

# INVESTIGATING LIQUEFIED NATURAL GAS AS A MARINE FUEL FOR CANADA'S ARCTIC

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# Foreword

## Message from Clear Seas Centre for Responsible Marine Shipping

Amid a growing recognition of the impacts of commercial marine shipping traffic on climate change, the environment, and human health, the shipping industry is beginning to adopt cleaner and greener ways of operating. Many of the initiatives and measures taken have not yet been applied to the Arctic, but changing the ship's fuel to produce fewer pollutants and reduce global warming potential is a tactic that has been employed to some extent almost everywhere around the world. To provide evidence to support communities and ship operators in their decision-making, this report seeks to evaluate the role of liquefied natural gas (LNG) as a fuel for ships in the Canadian Arctic to reduce pollution and global warming.

This collaborative study, conducted by the Canadian Natural Gas Vehicle Alliance, Vard Marine, and Clear Seas Centre for Responsible Marine Shipping with matching funding from Transport Canada's Innovation Centre, investigated the feasibility, benefits, and risks of the use of LNG to replace some or all the diesel and [heavy fuel oil](#) (HFO) used for shipping and other needs – such as electricity – in the Canadian Arctic. LNG is a cost competitive option compared to distillate and diesel fuels and it has the potential to reduce greenhouse gas emissions by up to 25% and other air contaminants, such as sulphur oxides, particulate matter and black carbon, by 80% or more, depending on fuel source for lifecycle emissions and engine technology for amount of methane emissions.

In the Arctic region, a ban on HFO is coming into effect starting in 2024 to reduce the risk of oil spills and the amount of locally generated black carbon from ships. Recognizing the Arctic is experiencing the effects of climate change at a faster rate than the rest of the world, there is growing interest and investigation into alternative ship fuels that are being proposed as solutions to decarbonizing marine shipping. However, some alternative fuels – including hydrogen, ammonia, methane, methanol – are in the early stages of investigation and not yet viable for large-scale commercial marine shipping applications. With growing pressure to attain net-zero emissions from shipping, use of LNG as a ship fuel in the Arctic could form part of a pathway to renewable bio-LNG and finally to zero emissions synthetic methane electric-fuel to meet these objectives. This study did not assess or model renewable natural gas, which can reach or exceed net-zero emissions outcomes, because the supply is limited and the cost is high – but considering the cost per tonne of greenhouse gases, renewable natural gas may become a pathway to net-zero for some situations.

In addition to describing ship engine technology and the availability of LNG supply for different ship routes, this study also sought out a range of opinions and perspectives on the topic of LNG as a fuel in the Arctic from the Inuit homeland, government, industry, shipping, and environmental non-governmental organizations. The participants recognized the urgency of the conversation and the need for this study. Those who live in the Canadian Arctic and rely on its lands, waters, and wildlife for survival are especially aware of the impacts of a warming environment. In the short term, ice formation is more unpredictable; in the long term, a longer ice-free season is anticipated, which will open the Arctic to even more shipping traffic of different types of vessels with different patterns of movement. In this remote and fragile environment, where even one ship can have a significant impact on a community, more shipping traffic increases the risks of [fuel spills](#), [underwater noise](#) pollution, introduction of [invasive species](#), as well as [air pollution](#) and greenhouse gas emissions.

When stakeholders in international shipping meet to talk about issues like decarbonization and increased marine traffic, Indigenous Peoples need to be present at the table. In the Arctic, Inuit have thousands of years of habitation in the region. The importance of Indigenous perspectives is why Inuit

Circumpolar Council Canada applied for and received provisional consultative status at the International Maritime Organization. They are the first Indigenous organization to gain this standing and sought it due to their awareness of the threats from international shipping to their ways of life. The opportunities for shipping companies of economic expansion and increased ship traffic need to be balanced against the Inuit way of life, where human health and food sources depend on a healthy environment and freedom of movement.

The search for an optimal fuel is a key part of this conversation, and this study poses a central question: Is LNG a better option for the Arctic than petroleum-based distillate fuels like marine diesel oil (MDO) or ultra-low sulphur diesel (ULSD)? Any fuel presents risks to human health and the environment, but fuel is needed to get the goods communities need and connect Inuit to the rest of the world. In assessing the benefits and risks of LNG as a fuel for shipping and as part of the transition to a decarbonized shipping fleet, this study considers the health, climate and cost implications for communities, shipping companies, industry, and regulators.

As this study illustrates, LNG is already in use in Canada and in the Arctic region. With a careful approach to ongoing use, regulatory oversight and economic analysis, LNG use in the Arctic marine sector can provide the region with a number of benefits. Air pollutant and emissions reductions and local environmental benefits can be attained in conjunction with energy and economic opportunities for the region. Though not without risks, marine use of LNG is an option for Canadians to consider.

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# Overview

*Investigating Liquefied Natural Gas as a Marine Fuel for Canada's Arctic* is a condensed version of a report submitted to Transport Canada by Canadian Natural Gas Vehicle Alliance, VARD Marine, and Clear Seas: *Canadian Marine Liquefied Natural Gas (LNG) Supply Chain Project – Arctic*.

This report follows ones similar in scope carried out for the West Coast (phase 1) and the Great Lakes and East Coast (phase 2) published in 2014 and 2017, respectively. Although some aspects of the work from the previous phases were transferrable to this study, new work was required to update technological and regulatory changes made since the previous phases were undertaken and also for those aspects that were unique to the Arctic region, including economic modelling, environmental risks and benefits analysis, potential local supply of natural gas (such as Inuvialuit Energy Security Project), infrastructure requirements, implementation scenarios and related benefits to Canada's Arctic region.

This report, based on information available in 2021-2022, focuses on liquefied natural gas (LNG) as an alternative to heavy fuel oil (HFO), marine diesel oil (MDO), or ultra-low sulphur diesel (ULSD). While LNG offers immediate air pollutant and emissions reductions (the extent of the reduction is dependent on fuel source and ship engine technology), the use of this fuel is compatible with net-zero and negative greenhouse gas lifecycle emissions fuels such as renewable and synthetic natural gas, although this pathway to net-zero emissions was not part of this study on the use of LNG. These options are not yet viable but are expected to continue to develop in parallel with other alternative fuels.

LNG is only one of many options in the mix of future energy sources, which include renewable energy sources such as wind and solar power, biofuels from renewable sources, and also alternative – non-fossil – ship fuels that can be manufactured using renewable electricity from water and the gases found in the atmosphere, such as hydrogen, ammonia, methane, or methanol. Such alternative fuels are being proposed as the solution to decarbonizing marine shipping but are in the early stages of investigation and not yet viable for commercial marine shipping applications. As technology continues to advance and as national and international regulations continue to evolve to reduce climate warming emissions, the viability and availability of these alternative fuels and energy sources will likewise change.

## Key Findings

- › The technologies that support all aspects of using LNG as a marine fuel are well proven and, in general, no technological barriers exist preventing the use of LNG under Arctic conditions.
- › The main challenge with LNG bunkering in the Arctic is the absence of established berths. A lack of installed marine infrastructure will require new bunkering processes and procedures to be developed using either an LNG supply vessel or hose from a shore-based tank.
- › The variables with the most impact on the economic feasibility of LNG for a vessel include the price differential between MDO/ULSD/HFO and LNG, the capital costs for LNG systems, and the availability of LNG.
- › When comparing LNG to HFO at current prices, the lengthy payback period for switching to LNG makes it unappealing in most cases, particularly for vessel conversions. However, with the

impending HFO ban in the Arctic and the fuel choice being narrowed to MDO/ULSD or LNG, LNG becomes an attractive option with reasonable payback periods.

- › LNG's ability to reduce emissions has potential to drive the growth of LNG as a marine fuel in support of meeting current and pending environmental regulations. The environmental benefits can include reductions at some level in CO<sub>2</sub>, CO<sub>2</sub>-e, SO<sub>x</sub>, NO<sub>x</sub>, particulate matter, and black carbon emissions, depending on the engine technology and the LNG source.

### Implications for the Use of Liquefied Natural Gas as a Marine Fuel in Canada's Arctic

- 1 For LNG to be sufficiently available in the Arctic, new infrastructure is required, including liquefaction plants and delivery systems.
- 2 Accidental releases of LNG are undesirable, however, from an environmental standpoint, they are more benign than either HFO or diesel oil spills as any LNG spill will quickly dissipate with minimal immediate or lasting harm to the local environment.
- 3 It may be possible to develop an Arctic LNG supply chain at attractive prices in comparison with fuel oil alternatives. LNG pricing is sensitive to many factors and assumptions, with the level of utilization of capital-intensive assets being an important consideration.
- 4 Operating a supply chain for LNG-fuelled operations in the Canadian Arctic requires personnel with competencies in design, operation, maintenance, and safety management and response. While there are some unique challenges in the Canadian Arctic, there are no major barriers to building the necessary competencies for an Arctic LNG supply chain.
- 5 An effective regulatory framework for the design, build, and operation of vessels and onshore facilities is critical for the establishment of an Arctic marine LNG supply chain. There are some gaps and uncertainties in the current Canadian regulatory framework, particularly for vessels/barges that may be used for bunkering or local LNG distribution. The approvals process for small-scale shore-side LNG facilities is unclear.
- 6 Emissions analysis showed significant SO<sub>x</sub> and particulate matter reductions. CO<sub>2</sub> emissions were also reduced as was black carbon, a powerful short-lived climate forcer with particularly significant effect in the Arctic. However, emissions of methane, a powerful short-term greenhouse gas, increased. The change in 100-year global warming potential CO<sub>2</sub>-e emissions in the Canadian Arctic region from the implementation scenarios is heavily dependent on which engine technology is used, with limited or no benefit from using the highest methane emissions engines and up to 29% reduction from the best available technology.
- 7 The vessel types modelled showed a range of emissions reductions. In some cases, air quality improvements have to be weighed against significant increases in methane emissions that will eliminate the GHG emissions reductions from using lower-carbon LNG. While the well-to-wake (overall lifecycle) GHG emissions can be reduced with the use of LNG, care must be taken by policy makers and industry to apply appropriate regulations and equipment. The best available technology that has the lowest methane emissions modelled in this study is the high-pressure dual-fuel engine technology. But these engines are currently only available for larger ships, and this technology is more expensive and far less common. The less expensive but high-methane emissions low-pressure dual-fuel engines are far more common; however, their use is likely to face greater scrutiny as lifecycle methane emissions become factored into clean fuel standards and energy efficiency index calculations. Achieving the reduction in GHG emissions outlined in this report requires great care in selecting ship technologies and fuel sources, coupled with a commitment to operational practices that reduce methane slip. Efforts to improve engine

emissions performance are needed to provide shipowners with access to high-performing equipment and allow for policy requirements for higher standards and better performance on the pathway to zero emissions shipping.

# Glossary

|                    |   |
|--------------------|---|
| CCG                | Canadian Coast Guard  |
| CO <sub>2</sub>    | Carbon Dioxide  |
| CO <sub>2</sub> -e | Carbon Dioxide Equivalent   |
| CNGVA              | Canadian Natural Gas Vehicle Alliance   |
| DNV-GL             | Det Norske Veritas – Germanischer Lloyd   |
| GHG                | Greenhouse gas  |
| GJ/day             | Gigajoules per day  |
| HFO                | Heavy fuel oil  |
| ICCT               | International Council on Clean Transportation                                   |
| IGC                | International Gas Code  |
| IGF                | International Code of Safety for Ships using Gas Fuels                          |
| IMO                | International Maritime Organization   |
| ISO                | International Standards Association   |
| kW                 | Kilowatt  |
| LNG                | Liquefied natural gas   |
| m                  | Metre   |
| m <sup>3</sup>     | Cubic metre   |
| MARPOL             | International Convention for the Prevention of Pollution from Ships             |
| MDO                | Marine diesel oil   |
| MEIT               | Marine Emissions Inventory Tool   |
| MGO                | Marine Gas Oil  |
| MW                 | Megawatt  |
| NORDREG            | Northern Canada Vessel Traffic Services   |
| NO <sub>x</sub>    | Nitrogen oxides   |
| SGMF               | Society for Gas as a Marine Fuel  |
| SIGTTO             | Society of International Gas Tanker and Terminal Operators                      |
| SO <sub>x</sub>    | Sulphur oxides  |
| SOLAS              | International Convention for the Safety of Life at Sea                          |
| STCW               | International Convention on Standards of Training, Certification & Watchkeeping |
| STQ                | Société des traversiers du Québec   |
| TERMPOL            | Technical Review Process of Marine Terminal Systems and Transshipment Sites     |
| ULSD               | Ultra-low sulphur diesel  |
| VARD               | Vard Marine Inc.  |

# Introduction

This report, *Investigating Liquefied Natural Gas as a Marine Fuel for Canada's Arctic*, is the result of a multi-participant study into the feasibility of a natural gas marine fuel supply chain in the Arctic region of Canada. The project was coordinated by the Canadian Natural Gas Vehicle Alliance (CNGVA), VARD Marine, and Clear Seas Centre for Responsible Marine Shipping (Clear Seas), contracted by Transport Canada's Innovation Centre. This report is the continuation of similar work completed on the same subject dealing with Canada's West Coast and Great Lakes and East Coast marine regions.

Although some aspects of the work from the previous phases were transferrable to this study, new work was required to update technological and regulatory changes made since the previous phases were undertaken and also for those aspects that were unique to the Arctic region, including economic modelling, environmental risks and benefits analysis, infrastructure requirements, implementation scenarios and related benefits to Canada's Arctic region.

Natural gas has traditionally been used for power generation, space and water heating, as well as a process feedstock. Its use as a marine transportation fuel has been limited by a number of barriers, including its much lower energy density compared to that of liquid hydrocarbons, a challenge that can be addressed by storage of gas in its liquefied or compressed forms. Recent trends in international emission regulations, technology development and shipping economics make natural gas increasingly appealing in comparison to more traditional fuels, though not without its obstacles for storage, handling, and emissions.

The objective of this project has been to develop a comprehensive understanding of all issues relating to the introduction and use of natural gas as a marine fuel in the Arctic region of Canada. The main focus has been on liquefied natural gas (LNG); although compressed natural gas is used as a marine fuel in some areas, it was not considered for use in the Canadian Arctic at this time.

## Project Participants

The project successfully engaged a diverse set of stakeholders, covering all stages of a potential supply chain and the industry and government sectors which are most likely to be involved. Participants came from:

- > Fuel suppliers
- > Vessel operators
- > Vessel designers
- > Building and repair companies
- > Engine and equipment suppliers
- > Ports
- > Training organizations
- > Regulators and classification societies
- > Communities
- > Non-governmental organizations
- > Governments

Federal government involvement included participation, information and/or review from Transport Canada, Environment and Climate Change Canada and Natural Resources Canada. Participation by provincial/territorial governments included the Government of Nunavut and the Government of Northwest Territories.

### **Project Scope**

The work was undertaken as a set of tasks, with task team membership drawn from the project participants, addressing the following aspects of the use of natural gas as a marine fuel:

1. Technological readiness for the use of natural gas as a marine fuel.
2. Economic aspects associated with natural gas fuel for a range of vessel types operating in the Arctic region of Canada.
3. Environmental risks and benefits of adopting natural gas in various sectors of the shipping fleet.
4. Infrastructure options for marine natural gas refuelling with reference to pipelines, liquefaction, distribution hubs, local transportation and storage, and other significant marine-related components.
5. Human resource and training challenges for the installation, operation, and maintenance of natural gas vessels and refuelling systems.
6. Regulatory challenges to the introduction of natural gas at the federal, provincial, municipal, and community levels, and formulating policies and procedures to address these challenges.
7. Implementation scenarios for the introduction of natural gas-powered vessels, including quantification of changes in emissions.
8. The potential benefits to the Arctic and to Canada of adopting natural gas as a marine fuel.



## 1.1 Introduction

Many technologies are required for any future liquefied natural gas (LNG) supply chain for Canada's Arctic region. Some are mature technologies while others require further research and development to enhance performance, reduce emissions or reduce costs.

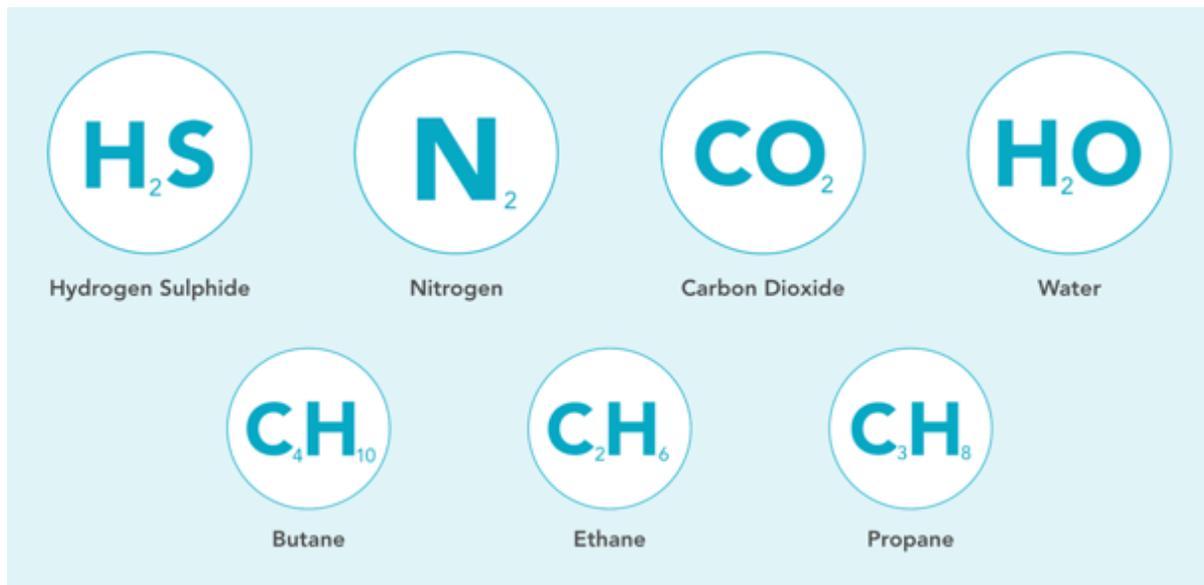
This section addresses the following topics:

- › Characteristics of natural gas
- › LNG safety
- › Gas liquefaction and bulk storage systems
- › LNG distribution and bunkering systems
- › Onboard storage and distribution for LNG fuel
- › Engine technologies for natural gas and their integration into propulsion systems
- › Safety technologies that enable LNG to be used as fuel
- › Technical standards that can be applied to equipment using LNG

## 1.2 Characteristics of Natural Gas

The term "natural gas" describes a wide range of gaseous mixtures of hydrocarbons and associated compounds. Mostly methane, natural gas also normally includes smaller amounts of other heavier

hydrocarbons. Nitrogen, oxygen, carbon dioxide (CO<sub>2</sub>), hydrogen sulphide, water, and a variety of trace compounds are also often found in natural gas.



**Figure 1: Compounds and elements found in natural gas**

The percentages of these various components depend on where the natural gas is produced and most are removed before the gas leaves its region of origin. Nevertheless, engine suppliers build in tolerances for gas fuel quality.

### Characteristics of LNG

To hold enough energy to be used as a marine transportation fuel, natural gas must be densified by lowering its temperature to -161°C to create a liquid (called liquefaction). The volume is reduced by about 600 times, which means that LNG has roughly six hundred times greater energy density compared to natural gas. To maintain its cold liquid state, LNG is stored in insulated vessels. LNG is odourless, colorless, non-corrosive, and non-toxic.

Compressed natural gas (CNG) has also been used as fuel for transportation however it is not considered at this time for Arctic transportation.

### LNG as a Marine Fuel

For several decades, LNG has been used globally as a marine fuel on a very limited basis. In most cases, the users have been bulk LNG carriers using boil-off gas (LNG in storage tanks that has warmed into a gas) to supplement onboard fuel. Approximately 600 gas carriers partially operate on natural gas in this way.

More recently, there has been a considerable surge in vessels adopting LNG as their main fuel, with an estimated 10%-20% of the new ships being ordered as LNG fuelled. This trend is driven by both economic reasons (LNG is a lower cost fuel) and a global tightening of emission standards for commercial shipping (LNG has significantly lower levels of air pollutants). Early adopting sectors such as ferries and off-shore supply vessels have been joined by container ships, tankers, cruise ships, bulk carriers, vehicle carriers, and others. International shipping classification society DNV-GL forecasts that LNG will account for 41% of the global marine fuel portfolio by 2050.

North America has an increasing number of LNG-fuelled vessels in operation with more projects at various stages of implementation. In Canada:

- › Société des traversiers du Québec (STQ) has three LNG-fuelled ferries in service
- › B.C. Ferries has three new LNG-fuelled vessels and has retrofitted its two largest vessels to LNG fuel
- › Groupe Desgagnés has a fleet of six LNG-fuelled vessels in Quebec including asphalt carriers and product tankers
- › Seaspans Ferries in B.C. has two LNG-fuelled vessels in service and two more under construction
- › Major cruise lines (e.g., Carnival) are building LNG-fuelled cruise ships, some of which may call at Canadian ports

This growth in LNG fleet numbers and vessel size has created a need for ship fuelling (bunker) vessels that can efficiently supply large volumes of LNG to ships during port calls.

### 1.3 LNG Safety

The LNG carrier industry has a strong safety track record. In over 60 years of operating, there have been no LNG-related fatalities onboard carriers. This safety record is attributed to several key factors (Foss, 2006) (International):

- › The industry is committed to understanding and managing the risks
- › The risks and hazards due to the chemical and physical properties of LNG are known and understood in LNG-related technology and operations
- › International standards and codes developed by regulators and also the LNG industry to provide a framework for safe LNG operations, including operational protocols, operator knowledge, training, and experience
- › Technological advances in the LNG industry

Industry continues to work collectively to develop and evolve best practices and standards, including tools to help assess the potential impacts of accidental releases of LNG. Many Canadian stakeholders participate in these efforts, including B.C. Ferries, Seaspans Ferries, the Vancouver Fraser Port Authority, FortisBC, Groupe Desgagnés, and others.

### 1.4 Liquefaction and Storage

The liquefaction process to reduce the volume and increase the energy density of natural gas by more than 600 times is both cost and energy intensive. For this reason, efforts are ongoing to increase efficiency of liquefaction processes and decrease plant complexity and cost.

There are two main types of LNG plants:

- › Large-scale facilities prepare LNG for shipment to overseas markets using LNG carriers. These facilities typically use “raw” gas directly from extraction and, as such, require pre-treatment to remove contaminants.

- › Mini, small and medium facilities serve a wider range of users including supplementing utilities during periods of peak demand (called peak-shaving plants) and fuelling various transportation modes. These facilities are located near to consumers and normally use pipeline gas.

Large plants require some components to be built on-site, often resulting in higher costs and longer schedules. By comparison, smaller plants are less costly to construct as they use standardized components that can be either delivered as complete units or as modules that can be assembled on-site.

Existing LNG facilities in Canada were mostly designed as peak-shaving plants. Outside of these, a few larger plants were constructed as import terminals for LNG from overseas. However, with a current oversupply of North American gas, some facilities have been re-purposed for export at the same time as new export terminals are being developed or proposed. Meanwhile, existing peak-shaving plants have been adapted to supply a broader range of end uses, and other smaller scale facilities have been built and planned.

