/mmBtu]
US NG Recovery (Onshore Gas)	Well Completion	51% Controlled	100% Controlled (95% Reduction)		0.4	0.0	10.2	1.0
	Liquid Unloading	51% Controlled	100% Controlled (70% Reduction)		191.6	111.5	4,789.3	2,787.2
	Workovers	51% Controlled	100% Controlled (95% Reduction)		0.0	0.0	0.8	0.1
	Valve Fugitive Emissions (Extract)	Uncontrolled	95% Reduction		42.3	2.1	1,058.3	52.9
	Other Point Source Emissions (Extract)	Uncontrolled	95% Reduction		0.8	0.0	19.1	1.0
	Other Fugitive Emissions (Extract)	Uncontrolled	95% Reduction		16.5	0.8	411.9	20.6
	Other Sources	Uncontrolled	95% Reduction		16.7	0.8	417.6	20.9
			Total	**880.8**	**251.8**	**115.3**	**7,176.1**	**3,764.4**
US NG Processing	Compressors				22.0	22.0	550.0	550.0
	Valve Fugitive Emissions (Process)	Uncontrolled	95% Reduction		0.1	0.0	2.4	0.1
	Other Point Source Emissions (Process)				0.1	0.1	3.5	3.5
	Other Fugitive Emissions (Process)	Uncontrolled	95% Reduction		12.7	0.6	317.7	15.9
	Dehydration	NA	NA		0.0	0.0	0.1	0.1
	Acid Gas Removal				16.4	16.4	410.3	410.3
			Total	**2,196.0**	**51.4**	**39.2**	**3,479.9**	**3,175.8**
US NG Transport (pipeline)	Pipeline Fugitive Emissions				96.8	96.8	2,420.9	2,420.9
	Pipeline Compressors				0.0	0.0	0.6	0.6
	Pipeline Construction				0.0	0.0	0.2	0.2
			Total	**497.0**	**96.9**	**96.9**	**2,918.8**	**2,918.8**
US NG Liquefaction		Assumes no CH_4 leakage in production	Current practice is best practice	16,655	0.0	0.0	16,655.0	16,655.0
LNG Storage at Production site	Boil-off rate [%/day]:	0.05%	Current practice is best practice	0.0	0.0	0.0	0.0	0.0
	Duration [day]:	5						
	Recovery Rate [%]:	100%						
LNG Vessel Fueling	Vapor Displaced [% of LNG fill mass]	0.22%	Current practice is best practice – BOG handling system captures vapors	0.0	0.0	0.0	0.0	0.0
	Recovery rate [%]:	100%						
LNG Vessel Boil Off	Boil-off rate [%/day]:	0.15%	Current practice is best practice – boil off used for vessel propulsion unless vessel is idle	0.0	2.2	2.2	55.7	55.7
	Duration [day]:	4						
	Recovery Rate [%]:	98%						
LNG Engine Emissions	Exhaust CH_4 Emissions [g/KWh]:	4.0	80% reduction using methane-targeted DOC	51,058.4	445.5	89.1	62,195.1	54,265.8
TOTAL				**71,287.2**	**847.7**	**342.7**	**92,480.6**	**80,835.4**

Table A5. Process data for Pathway 5

PATHWAY 5: EXISTING DOMESTIC LIQUEFACTION FACILITY – DISTRIBUTED BUNKERING WITH STORAGE								
PROCESS	**Major Leakage Assumptions**			**GHG from Energy use [g CO_2e/mmBtu]**	**NG Leakage**		**GHG Emissions**	
		Current	**Best Practice**		**Current [g/mmBtu]**	**Best Practice [g/mmBtu]**	**Current [g CO_2e/mmBtu]**	**Best Practice [g CO_2e/mmBtu]**
US NG Recovery (Onshore Gas)	Well Completion	51% Controlled	100% Controlled (95% Reduction)		0.4	0.0	10.2	1.0
	Liquid Unloading	51% Controlled	100% Controlled (70% Reduction)		191.6	111.5	4,789.3	2,787.2
	Workovers	51% Controlled	100% Controlled (95% Reduction)		0.0	0.0	0.8	0.1
	Valve Fugitive Emissions (Extract)	Uncontrolled	95% Reduction		42.3	2.1	1,058.3	52.9
	Other Point Source Emissions (Extract)	Uncontrolled	95% Reduction		0.8	0.0	19.1	1.0
	Other Fugitive Emissions (Extract)	Uncontrolled	95% Reduction		16.5	0.8	411.9	20.6
	Other Sources	Uncontrolled	95% Reduction		16.7	0.8	417.6	20.9
			Total	**880.8**	**251.8**	**115.3**	**7,176.1**	**3,764.4**
US NG Processing	Compressors				22.0	22.0	550.0	550.0
	Valve Fugitive Emissions (Process)	Uncontrolled	95% Reduction		0.1	0.0	2.4	0.1
	Other Point Source Emissions (Process)				0.1	0.1	3.5	3.5
	Other Fugitive Emissions (Process)	Uncontrolled	95% Reduction		12.7	0.6	317.7	15.9
	Dehydration	NA	NA		0.0	0.0	0.1	0.1
	Acid Gas Removal				16.4	16.4	410.3	410.3
			Total	**2,196.0**	**51.4**	**39.2**	**3,479.9**	**3,175.8**
US NG Transport (pipeline)	Pipeline Fugitive Emissions				96.8	96.8	2,420.9	2,420.9
	Pipeline Compressors				0.0	0.0	0.6	0.6
	Pipeline Construction				0.0	0.0	0.2	0.2
			Total	**497.0**	**96.9**	**96.9**	**2,918.8**	**2,918.8**
US NG Liquefaction		Assumes no CH_4 leakage in production	Current practice is best practice – no significant leak points	16,655.0	0.0	0.0	16,655.0	16,655.0
LNG Storage at Production site	Boil-off rate [%/day]:	0.05%	Current practice is best practice; BOG handling system captures and re-uses BOG	0.0	0.0	0.0	0.0	0.0
	Duration [day]:	5						
	Recovery Rate [%]:	100%						
LNG Truck Loading	Vapor Displaced [% of LNG fill mass]	0.74%	Current practice is best practice; BOG handing system at production site captures and re-uses displaced vapor	0.0	0.0	0.0	0.0	0.0
	Vapor Captured by BOG Handling	100%						
LNG Truck Transport*	Boil-off rate [%/day]:	0.25%	Current practice is best practice; use of 70 psi transport tanks allows retention of BOG on truck	336.6	0.0	0.0	336.6	336.6
	Duration [day]:	1						
	Retention Rate [%]:	100%						
LNG Truck Off-Loading**	LNG loss to hose purging [% of load]	0.03%	Current practice is best practice; there is no practical method to capture or flare gas from hose purging	33.7	5.6	5.6	172.9	172.9
	% vented	100%						
LNG Tank Filling at Bunker Site	Vapor Displaced [% of LNG fill mass]	0.13%	Best practice assumed to be flaring, with efficiency of 95%	0.0	24.1	1.2	603.4	93.2
	Vapor Vented	100%						
LNG Storage at Bunker Site	Boil-off rate [%/day]:	0.15%	Best practive assumed to be flaring with efficiency of 95%	0.0	111.4	5.6	2,785.0	430.3
	Duration [day]:	4						
	Recovery Rate [%]:	0%						
LNG Vessel Fueling	Vapor Displaced [% of LNG fill mass]	0.22%	Best practice assumed to be flaring, with efficiency of 95%	0.0	40.8	2.0	1,021.2	157.8
	Vapor Vented	100%						
LNG Vessel Boil Off	Boil-off rate [%/day]:	0.15%	Current practice is best practice – boil off used for vessel propulsion unless vessel is idle	0.0	2.2	2.2	55.7	55.7
	Duration [day]:	4						
	Recovery Rate [%]:	98%						
LNG Engine Emissions	Exhaust CH_4 Emissions [g/KWh]:	4.0	80% reduction using methane-targeted DOC	51,058.4	445.5	89.1	62,195.1	54,265.8
TOTAL				**71,657.6**	**1,029.7**	**357.1**	**97,399.7**	**82,026.3**

* GHG from truck energy use assumes: 5 MPG and 100 mile trip and 7,000 gal tanker
** GHG from energy use assumes truck idle fuel use of 1 gal/hr and 2 hour off-load time