### **Liquefaction Processes**

There are three main natural gas liquefaction processes: cascade, mixed refrigerant, and expansion. Cascade processes are more suited to large-scale facilities, expansion to small-scale facilities, while mixed refrigerant is suitable for all scales. Large-scale plants can achieve greater efficiency (lower energy use); however, this is at the cost of complexity and (generally) higher cost per unit of production. To serve export demand, the number and size of large-scale plants has increased since the 1970s. A large-scale LNG plant takes up many square kilometers of land and represents an investment of tens of billions of dollars.

In the case of smaller scale liquefaction plants, the range in sizes and technologies has likewise evolved over the years. This market continues to see considerable research and development efforts to bring compact plants closer to the efficiency of larger plants while retaining their lower cost advantage.

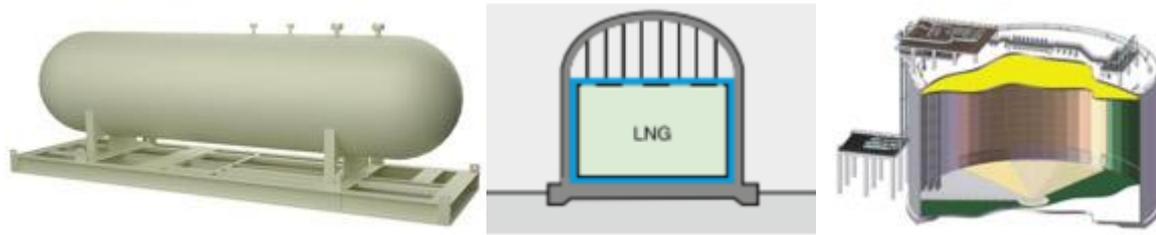
### **On-Shore Bulk Storage Systems**

Several types of tanks have been used for LNG storage depending on environmental considerations, cost, design and safety, and operation and maintenance.

Full containment tanks are most common for storing large quantities of LNG (7,500 m<sup>3</sup> to 160,000 m<sup>3</sup>). Single and double containment tanks can also be considered for some situations. In all cases, a primary container contains the liquid and vapour. Unlike the single or double containment tanks, the structurally independent secondary containment of the full containment tank is additionally liquid and vapour-tight, removing the need for a surrounding bund (wall) to capture spilled liquid or vapour.

Another type of full containment tank, the membrane tank, has increased in popularity since its inclusion in 2015 in the Canadian Standards Association Z276 Standard on LNG. The primary metal tank is a light structure, requiring a heavier secondary tank (prestressed concrete or metal) to surround and support it as well as provide secondary containment in the event of primary tank failure.

For smaller volumes of LNG, prefabricated bullet tanks are a cost-effective solution. These modular tanks have an inner shell made of cryogenic steel and an outer shell of cryogenic or non-cryogenic steel. To achieve the desired total capacity, multiple tanks can be grouped in tank 'farms'. For the smallest volume requirements, portable intermodal tanks of up to 40 m<sup>3</sup> each can be delivered and used as both storage and supply tanks.



**Figure 2: Examples of Bullet Tank, Full Containment Flat-Bottom Tank, Membrane Tank**

Larger Arctic communities could warrant the construction of flat-bottom tank LNG storage (a more expensive built-in-place option) if the primary community energy source was switched from diesel to LNG. Any additional ship fuelling demand at a coastal community could be serviced by such a facility. The volumes of gas required in smaller communities, for both local energy needs and ship bunkering, are unlikely to require flat-bottom storage tanks. Rather, delivered bullet tanks or intermodal tanks (single or multiple) are likely the most cost-effective solution. In all cases, the technologies are proven and available.

## 1.5 Distribution and Bunkering Systems

### Distribution

Making the best choice for an LNG distribution system depends on the volume of LNG needed and the location to be serviced. Today's common options include permanent shore-side facilities, tanker trucks, intermodal tanks, and bunkering vessels. For an Arctic LNG supply chain, where there are few roads and little rail infrastructure, the supply of fuel to most ports, communities, and other refuelling sites will require marine transportation.

Permanent shore-side LNG installations can supply ships and also potentially serve as an energy distribution hub for local communities. Typically, such facilities include at least two storage tanks and dedicated piping to transfer the LNG to a ship at berth.

Tanker trucks can serve the current low LNG demand from smaller coastal vessels or occasional larger vessels. Trucks can be used for distribution as well as directly for bunkering by installing the tank on board. If required for efficiency, multiple trucks can connect to a supply at the same time through a manifold system.

Containerized intermodal tanks can be transported via ship, rail, and road, and can act both as a distribution system and as an on-board storage system. The Canadian Coast Guard (CCG) has explored the feasibility of using containerized fuel systems on some of their existing and new vessels.

The use of bunkering vessels to deliver fuel to a ship has grown in recent years. In general, ports intending to become LNG bunkering hubs prefer the use of these vessels (self-propelled vessels and barges) to fuel customers. Bunkering vessel solutions may still involve a shore-side storage facility if LNG is being supplied from a remote source.

Most bunkering vessels are intended for local use around a major port, however, there are well-proven designs that could service any part of an Arctic LNG supply chain.

## Bunkering Systems

While the processes for loading and unloading LNG cargo are well established, the infrastructure and many requirements for safe bunkering of LNG-fuelled ships are still evolving. In part, this is due to the extremely low temperatures associated with handling LNG, raising issues and safety requirements that are very different than normal marine fuelling operations.

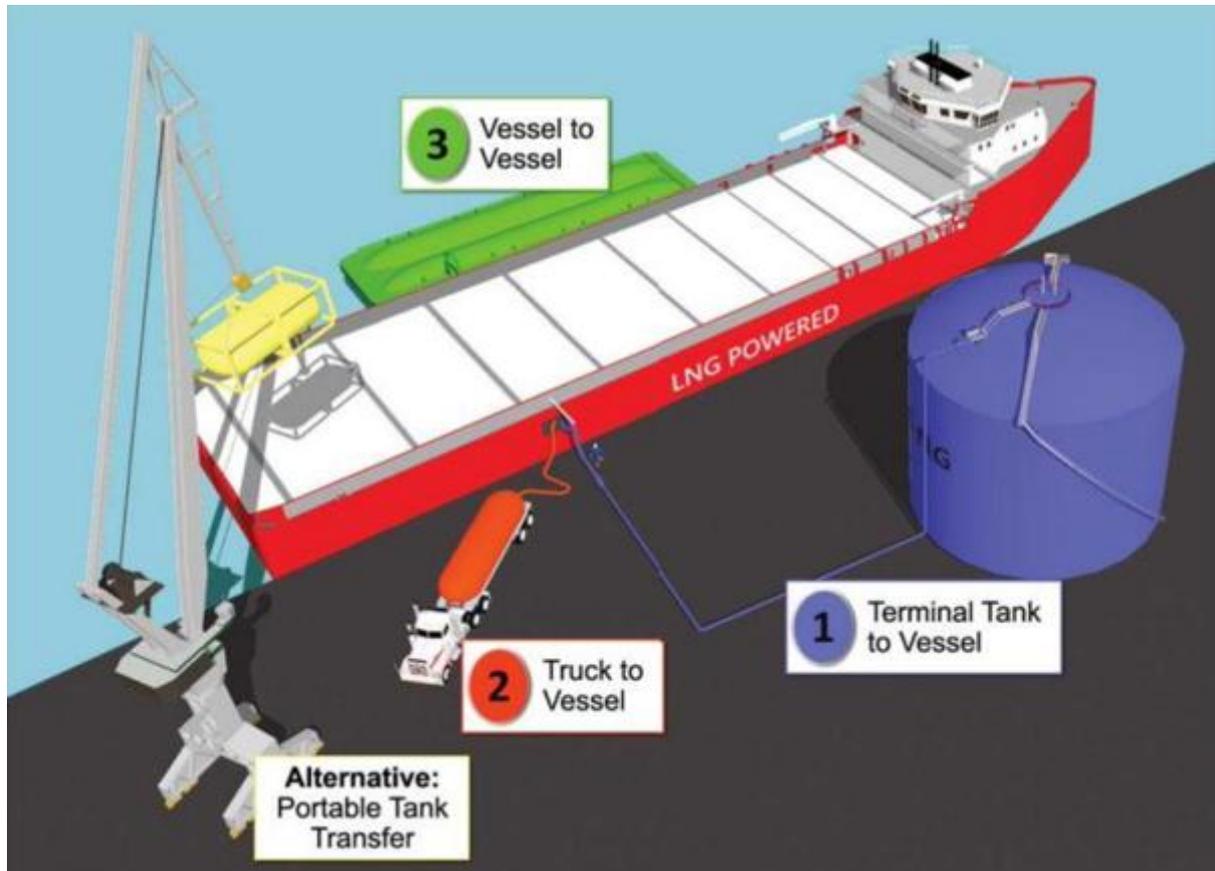


Figure 3: LNG Bunkering Options (ABS, 2015)

Examples of established LNG transfer procedures and practices include:

- › Control of operations
- › Safety (checklists for risk mitigation)
- › Communications
- › Maneuvering/mooring/connection
- › Procedures for ship-to-ship or ship-to-jetty transfers
- › Vapour management for safety and emissions control

A bunkering station on board a vessel must meet the requirements of the classification society and International Maritime Organization (IMO). While the specific requirements may vary between different regulatory bodies, all bunkering stations generally consist of the same main components and safety arrangements. An example is the requirement for quick connect/disconnect couplings to connect the supply hose to the ship's pipework with an emergency release system.

The source of LNG for transfer to the ship's tanks may be shore-side storage tanks, road (or rail) tanker, bunkering vessel or barge, or portable tank transfer. Choosing a suitable bunkering method depends on a vessel's LNG tank capacity, location, and frequency of bunkering. Each method calls for a mechanical system arrangement of valves, pipes, connectors, meters, and pumps and operation to move the LNG into place and make it available to the ship's engines.

In the absence of any shore-side storage of LNG, and until there is the capability to use portable LNG fuel tanks, ship-to-ship transfer is the remaining option for bunkering in the Arctic. It is conceivable that LNG supply chains from the Pacific or Atlantic coasts of Canada (or the United States) may provide bunkering vessels to service LNG-fuelled ships in the Arctic.

## 1.6 On-Board Storage and Distribution

Conventional ship fuel tanks are integral tanks enclosed by the ship's structure. In contrast, LNG tanks for use in gas-fuelled ships must be independent and contained in a tank room or on deck. Tank rooms must be arranged with fuel containment provisions and secondary barriers to reduce the risk of gas or liquid release from the tanks. Additionally, an LNG-fuelled vessel requires a fully redundant fuel supply system with at least two tanks.

There are three types of independent tanks – A, B, and C – with the main differences being that types A and B are non-pressurized (requiring full or partial secondary barriers) while type C tanks are pressurized. Other tank types include membrane tanks and lattice tanks. Membrane tanks are non-self-supporting prismatic tanks that are used by LNG carriers, while lattice tanks are box-shaped tanks with lattice type structures that increase the load a tank can accommodate.

LNG requires 70 per cent more volume than an oil-based fuel to contain the same amount of energy. As such, all LNG tank options require more space to provide the same voyage range and endurance. This can present a challenge for converting a vessel to LNG that was designed for a fuel oil.

All tank types are highly insulated; however, a gradual boil-off (vaporization) of the gas is inevitable as the fuel warms up over time. Most LNG-fuelled vessels use the pressurized Type C tank where boil-off gas can be held under pressure or released to be used as fuel for the engines or auxiliary systems.

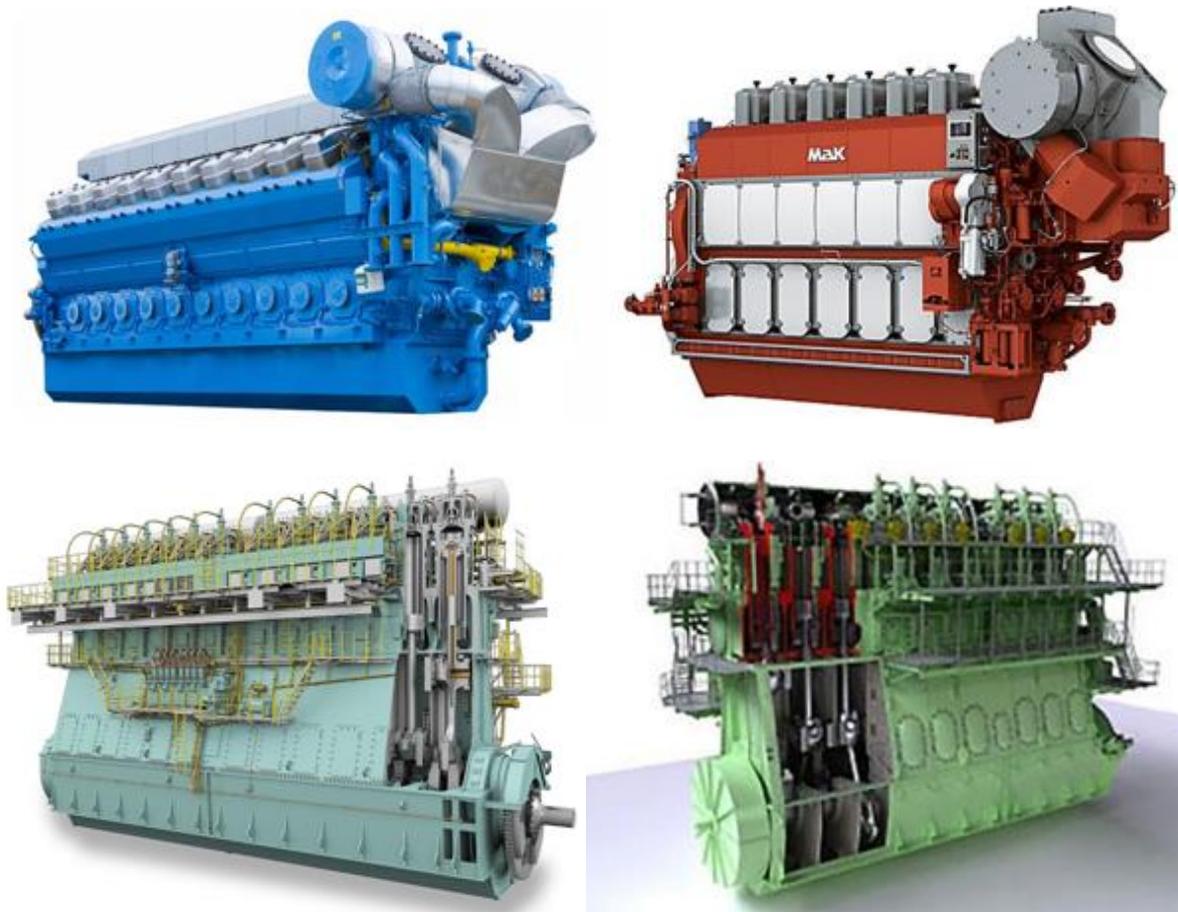
Ancillary equipment conditions the gas before it is supplied to an engine. Additional key elements complete the on-board fuel distribution system and depend on whether the system is a high- or low-pressure fuel system and whether it uses pumps or a pressure build-up unit to supply fuel to the engines.

Ventilation systems are important for the prevention of explosions in the event of a gas leak. Inlet and outlet locations, flow velocities, and equipment specifications are all important considerations when designing ventilation systems for hazardous zones.

The storage tank is one of the most expensive components of an on-board system. A recent improvement in Type C tanks has been the introduction of lighter, thinner insulation materials that reduce the space required between the double walls of the tank. There have also been improvements in the mechanical design with enhanced integration of the complete gas supply system and the control system.

## 1.7 Engine Technologies

Internal combustion (reciprocating) engines are the preferred type of engine for marine vessels, both new builds and for major conversions. These engines are broadly categorized as high speed, medium speed, and slow speed. Generally speaking, slow-speed engines are physically the largest and deliver the highest power outputs. Deep-sea vessels typically use highly efficient slow-speed engines that are well suited to continuous, steady speed applications. High-speed engines are the most compact and are capable of quick response to changes in power demand. Examples of these engines are shown in Figure 4 and further described in Table 1.



**Figure 4: (clockwise) Bergen B35:40 Spark Ignition Gas Engine; MaK Dual-Fuel Medium-Speed Engine; MAN 9-Cylinder High-Pressure Gas Slow-Speed Engine; WinGD 10 Cylinder Low-Pressure Gas 63MW Engine**

There are numerous higher horsepower engine options for larger types of vessels, using both pure gas and dual-fuel (natural gas plus diesel) options. An ignition source is required in all cases.

- › Spark ignition uses a pre-chamber similar to spark plugs in a gasoline automotive engine
- › Dual fuel first ignites a small quantity of pilot diesel fuel that then ignites the main gas fuel

Lean-burn spark ignition engines are pure gas medium-speed engines that operate on the Otto cycle. A low-pressure mixture of natural gas and air are introduced to the combustion chamber. The typical power output of this engine type is 1 to 9 megawatts.

Vessels with dual-fuel engines can operate solely on fuel oil if needed, allowing the operator flexibility of which fuel to use, based on price and availability. There are three dual-fuel configurations. One configuration (Otto cycle, medium speed) introduces a mixture of gas and air to the engine’s cylinder. This type of engine can generate 3 to 18 megawatts of power. The other two (slow speed) engines use direct injection to introduce gas directly to the cylinder. In one case, the diesel cycle is used together with high pressure gas. In the other, the Otto cycle is used with injected low-pressure gas. These direct injection engines can generate power in the range of 5 to 60 megawatts. Conversion of an existing diesel engine requires limited modification to the engine itself, so the direct injection diesel cycle engine offers a higher potential for retrofitting existing units. The most commonly used engine types are:

- › Low pressure Otto cycle engines – or the engines with the highest methane emissions
- › High pressure diesel cycle engines – or the engines with the lowest methane emissions

The different engine technologies are categorized in Table 1.

**Table 1: Natural Gas Engine Technologies**

| Factor               | Lean burn spark ignition pure gas engine (e.g., Bergen B35:40) | Dual fuel with diesel pilot (e.g., MaK Dual-Fuel Medium-Speed) | High pressure direct gas injection with diesel pilot (e.g., MAN 9-Cylinder) | Low pressure gas with diesel pilot (e.g., WinGD 10 Cylinder 63 MW) |
|----------------------|--|--|---|--|
| Thermodynamic cycle  | Otto (4-stroke cycle)  | Otto (4-stroke cycle)  | Diesel (2-stroke cycle)   | Otto (2-stroke cycle)  |
| Fuel introduction    | Low pressure gas pre-mixed in intake or port injection         | Low pressure gas/air pre-mixed in intake                       | High pressure gas direct in cylinder head                                   | Low pressure gas added to scavenge air in cylinder trunk           |
| Ignition source      | Spark plug pre-chamber   | Liquid fuel pilot  | Liquid fuel pilot   | Liquid fuel pilot  |
| Speed range          | Medium   | Medium   | Slow  | Slow   |
| Example power output | 1 – 9 MW   | 3 – 18 MW  | 5 – 60 MW   | 10 – 60 MW   |
| Example weight       | 17 – 99 t  | 40 – 300 t   | 400 – 2000 t  | 500 – 2000 t   |
| Methane slip         | High   | High   | Low   | Medium   |

The technology of LNG-fuelled engines is considered mature, but design refinement continues. For example, there are ongoing efforts to reduce the amount of pilot fuel required in dual-fuel engines. Likewise, there is continuous refinement to reduce methane slip from engines whereby unburned methane (a potent climate warming gas) is leaked to the atmosphere.

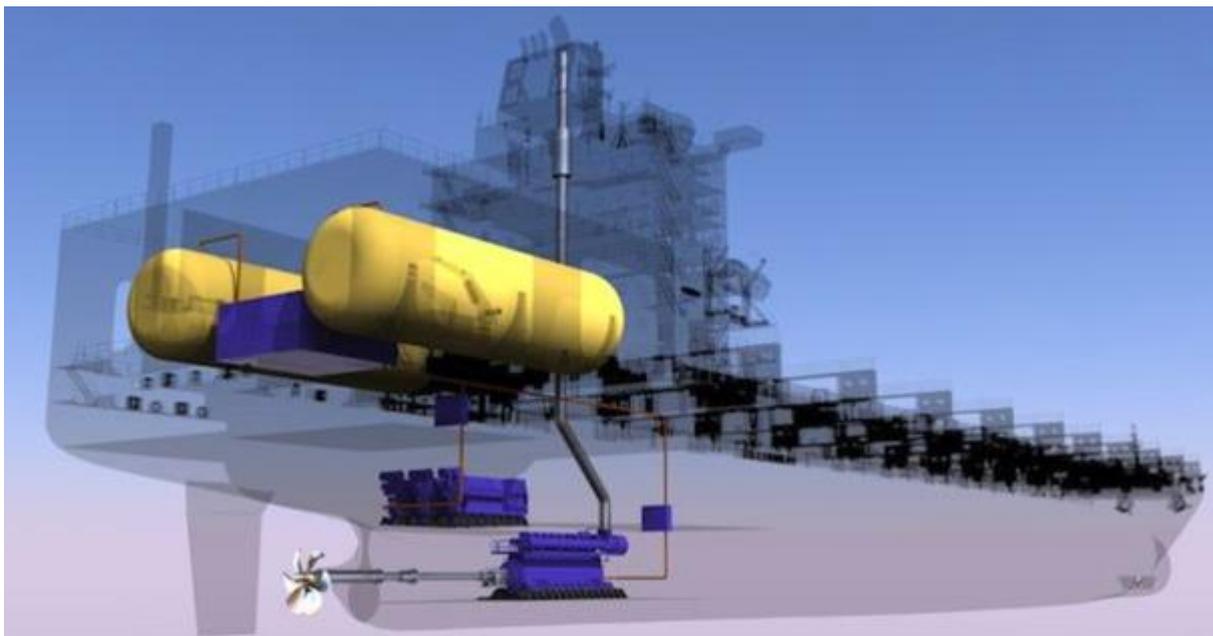
Additionally, slow-speed engine manufacturers offer conventional liquid fuel engines in LNG-ready versions to which dual-fuel components can be added later. Ship owners who are building ships with LNG-ready engines may choose to allow space for LNG gas storage and handling to allow addition of dual-fuel capability later.

## 1.8 Propulsion Systems

A ship engine transmits its power into the water through a propulsion train whose final element is the propulsor – typically a propeller. The performance of the propulsion system must meet a full range of voyage requirements including acceleration, cruise and maximum speed, deceleration, maneuvering, load fluctuations, and other types of variability.

The propulsion systems for LNG-fuelled vessels are more complex and incorporate supporting systems that are not typically found on liquid-fuelled vessels. Also, LNG-fuelled engines have different operating characteristics which need to be considered when designing propulsion systems and selecting machinery. However, the increasing number and variety of ships using LNG fuel demonstrate there are no insurmountable technological barriers when considering a propulsion system that uses natural gas.

Of the two major propulsion options for LNG engines, the first is direct drive. The engines drive the propeller shaft directly or through a gearbox, depending on the engine speed. Deep-sea vessels typically use highly efficient slow-speed engines that are well suited to continuous, steady speed applications, directly coupled to fixed-pitch propellers. Medium- and high-speed engines are more common in ships such as ferries and smaller vessels that experience more frequent demand changes. Such installations often use controllable pitch propellers that allow the engines to run in a relatively narrow speed range.



**Figure 5: Direct Drive LNG-Fuelled Propulsion System of *Isla Bella***

The second option is an electric drive system that consists of engine-powered generators connected to electric motors, which drive propellers, thrusters, or a combination of the two. These systems offer increased flexibility in optimizing engine load. They also permit greater design flexibility because the engines do not need to be mechanically connected to the propulsion equipment. The sophisticated power management systems that are required for electric propulsion are readily available for LNG vessels. Electric drive systems are well suited to ships with high energy needs outside of propulsion, in particular cruise ships and some warships.