Table A6. Process data for Pathway 6

PATHWAY 6: EXISTING DOMESTIC LIQUEFACTION FACILITY – DISTRIBUTED BUNKERING WITHOUT STORAGE								
	Major Leakage Assumptions			GHG from Energy use	NG Leakage		GHG Emissions	
PROCESS		**Current**	**Best Practice**	**[g CO_2e/mmBtu]**	**Current [g/mmBtu]**	**Best Practice [g/mmBtu]**	**Current [g CO_2e/mmBtu]**	**Best Practice [g CO_2e/mmBtu]**
US NG Recovery (Onshore Gas)	Well Completion	51% Controlled	100% Controlled (95% Reduction)		0.4	0.0	10.2	1.0
	Liquid Unloading	51% Controlled	100% Controlled (70% Reduction)		191.6	111.5	4,789.3	2,787.2
	Workovers	51% Controlled	100% Controlled (95% Reduction)		0.0	0.0	0.8	0.1
	Valve Fugitive Emissions (Extract)	Uncontrolled	95% Reduction		42.3	2.1	1,058.3	52.9
	Other Point Source Emissions (Extract)	Uncontrolled	95% Reduction		0.8	0.0	19.1	1.0
	Other Fugitive Emissions (Extract)	Uncontrolled	95% Reduction		16.5	0.8	411.9	20.6
	Other Sources	Uncontrolled	95% Reduction		16.7	0.8	417.6	20.9
			Total	**880.8**	**251.8**	**115.3**	**7,176.1**	**3,764.4**
US NG Processing	Compressors				22.0	22.0	550.0	550.0
	Valve Fugitive Emissions (Process)	Uncontrolled	95% Reduction		0.1	0.0	2.4	0.1
	Other Point Source Emissions (Process)				0.1	0.1	3.5	3.5
	Other Fugitive Emissions (Process)	Uncontrolled	95% Reduction		12.7	0.6	317.7	15.9
	Dehydration	NA	NA		0.0	0.0	0.1	0.1
	Acid Gas Removal				16.4	16.4	410.3	410.3
			Total	**2,196.0**	**51.4**	**39.2**	**3,479.9**	**3,175.8**
US NG Transport (pipeline)	Pipeline Fugitive Emissions				96.8	96.8	2,420.9	2,420.9
	Pipeline Compressors				0.0	0.0	0.6	0.6
	Pipeline Construction				0.0	0.0	0.2	0.2
			Total	**497.0**	**96.9**	**96.9**	**2,918.8**	**2,918.8**
US NG Liquefaction		Assumes no CH_4 leakage in production	Current practice is best practice – no significant leak points	16,655.0	0.0	0.0	16,655.0	16,655.0
LNG Storage at Production site	Boil-off rate [%/day]:	0.05%	Current practice is best practice; BOG handling system captures and re-uses BOG	0.0	0.0	0.0	0.0	0.0
	Duration [day]:	5						
	Recovery Rate [%]:	100%						
LNG Truck Loading	Vapor Displaced [% of LNG fill mass]	0.68%	Current practice is best practice; BOG handing system at production site captures and re-uses displaced vapor	0.0	0.0	0.0	0.0	0.0
	Vapor Captured by BOG Handling	100%						
LNG Truck Transport*	Boil-off rate [%/day]:	0.25%	Current practice is best practice; use of 70 psi transport tanks allows retention of BOG on truck	336.6	0.0	0.0	336.6	336.6
	Duration [day]:	1						
	Retention Rate [%]:	100%						
LNG Truck Off-Loading**	LNG loss to hose purging [% of load]	0.03%	Current practice is best practice; there is no practical method to capture or flare gas from hose purging	33.7	5.6	5.6	172.9	172.9
	% vented	100%						
LNG Vessel Fueling	Vapor Displaced [% of LNG fill mass]	0.22%	Best practice assumed to be flaring, with efficiency of 95%	0.0	40.8	2.0	1,021.2	157.8
	Vapor Vented	100%						
LNG Vessel Boil Off	Boil-off rate [%/day]:	0.15%	Current practice is best practice – boil off used for vessel propulsion unless vessel is idle	0.0	2.2	2.2	55.7	55.7
	Duration [day]:	4						
	Recovery Rate [%]:	98%						
LNG Engine Emissions	Exhaust CH_4 Emissions [g/KWh]:	4.0	80% reduction using methane-targeted DOC	51,058.4	445.5	89.1	62,195.1	54,265.8
TOTAL				**71,657.6**	**894.2**	**350.3**	**94,011.3**	**81,502.8**

* GHG from truck energy use assumes: 5 MPG and 100 mile trip and 7,000 gal tanker
** GHG from energy use assumes truck idle fuel use of 1 gal/hr and 2 hour off-load time

Table A7. Process data for Pathway 7

PATHWAY 7: NEW DOMESTIC LIQUEFACTION FACILITY – BUNKER AT PRODUCTION SITE								
	Major Leakage Assumptions				NG Leakage		Total GHG Emissions	
PROCESS		Current	Best Practice	GHG from Energy use [g CO_2e/mmBtu]	Current [g/mmBtu]	Best Practice [g/mmBtu]	Current [g CO_2e/mmBtu]	Best Practice [g CO_2e/mmBtu]
US NG Recovery (Onshore Gas)	Well Completion	51% Controlled	100% Controlled (95% Reduction)		0.4	0.0	10.2	1.0
	Liquid Unloading	51% Controlled	100% Controlled (70% Reduction)		191.6	111.5	4,789.3	2,787.2
	Workovers	51% Controlled	100% Controlled (95% Reduction)		0.0	0.0	0.8	0.1
	Valve Fugitive Emissions (Extract)	Uncontrolled	95% Reduction		42.3	2.1	1,058.3	52.9
	Other Point Source Emissions (Extract)	Uncontrolled	95% Reduction		0.8	0.0	19.1	1.0
	Other Fugitive Emissions (Extract)	Uncontrolled	95% Reduction		16.5	0.8	411.9	20.6
	Other Sources	Uncontrolled	95% Reduction		16.7	0.8	417.6	20.9
			Total	**880.8**	**251.8**	**115.3**	**7,176.1**	**3,764.4**
US NG Processing	Compressors				22.0	22.0	550.0	550.0
	Valve Fugitive Emissions (Process)	Uncontrolled	95% Reduction		0.1	0.0	2.4	0.1
	Other Point Source Emissions (Process)				0.1	0.1	3.5	3.5
	Other Fugitive Emissions (Process)	Uncontrolled	95% Reduction		12.7	0.6	317.7	15.9
	Dehydration	NA	NA		0.0	0.0	0.1	0.1
	Acid Gas Removal				16.4	16.4	410.3	410.3
			Total	**2,196.0**	**51.4**	**39.2**	**3,479.9**	**3,175.8**
US NG Transport (pipeline)	Pipeline Fugitive Emissions				96.8	96.8	2,420.9	2,420.9
	Pipeline Compressors				0.0	0.0	0.6	0.6
	Pipeline Construction				0.0	0.0	0.2	0.2
			Total	**497.0**	**96.9**	**96.9**	**2,918.8**	**2,918.8**
US NG Liquefaction		Assumes no CH_4 leakage in production	Current practice is best practice	8,063.0	0.0	0.0	8,063.0	8,063.0
LNG Storage at Production site	Boil-off rate [%/day]:	0.05%	Current practice is best practice	0.0	0.0	0.0	0.0	0.0
	Duration [day]:	5						
	Recovery Rate [%]:	100%						
LNG Vessel Fueling	Vapor Displaced [% of LNG fill mass]	0.22%	Current practice is best practice – BOG handling system captures vapors	0.0	0.0	0.0	0.0	0.0
	Recovery rate [%]:	100%						
LNG Vessel Boil Off	Boil-off rate [%/day]:	0.15%	Current practice is best practice – boil off used for vessel propulsion unless vessel is idle	0.0	2.2	2.2	55.7	55.7
	Duration [day]:	4						
	Recovery Rate [%]:	98%						
LNG Engine Emissions	Exhaust CH_4 Emissions [g/KWh]:	4.0	80% reduction using methane-targeted DOC	51,058.4	445.5	89.1	62,195.1	54,265.8
TOTAL				**62,695.2**	**847.7**	**342.7**	**83,888.6**	**72,243.4**