Hybrid power systems are a relatively new technology in the marine industry. Using a combination of engine power and batteries, a hybrid system offers significant efficiency improvement by running the engines on optimal load and absorbing load fluctuations through batteries.

## 1.9 Safety Technologies

None of the technologies involved in LNG-fuelled vessels are inherently novel, and all have good track records in other applications. However, their application in LNG-fuelled ships is quite recent, and work on safety technologies is ongoing to address any risks associated with system installation and operation under normal and emergency conditions. Specific areas of interest are materials that withstand cryogenic temperatures, fire and explosion prevention, gas dispersion, and personnel protection. This far, LNG-fuelled vessels have placed great emphasis on safety in both design and operation, and their safety record is excellent.

The growth in the use of LNG in the marine industry has been accompanied by the development of a wide range of codes, regulations, standards, and guidelines that apply to the design and operation of systems throughout the supply chain. These regulatory instruments are now being applied to new projects in generally similar ways. Transport Canada has adopted most international codes by reference under the Canada Shipping Act, 2001, with supplementary requirements in certain areas including for gas-fuelled ships.

## 1.10 Conclusion

The growing interest in LNG as a cleaner fuel than conventional hydrocarbon fuels has encouraged the development of products and technologies over the last decade. Indeed, the technologies that support all aspects of using LNG as a marine fuel are well proven and, in general, no technological barriers exist preventing the use of LNG under Arctic conditions.

The cost of liquefaction is an area where recent technology developments are highly significant. For example, the emergence of small-scale liquefaction plants may address certain adoption barriers by reducing capital investment and offering the freedom to locate close to markets.

The bunkering aspect of the LNG supply chain has been a key focus and new distribution systems and technologies have addressed scaling and location issues. Under current demand, road tanker trucks are a convenient distribution option that can be combined with local storage. For larger volumes, many ports or port fuel suppliers are investing in bunker barges or ships. These LNG bunker vessels have the flexibility to provide service to ports and customers elsewhere on the coast. Safety issues around bunkering are being continuously explored and improved.

The main challenge with LNG bunkering in the Arctic is the absence of established berths. A lack of installed marine infrastructure will require new bunkering processes and procedures to be developed using either an LNG supply vessel or hose from a shore-based tank. On the plus side, all fuel system components are designed to cope with stringent demands and appropriate safety and personal protective equipment is available, as human factors also demand particular attention for Arctic winter operations.

The cost of on-board components for LNG is another barrier to adoption. While the costs of natural gas systems have decreased, most natural gas engines remain more expensive than traditional liquid-fuel equivalents. Another factor to consider is that of efficiency. Engine manufacturers are making progress in reducing methane slip and reducing the pilot fuel consumption in dual-fuel engines, but

any amount of methane slip begins to erode the benefits of using a fuel with lower greenhouse gas (GHG) emissions.

Ultimately, the technology is mature and the operation of LNG-fuelled ships in Canada's Arctic presents no significant challenges while offering benefits compared to conventionally fuelled ships such as lower cost of fuel and reduced air pollution contaminants



## 2.1 Introduction

To determine the potential economic benefits of using LNG as a marine fuel for the Arctic marine industry a modelling approach analyzed seven case studies of vessels operating within or visiting the Arctic.

The results indicate that economic feasibility depends on the following variables:

- › Price differences among heavy fuel oil (HFO), marine diesel oil (MDO), ultra-low sulphur diesel (ULSD) and LNG
- › Fuel consumption requirements or energy demand
- › Capital and operating costs for LNG supply and distribution systems

Availability of LNG is key factor of its cost. LNG is already a feasible option for some major trade routes where investments in LNG infrastructure have been made. Outside of these routes, new investment is required for reliable supply of LNG to ships. Additional investments in larger scale LNG infrastructure may increase the end-user price of LNG in the short term, however, economies of scale may occur as production capacity increases to meet demand.

Adoption of LNG also requires significant ship-side investment by vessel operators in that LNG engines and fuel storage systems are more expensive than for conventional fuels, and the use of LNG – with its larger storage tanks – may reduce cargo capacity. Operators also face training costs and other costs associated with modifying operating and emergency procedures to use natural gas vessels.

The results presented here are the product of data and assumptions provided by project participants. Actual economic benefits will depend on the in-service operating profile of a vessel, its engine performance, and the delivered cost of natural gas.

## 2.2 Analysis Approach

### Case Study Vessels

Not all vessel types are suited for LNG fuel. The extra volume needed for LNG storage and systems makes it difficult to adapt small, densely packed vessels and vessels with very long range and endurance requirements. Ultimately, the seven cases selected represent a cross-section of ships operating within the Canadian Arctic that realistically could use LNG fuel:

- › CCG icebreakers
- › Vessels that provide supplies to Arctic communities
- › Expedition cruise ships
- › LNG carriers
- › Vessels that provide supplies to and remove ore from mining sites

Large LNG carriers comprise a substantial part of the traffic on the Northern Sea Route to export LNG from megaprojects on the Yamal peninsula. The LNG carrier considered here is a much smaller vessel to bring LNG to the Arctic from southern ports or distribute small-scale Arctic-produced LNG to other Canadian Arctic locations.

A summary of the analyzed cases is provided in Table 2.

**Table 2: Summary of Case Study Vessels**

| No | Vessel             | Power (kW) | Newbuild / Conversion | LNG Engine Type                      |
|----|--------------------|------------|-----------------------|--------------------------------------|
| A1 | CCG Icebreaker     | 20,000     | Newbuild              | Medium-Speed Otto 4-Stroke Dual Fuel |
| A2 | General Cargo      | 6,000      | Newbuild              | Slow-Speed Diesel 2-Stroke Dual Fuel |
| A3 | Tanker             | 5,500      | Newbuild              | Slow-Speed Diesel 2-Stroke Dual Fuel |
| A4 | Cruise Ship        | 11,200     | Newbuild              | Medium-Speed Otto 4-Stroke Dual Fuel |
| A5 | LNG Carrier        | 4,000      | Newbuild              | Medium-Speed Otto 4-Stroke Dual Fuel |
| A6 | Icebreaking Bulker | 22,000     | Conversion            | Slow-Speed Diesel 2-Stroke Dual Fuel |
| A7 | Ice-going Bulker   | 14,500     | Conversion            | Slow-Speed Diesel 2-Stroke Dual Fuel |

Vessels for Arctic operations are specialized (strengthened for operating in ice conditions) and expensive to build and operate. They are also likely to remain in service for longer than open water vessels. While conversion to LNG is generally more expensive than including LNG capability in a newly built vessel, conversion may still be cost effective for high-value and specialized ships such as these. To date, there have been LNG conversions of various vessels ranging from B.C. Ferries to container ships and specialized tankers.

These case studies were analyzed to determine the capital costs required to implement LNG systems as well as the lifecycle costs for each of the vessels.

### **Model Methodology**

This study analyzed the ship-side capital investment and lifecycle operational cost by comparing three fuel options for each vessel – HFO, MDO, and LNG with MDO used as the pilot fuel.

The ship-side capital investment considered the propulsion power-related costs associated with engines, LNG tanks, LNG system equipment, and installation for newbuild and conversion. Overall vessel costs were not considered.

The lifecycle cost considered the ship type, route information, installed power, operational profile, energy costs, and crew training requirements. It is assumed that the power, route, and vessel life requirements remain constant regardless of the fuel bunkered.

The modelling entailed certain other assumptions and allowances, such as:

- › The fuel costs and required tank sizes are based on bunkering taking place primarily in major ports. The cost of LNG in the ports of Montreal and Rotterdam is used.
- › For newbuilds, LNG tanks are accommodated by increasing the vessel size or by integrating the LNG tanks into the vessel with no impact on cargo carrying capacity
- › Auxiliary engines for supplying the ship underway and while in port would also be dual-fuel engines or power would be drawn from the main engines
- › LNG-fuelled vessel maintenance costs are assumed to be the same as ULSD/MDO/HFO vessels
- › Additional crew training

The following aspects are not covered by the model:

- › Costs (lost revenue) associated with lost cargo capacity related to the increased space requirements of LNG storage systems
- › Taxes associated with fuel cost
- › Costs associated with engine maintenance
- › Costs associated with time the vessel is out of service during a conversion
- › Additional operating costs caused by limited options for LNG bunkering facilities
- › Project-specific variables

## **2.3 Analysis and Results**

### **Propulsion System Capital Costs**

The analysis of the propulsion system capital cost, illustrated in Figure 6, shows that in vessel cases A1 to A4 the capital costs are greater for an LNG propulsion system when compared to HFO/MDO/ULSD propulsion systems. The rest of the cases do not have this direct comparison as LNG fuel only applies

to A5 – LNG Carrier. A6 – Icebreaking (I/B) Bulker and A7 – Ice-going Bulker are conversion options where the same equipment is considered suitable for both HFO and MDO.

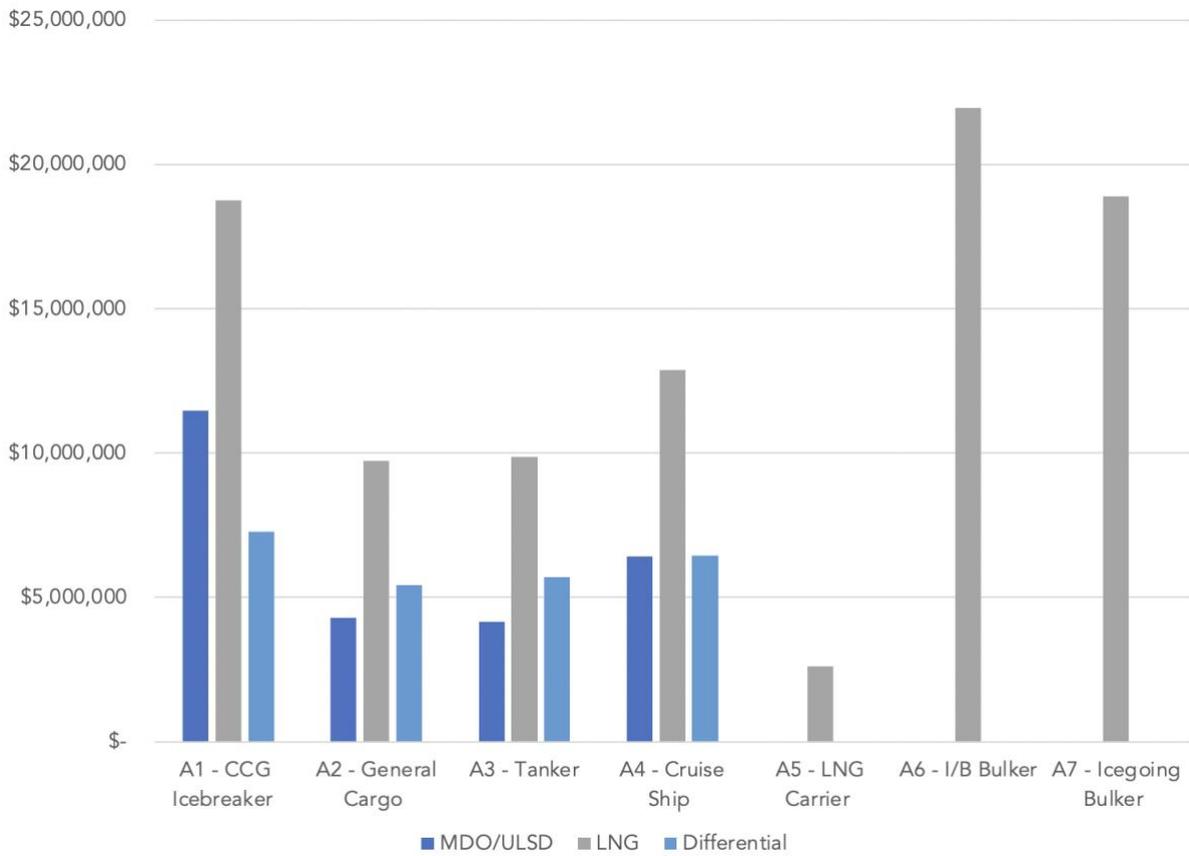


Figure 6: Propulsion System Capital Costs

### Energy Costs

Figure 7 compares MDO/ULSD and LNG, which includes a wider range of vessel cases. In this comparison, all vessels are projected to eventually deliver savings if they switch to the less expensive LNG. Potential savings depend heavily on pricing trends for LNG, HFO, and MDO.

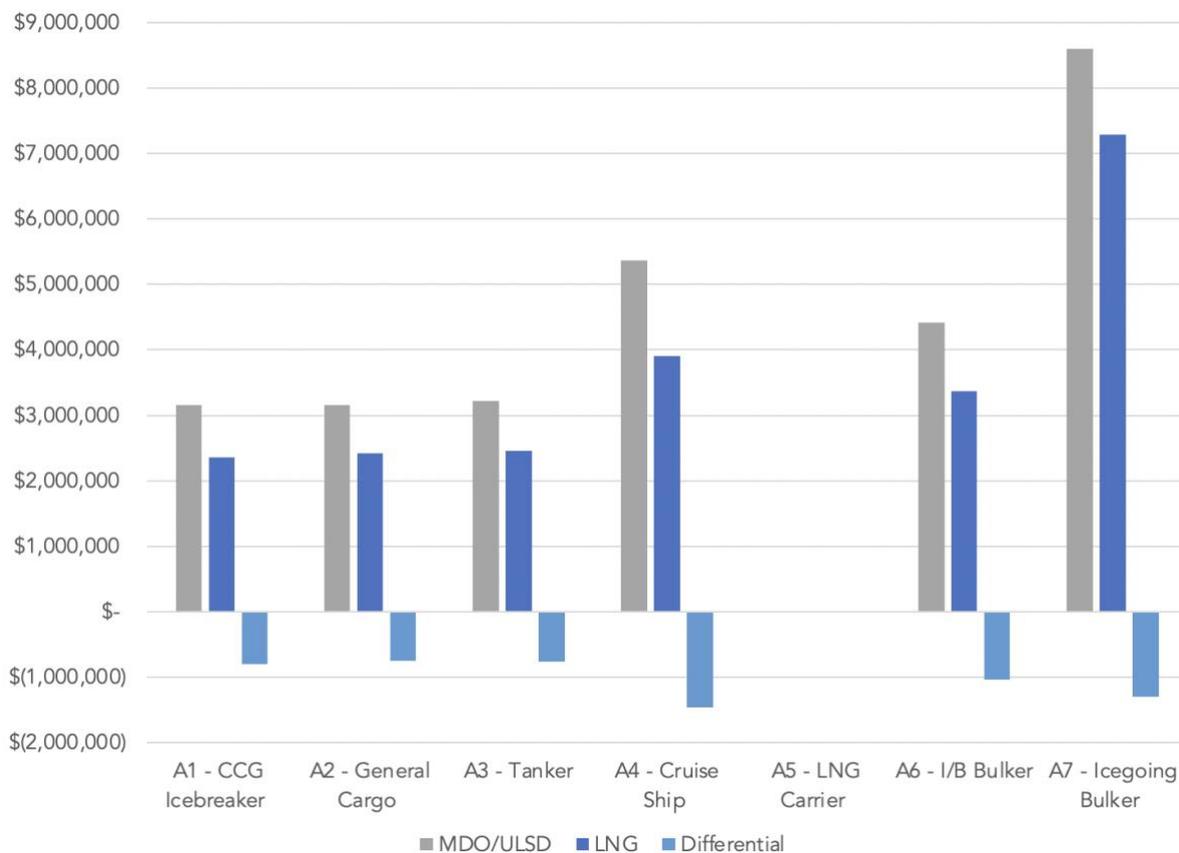


Figure 7: Annual Energy Costs – MDO/ULSD and LNG

### Payback Period

When making a capital investment, shipowners typically require a payback period no longer than 5-10 years.

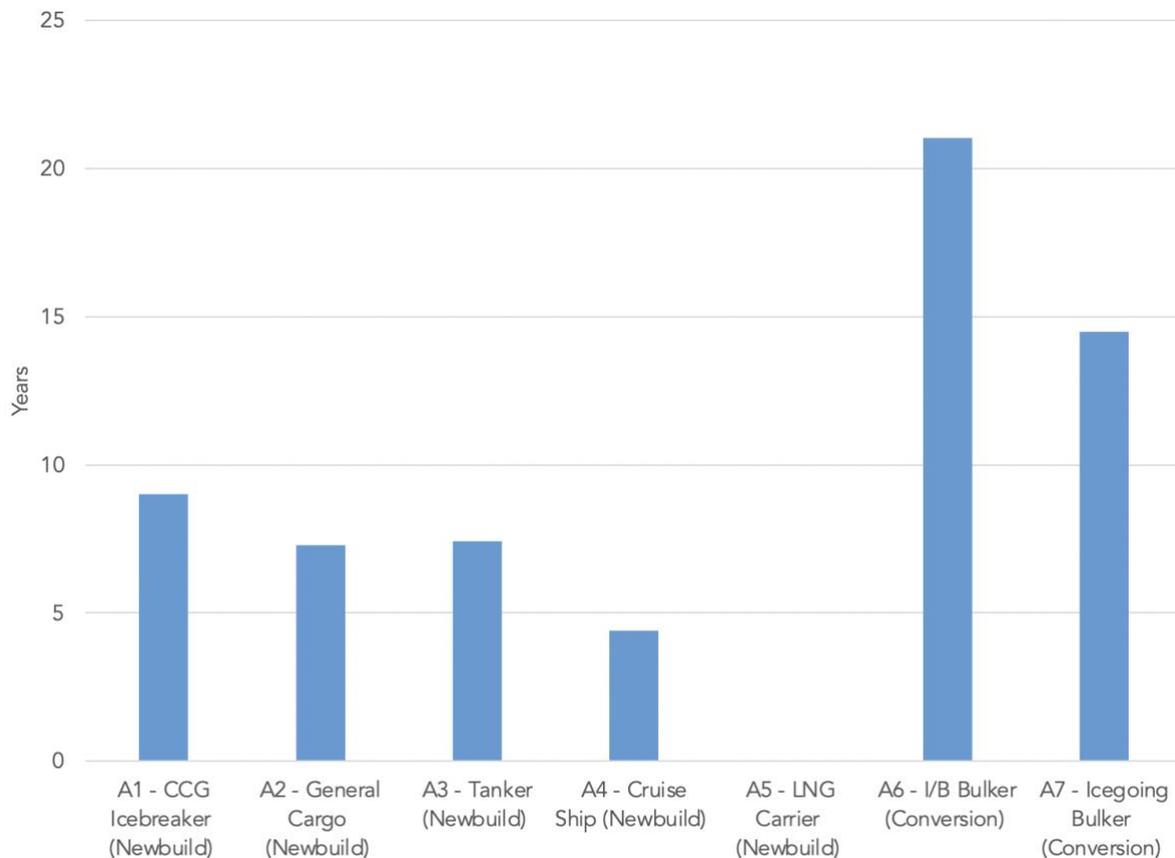
Modelling of all vessels showed that switching from HFO to LNG shows limited likelihood of producing energy cost savings because of the significantly lower cost of HFO compared to LNG. This is particularly the case for conversion case vessels (A6 - Icebreaking Bulker and A7 - Ice-going Bulker) that are currently using HFO. The price of LNG needs to drop significantly to achieve an acceptable payback period to convert an HFO-fuelled vessel to use LNG fuel.

With the impending HFO ban in the Arctic, a more meaningful comparison is between MDO/ULSD and LNG, as shown in Figure 8. Looking first at vessels switching from MDO, the payback period for the General Cargo, Tanker, and Cruise vessels assumes that all are newbuilds that incur capital costs associated with new equipment. The payback period then reflects the time taken to recoup the higher capital costs associated with LNG, based on the difference in fuel costs and consumption of LNG compared to MDO. The payback period for the CCG Icebreaker, which compares ULSD and LNG, is slightly longer.

For the conversion vessels (A6 - Icebreaking Bulker and A7 - Ice-going Bulker) to switch to MDO, payback periods are significantly longer. This is because of the assumption that the original HFO engine is still used, whereby no capital costs are incurred with the MDO option. Meanwhile, for the LNG option, these vessels face large conversion costs that can only be recouped through the

difference in fuel costs and consumption of LNG instead of MDO. If these vessels were newbuilds, the payback period for each would be around 5 and 8 years, respectively.

LNG price sensitivity is also a factor in the payback period analysis. Analysis shows that if the price of LNG increases by more than 10%, the increase in payback period would make LNG unviable. Conversely, if the price of LNG remains steady and the price of MDO/ULSD increases, this may make LNG more attractive.



\*A1 – CCG Icebreaker comparison is ULSD vs LNG

\*A5 – LNG Carrier has no payback period as it is always assumed to run on LNG

**Figure 8: Payback Period – MDO/ULSD vs LNG**

## 2.4 Conclusion

An economic model was developed and used to explore the economic feasibility of using LNG as a marine fuel for seven different vessel cases. The model incorporates the capital costs associated with LNG propulsion plants using dual-fuel engines, the vessel operational profiles, and the vessel fuel consumption to ultimately calculate a predicted payback period and lifecycle costs.

The following variables have the most impact on the economic feasibility of LNG for a vessel:

- › Price differential between MDO/ULSD/HFO and LNG
- › Capital costs for LNG systems
- › LNG availability

For LNG to be sufficiently available in the Arctic, new infrastructure is required, including liquefaction plants and delivery systems. The delivered cost of LNG depends on the cost of the source natural gas, the location and scale of the liquefaction plant, the distance to bunkering locations, the method of delivery used, and the degree of use of all supply chain components.

When comparing LNG to HFO at current prices, the lengthy payback period for switching to LNG makes it unviable in some cases, particularly for vessel conversions. However, with the impending HFO ban in the Arctic and the fuel choice being narrowed to MDO/ULSD or LNG, LNG becomes an attractive option with reasonable payback periods. Other operation and maintenance aspects may also be lowered with the use of natural gas engines, reducing overall lifecycle costs and enhancing the case for using LNG.



### 3.1 Introduction

This chapter quantifies the potential environmental risks and benefits of LNG fuel. Modelling considers the lifecycle emissions of LNG use, from fuel production and supply chain through to its combustion in a ship's engines in Canada's Arctic waters. Upstream emissions associated with LNG production were added to ship-based emissions using data from engine manufacturers and the Fourth IMO GHG Study 2020 to determine the final carbon dioxide equivalent (CO<sub>2</sub>-e) emissions impact of marine LNG use. The potential environmental impacts associated with LNG-related accidents are also identified.

Carbon dioxide (CO<sub>2</sub>) is the most significant GHG resulting from marine transportation. LNG produces less carbon dioxide than other liquid fossil fuels, however, LNG is methane and there is a risk that methane – a potent climate warming gas – will reach the atmosphere if natural gas fuel is not completely burned during combustion. Climate benefits from switching to LNG can only be realized if methane emissions are at least offset by a reduction in carbon dioxide emissions.

Finally, there is an increasing focus on how marine transportation impacts air pollution, both local and global. Fundamental changes are expected in both marine fuels and marine engines to address pollution.

### 3.2 Marine Fuels and Propulsion Options

#### Oils, Distillates and LNG

The marine fuel options studied include HFO, distillates, and LNG. Each fuel has its own set of properties that determine how emissions will impact the environment.