Table A8. Process data for Pathway 8

PATHWAY 8: NEW DOMESTIC LIQUEFACTION FACILITY – DISTRIBUTED BUNKERING WITHOUT STORAGE								
PROCESS	Major Leakage Assumptions			GHG from Energy use [g CO_2e/mmBtu]	NG Leakage		GHG Emissions	
		Current	Best Practice		Current [g/mmBtu]	Best Practice [g/mmBtu]	Current [g CO_2e/mmBtu]	Best Practice [g CO_2e/mmBtu]
US NG Recovery (Onshore Gas)	Well Completion	51% Controlled	100% Controlled (95% Reduction)		0.4	0.0	10.2	1.0
	Liquid Unloading	51% Controlled	100% Controlled (70% Reduction)		191.6	111.5	4,789.3	2,787.2
	Workovers	51% Controlled	100% Controlled (95% Reduction)		0.0	0.0	0.8	0.1
	Valve Fugitive Emissions (Extract)	Uncontrolled	95% Reduction		42.3	2.1	1,058.3	52.9
	Other Point Source Emissions (Extract)	Uncontrolled	95% Reduction		0.8	0.0	19.1	1.0
	Other Fugitive Emissions (Extract)	Uncontrolled	95% Reduction		16.5	0.8	411.9	20.6
	Other Sources	Uncontrolled	95% Reduction		16.7	0.8	417.6	20.9
			Total	**880.8**	**251.8**	**115.3**	**7,176.1**	**3,764.4**
US NG Processing	Compressors				22.0	22.0	550.0	550.0
	Valve Fugitive Emissions (Process)	Uncontrolled	95% Reduction		0.1	0.0	2.4	0.1
	Other Point Source Emissions (Process)				0.1	0.1	3.5	3.5
	Other Fugitive Emissions (Process)	Uncontrolled	95% Reduction		12.7	0.6	317.7	15.9
	Dehydration	NA	NA		0.0	0.0	0.1	0.1
	Acid Gas Removal				16.4	16.4	410.3	410.3
			Total	**2,196.0**	**51.4**	**39.2**	**3,479.9**	**3,175.8**
US NG Transport (pipeline)	Pipeline Fugitive Emissions				96.8	96.8	2,420.9	2,420.9
	Pipeline Compressors				0.0	0.0	0.6	0.6
	Pipeline Construction				0.0	0.0	0.2	0.2
			Total	**497.0**	**96.9**	**96.9**	**2,918.8**	**2,918.8**
US NG Liquefaction		Assumes no CH_4 leakage in production	Current practice is best practice – no significant leak points	8,063.0	0.0	0.0	8,063.0	8,063.0
LNG Storage at Production site	Boil-off rate [%/day]:	0.05%	Current practice is best practice; BOG handling system captures and re-uses BOG	0.0	0.0	0.0	0.0	0.0
	Duration [day]:	5						
	Recovery Rate [%]:	100%						
LNG Truck Loading	Vapor Displaced [% of LNG fill mass]	0.68%	Current practice is best practice; BOG handing system at production site captures and re-uses displaced vapor	0.0	0.0	0.0	0.0	0.0
	Vapor Captured by BOG Handling	100%						
LNG Truck Transport*	Boil-off rate [%/day]:	0.25%	Current practice is best practice; use of 70 psi transport tanks allows retention of BOG on truck	336.6	0.0	0.0	336.6	336.6
	Duration [day]:	1						
	Retention Rate [%]:	100%						
LNG Truck Off-Loading**	LNG loss to hose purging [% of load]	0.03%	Current practice is best practice; there is no practical method to capture or flare gas from hose purging	33.7	5.6	5.6	172.9	172.9
	% vented	100%						
LNG Vessel Fueling	Vapor Displaced [% of LNG fill mass]	0.22%	Best practice assumed to be flaring, with efficiency of 95%	0.0	40.8	2.0	1,021.2	157.8
	Vapor Vented	100%						
LNG Vessel Boil Off	Boil-off rate [%/day]:	0.15%	Current practice is best practice – boil off used for vessel propulsion unless vessel is idle	0.0	2.2	2.2	55.7	55.7
	Duration [day]:	4						
	Recovery Rate [%]:	98%						
LNG Engine Emissions	Exhaust CH_4 Emissions [g/KWh]:	4.0	80% reduction using methane-targeted DOC	51,058.4	445.5	89.1	62,195.1	54,265.8
TOTAL				**63,065.5**	**894.2**	**350.3**	**85,419.3**	**72,910.7**

* GHG from truck energy use assumes: 5 MPG and 100 mile trip and 7,000 gal tanker
** GHG from energy use assumes truck idle fuel use of 1 gal/hr and 2 hour off-load time

SENSITIVITY ANALYSIS

Throughout this analysis, several fuel cycle processes and assumptions were found to have a degree of uncertainty. These variables, and their impact on overall GHG emission intensity for the eight LNG pathways, have been analyzed. A summary of this sensitivity analysis is given here.

Upstream natural gas leakage is an area that is receiving substantial research investigation. There is no scientific consensus as to whether average upstream natural gas leakage might be as low as 1 percent of total volume or as high as 4 percent throughout the supply chain. In addition, results from particular natural gas operations and processes show considerably lower or higher leak estimates. This analysis uses the best available data, showing upstream leak rates that are approximately 2 percent (but the pathway-specific analysis results in somewhat different leakage rates by pathway). For sensitivity analysis here, the upstream methane emissions are reduced by 50 percent in the low case and doubled in the high case. Note that these ranges are meant to encompass realistic averages for upstream processes but not to encompass all particular gas fields. Also as part of the upstream processes, the liquefaction of natural gas requires significant energy expenditure, assumed to be 10 percent of the delivered LNG energy output for new facilities and 20 percent for older facilities in the analysis base case. The sensitivity analysis includes a 20 percent increase and decrease from the base case energy requirements.

The analysis indicates that the direct ship exhaust CH_4 emission rate is a substantial contributor to the overall LNG emission profile. Methane emissions are not tightly controlled by regulatory standards for ships. These direct CH_4 emissions can be quite high but engine development is an field of concerted activity (as illustrated by Horgen 2012; Trent 2012; Czajkowski 2011), and there may be potential trade-offs between methane and other emissions. This report takes 8 grams per kilowatt-hour and 2g/kWh CH_4 emissions as the estimated high and low values, respectively.

Linked to the progress on LNG engine development is the issue of LNG's relative energy efficiency at the engine level. Technically, engine efficiency might be considered outside the scope of this assessment. However, examination of the full fuel cycle of LNG requires having it perform the same level of work in marine engines as conventional petroleum fuels. Regulatory agencies like the California Air Resources Board include known downstream vehicle efficiency differences to adjust fuel carbon intensities for regulatory purposes (using energy economy ratios to reflect the engine-level efficiency differences between the conventional and alternative fuel, for example) for full fuel cycle accounting. The base case ignores engine efficiency, effectively assuming no thermal efficiency difference for LNG. It is not clear to what extent there may be an LNG efficiency loss (see, e.g., Wärtsilä 2011; Rolls-Royce 2011; Germanischer Lloyd and MAN 2012). To reflect a possible energy efficiency loss in terms of propeller work per fuel energy output in an LNG engine, this analysis postulates a 5 percent efficiency penalty. This is equivalent to, say, a diesel marine engine with 40 percent thermal efficiency in operation, on average, versus a 38 percent thermal efficiency LNG engine.

Table A9 shows the overall GHG findings for this sensitivity analysis of primary assumptions. Figure A1 illustrates the same summary results graphically. The sensitivity results indicate that three variables appear to have the greatest impact in potentially increasing the GHG emissions from LNG as a marine fuel: (1) a less efficient LNG engine versus diesel; (2) higher CH_4 exhaust emissions, (3) higher average upstream methane leakage.

In the higher-emission scenarios for each of these variables, LNG as a marine fuel offers either a minimal GHG benefit or a significant setback compared with conventional marine petroleum fuels. Conversely, improvements in these variables, as compared with the base case, would result in significant GHG emission reductions.