The combustion processes in marine diesel engines also create environmental challenges. The engines that drive propulsion are very fuel-efficient, but the diesel cycle on which most marine engines operate requires high combustion temperatures. This promotes the formation and emission of nitrous oxides (NO<sub>x</sub>), which can damage ecosystems and affect human health. By comparison, natural gas engines have lower combustion temperatures, and consequently emit less NO<sub>x</sub>. HFO and distillates have typically contained higher levels of sulphur, which emits sulphur oxides (SO<sub>x</sub>) when burned, another contaminant that damages ecosystems and human health. Recent regulations have reduced the permitted levels of sulphur in fuels, but the amount of SO<sub>x</sub> produced by HFO and distillates is still higher than LNG.

### **Heavy Fuel Oil (HFO)**

Much of polar shipping has traditionally operated on HFO. This lower cost fuel type is a residual product derived from what is left after more valuable components of the stock crude oil have been extracted through refining. HFO typically includes a wide range of contaminants, such as ash, sulphur, and aluminum to name a few. The contents of the combustion exhaust from burning HFO are generally harmful to the environment and human health. In 2012, the World Health Organization classified diesel engine exhaust as carcinogenic to humans (World Health Organization, 2012). The International Maritime Organization is set to ban the use of HFO in polar waters as of July 1, 2024, with many ships being further exempt until July 1, 2029.

### **Marine Distillates**

Marine distillates can be divided into two categories: marine diesel oil (MDO) and marine gas oil (MGO). MDO is typically a blend of distillates with a small amount of HFO. While MDO normally contains lower concentration levels of certain contaminants such as sulphur, permissible levels remained quite high until the introduction of new standards in 2020. MGO is similar to MDO except that it does not contain any HFO or residual fuels.

### **LNG**

North American pipeline natural gas used to make LNG has relatively few chemical components, making it a cleaner-burning fuel compared to oil-based fuels. Pre-treatment of natural gas eliminates constituents such as CO<sub>2</sub>, hydrogen sulphide, water, odorant, and mercury.

Natural gas offers a means of reducing air pollution contaminants and emissions to meet current and pending international regulations and related domestic legislation. These regulatory changes could encourage the use of LNG as a marine fuel.

### **Marine Propulsion Systems**

The marine engines discussed here are adaptable to LNG.

### **Diesel Engines**

Various types of diesel engines are widely used for the marine propulsion market. They can be categorized as slow, medium, and high speed, coupled with two and four-stroke designs. Smaller engines are generally higher speed than larger engines, but not always. High- and medium-speed engines are usually four-stroke, while slow-speed engines are usually two-stroke.

Modern diesels can burn a variety of fuels. Slow speed engines will work with any grade of diesel fuel, as will most medium-speed engines. High-speed engines tend to require more refined diesel.

The high cylinder temperatures and pressures in modern diesels result in exhaust streams that contain oxide pollutants, notably SO<sub>x</sub> and NO<sub>x</sub>. Changes in fuel standards and engine emissions regulations have typically focused on reducing SO<sub>x</sub>, NO<sub>x</sub>, and particulate matter emissions.

### **Gas Turbines**

Gas turbines are used in the marine industry, although their use is predominantly for military vessels where the high-power density and rapid response compared to marine diesels outweigh the higher cost and higher fuel consumption. A few cruise ships, icebreakers, and other commercial vessels have been designed with gas turbine plants, but most of these were either converted to diesel or removed from service when the price of fuel escalated over the last decade. Gas turbines can run on natural gas, but the marine industry normally uses some grade of distillate fuel.

### **Natural Gas Engines**

Natural gas engines are discussed in Chapter 1 (Technological Readiness). From an environmental standpoint, the concern with natural gas engines is the potential for methane slip - when methane escapes to the atmosphere due to incomplete combustion. As methane is a potent GHG, methane slip reduces the GHG benefit of the natural gas fuel.

The majority of the marine LNG-fuelled engines are dual-fuel medium-speed engines operating on the Otto cycle or a modified version known as the Otto/Miller cycle. Some vessels have slow-speed or medium-speed direct injection dual-fuel engines operating on the diesel cycle.

## **3.3 Exhaust Emissions from Marine Engines**

The main emissions from marine engines are CO<sub>2</sub> or CO<sub>2</sub>-e GHG, SO<sub>x</sub>, NO<sub>x</sub>, and particulate matter.

### **Greenhouse Gases (CO<sub>2</sub>, Methane)**

The quantity of CO<sub>2</sub> emissions is a direct function of how much carbon is in the fuel and the amount of fuel that is used. CO<sub>2</sub> reduction is therefore achievable with the use of more efficient engines, a switch to fuels containing less carbon per unit energy, or measures that reduce energy demand. Factors that affect engine efficiency include mechanical efficiency, operating speed, type of cycle (Diesel, Otto, or Otto/Miller) and whether the engine is two-stroke or four-stroke.

Regardless of engine type and speed, LNG's lower carbon content will result in reduced CO<sub>2</sub> from the engine. However, as methane is a potent short-term GHG, the reduction in engine-produced CO<sub>2</sub> can be effectively lost if fuel passes through the engine without burning. This is known as methane slip and it is more prevalent in engines operating on the Otto cycle.

### **SO<sub>x</sub> Emissions**

The quantity of SO<sub>x</sub> produced is a function of the sulphur content of the fuel. As there is almost no sulphur in LNG, the amount of SO<sub>x</sub> is significantly reduced when compared to oil-based fuels. The use of dual-fuel engines, which require the use of a fuel oil as pilot fuel, produces some SO<sub>x</sub> emissions, the

amount depending on the engine technology. There are essentially no SO<sub>x</sub> emissions from a spark ignition Otto cycle engine.

### **NO<sub>x</sub> Emissions**

NO<sub>x</sub> is primarily a function of the combustion temperature. The higher the cylinder temperatures during combustion, the more NO<sub>x</sub> is produced. With their higher combustion temperatures, engines operating on the Diesel cycle have higher NO<sub>x</sub> emissions than engines operating on the Otto cycle. This is the case whether they are fuelled by LNG or by fuel oils.

### **Particulate Matter Emissions**

Particulate matter emissions such as carbon particles, sulphates, and nitrate aerosols are the result of incomplete combustion of fuels caused by high cylinder temperatures and pressures.

The most damaging component of particulate matter is black carbon. In the Arctic, black carbon is especially damaging because of its impact on snow and ice. The ban of HFO use in polar waters by July 1, 2024, is in part to reduce black carbon emissions from marine traffic.

## **3.4 Emissions Compliance**

Since the 1990s, there has been a worldwide focus on limiting SO<sub>x</sub> emissions from ships with the IMO's International Convention for the Prevention of Pollution From Ships (MARPOL) Annex VI being the principal SO<sub>x</sub> control regime. Under Annex VI, MARPOL provides for the designation of Emission Control Areas (ECA) where environmental concerns justify more stringent limits on discharges and emissions. It has led to drastic reductions in the permissible levels of sulphur in fuel. Currently, Arctic waters are not designated as an ECA.

Another recent development under MARPOL is the Energy Efficiency Design Index (EEDI). The objective of the EEDI, now mandatory for new builds of various ship types, is to reduce the GHG emissions through the adoption of vessel design measures. The use of LNG stands to address this compliance challenge as LNG has lower carbon than alternatives.

The International Code for Ships Operating in Polar Waters supplements existing IMO instruments to further mitigate the impact on people and the environment in remote, vulnerable, and potentially harsh polar waters.

The International Maritime Organization's Pollution Prevention and Response sub-committee has banned the use of HFO in Polar waters in two phases. Phase one, effective July 2024, bans the use of HFO with certain exemptions. Phase two, effective July 2029, bans the use of HFO with no allowances for exemptions or waivers.

## **3.5 Emissions Reduction Solutions**

The current solutions available to vessel owners and operators to manage emissions include changing fuels, improving engine technology, or increasing operational efficiency.

## Fuel Switching

Outside of designated emission control areas, commercial vessel operators can use less costly, higher emission residual fuels (such as HFO). However, within emission control areas, measures are required to meet the emission restrictions. Cleaner distillate fuels are an option, but in some cases, the characteristics of distillate fuels are not compatible with an engine that normally operates on HFO.

An alternative solution is to use an LNG/HFO dual-fuel engine whereby the engines are converted to burn LNG. LNG can be used 100% of the time although this may not be feasible for long-distance transits. In such cases, the vessel could use HFO and switch to LNG when necessary to meet emission restrictions.

## SO<sub>x</sub> Reduction Options

All the sulphur contained in the fuel is discharged in the exhaust gas. Two options for reducing SO<sub>x</sub> emissions are to remove sulphur from the fuel (through switching to a lower-sulphur fuel as above) or remove the sulphur from the exhaust before it is released.

Exhaust gas cleaning systems (“scrubbers”) remove 90-95% of sulphur from the engine exhaust by using water – either seawater in an ‘open loop’ system or an alkaline solution in a ‘closed loop’ system to buffer the acidic sulphur. Scrubbers take up space on the vessel, require more fuel use and increase GHG emissions. The open loop system is most common but its use is contentious as the contaminants are disposed of in the ocean. Closed loop systems are more costly and complex to install and operate. The majority of contaminants are retained for disposal on land, but small amounts of wastewater from closed loop systems are disposed of in the ocean.

## NO<sub>x</sub> Reduction Options

Diesel engine manufacturers focus on controlling NO<sub>x</sub> emissions with internal, on-engine changes, rather than using exhaust after-treatment. Technology limitations may still require the use of exhaust after-treatment which is generally not cost effective.

## Energy Efficiency Improvements

The main areas of vessel design enhancement to increase efficiency include improvements in the hull form, propulsion efficiency, and propulsion machinery.

The most significant operational practice to reduce energy consumption is the reduction of vessel speed. Many new ships are being designed to have lower ship service speeds to meet Energy Efficiency Design Index requirements.

The presence of ice may require ships in the Arctic to operate at lower speeds, either as a safety measure or because of the need to break ice to proceed. The latter case requires high power levels and fuel consumption. To at least partially account for this, correction factors are built into the International Maritime Organization’s Energy Efficiency Design Index, Energy Efficiency Existing Ship Index and Carbon Intensity Indicator formulae.

### 3.6 Accidental Pollution

Arctic waters are particularly vulnerable to pollution from accidental spills of liquid hydrocarbons, whether fuel oils or cargoes. A shift towards the use of LNG in the Arctic will positively affect the risk of spills and their impact. This is partly because of LNG vessel design requirements that reduce the likelihood of damage leading to a fuel spill. It is also because the consequences of a spill would be much less severe in that any released LNG will float on the surface of the water. Being a cryogenic gas (at -160°C), it immediately starts to vaporize and disperse when released. No clean-up effort is required.

LNG is non-toxic. Unless it is present in high concentrations and for long enough to replace oxygen and cause suffocation, there is little direct risk to either marine or airborne life. Any methane emissions from the occasional accidental spill are unlikely to significantly add to overall GHG emissions.

### 3.7 Emissions Modelling: Case Studies

As in Chapter 2 (Economics), the same seven vessel types were modelled to assess and compare their emissions. Most of the analyses relate to emissions from the ship itself during voyages in the Arctic region, which is important when considering regulatory compliance for a vessel. The discussion on total GHG emissions includes upstream components (emissions created before the fuel is burned in the ship’s engine) to present the overall lifecycle emissions from using LNG as a marine fuel in the Canadian Arctic.

The analyses presented here include CO<sub>2</sub> emissions produced by the ship when burning different fuel types, the total greenhouse gas emissions (CO<sub>2</sub>, methane, and black carbon emissions) produced by the ship, and then finally, the total lifecycle emissions or CO<sub>2</sub>-equivalent emissions – all of the climate warming emissions from fuel source to fuel combustion, known as well-to-wake emissions. The final analysis of well-to-wake gives the most complete view of the impacts of different fuel options.

#### Ship-level CO<sub>2</sub> Emissions

The 21-29% reduction in CO<sub>2</sub> emissions in the LNG options is primarily due to the lower carbon content of the fuel. Table 3 and Figure 9 illustrate the CO<sub>2</sub> results.

**Table 3: CO<sub>2</sub> emissions (baseline fuel is 100%)**

| Emission Type   | Fuel Option | Case A1<br>CCG<br>Icebreaker | Case A2<br>General<br>Cargo | Case A3<br>Tanker | Case A4<br>Cruise<br>Ship | Case A5<br>LNG<br>Carrier | Case A6<br>Icebreaking<br>Bulk | Case A7<br>Ice-going<br>Bulk |
|-----------------|-------------|------------------------------|-----------------------------|-------------------|---------------------------|---------------------------|--------------------------------|------------------------------|
| CO <sub>2</sub> | HFO         | -                            | -                           | -                 | -                         | -                         | 100.0%                         | 100.0%                       |
|                 | MDO/ULSD    | 100.0%                       | 100.0%                      | 100.0%            | 100.0%                    | -                         | 97.2%                          | 97.3%                        |
|                 | LNG         | 78.6%                        | 72.5%                       | 72.1%             | 78.6%                     | 100.0%                    | 71.4%                          | 71.3%                        |

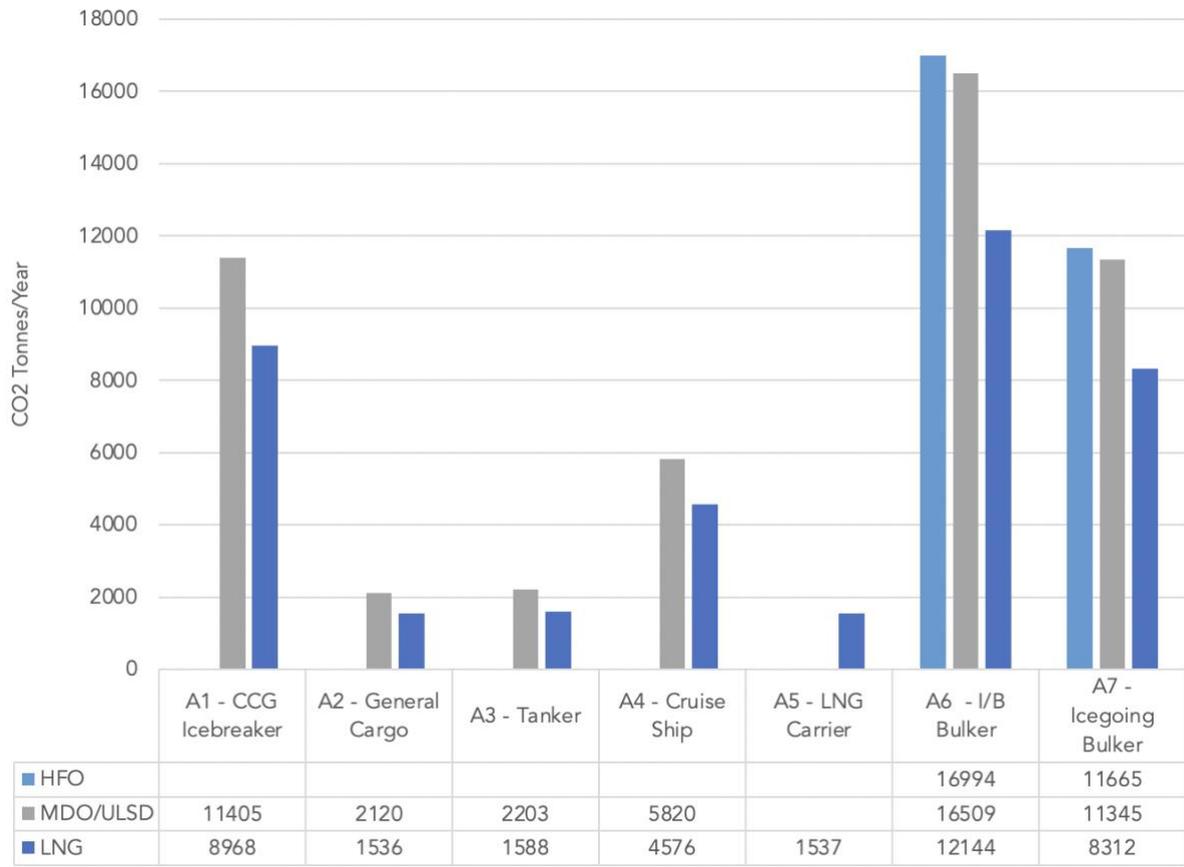


Figure 9: CO<sub>2</sub> Emissions

### Ship-level Greenhouse Gas Production

The reduction in GHGs at the ship level is shown in Figure 10. For some LNG cases, the reductions are significantly lower than for CO<sub>2</sub> alone (see Figure 9) mostly due to methane slip during combustion. In some cases, they are slightly higher due to the reduction in black carbon emissions. The GHG emission reductions are up to 31% depending on the engine technology and type.

Table 4: CO<sub>2</sub>-e Emissions (Baseline fuel is 100%)

| Emission Type      | Fuel Option | Case A1 CCG Icebreaker | Case A2 General Cargo | Case A3 Tanker | Case A4 Cruise Ship | Case A5 LNG Carrier | Case A6 Icebreaking Bulker | Case A7 Ice-going Bulker |
|--------------------|-------------|------------------------|-----------------------|----------------|---------------------|---------------------|----------------------------|--------------------------|
| CO <sub>2</sub> -e | HFO         | -                      | -                     | -              | -                   | -                   | 100.0%                     | 100.0%                   |
|                    | MDO/ULSD    | 100.0%                 | 100.0%                | 100.0%         | 100.0%              | -                   | 93.0%                      | 93.7%                    |
|                    | LNG         | 102.7%                 | 72.2%                 | 71.7%          | 97.6%               | 100.0%              | 68.7%                      | 68.9%                    |

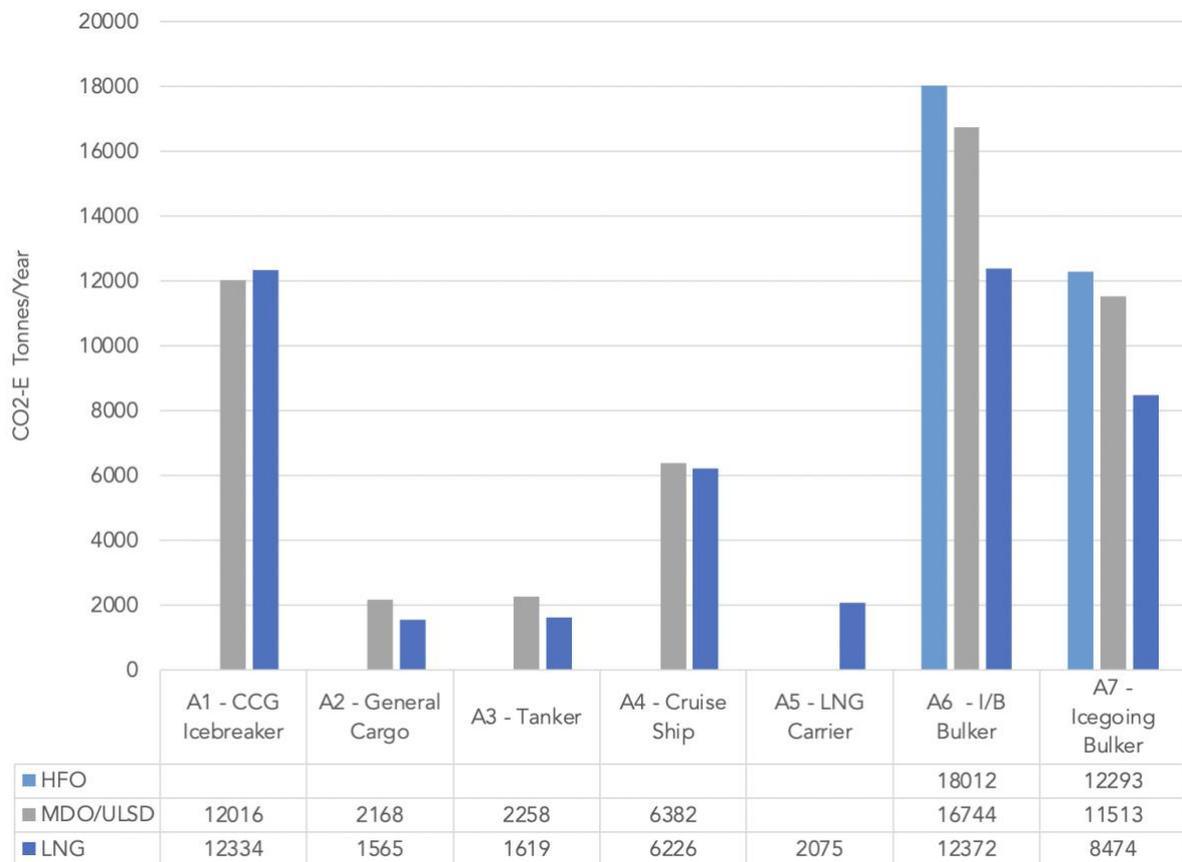


Figure 10: CO<sub>2</sub>-e Emissions

### NO<sub>x</sub> Emissions

The LNG engine scenarios operating on the Otto cycle (A1, A4 and A5) have significantly lower NO<sub>x</sub> emissions than their fuel oil counterparts due to lower temperatures in the combustion chamber. Vessels with LNG-fuelled engines operating on the hotter-burning Diesel cycle require after-treatment to remove NO<sub>x</sub> emissions. With after-treatment, they have similar NO<sub>x</sub> emissions as their fuel oil counterparts. See Figure 11.

Table 5: NO<sub>x</sub> Emissions (Baseline fuel is 100%)

| Emission Type   | Fuel Option | Case A1 CCG Icebreaker | Case A2 General Cargo | Case A3 Tanker | Case A4 Cruise Ship | Case A5 LNG Carrier | Case A6 Icebreaking Bulker | Case A7 Ice-going Bulker |
|-----------------|-------------|------------------------|-----------------------|----------------|---------------------|---------------------|----------------------------|--------------------------|
| NO <sub>x</sub> | HFO         | -                      | -                     | -              | -                   | -                   | 100.0%                     | 100.0%                   |
|                 | MDO/ULSD    | 100.0%                 | 100.0%                | 100.0%         | 100.0%              | -                   | 100.0%                     | 100.0%                   |
|                 | LNG         | 12.3%                  | 100.0%                | 100.0%         | 12.3%               | 100.0%              | 100.0%                     | 100%                     |

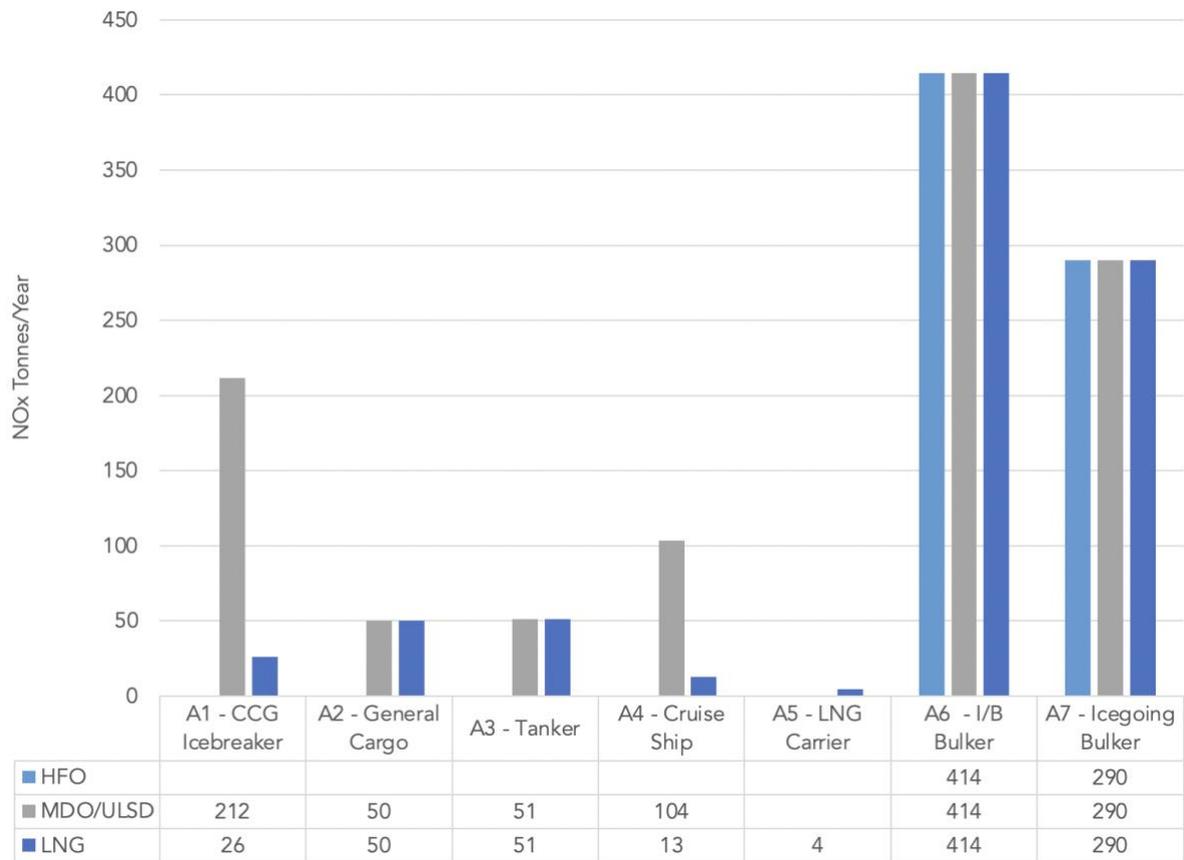


Figure 11: NO<sub>x</sub> Emissions

### SO<sub>x</sub> Emissions

The quantity of SO<sub>x</sub> produced by an engine directly relates to the amount of sulphur in the fuel. Figure 12 and Table 6 show that vessels using ULSD already produce very low SO<sub>x</sub> emissions. They also show a reduction in SO<sub>x</sub> production of approximately 99% when vessels operating on HFO switch to LNG.

Table 6: SO<sub>x</sub> Emissions (baseline fuel is 100%)

| Emission Type   | Fuel Option | Case A1 CCG Icebreaker | Case A2 General Cargo | Case A3 Tanker | Case A4 Cruise Ship | Case A5 LNG Carrier | Case A6 Icebreaking Bulker | Case A7 Ice-going Bulker |
|-----------------|-------------|------------------------|-----------------------|----------------|---------------------|---------------------|----------------------------|--------------------------|
| SO <sub>x</sub> | HFO         | -                      | -                     | -              | -                   | -                   | 100.0%                     | 100.0%                   |
|                 | MDO/ULSD    | 100.0%                 | 100.0%                | 100.0%         | 100.0%              | -                   | 19.4%                      | 20.0%                    |
|                 | LNG         | 19.4%                  | 4.2%                  | 4.2%           | 2.9%                | 100.0%              | 0.8%                       | 0.9%                     |

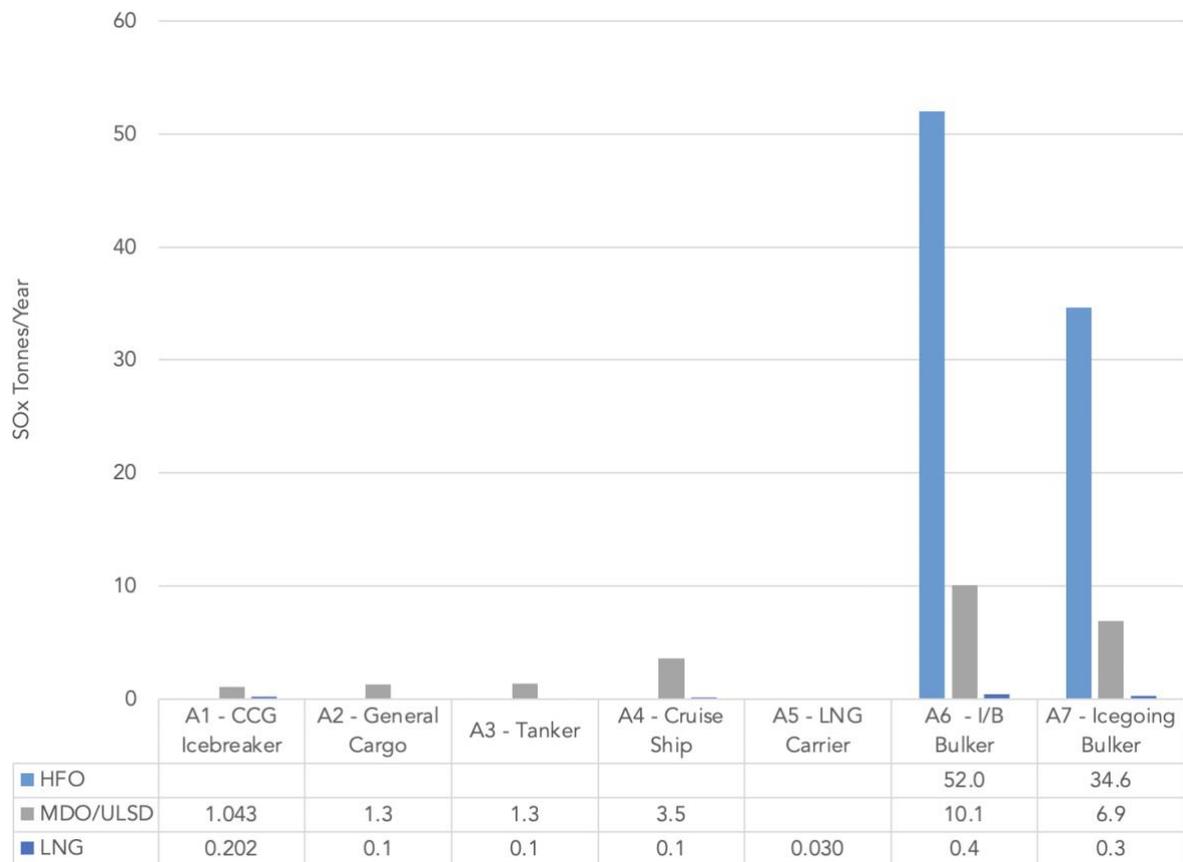


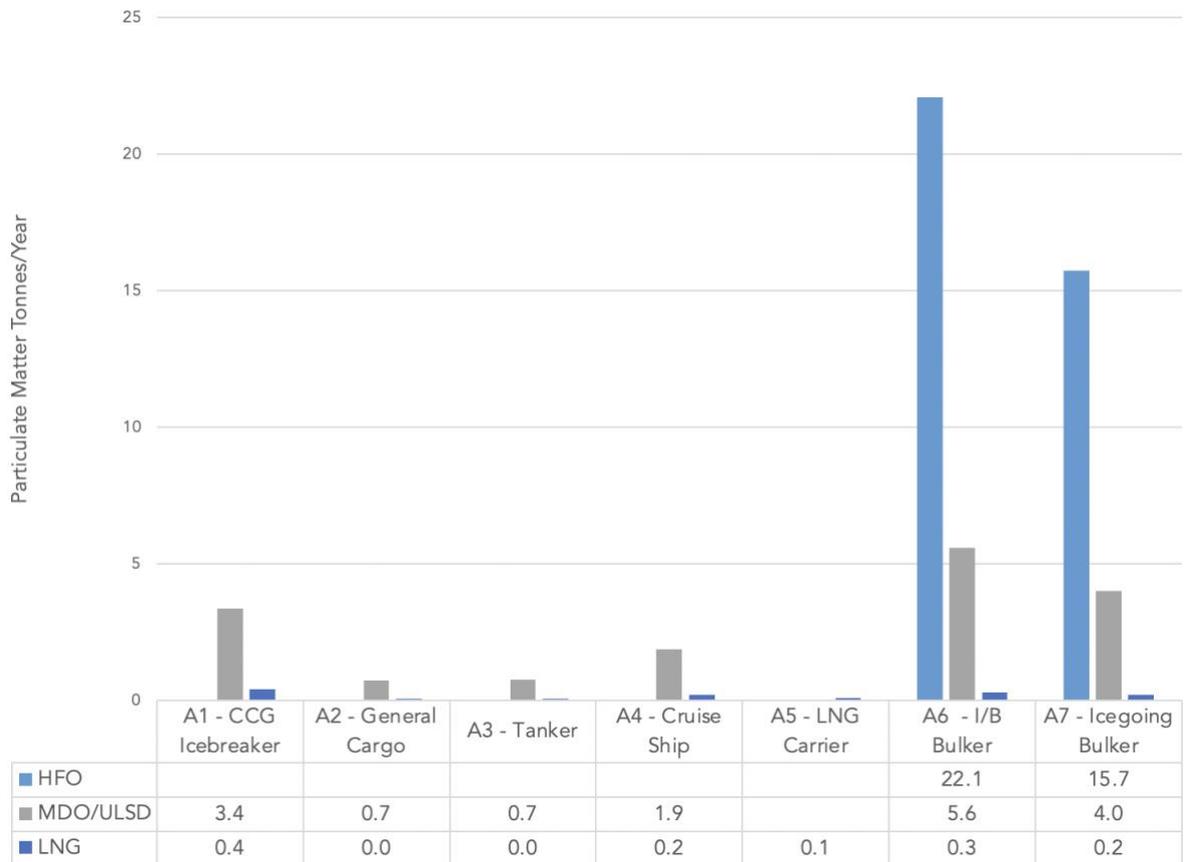
Figure 12: SO<sub>x</sub> Emissions

### Particulate Matter Emissions

Significant particulate matter reductions are achievable through the use of LNG fuel. Figure 13 and Table 7 show that particulate matter emissions are reduced by approximately 88-99% when comparing HFO/ULSD to LNG. This is primarily due to the lower sulphur content in LNG.

Table 7: Particulate Matter Emissions (baseline fuel is 100%)

| Emission Type      | Fuel Option | Case A1 CCG Icebreaker | Case A2 General Cargo | Case A3 Tanker | Case A4 Cruise Ship | Case A5 LNG Carrier | Case A6 Icebreaking Bulker | Case A7 Ice-going Bulker |
|--------------------|-------------|------------------------|-----------------------|----------------|---------------------|---------------------|----------------------------|--------------------------|
| Particulate Matter | HFO         | -                      | -                     | -              | -                   | -                   | 100.0%                     | 100.0%                   |
|                    | MDO/ULSD    | 100.0%                 | 100.0%                | 100.0%         | 100.0%              | -                   | 25.3%                      | 25.4%                    |
|                    | LNG         | 12.0%                  | 5.2%                  | 5.2%           | 10.6%               | 100.0%              | 1.3%                       | 1.3%                     |



**Figure 13: Particulate Matter Emissions**

### Black Carbon Emissions

Black carbon emissions vary as a function of engine type and fuel. Figure 14 and Table 8 show that switching to LNG-fuelled engines reduces black carbon by approximately 85-95% when compared to engines fuelled by HFO/MDO.

**Table 8: Black Carbon Emissions (baseline fuel is 100%)**

| Emission Type | Fuel Option | Case A1 CCG Icebreaker | Case A2 General Cargo | Case A3 Tanker | Case A4 Cruise Ship | Case A5 LNG Carrier | Case A6 Icebreaking Bulker | Case A7 Ice-going Bulker |
|---------------|-------------|------------------------|-----------------------|----------------|---------------------|---------------------|----------------------------|--------------------------|
| Black Carbon  | HFO         | -                      | -                     | -              | -                   | -                   | 100.0%                     | 100.0%                   |
|               | MDO/ULSD    | 100.0%                 | 100.0%                | 100.0%         | 100.0%              | -                   | 22.6%                      | 26.0%                    |
|               | LNG         | 9.0%                   | 14.5%                 | 12.9%          | 4.8%                | 100.0%              | 5.2%                       | 6.0%                     |

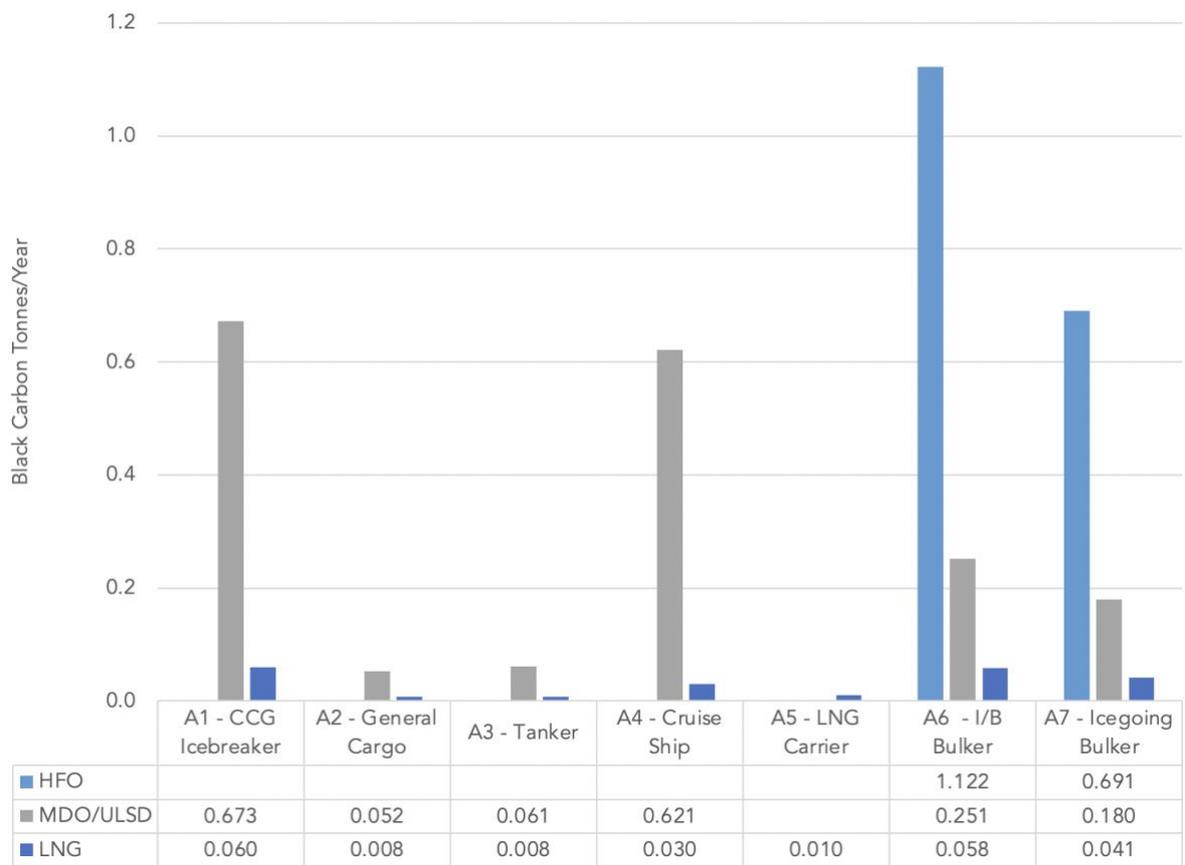


Figure 14: Black Carbon Emissions

### Combined Upstream and Downstream GHG Production

Available fuel production supply chain data for GHG emissions, together with the calculated emissions from ship engines, enables the total GHG or CO<sub>2</sub>-e to be calculated for each case. The results are shown in Figure 15 and Table 9. These results, showing a 4-32% reduction in GHGs depending on case study specifics, offer an overall indication of the impacts of using LNG when compared to oil-based fuels.

Table 9: CO<sub>2</sub>-e Emissions - Full Lifecycle Basis (baseline fuel is 100%)

| Emission Type                 | Fuel Option | Case A1 CCG Icebreaker | Case A2 General Cargo | Case A3 Tanker | Case A4 Cruise Ship | Case A5 LNG Carrier | Case A6 Icebreaking Bulker | Case A7 Ice-going Bulker |
|-------------------------------|-------------|------------------------|-----------------------|----------------|---------------------|---------------------|----------------------------|--------------------------|
| CO <sub>2</sub> with Upstream | HFO         | -                      | -                     | -              | -                   | -                   | 100.0%                     | 100.0%                   |
|                               | MDO/ULSD    | 100.0%                 | 100.0%                | 100.0%         | 100.0%              | -                   | 93.7%                      | 95.1%                    |
|                               | LNG         | 96.0%                  | 70.6%                 | 70.1%          | 92.3%               | 100.0%              | 67.5%                      | 77.4%                    |

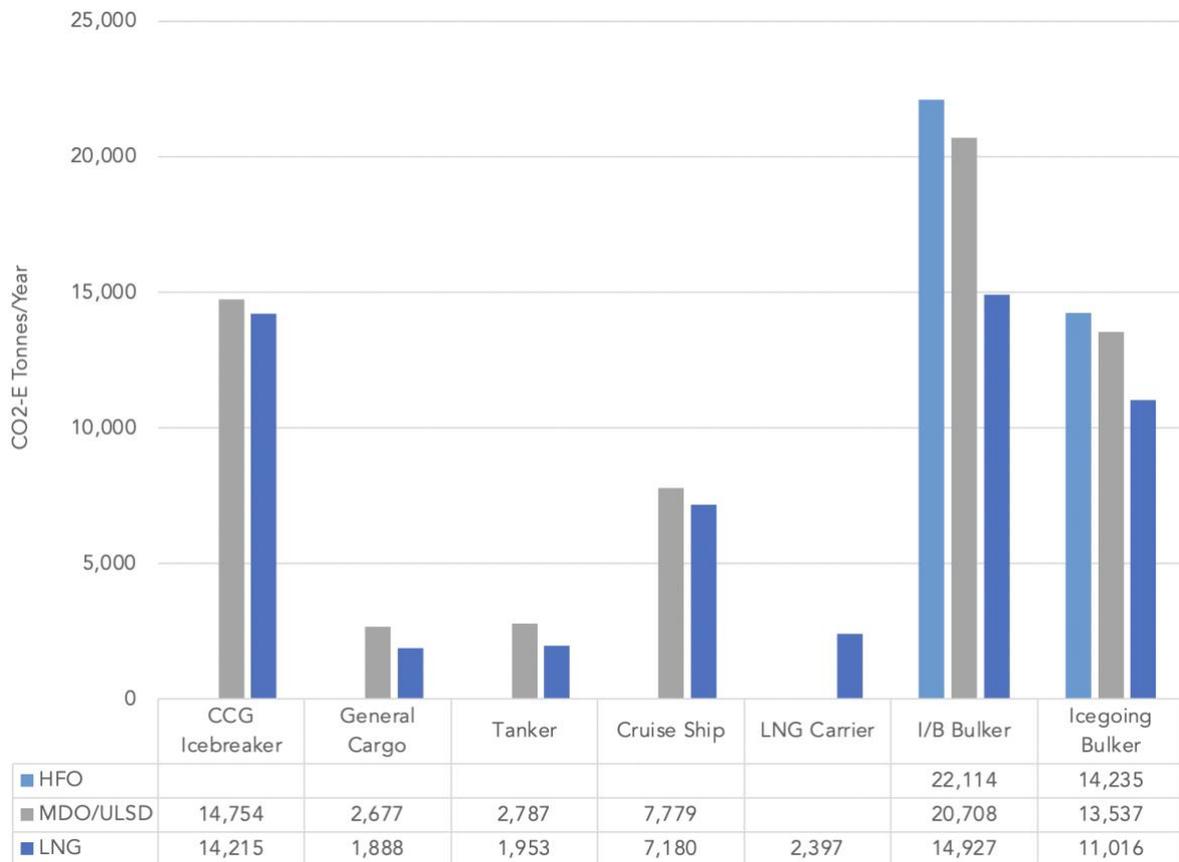


Figure 15: CO<sub>2</sub>-e Emissions - Full Lifecycle Basis

### 3.8 Conclusions

LNG’s ability to reduce emissions has potential to drive the growth of LNG as a marine fuel in support of meeting current and pending environmental regulations. The environmental benefits can include reductions at some level in CO<sub>2</sub>, CO<sub>2</sub>-e, SO<sub>x</sub>, NO<sub>x</sub>, particulate matter, and black carbon emissions, depending on the engine technology and the LNG source. The degree of emission reduction depends on the baseline oil-based fuel used for comparison.

Accidental releases of LNG are undesirable, however, from an environmental standpoint, they are more benign than either HFO or diesel oil spills. LNG’s lightness and rapid vaporization means that any spill will float on water and quickly dissipate to the atmosphere with minimal immediate or lasting harm to the local environment.

Until LNG availability, relative cost, and emission requirements can enable wider adoption by the Arctic fleet, the use of LNG can have positive, though modest, effects on total emissions by reducing the use of HFO/MDO.

# Infrastructure Options



## 4.1 Introduction

This chapter addresses infrastructure availability and requirements for the supply and distribution of LNG to ships. It also considers community energy needs that are currently supplied by ship. An Arctic supply of LNG is assumed to be created either by LNG imported into the region or LNG produced in the Arctic.

Topics here include:

- › Overview of the Canadian natural gas supply and demand situation
- › Overview of Arctic energy requirements
- › Relevant existing and planned natural gas and LNG infrastructure in Canada and the Arctic
- › Modelling approach to estimating LNG cost
- › Case study scenarios for the development of a marine LNG supply infrastructure for the Arctic

## 4.2 Natural Gas Supply and Demand

According to Natural Resources Canada, Canada is the world's fourth largest producer of natural gas with the majority produced in Alberta. The only gas production in the Canadian Arctic, representing less than 0.1% of total Canadian production, is in the Northwest Territories, near the town of Norman Wells, a by-product of oil production at the Imperial Oil facility. Canada's natural gas pipeline network does not currently extend into the Arctic.

The town of Inuvik in Northwest Territories receives LNG by tanker truck from British Columbia. The local Ikhil field also supplies a small quantity of natural gas and there are plans to expand production and possibly build a small liquefaction facility in the area.

Arctic communities rely heavily on petroleum products for energy needs. Nunavut relies solely on petroleum for both heating and electricity. The Northwest Territories has some hydroelectric generating capacity, however, 30 communities still fully rely on diesel generators for their electricity. Diesel-generated electricity costs more than double the national average for electricity. Finally, this electricity is also high in emissions that can impact both community health and the environment.

### 4.3 Existing and Planned LNG Infrastructure

The current East Coast, Great Lakes and St. Lawrence Seaway natural gas and LNG infrastructure could potentially provide marine fuel for Canadian Arctic shipping. As well, additional LNG and compressed natural gas infrastructure is being proposed or planned on the East Coast and St. Lawrence areas to support demand for natural gas for transportation or export.

#### Pipelines

In the East Coast, Great Lakes and St. Lawrence Seaway region, transmission pipelines are the main lines and distribution pipelines deliver gas to homes, businesses, and various industries. The main transmission pipeline, TransCanada's Mainline, moves natural gas from the Alberta/Saskatchewan border to the Quebec/Vermont border. Several pipelines connect with the Mainline, most notably the Great Lakes Gas Transmission pipeline that connects at the Manitoba-North Dakota border and continues to Michigan and the Dawn Hub in southern Ontario. Able to store up to 4.4 billion m<sup>3</sup> of natural gas, the Dawn Hub's pipeline network can receive gas from Western Canada and the United States and deliver to markets in Eastern Canada and the Northeast United States.