Table A9. Summary of GHG intensity findings with varying assumptions on engine efficiency, exhaust emission, upstream gas leakage, and liquefaction efficiency

Scenario	GHG emissions (gCO_2e/MJ) by bunkering pathway								Description of changes from the base case
	1	2	3	4	5	6	7	8	
Engine efficiency -5%	78	86	85	103	111	111	105	110	LNG engine is 5% less efficient per engine output than diesel (and this is included as fuel cycle impact)
Engine CH_4 emission rate +100%	83	87	84	98	103	100	90	92	CH_4 exhaust emissions are increased by 100% (from 4 g/kWh to 8 g/kWh) for each pathway
Upstream CH_4 leakage +100%	74	79	75	97	102	99	89	90	Upstream CH_4 emissions are increased by 100% for each pathway
Liquefaction energy +20%	74	78	75	91	95	92	81	82	Liquefaction energy requirement is increased by 20% for each pathway
Base case	72	77	74	88	92	89	80	81	(See analysis)
Liquefaction energy -20%	71	75	72	85	89	86	78	79	Liquefaction energy requirement is reduced by 20% for each pathway
Upstream CH_4 leakage -50%	71	76	73	83	88	84	75	76	Upstream CH_4 emissions are reduced by 50% for each pathway
Engine CH_4 emission rate -50%	67	72	68	82	87	84	74	76	CH_4 exhaust emissions are reduced by 50% (from 4 g/kWh to 2 g/kWh) for each pathway
Best practice case	65	66	65	77	78	77	68	69	(See analysis)

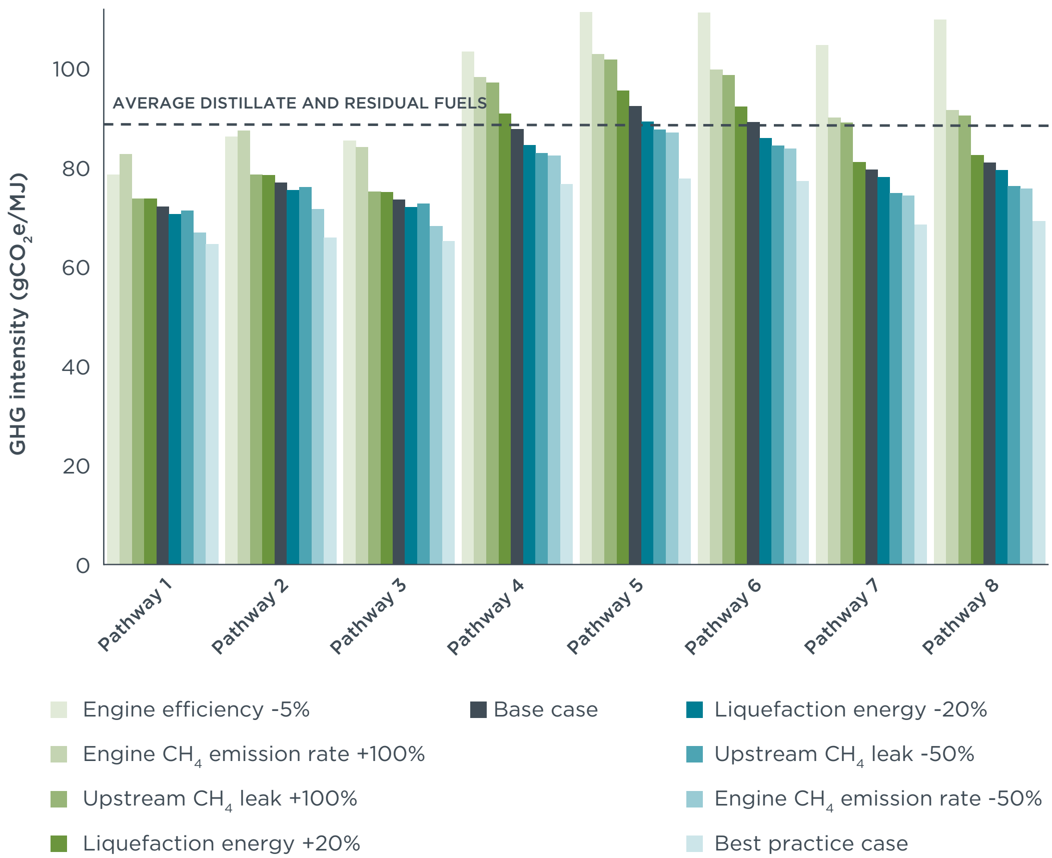

Figure A1. GHG intensity of fuel pathways for base case, sensitivity cases, and best practices case