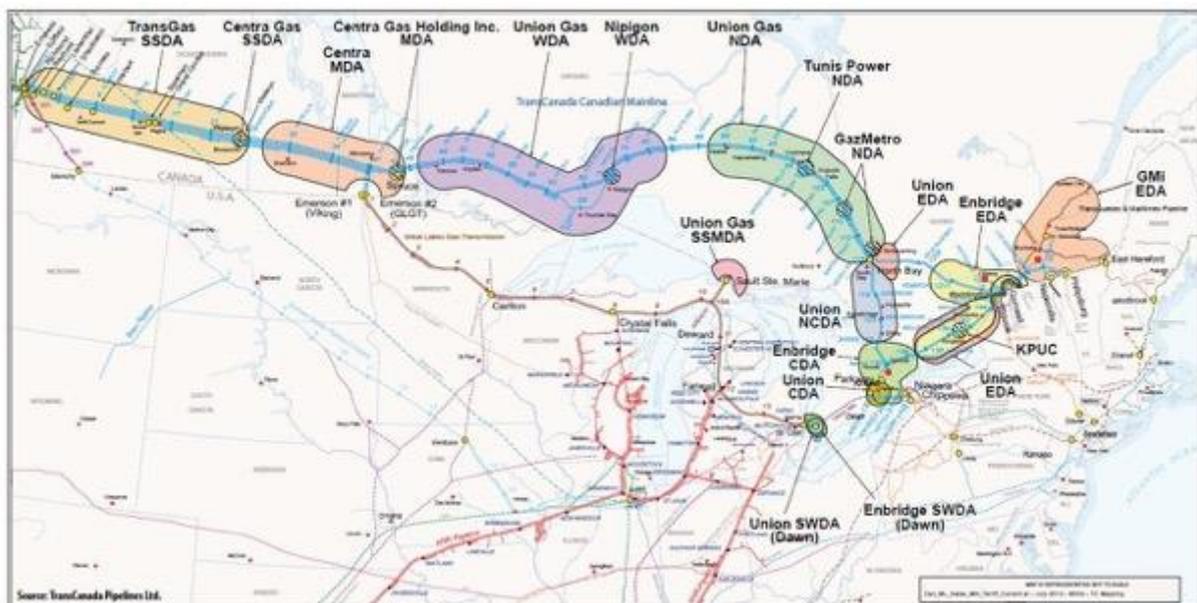


Figure 16: TransCanada Mainline Map

The primary East Coast pipeline is the Maritimes and Northeast Pipeline, which is currently in a state of transition that will affect its ability to service potential Arctic needs.

## LNG Production and Export Capacity

Potential sources of LNG for marine and other transportation demands include existing domestic facilities, newer export-oriented projects, and supplies from the United States.

Two LNG production facilities in Eastern Canada – Enbridge’s Hagar facility in Ontario and Énergir’s Montreal LNG facility in Quebec – mostly supplement the natural gas supply during periods of peak demand. The Hagar facility has a current liquefaction rate of 84,103 m<sup>3</sup>/day (3,165 gigajoules (GJ)/day) and a storage capacity of 17,000,103 m<sup>3</sup> (640,000 GJ). Énergir’s plant can produce 775,804 m<sup>3</sup>/day of LNG and store up to 90,000 m<sup>3</sup>. Quebec-based Distributed Gas Solutions Canada has an approval-pending project to construct a micro-liquefaction site in Saguenay, Quebec.

Current and future LNG export or import facilities could provide LNG fuel for Arctic use. Such facilities include the former Canaport LNG import facility (now Saint John LNG) in Saint John, New Brunswick, and the proposed (and recently downsized) Bear Head LNG export facility in Point Tupper, Nova Scotia. Also in Nova Scotia, the Goldboro LNG project proposed to build a 10 metric tonnes per year export facility at the end of the Maritimes and Northeast Pipeline to bring in gas from the United States. Officially cancelled in June 2021, options for downsizing are being evaluated.

## Arctic LNG Projects

Pending approval, the Inuvialuit Petroleum Corporation proposes to construct a small-scale LNG plant – the Inuvialuit Energy Security Project – connected to a gas supply near Tuktoyaktuk, Northwest Territories. This proposed facility is the basis for Case Study 2 discussed in section 4.4.

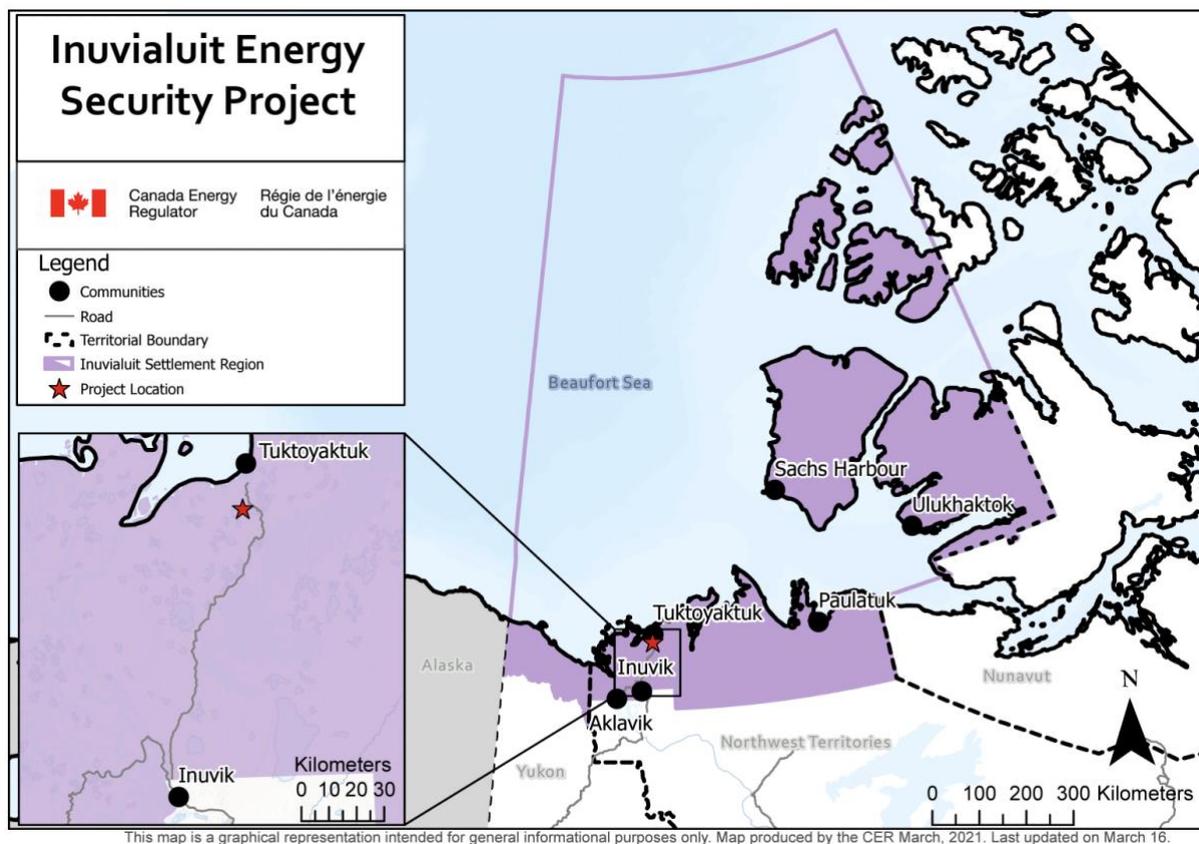


Figure 17: Location of the Inuvialuit Energy Security Project

Cryopeak LNG Solutions constructed an LNG production facility in Fort Nelson, British Columbia. Phase one, with production capacity of 102 m<sup>3</sup> per day of LNG, supplies customers in Canada and the United States, including the community of Inuvik in the Canadian Arctic.

The government of Northwest Territories is doing a prefeasibility study to construct an export-scale LNG facility near Tuktoyaktuk with gas being supplied from the offshore Mackenzie Delta gas fields.

## 4.4 Development of Arctic Marine LNG Supply Infrastructure

The Canadian Arctic currently has no existing supply chain with capacity to supply LNG as a marine fuel. If demand for LNG increases, new capacity to one or more elements of the supply chain will be needed.

The LNG price charged to a marine customer is a function of:

- › Source natural gas costs
- › Liquefaction costs
- › Fuel delivery costs
- › Fuel taxes and/or subsidies (not analyzed in this study)

A model was designed where the cost for LNG considers all elements of the supply chain. The model is applied to two hypothetical Arctic LNG supply chain case studies.

Equipment, operating, and maintenance costs can be estimated with reasonable accuracy. Extra costs associated with Arctic construction and operation are estimated and vary greatly depending on the location and nature of the project.

The following discusses the modelled infrastructure components with an Arctic context.

### Liquefaction

To date, there are no operating Canadian Arctic natural gas liquefaction plants.

The production of Arctic LNG for transportation requires smaller-scale liquefaction plants near end users. The economics of constructing a small-scale plant depends on the size of the facility, location, amount of use, and energy requirements, and also operating costs such as labour and maintenance. In the model, costs include all anticipated challenges related to building and operating in the Arctic, such as permafrost, shipping logistics, and seasonal schedules.

Analysis shows that liquefaction cost will always be a significant component of the cost of LNG fuel, and that it is highly sensitive to plant size and utilization. Achievable economies of scale make it crucial to accurately forecast the demand for LNG.

Large-scale liquefaction for natural gas export is impacted by various market forces that tend to influence the cost of large-scale projects of all types. There are two uniquely Canadian challenges that are expected to apply to any Arctic LNG facility:

- › Lack of domestic experience in delivering LNG projects
- › The need for Inuit communities' support

## Distribution

A liquefaction facility may be able to be positioned to supply LNG directly to a marine fuelling location, but most cases will require some form of distribution system. Options include tanker trucks, rail cars, intermodal containers, and bunker barge or vessel options. Currently, bunker barge or vessel is the most likely option in the Arctic, with local land-based distribution by tanker truck.

A tanker truck can be used to transport fuel to distribution centres, shore-side storage tanks, or directly to a marine bunkering location. Capital costs include purchase or lease cost of the trailer and the tractor. The combined cost of the tractor and trailer is spread over the volume of fuel delivered over the life of the tractor and trailer. The cost per unit of LNG delivered increases with distance from the liquefaction facility to delivery location.

Dedicated bunker barges or vessels have much higher capital and operating costs. However, they can deliver much greater volumes of LNG to far more remote coastal areas. Bunker barges or vessels do not have “standard” units. Both the bunker barge and bunker vessel delivery options can be economically competitive with trucks, even on shorter routes, as long as their capacity is well used. Furthermore, lack of road access to many Arctic communities will likely require the use of a bunker barge or bunker vessel for either marine or community energy use.

## Storage and Bunkering Facilities

A shore-based bunkering facility is also an option for supplying LNG fuel to a ship. Bunkering facilities can be designed to manage all the necessary transfer requirements, depending on the vessels to be supplied. In situations with high throughput (more than 10 tank turnovers per year), there is little impact on the delivered cost of LNG. However, in the case of low annual LNG throughput, the additional cost can be quite significant as larger (more expensive) tanks would be needed to provide sufficient storage. As with most Arctic storage situations, there is only a short window in the year to fill tanks, which results in large storage volumes and low turnover rates.

## 4.5 Case Studies

This report models two hypothetical Arctic LNG supply chain case studies. The various costs associated with each section of the supply chain are summed to present the total cost of delivered energy, in \$/GJ of LNG, to the end user. Profit and required rate of return on investment are included in the model to reflect a real project.

### Case 1: Montreal to Iqaluit

In this example, to potentially offset up to ~30% of its annual energy needs currently provided by conventional diesel tanks, the town of Iqaluit in Nunavut installs an LNG storage facility with a volume of 30,000 m<sup>3</sup>. This storage facility can supply ships with LNG via shore-to-ship bunkering during the summer months as well as provide natural gas to local residents year-round. A 10,000 m<sup>3</sup> ice-class LNG bunker vessel is built to deliver LNG to Iqaluit from Montreal during three summer months with 100% utilization.

The analyzed supply chain route is from a Montreal LNG terminal to an Iqaluit LNG storage facility via bunker vessel. The end user could be the town of Iqaluit or marine customers via shore-to-ship bunkering. Table 10 presents some of the factors included in the model.

**Table 10: Case Study 1 Inputs**

| Category                    | Value         | Units       |
|-----------------------------|---------------|-------------|
| <b>LNG Storage Tank</b>     |               |             |
| Capex                       | \$50,000,000  | \$          |
| Labour, Materials and Other | 2%            | %CAPEX/year |
| Amortization Period         | 20            | years       |
| <b>Bunker Vessel</b>        |               |             |
| Capex                       | \$100,000,000 | \$          |
| Maintenance                 | 3%            | %CAPEX/year |
| Salvage Value               | 0             | \$          |
| Amortization Period         | 20            | years       |
| Annual Insurance            | \$100,000     | \$/year     |
| Fleet Overhead*             | \$375,000     | \$/year     |
| Crew - Bunker Vessel        | 24            | #           |
| Source LNG Price            | \$10.35       | \$/GJ       |

\*fleet overhead is the cost of business operations to support a marine fleet

The model results show that the end-user cost is 18.83 \$/GJ of LNG in Iqaluit – approximately twice the cost of the source LNG. Comparing the final LNG price to diesel prices in terms of delivered energy per dollar, the cost of LNG in this case study is \$0.69 Diesel Litre Equivalent.



**Figure 18: Case Study 1 Results**

## Case 2: Tuktoyaktuk to Cambridge Bay

In this example, Tuktoyaktuk installs an LNG liquefaction plant and storage tank. A 5,000 m<sup>3</sup> ice-class LNG Articulated Tug Barge is built to transport LNG from Tuktoyaktuk to Cambridge Bay to fill a 10,000 m<sup>3</sup> LNG storage tank that supplies ships with LNG via shore-to-ship bunkering during the summer months. It can also provide natural gas to Cambridge Bay residents throughout the year. The barge has 100% utilization in three summer months and 0% utilization in nine winter months.

The 30,000 m<sup>3</sup>/year Tuktoyaktuk liquefaction plant dedicates about one-third of its annual production of LNG to supply Cambridge Bay as above. The rest of the plant's annual production will either be exported via the port or be sent south to other customers via truck tankers.

A 5,000 m<sup>3</sup> LNG storage tank built in Tuktoyaktuk to receive LNG from the liquefaction plant can supply both shore-to-ship bunkering and truck tanker bunkering in Tuktoyaktuk.

Table 11 presents some of the factors included in the model.

**Table 11: Case Study 2 Inputs**

| Category                         | Value        | Units       |
|----------------------------------|--------------|-------------|
| Small-scale LNG Plant            |              |             |
| Capex                            | \$46,000,000 | \$          |
| Labour, Maintenance and Other    | 3%           | %CAPEX/year |
| Amortization Period              | 20           | years       |
| LNG Storage Tank – Tuktoyaktuk   |              |             |
| Capex                            | \$26,000,000 | \$          |
| Labour, Materials and Other      | 2%           | %CAPEX/year |
| Amortization Period              | 20           | years       |
| LNG Articulated Tug Barge Bunker |              |             |
| Capex                            | \$60,000,000 | \$          |
| Maintenance                      | 3%           | %CAPEX/year |
| Salvage Value                    | 0            | \$          |
| Amortization Period              | 20           | years       |
| Annual Insurance                 | \$50,000     | \$/year     |
| Fleet Overhead*                  | \$200,000    | \$/year     |
| Crew (Bunker Barge Only)         | 2            | #           |
| Tug Rental Rate                  | \$25,000     | \$/day      |
| LNG Storage Tank – Cambridge Bay |              |             |
| Capex                            | \$31,000,000 | \$          |
| Labour, Material and Other       | 2%           | %CAPEX/year |
| Amortization Period              | 20           | years       |

\*fleet overhead is the cost of business operations to support a marine fleet

The end-user cost is 37.95 \$/GJ of LNG in Cambridge Bay, as shown in Figure 19, roughly triple the cost of LNG further south. Comparing the final LNG price to diesel prices in terms of delivered energy per dollar, the cost of LNG in this case study is \$1.39 Diesel Litre Equivalent.



Figure 19: Case Study 2 Results

## 4.6 Conclusions

Only minimal LNG production or distribution capacity currently exists in the Arctic to support LNG-fuelled marine vessels. Even if various LNG export projects are completed, it is not clear whether any of this new capacity will be made available for marine fuelling use. As it stands now, LNG for marine use may be drawn from large export-oriented facilities, or from small-scale facilities that target transportation fuel and other sectors.

It may be possible to develop an Arctic LNG supply chain at attractive prices in comparison with fuel oil alternatives. However, as the case studies show, LNG pricing is sensitive to many factors and assumptions, with the level of utilization of capital-intensive assets being an important consideration. Another significant factor in the cost of delivered LNG is the distance between the LNG production facility and the bunkering location for end users, with the price increasing with distance travelled.



## 5.1 Introduction

This chapter identifies the competency and training requirements for the introduction of LNG in the Arctic. It considers the people required at all stages in the vessel lifecycle: vessel designers, shipyard workers, original equipment manufacturers, certification and inspection authorities, seafarers, facility and bunkering personnel and emergency responders.

## 5.2 Required Competencies and Related Training

### Vessel Designers

As the number of LNG and LNG-ready vessels has increased, so has the number designed in North America, adding to the experience of vessel designers in LNG. There are no formal training requirements, but several training options are available for vessel designers to give them knowledge of design and operations considerations.

### Seafarers

Established competency requirements for seafarers are detailed in Standards of Training, Certification and Watchkeeping for Seafarers (95) Convention and Part A of the related Code. Advanced training is required for masters, engineer officers, and all personnel with immediate responsibility for the fuel and fuel system on gas-fuelled vessels. Basic training applies to seafarers who have safety duties related to the care, use, or emergency response to the fuel on board these vessels. While the Code sets training requirements, the actual training is the responsibility of individual governments. Transport Canada

does not have specific training requirements for seafarers on board LNG-fuelled vessels but rather endeavors to bring current regulations in line with the international code for gas-fuelled vessels.

### **Certification and Inspection Authorities**

All recognized classification societies have experience with LNG-fuelled vessels. Most of these organizations train their surveyors through in-house training programs.

### **Original Equipment Manufacturers**

Original equipment manufacturers have training programs for their personnel involved in the design, construction, and commissioning of LNG-fuelled vessels. They also offer training to vessel crews upon installation of their equipment.

### **Shipyards Personnel**

Whether constructing or maintaining LNG-fuelled vessels, shipyard personnel must be familiar with safety precautions and procedures specific to working with natural gas and LNG. Original manufacturers of equipment often assist by providing technical expertise and detailed installation and servicing requirements to shipyards.

### **Bunkering Personnel**

The safe bunkering of a gas-fuelled vessel, by any method, requires additional training to build safety awareness and competencies. Two standards provide details on recommended training – Canadian Standards Association Z276-18: *LNG Production, Storage and Handling*, and the National Fire Protection Association 59A: *Standard for the Production, Storage, and Handling of Liquefied Natural Gas*.

In the case of truck-to-ship bunkering in Canada, truck operators must be trained in LNG bunkering. In Quebec there is a requirement for the operator to complete six bunkering operations under supervision by a certified trainer. Proponents of Canadian projects involving ship-to-ship LNG bunkering plan to use guidance from organizations such as the Society for Gas as a Marine Fuel to set up procedures for training and operations. Shore-side bunkering facilities are similar to LNG export terminals and as such have existing standards and industry best practices to address training requirements.

### **Emergency Responders**

Firefighters and other emergency responders to marine vessel emergencies typically need additional training to ensure that they can respond safely and effectively to emergencies involving LNG vessels and facilities.

## **5.3 Additional Knowledge and Training**

### **Seafarers**

Transport Canada provides a list of recognized institutions and their approved training courses for mariners, including:

- › Institut Maritime du Québec
- › Société des traversiers du Québec
- › Justice Institute of British Columbia

Canadian operators also use training courses approved by the United States Coast Guard and provided by:

- › STAR Center
- › State University New York Maritime College
- › United States Maritime Resource Center
- › United States Merchant Marine Academy

Larger companies with significant numbers of LNG vessels and staff involved in their operations often establish in-house training programs.

### **Shore-side Bunkering Personnel**

Training of facility and shore-side bunkering personnel exists as both formal external training courses and internal training on practical skills. Internal training programs can draw on Canadian companies who already have LNG facilities, such as Fortis BC and Cryopeak.

An example of an external training program is the Liquefied Natural Gas Process Operations program offered by Southern Alberta Institute of Technology.

### **Emergency Responders**

United States institutions offering LNG emergency response training include Marine Firefighting Inc., Texas A&M Engineering Extension Service, and Fire Academy of the South. In Canada, the Justice Institute of British Columbia promotes an LNG Facilities Emergency Response Training.

Ferus NGF, a provider of trucked-in LNG to the Yukon and Northwest Territories, has delivered virtual LNG safety training to many organizations, primarily fire departments, to educate participants on LNG characteristics and hazards. The intent is to equip emergency responders with knowledge for decision-making in emergency events. A similar initiative should be considered if there is an increase in LNG vessels in the Arctic, or when new facilities are built.

## **5.4 Arctic Training Needs and Capabilities**

In early stages of using LNG in the Arctic, ship personnel will likely be trained by the above-mentioned organizations and obtain practical experience with an existing LNG-capable fleet in Canada or elsewhere. An increase in the number of LNG-fuelled vessels in the Arctic will expand the opportunities for personnel to gain experience directly on these vessels.

For shore-side personnel, it is likely more cost-effective for facility suppliers to arrange for on-site training using the actual installed equipment. Different levels of training could be provided to the facility staff and to local emergency responders.

## 5.5 Conclusions

Operating a supply chain for LNG-fuelled operations in the Canadian Arctic requires personnel with competencies in design, operation, maintenance, and safety management and response. Training is available within Canada for most of these requirements, with organizations in the United States and elsewhere available to supplement Canadian resources.

Canadian shipowners, fuel distribution companies, and LNG facility operators have responsibly undertaken the training of their staff, using a mix of in-house and external resources. This is aided by an increasing number of standards and best practices documents.

While there are some unique challenges in the Canadian Arctic, there are no major barriers to building the necessary competencies for an Arctic LNG supply chain.



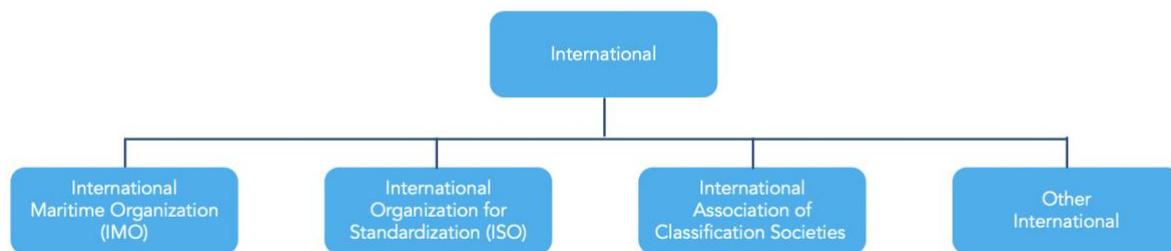
## 6.1 Introduction

This chapter describes the regulatory framework for the use of NG as a marine fuel from the supply of the gas plant to the operations of the ship. The framework has been developed by reviewing present and planned regulations, rules, standards, and guidelines that relate to:

- › Vessel design and construction
- › Operations in coastal waters and waterways
- › Bunkering and terminal facilities
- › Personnel (see also Chapter 5)

## 6.2 International Framework

At the international level, there are several bodies which provide regulations or guidance related to the use of LNG as marine fuel.



**Figure 20: International Regulatory Framework**

### **International Maritime Organization**

The International Maritime Organization (IMO) is a specialized agency of the United Nations with responsibility for the safety and security of shipping and the prevention of marine pollution by ships. The IMO oversees marine shipping through three major conventions, and a range of Codes, Guidelines and other instruments which address more specialized aspects of shipping. The conventions are:

- International Convention for the Safety of Life at Sea (SOLAS)
- International Convention for the Prevention of Pollution from Ships, 1973, as modified by the Protocol of 1978 (MARPOL 73/78)
- International Convention on Standards of Training, Certification and Watchkeeping for Seafarers (STCW)

A recently updated MARPOL convention established a ban on using or carrying HFO in the Arctic. This ban on HFO takes effect partially in 2024 and fully in 2029 and is expected to result in many vessel operators considering alternative fuels, such as LNG.

Various codes support the implementation of these conventions. Codes most relevant to LNG-fuelled vessels include:

#### ***International Code for the Construction and Equipment of Ships Carrying Liquefied Gases in Bulk (IGC)***

In the 1980s, IMO introduced this code to minimize additional risks to the ship and the environment owing to cryogenic or pressurized products. It is mandatory for all gas carriers and is applicable to vessels carrying fuel to refuel gas-fuelled ships.

#### ***International Code of Safety for Ships Using Gases or Other Low Flashpoint Fuels (IGF Code)***

The IMO developed a code to cover ships using natural gas and other low flashpoint fuels, which took effect on January 1, 2017.

Generally speaking, a ship is subject to either IGF or to IGC: a gas carrier using its cargo as a fuel is under IGC, while other ships using LNG fuel will be under IGF.

#### ***International Safety Management Code (ISM Code)***

The International Safety Management Code addresses human error in marine accidents by requiring the shipowner or other responsible person to develop and implement a policy and a safety management system with assigned resources and shore-based support.

## ***Standards of Training, Certification and Watchkeeping for Seafarers (95) (STCW 95) Convention***

This international convention, originally established in 1978, sets minimum standards of competence for seafarers. The 2010 amendments added requirements for personnel serving on liquefied gas tankers and further 2015 amendments added training requirements for personnel on ships subject to the IGF Code.

## ***Code for Recognized Organizations (RO Code)***

This Code, introduced in 2015, provides for flag states such as Canada to delegate inspection and certification responsibilities to “recognized” external organizations, typically classification societies.

## **International Organization for Standardization**

The International Organization for Standardization (ISO) has developed many standards and guidelines that are used in the marine industry. Those relevant to gas-fuelled shipping include:

- › *ISO/TS 18683:2015 Guidelines for Systems and Installations for Supply of LNG as Fuel to Ships* gives guidance on the minimum requirements for the design and operation of the LNG bunkering facility, including the interface between the facility and the receiving ship.
- › *ISO/TS 16901:2015 Guidance on Performing Risk Assessment in the Design of Onshore LNG Installations Including the Ship/shore Interface* provides guidance for doing an assessment of the major safety hazards as part of the planning, design, and operation of LNG facilities on shore and at shoreline.
- › *ISO 20519:2017 Specification for Bunkering of LNG-fuelled Vessels* sets the requirements for LNG bunkering systems used to fuel vessels with LNG.

## **Classification Societies**

Industry-led classification societies set and maintain technical standards for the design, construction, and operation of ships. They develop their own rules and adopt, adapt, and apply international standards. Many have modified their rules to cover LNG-fuelled vessels. Classification societies often work on behalf of national administrations. Currently, Canada authorizes seven societies, all of which have rules for gas-fuelled ships.

## **Other International Bodies**

Other international bodies that offer regulatory guidance to the gas-fuelled marine industry include:

- › Society of International Gas Tanker and Terminal Operators (SIGGTO) has developed guidelines for the handling of LNG as a cargo
- › Society for Gas as a Marine Fuel (SGMF) has issued 16 publications, including an introductory guide, LNG Bunkering Safety Guidelines, and LNG Bunkering Competency Guidelines
- › United States Coast Guard has actively developed policies, guidance, and regulatory proposals related to natural gas as a fuel.

## 6.3 Canadian National Framework

Almost all aspects of marine transportation in Canada are federally regulated with Transport Canada being responsible for design and maintenance regulations. Other departments and agencies, such as the Canadian Coast Guard, have roles in operational safety and emergency response.

Regulations pertaining to terminal infrastructure have more complex jurisdictions, mostly at the federal level. As infrastructure goes inland, provincial and territorial ministries and agencies typically take a leadership role. The national regulatory framework is shown in Figure 21.

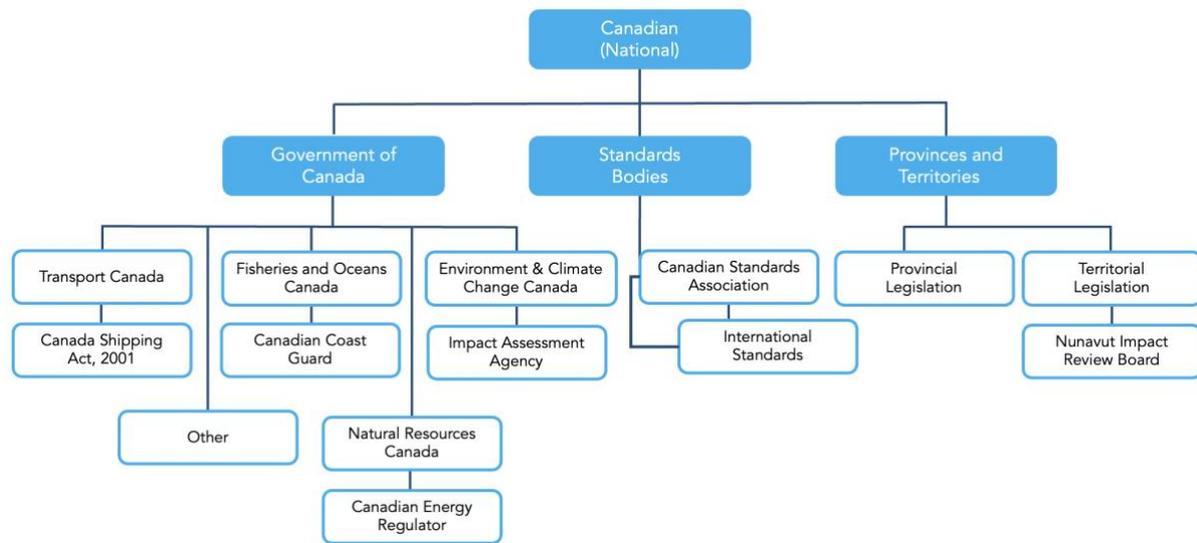


Figure 21: National Regulatory Framework

### Transport Canada

#### *Canada Shipping Act, 2001*

The *Canada Shipping Act, 2001* applies to all Canadian flagged vessels and all vessels in Canadian waters except those belonging to the Canadian Forces or foreign military. It includes regulations for hull construction, marine machinery, crewing, security, and other aspects.

Most Canadian regulations are aligned with IMO Conventions and Codes, but some are not, including those applicable to LNG, either as fuel or cargo. An alternative set of federal policies and procedures apply, including:

- TP 13585 E – Acceptance of an Alternative Regulatory Regime for Inspection, Construction and Safety Equipment
- TP 15211 – Canadian Supplement to the SOLAS Convention
- RDIMS 11153519 - Transport Canada Tier I Policy Requirements for Vessels Using Natural Gas as Fuel

Combined, these allow for the use of the IMO Convention framework together with some specific Canadian supplementary requirements to demonstrate an equivalent level of safety to the Canada maritime system.

### **Arctic Waters Pollution Prevention Act**

The Arctic Shipping Safety and Pollution Prevention Regulations under the *Arctic Waters Pollution Prevention Act* closely align with the IMO Polar Code. Although there are no specific LNG-related provisions under these regulations, they are an important element of the overall Arctic marine safety system.

### **Navigation Protection Act**

The most relevant aspects of the *Navigation Protection Act* for LNG use and transportation are contained under the TERMPOL (Technical Review Process of Marine Terminal Systems and Transshipment Sites) Code (TP 743 E). When a marine terminal is built, regional shipping changes as vessel routes adapt to the new location. TERMPOL reviews the expected changes to determine potential risks to safety.

### **Other Relevant Federal Departments**

Other federal departments that have a role in the regulatory aspects of marine transportation include:

- › Fisheries and Oceans Canada along with Transport Canada and Environment and Climate Change Canada shares the responsibility for the Oceans Protection Plan.
- › Canadian Coast Guard is the lead agency for marine emergency response, sharing search and rescue responsibilities with National Defense. To date, the Canadian Coast Guard has not been called on to develop emergency response plans, in or outside the Arctic, that specifically address vessels carrying LNG or fuelled by LNG.
- › Natural Resources Canada has jurisdiction over offshore resources, trade and commerce in natural resources, statistics, international relations, and boundaries.
- › Environment and Climate Change Canada is responsible for federal aspects of environmental policies and programs.

## **6.4 Canadian Provincial / Territorial**

Regulatory responsibilities for Canadian energy vary across the country. Arctic regions regulate gas exploration and development in Nunavut and part of the Northwest Territories. In these areas, the applicable regulations are the *Canada Oil and Gas Operations Act* and the *Oil and Gas Operations Act*. These regulations are more suited to traditional oil and gas facilities than LNG facilities, however, the lack of LNG development in the Arctic has not created any urgency to update them. As necessary, facilities have progressed through successful deviation requests.

Developments in the Arctic also require approval through the local environmental assessment process.

## **6.5 Risk Assessment and Mitigation**

The IGF Code, and its incorporation into classification society rules, has considerably reduced the scope of risk assessment as it relates to ship design and operational elements for gas-fuelled vessels.

Ship-to-ship bunkering relies on a risk assessment as it involves at least two vessels that are normally operated by different organizations with different operating procedures. Compatibility is of great

importance and relies to some degree on the two parties. Additionally, most bunkering occurs within port jurisdictions where local authorities (e.g., ports) may assume a leading role to ensure risk-management measures are implemented.

Any shore-based facility is likely to require some form of risk assessment under applicable regulations and policies, in accordance with the size and location of the facility. Transfer, either offloading or onloading, between a shore facility and an LNG carrier involves many similar risk factors to bunkering.

## 6.6 Regulatory Gaps and Recommendations

Transport Canada policies have several perceived high-level gaps in the current and planned Canadian regulatory regime for LNG-fuelled vessels, LNG carriers, and the onshore facilities that are needed for an Arctic LNG supply chain. Most notably, the regulatory needs around bunkering of LNG-fuelled ships exhibit significant gaps and uncertainties.

### Design and Construction

As the use of bunkering vessels increases, there is concern with how these vessels are regulated. The IGC Code can be applied, however, the nature of the bunkering operation is different than the usual IGC Code vessel given the alongside position that exists between a bunkering vessel and a receiving ship, often in congested ports and harbours. There is also no requirement for risk assessment of the design, though LNG tanker operations are normally subjected to extensive and stringent assessments.

### Operation in Canadian Waterways and Ports

LNG-fuelled vessels are now operating in most Canadian waterways and in many ports with no need for special provisions or restrictions. The situation regarding LNG carriers, and particularly smaller bunkering vessels and local supply carriers, is less clear. The escort tugs and pilotage requirements required for large LNG carriers are not needed for smaller carriers, leaving a regulatory gap for bunkering vessels and smaller LNG carriers. Overlapping jurisdictions among federal agencies, port authorities, and other stakeholders increases the complexity.

Uncertainties in these areas can pose barriers to future LNG projects, and may increase costs and delays. The following are offered as recommendations to address the regulatory gaps and uncertainties that marine LNG projects may encounter in the Arctic:

Design:

- Clarify expectations for risk assessments of various aspects of design.
- Facilitate an exchange of information on best practices and of safety concerns. Collate information to allow for a more consistent evaluation of risks.
- Develop a policy for smaller LNG carriers, similar to that in the IGF Code, to address bunkering needs of larger LNG-fuelled vessels operating in the Arctic.
- Transport Canada and other federal bodies formulate policy and provide guidance on route to approval for small-scale LNG plants serving shore-side facilities.

#### Operations:

- › Consider suitable restrictions on coastal navigation and loading and offloading of cargoes for LNG carriers such as are required to build Arctic LNG infrastructure.
- › Regulatory bodies work together to define realistic worst-case scenarios that should be considered in risk assessments.

#### Personnel:

- › Transport Canada provides approvals for basic and advanced training programs, including any expectations for personnel who are to operate bunkering vessels and LNG carriers.
- › Establish a suitable level of training specific to bunkering operations.

## 6.7 Conclusions

An effective regulatory framework for the design, build, and operation of vessels and onshore facilities is critical for the establishment of an Arctic marine LNG supply chain. This includes international, federal, provincial/territorial, and other instruments such as classification society rules, industry standards, and guidance on best practices.

The trend toward performance-based elements has increased the need for risk assessments of the many combinations of hardware, procedures, and training used to ensure safety in handling and using LNG.

There are some gaps and uncertainties in the current Canadian regulatory framework, particularly for vessels/barges that may be used for larger scale bunkering and/or local LNG distribution. The approvals process for small-scale shore-side LNG facilities is also unclear.



## 7.1 Introduction

This chapter presents the results of the Implementation Scenarios, based on the previously presented seven case study results, to first generate a picture of all the emissions from shipping in the Canadian Arctic region and then to consider the impact of various implementation scenarios for the uptake of LNG as a ship fuel in the Arctic. This analysis assesses the fuel demand and emissions impacts these scenarios would have.

While earlier chapters on Economics (Chapter 2) and Environment (Chapter 3) focused on individual vessels, the focus here is the overall fleet of ships in the Canadian Arctic region in a typical year. The implementation scenarios evaluate what the impact would be if each type of vessel studied were to switch to natural gas fuel. The present discussion on implementation scenarios relies on the technical feasibility and fuel supply options from these earlier studies.

Case Study 2 – Tuktoyaktuk to Cambridge Bay – in Chapter 4 considers the implications of locally produced LNG for use in the Arctic. The best practices for design, development and regulatory approvals of any new infrastructure are well documented in Chapter 1 (Technological Readiness) and Chapter 6 (Regulations); therefore, no additional information on locally produced LNG is provided in this section.

In considering the fleet of ships that currently use Canada's Arctic waters, the implementation scenarios attempt to answer the following questions:

1. How many ships of each type visit each year?
2. What fuels do these ships currently burn?

3. What are the emissions from these ships?
4. If the ships represented by the case examples switched to LNG fuel:
  - a. What would the change in Canadian Arctic region emissions be?
  - b. How much LNG would be required and at what locations to supply these ships?

## 7.2 Shipping Fuel Use and Emissions in Canada's Arctic

Canada's Arctic region is defined, for the purposes of this study, as the Northern Canada Vessel Traffic Services (NORDREG) Zone and is made up of Canadian waters north of 60 degrees latitude and Hudson Bay. Drawing on publicly available data sources, such as Environment and Climate Change Canada's online Marine Emissions Inventory Tool (MEIT), this chapter characterizes the fleet of ships travelling in these waters and quantifies the emissions from these ships.

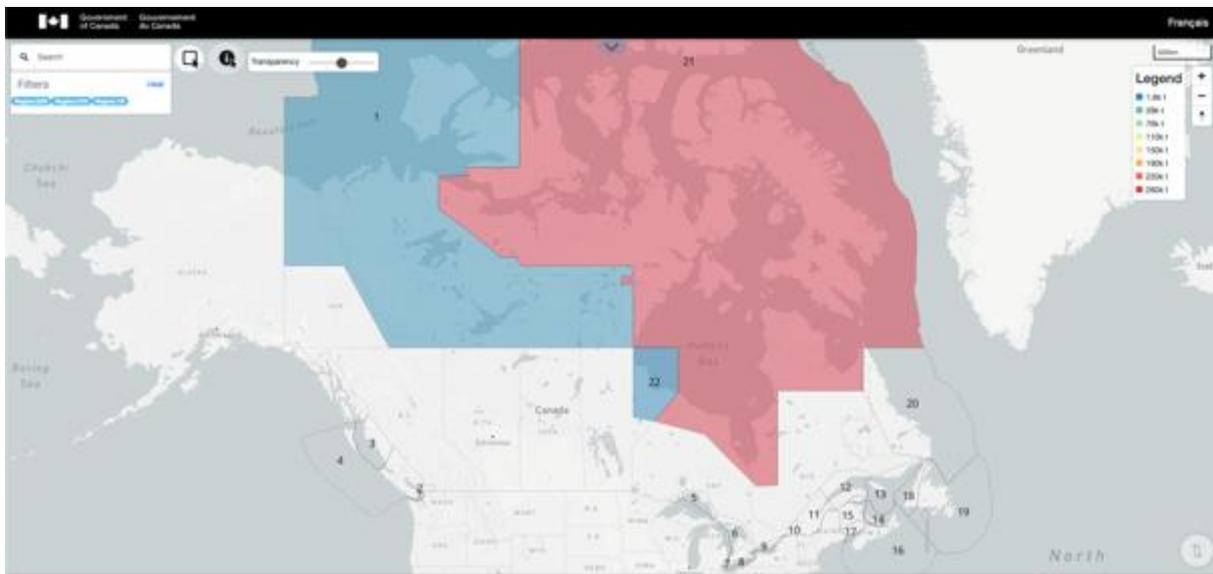


Figure 22: Marine Emissions Inventory Tool Region Map

For comparison purposes, MEIT regions were grouped as follows:

- > Arctic                    1, 21, 22
- > Pacific                    2, 3, 4
- > Great Lakes            5, 6, 7, 8, 9
- > St. Lawrence            10, 11
- > Atlantic                  12, 13, 14, 15, 16, 17, 18, 19, 20, 21

Using 2019 data from MEIT, the GHG emissions were estimated for each region in megatonnes (or millions of metric tonnes) of CO<sub>2</sub>-e, as shown in Table 12.

**Table 12: Canadian Shipping Greenhouse Gas Emissions for 2019 in Megatonnes**

| Region       | 2019 GHG Emissions<br>Megatonnes CO <sub>2</sub> -e | Percentage of Total |
|--------------|---|---------------------|
| Pacific      | 3.53  | 40.6%               |
| Atlantic     | 3.48  | 40.0%               |
| St. Lawrence | 0.82  | 9.4%                |
| Great Lakes  | 0.60  | 6.9%                |
| Arctic       | 0.27  | 3.1%                |
| Grand Total  | 8.70  | 100.0%              |

The Canadian Arctic region shipping was responsible for 0.27 megatonnes of CO<sub>2</sub>-e emissions in 2019, representing approximately 3% of total emissions from shipping in and around Canadian waters. Although this is significantly lower than emissions from the large, heavily trafficked regions off the Pacific Coast and Atlantic Coast of Canada, it is in the same order of magnitude as emissions from the Great Lakes and St. Lawrence regions.

Refer to Table 13 for Arctic shipping emissions in 2019 by ship type, aligned with the case studies considered previously.

**Table 13: Arctic Shipping Emissions in 2019 by Ship Type**

| MEIT Ship Type                        | Summary Ship Type        | Case Number |
|---------------------------------------|--------------------------|-------------|
| Coast Guard Icebreaker                | CCG Icebreaker           | A1          |
| Coast Guard Rescue                    | Other                    |             |
| Coast Guard Supply                    | Other                    |             |
| Coast Guard Tender                    | Other                    |             |
| Cruise                                | Cruise                   | A4          |
| Factory Ship                          | Fishing Vessel           |             |
| Fishing Vessel                        | Fishing Vessel           |             |
| Merchant (Tanker)                     | Tanker                   | A3          |
| Merchant Bulk                         | Bulk Carrier             | A7          |
| Merchant Chemical                     | Tanker                   | A3          |
| Merchant Chemical/Oil Products Tanker | Tanker                   | A3          |
| Merchant General                      | General Cargo            | A2          |
| Merchant Ore/Bulk/Oil                 | Icebreaking Bulk Carrier | A6          |
| Merchant Passenger                    | Other                    |             |
| Special Purpose Research VSL          | Other                    |             |
| Special Purpose Supply VSL            | Other                    |             |
| Trawler                               | Fishing Vessel           |             |
| Tug                                   | Tug                      |             |
| Tug Harbour                           | Tug                      |             |
| Tug Ocean                             | Tug                      |             |
| Tug Supply                            | Tug                      |             |
| Warship Surface                       | Other                    |             |

The summary by ship type of individual GHG emissions including CO<sub>2</sub>, methane, nitrous oxide (N<sub>2</sub>O), black carbon and CO<sub>2</sub>-e emissions calculated according to the MEIT methodology<sup>1</sup> is summarised in Table 14.

**Table 14: 2019 Canadian Arctic Greenhouse Gas Emissions by Ship Type in Metric Tonnes**

| Ship Type                | Case | Black Carbon | CO <sub>2</sub> | Methane | N <sub>2</sub> O | CO <sub>2</sub> -e | % of Total |
|--------------------------|------|--------------|-----------------|---------|------------------|--------------------|------------|
| General Cargo            | A2   | 3.9          | 67,900          | 1.0     | 3.8              | 69,053             | 25.4%      |
| Bulk Carrier             | A6   | 2.8          | 61,902          | 1.0     | 3.4              | 62,937             | 23.2%      |
| Tanker                   | A3   | 1.4          | 31,393          | 0.4     | 1.7              | 31,902             | 11.7%      |
| CCG Icebreaker           | A1   | 2.8          | 24,516          | 0.4     | 1.2              | 24,882             | 9.2%       |
| Cruise                   | A4   | 1.7          | 16,808          | 0.2     | 0.8              | 17,048             | 6.3%       |
| Icebreaking Bulk Carrier | A7   | 0.8          | 12,480          | 0.2     | 0.6              | 12,671             | 4.7%       |
| Sub-Total                |      | 13.4         | 214,998         | 3.2     | 11.5             | 218,494            | 80.4%      |
| Fishing Vessel           |      | 1.1          | 31,593          | 0.4     | 1.7              | 32,116             | 11.8%      |
| Tug                      |      | 1.3          | 9,801           | 0.2     | 0.5              | 9,954              | 3.7%       |
| Other                    |      | 0.8          | 11,028          | 0.2     | 0.6              | 11,205             | 4.1%       |
| Total                    |      | 16.5         | 267,420         | 4.0     | 14.3             | 271,769            | 100.0%     |

The six case study vessels in Table 14 represent approximately 80% of shipping GHG emissions in the Canadian Arctic region. A similar summary of other air pollution emissions by ship type, including nitrogen oxides (NO<sub>x</sub>), sulphur oxides (SO<sub>x</sub>), and particulate matter, is presented as Table 15.

**Table 15: 2019 Canadian Arctic Air Pollution Emissions by Ship Type in Metric Tonnes**

| Vessel Type              | NO <sub>x</sub> | SO <sub>x</sub> | Particulate Matter |
|--------------------------|-----------------|-----------------|--------------------|
| Bulk Carrier             | 1,416.8         | 866.9           | 107.0              |
| General Cargo            | 1,369.7         | 967.6           | 95.7               |
| Tanker                   | 659.4           | 436.2           | 40.4               |
| Icebreaking Bulk Carrier | 205.3           | 171.9           | 9.5                |
| Fishing Vessel           | 511.3           | 0.3             | 2.6                |
| CCG Icebreaker           | 559.0           | 0.2             | 5.8                |
| Cruise                   | 285.9           | 158.3           | 18.8               |
| Tug                      | 162.3           | 0.1             | 2.4                |
| Other                    | 190.0           | 0.1             | 2.7                |
| Total                    | 5,359.8         | 2,601.6         | 284.9              |

Ship traffic data was collected by researchers from the University of Ottawa Environment, Society, and Policy Group (van Luijk, 2019) to identify the numbers of unique vessels in the Canadian Arctic between

<sup>1</sup> 100-year global warming potential from Intergovernmental Panel on Climate Change Fourth Assessment Report excluding black carbon

2010 and 2018. Using 2018 as a representative year for vessel traffic, the fuel consumption of vessels by case study number was assessed in thousands of metric tonnes using the latest available (2019) data from MEIT as shown in Table 16.

**Table 16: Canadian Arctic Region Shipping and Fuel Use**

| Vessel Type               | Number of Vessels in 2018* | Fuel Consumed in Arctic in 2019 in thousands of metric tonnes | Case Number |
|---------------------------|----------------------------|---|-------------|
| General Cargo             | 17                         | 21.8  | A2          |
| Bulk Carriers             | 33                         | 19.9  | A7          |
| Tanker                    | 14                         | 10.1  | A3          |
| CCG Icebreaker            | 7                          | 7.6   | A1          |
| Cruise                    | 10                         | 5.4   | A4          |
| Ice-breaking Bulk Carrier | 3                          | 4.0   | A6          |
| Sub-Total                 | 84                         | 68.8  |             |
| Fishing Vessel            | 32                         | 9.9   |             |
| Tug                       | 18                         | 3.1   |             |
| Other                     | 35                         | 3.4   |             |
| Grand Total               | 169                        | 85.2  |             |

\* Using 2018 as a representative year for Arctic marine traffic based on University of Ottawa research (van Luijk, 2019)

Vessel types represented by cases from this study make up 84 of the 169 vessels in the region (50%) and 68.8 of the 85.2 thousand metric tonnes (80%) of fuel consumed

### 7.3 Vessel Implementation Scenarios

The implementation scenarios consider the implications if the ships whose type matches with a case study number were to switch to LNG fuel. For each vessel type, the emissions impact, economic impact, investment, and fuel demand are calculated for the portion of the voyage that occurs within the Canadian Arctic region.

Emissions impact is calculated by applying the percentage change in emissions due to the adoption of LNG to the baseline emissions previously established for the fleet of the corresponding ship type. The emissions calculated are those that occur during voyages within the Arctic region.

Economic impact is calculated using the results described in Chapter 2 (Economic Aspects) with a methodology adapted to the business model of the vessel under consideration. The difference in fuel cost (currently lower for LNG than MDO) and amount of fuel required (less LNG than MDO) when switching from MDO to LNG is addressed by identifying the heating values (or energy density) for each fuel to create a comparative ratio. This approach determined that 1 metric tonne of LNG provides 13% more energy than 1 metric tonne of MDO. Applying this energy equivalency in dollars per metric tonne (\$/MT) provided the overall savings associated with switching from MDO to LNG in each scenario.

Where possible, the investment required to convert a vessel to use LNG fuel is also calculated using the case study results applied to the fleet of vessels.

## International – Ice-going Bulkers

**Scenario:** Bulk carriers calling on mines in the Canadian Arctic region to collect raw material for export are converted to use LNG instead of MDO required by HFO ban.

Reference Case: A7

Number of vessels: 33

**Emissions Impact Calculation:** Canadian Arctic region emissions from MEIT x Chapter 3 (Environmental) Factors as demonstrated by the table in section 7.4 - Summary of Emissions Impact.

**Economic Impact Calculation:** Impact on cost of mining operations in the Canadian Arctic = # vessels x Fuel consumption x Price differential of MDO vs. LNG

|                                 |   |
|---------------------------------|---|
| Fuel consumption                | 3,374 metric tonnes MDO per vessel per year |
| Price difference (savings)      | 93 \$/metric tonnes equivalent              |
| Total Economic Impact (savings) | \$10.4 million per year                     |

**Investment Calculation:** Retrofit cost of LNG vessels from Chapter 2 (Economic) x # vessels

|                                 |               |
|---------------------------------|---------------|
| Incremental investment per ship | \$22 million  |
| Total incremental investment    | \$726 million |

**Fuel Demand Calculation:** Fuel use in one season from Chapter 2 (Economic) x # vessels

|                         |                                    |
|-------------------------|------------------------------------|
| Arctic fuel consumption | 2,761 metric tonnes LNG per vessel |
| Total fuel demand       | 91,113 metric tonnes per year      |

### Notes:

- › Fuel is purchased in Europe
- › Reference case assumes the best available low-methane emissions engines. If Low Pressure Dual Fuel (MS-LPDF) engines are used instead, methane emissions increase, limiting or eliminating the GHG reduction but reducing NO<sub>x</sub> emissions.
- › Newbuild LNG-fuelled bulk carriers are available as an alternative to the conversion considered in this scenario.

## Quebec – General Cargo

**Scenario:** Arctic sealift ships replaced with best available technology LNG-powered ships instead of ships using MDO.

Reference Case: A2

Number of vessels: 17

**Emissions Impact Calculation:** Canadian Arctic region emissions from MEIT x Chapter 3 (Environmental) Factors, as demonstrated by the table in section 7.4 - Summary of Emissions Impact.

**Economic Impact Calculation:** Impact on cost of goods delivered to the Canadian Arctic = # vessels x Arctic fuel consumption x Price differential of MDO vs. LNG

|                                 |                                  |
|---------------------------------|----------------------------------|
| Arctic fuel consumption         | 538 metric tonnes MDO per vessel |
| Price difference (savings)      | 163 \$/metric tonnes equivalent  |
| Total Economic Impact (savings) | \$1.5 million per year           |

**Investment Calculation:** Incremental cost of LNG vessels from Chapter 2 (Economic) x # vessels

|                                 |                |
|---------------------------------|----------------|
| Incremental investment per ship | \$5.5 million  |
| Total incremental investment    | \$93.5 million |

**Fuel Demand Calculation:** Fuel use in one season from Chapter 2 (Economic) x # vessels

|                         |                                  |
|-------------------------|----------------------------------|
| Arctic fuel consumption | 440 metric tonnes LNG per vessel |
| Total fuel demand       | 7,480 metric tonnes per year     |

**Notes:**

- > Reference case assumes the best available low-methane emissions engines. If Low Pressure Dual Fuel engines are used instead, methane emission increase, limiting or eliminating the GHG reduction but reducing NO<sub>x</sub> emissions.
- > Vessels will take on fuel in Quebec for each voyage. Currently there is only truck-to-ship bunkering available.

**Quebec – Tanker**

**Scenario:** Arctic fuel delivery ships replaced with best available LNG-powered ships instead of ships using MDO.

Reference Case: A3

Number of Vessels: 14

**Emissions Impact Calculation:** Canadian Arctic region emissions from MEIT x Chapter 3 (Environmental) Factors, as demonstrated by the table in section 7.4 - Summary of Emissions Impact.

**Economic Impact Calculation:** # vessels x Arctic fuel consumption x Price differential of MDO vs. LNG

|                                 |                                 |
|---------------------------------|---------------------------------|
| Arctic fuel consumption         | 531 metric tonnes MDO           |
| Price difference (savings)      | 163 \$/metric tonnes equivalent |
| Total Economic Impact (savings) | \$1.2 million per year          |

**Investment Calculation:** Incremental cost of LNG vessels from Chapter 2 (Economic) x # vessels

|                                 |               |
|---------------------------------|---------------|
| Incremental investment per ship | \$5.5 million |
| Total incremental investment    | \$66 million  |

**Fuel Demand Calculation:** Fuel use in one season from Chapter 2 (Economic) x # vessels

|                         |                                  |
|-------------------------|----------------------------------|
| Arctic fuel consumption | 434 metric tonnes LNG per vessel |
| Total fuel demand       | 6,076 metric tonnes per year     |

**Notes:**

- > Reference case assumes the best available low-methane emissions engines. If Low Pressure Dual Fuel engines are used instead, methane emission increase, limiting or eliminating the GHG reduction but reducing NO<sub>x</sub> emissions.
- > Vessels will take on fuel in Quebec for each voyage. Currently there is only truck-to-ship bunkering available.

**Quebec – Icebreaking Bulkers**

**Scenario:** Icebreaking bulk carriers that service mines in the Canadian Arctic region are retrofitted with best available technology LNG systems instead of using MDO.

Reference Case: A6

Number of vessels: 3

**Emissions Impact Calculation:** Canadian Arctic region emissions from MEIT x Chapter 3 (Environmental) Factors, as demonstrated by the table in section 7.4 - Summary of Emissions Impact.

**Economic Impact Calculation:** Impact on cost of mining operations in the Canadian Arctic = # vessels x Fuel consumption x Price differential of MDO vs. LNG

|                                 |                                    |
|---------------------------------|------------------------------------|
| Fuel consumption                | 4,904 metric tonnes MDO per vessel |
| Price difference (savings)      | 163 \$/metric tonnes equivalent    |
| Total Economic Impact (savings) | \$2.4 million per year             |

**Investment Calculation:** Retrofit cost of LNG vessels from Chapter 2 (Economic) x # vessels

|                                 |              |
|---------------------------------|--------------|
| Incremental investment per ship | \$22 million |
| Total incremental investment    | \$66 million |

**Fuel Demand Calculation:** Fuel use in one season from Chapter 2 (Economic) x # vessels

|                         |                                   |
|-------------------------|-----------------------------------|
| Arctic fuel consumption | 4013 metric tonnes LNG per vessel |
| Total fuel demand       | 12,039 metric tonnes per year     |

**Notes:**

- › Reference case assumes the best available low-methane emissions engines. If Low Pressure Dual Fuel engines are used instead, methane emission increase, limiting or eliminating the GHG reduction but reducing NO<sub>x</sub> emissions.
- › Vessels will take on fuel in Quebec for each voyage. Currently there is only truck to ship bunkering available.

**Arctic – CCG Icebreaker**

**Scenario:** New CCG icebreakers are built as LNG-fuelled ships.

Reference Case: A1

Number of vessels: 6

**Emissions Impact Calculation:** Canadian Arctic region emissions from MEIT x Chapter 3 (Environmental) Factors, as demonstrated by the table in section 7.4 - Summary of Emissions Impact.

**Economic Impact Calculation:** Annual savings to the CCG calculated as fuel used in one season for Icebreakers from MEIT x Price difference of ULSD vs. in Arctic LNG Price from Chapter 4 (Infrastructure).

|                                 |                                 |
|---------------------------------|---------------------------------|
| Fuel Demand                     | 3,557 metric tonnes ULSD        |
| Price Difference (savings)      | 167 \$/metric tonnes equivalent |
| Total Economic Impact (savings) | \$3.5 million per year          |

**Investment Calculation:** Unable to calculate – refer to Chapter 2 (Economic) for additional information.

**Fuel Demand Calculation:** Fuel use in one season for Icebreakers from MEIT converted to LNG

|                 |                             |
|-----------------|-----------------------------|
| LNG Fuel Demand | 19,026 metric tonnes of LNG |
|-----------------|-----------------------------|

**Notes:**

- › Diesel-electric configuration currently limits choice of medium-speed engines to Low Pressure Dual Fuel technology which has higher methane emissions and therefore more limited GHG reduction potential.
- › Range requirement necessitates refuelling in the Arctic so this implementation scenario is contingent on LNG availability in the Arctic region.

**Arctic – Cruise Ship**

**Scenario:** Canadian-flagged LNG-fuelled cruise ships originating in Iqaluit replace current international cruise vessels visiting the Canadian Arctic region

Reference Case: A4

Number of Vessels: 10

**Emissions Impact Calculation:** Canadian Arctic region emissions from MEIT x Chapter 3 (Environmental) Factors, as demonstrated by the table in section 7.4 - Summary of Emissions Impact.

**Economic Impact Calculation:** Value of fuel purchased in Arctic calculated as # vessels x annual fuel demand x Chapter 4 (Infrastructure) cost

|                             |   |
|-----------------------------|---|
| Annual fuel demand          | 1,582 metric tonnes LNG per vessel            |
| Price of LNG from Chapter 4 | 911 \$/metric tonnes of LNG in Nunavut        |
| Economic Benefit            | \$14.4 million annual revenue from fuel sales |

**Investment Calculation:** Cost of LNG-fuelled cruise ships not calculated

**Fuel Demand Calculation:** Fuel use in one season from Chapter 2 (Economic) x # vessels

|                         |                                    |
|-------------------------|------------------------------------|
| Arctic fuel consumption | 1,582 metric tonnes LNG per vessel |
| Total fuel demand       | 15,820 metric tonnes per year      |

**Notes:**

- › Scenario is dependent on investment in LNG-fuelled cruise ships
- › Diesel-electric configuration currently limits choice of medium-speed engines to Low Pressure Dual Fuel technology which has higher methane emissions and therefore more limited GHG reduction potential.
- › Necessitates refuelling in Arctic so this implementation scenario is contingent on LNG availability in the Arctic region.

## 7.4 Summary of Emissions Impact

The change in emissions from baseline for the six implementation scenarios are calculated by applying the percentage change as calculated in Chapter 2 (Economic). The engine technologies (a non-exhaustive sample of possible engines) deployed in each implementation scenario are defined in Chapter 3 (Environmental). Because the MEIT data used to derive the baseline emissions assumes HFO use, the emissions changes in this section are presented in two steps:

Step 1: Move to distillate (MDO or ULSD) in response to HFO ban

Step 2: Move to natural gas in the form of LNG for the implementation scenario

## Greenhouse Gas Emissions

**Table 17: Impact on CO<sub>2</sub> Emissions of Implementation Scenarios in Metric Tonnes**

| Vessel Type              | HFO       |               | → Distillate (MDO/ULSD) |              | → LNG              |         |
|--------------------------|-----------|---------------|-------------------------|--------------|--------------------|---------|
|                          | Baseline  | Change vs HFO | Percent                 | New Baseline | Change vs MDO/ULSD | Percent |
| Bulk Carrier             | 67,899.6  | (1,862.7)     | -3%                     | 66,036.98    | (17,654.5)         | -27%    |
| General Cargo            | 61,901.6  | (1,508.5)     | -2%                     | 60,393.06    | (16,636.6)         | -28%    |
| Tanker                   | 31,393.5  | (724.9)       | -2%                     | 30,668.53    | (8,561.6)          | -28%    |
| Icebreaking Bulk Carrier | 12,479.8  | (354.1)       | -3%                     | 12,125.70    | (3,209.9)          | -26%    |
| CCG Icebreaker*          | 24,515.9  | -             | -                       | 24,515.87    | (5,238.5)          | -21%    |
| Cruise                   | 16,807.6  | (433.9)       | -3%                     | 16,373.7     | (3,499.8)          | -21%    |
| Total                    | 214,998.0 | (4,884.1)     |                         | 210,113.9    | (54,800.9)         |         |

\* using ULSD fuel, not HFO

**Table 18: Impact on Black Carbon Emissions of Implementation Scenarios in Metric Tonnes**

| Vessel Type              | HFO      |               | → Distillate (MDO/ULSD) |              | → LNG              |         |
|--------------------------|----------|---------------|-------------------------|--------------|--------------------|---------|
|                          | Baseline | Change vs HFO | Percent                 | New Baseline | Change vs MDO/ULSD | Percent |
| Bulk Carrier             | 2.8      | (2.1)         | -74%                    | 0.73         | (0.6)              | -77%    |
| General Cargo            | 3.9      | (2.5)         | -63%                    | 1.43         | (1.2)              | -85%    |
| Tanker                   | 1.4      | (0.8)         | -59%                    | 0.56         | (0.5)              | -87%    |
| Icebreaking Bulk Carrier | 0.8      | (0.6)         | -77%                    | 0.19         | (0.1)              | -77%    |
| CCG Icebreaker*          | 2.8      | -             | -                       | 2.75         | (2.5)              | -91%    |
| Cruise                   | 1.7      | (1.2)         | -68%                    | 0.53         | (0.5)              | -95%    |
| Total                    | 13.4     | (7.2)         |                         | 6.20         | (5.4)              |         |

\* using ULSD fuel, not HFO

**Table 19: Impact on Methane Emissions of Implementation Scenarios in Metric Tonnes**

| Vessel Type              | HFO      |               | → Distillate (MDO/ULSD) |          | → LNG              |         |
|--------------------------|----------|---------------|-------------------------|----------|--------------------|---------|
|                          | Baseline | Change vs HFO | Percent                 | Baseline | Change vs MDO/ULSD | Percent |
| Bulk Carrier             | 1.0      | -             | 0%                      | 1.00     | 19.0               | 1904%   |
| General Cargo            | 1.0      | -             | 0%                      | 0.99     | 18.7               | 1887%   |
| Tanker                   | 0.4      | -             | 0%                      | 0.43     | 8.1                | 1903%   |
| Icebreaking Bulk Carrier | 0.2      | -             | 0%                      | 0.15     | 2.9                | 1899%   |
| CCG Icebreaker*          | 0.4      | -             | -                       | 0.44     | 240.1              | 54827%  |
| Cruise                   | 0.2      | -             | 0%                      | 0.19     | 103.4              | 55113%  |
| Total                    | 3.2      | -             |                         | 3.19     | 392.2              |         |

\* using ULSD fuel, not HFO

Table 20: Impact of CO<sub>2</sub>-e GWP 100 Emissions of Implementation Scenarios in Metric Tonnes

| Vessel Type              | HFO       |               | → Distillate (MDO/ULSD) |           | → LNG              |         |
|--------------------------|-----------|---------------|-------------------------|-----------|--------------------|---------|
|                          | Baseline  | Change vs HFO | Percent                 | Baseline  | Change vs MDO/ULSD | Percent |
| Bulk Carrier             | 64,459.8  | (3,732.4)     | -6%                     | 60,727.40 | (17,594.4)         | -29%    |
| General Cargo            | 71,456.1  | (3,743.7)     | -5%                     | 67,712.34 | (17,167.9)         | -25%    |
| Tanker                   | 32,641.8  | (1,454.6)     | -4%                     | 31,187.15 | (8,757.5)          | -28%    |
| Icebreaking Bulk Carrier | 13,223.2  | (925.6)       | -7%                     | 12,297.58 | (3,252.2)          | -26%    |
| CCG Icebreaker*          | 27,008.1  | -             | 0%                      | 27,008.14 | (292.7)            | -1%     |
| Cruise                   | 18,336.6  | (1,476.4)     | -8%                     | 16,860.16 | (856.2)            | -5%     |
| Total                    | 227,125.5 | (11,332.8)    |                         |           | (47,920.9)         | -21%    |

\* using ULSD fuel, not HFO

### Other Air Pollutants

Table 21: Impact on NO<sub>x</sub> Emissions of Implementation Scenario

| Vessel Type              | HFO      |               | → Distillate (MDO/ULSD) |          | → LNG              |         |
|--------------------------|----------|---------------|-------------------------|----------|--------------------|---------|
|                          | Baseline | Change vs HFO | Percent                 | Baseline | Change vs MDO/ULSD | Percent |
| Bulk Carrier             | 1,416.8  | -             |                         | 1,416.82 | -                  | 0%      |
| General Cargo            | 1,369.7  | -             |                         | 1,369.68 | -                  | 0%      |
| Tanker                   | 659.4    | -             |                         | 659.39   | -                  | 0%      |
| Icebreaking Bulk Carrier | 205.3    | -             |                         | 205.29   | -                  | 0%      |
| CCG Icebreaker*          | 559.0    | -             |                         | 559.02   | (490.5)            | -88%    |
| Cruise                   | 285.9    | -             |                         | 285.9    | (250.2)            | -88%    |
| Total                    | 4,496.1  | -             |                         | 4,496.1  | (740.6)            | -16%    |

\* using ULSD fuel, not HFO

Table 22: Impact on SO<sub>x</sub> Emissions of Implementation Scenarios after IMO 2020 and HFO Ban

| Vessel Type              | HFO      |               | → Distillate (MDO/ULSD) |              | → LNG              |         |
|--------------------------|----------|---------------|-------------------------|--------------|--------------------|---------|
|                          | Baseline | Change vs HFO | Percent                 | New Baseline | Change vs MDO/ULSD | Percent |
| Bulk Carrier             | 866.9    | (694.0)       | -80%                    | 172.88       | (165.4)            | -96%    |
| General Cargo            | 967.6    | (774.6)       | -80%                    | 192.96       | (178.0)            | -92%    |
| Tanker                   | 436.2    | (336.8)       | -77%                    | 99.41        | (92.0)             | -93%    |
| Icebreaking Bulk Carrier | 171.9    | (138.5)       | -81%                    | 33.39        | (32.1)             | -96%    |
| CCG Icebreaker*          | 0.2      | -             | -                       | 0.22         | (0.2)              | -81%    |
| Cruise                   | 158.3    | (125.8)       | -79%                    | 32.5         | (30.6)             | -94%    |
| Total                    | 2,601.1  | (2,069.8)     | -80%                    | 531.4        | (498.2)            | -94%    |

\* using ULSD fuel, not HFO

**Table 23: Impact on Particulate Matter Emissions of Implementation Scenarios after IMO 2020 and HFO Ban**

| Vessel Type              | HFO      |               | → Distillate (MDO/ULSD) |              | → LNG              |         |
|--------------------------|----------|---------------|-------------------------|--------------|--------------------|---------|
|                          | Baseline | Change vs HFO | Percent                 | New Baseline | Change vs MDO/ULSD | Percent |
| Bulk Carrier             | 107.0    | (79.7)        | -75%                    | 27.26        | (25.9)             | -95%    |
| General Cargo            | 95.7     | (68.1)        | -71%                    | 27.58        | (26.2)             | -95%    |
| Tanker                   | 40.4     | (28.9)        | -71%                    | 11.52        | (11.5)             | -99%    |
| Icebreaking Bulk Carrier | 9.5      | (7.1)         | -75%                    | 2.40         | (2.3)              | -95%    |
| CCG Icebreaker*          | 5.8      | -             | -                       | 5.81         | (5.1)              | -88%    |
| Cruise                   | 18.8     | (13.7)        | -73%                    | 5.1          | (4.9)              | -96%    |
| Total                    | 277.1    | (197.5)       | -71%                    | 79.7         | (75.8)             | -95%    |

\* using ULSD fuel, not HFO

## 7.5 Supply Chain Options

The fuel demand from each of the vessel implementation scenarios was aggregated and compared to current local supply options.

### International LNG Demand

The 33 ice-going bulk carriers from case A7 would require approximately 91,000 metric tonnes per year of LNG. According to the Port of Rotterdam bunkering sales data, 213,250 m<sup>3</sup> of LNG were sold in Q3 of 2021, which approximates to 426,500 metric tonnes per year. The incremental demand from the ice-going bulk carrier scenario could therefore likely be absorbed by current LNG bunkering capacity in Rotterdam or other European ports.

### Quebec LNG Demand

The potential demand for LNG to be supplied from Quebec is as follows:

- › Direct LNG bunkering of ships refuelling of up to 24,727 metric tonnes per year
  - General Cargo 7,480 metric tonnes per year
  - Tanker 5,208 metric tonnes per year
  - Icebreaking Bulker 12,039 metric tonnes per year
- › Fuel to be transported to the Arctic to refuel ships in the region up to 22,520 metric tonnes per year
  - Icebreakers 6,700 metric tonnes per year
  - Cruise 15,820 metric tonnes per year

There is also potential demand for LNG to replace diesel used by communities and industry in the Canadian Arctic region (as discussed in Chapter 4). The total demand could be accommodated by a small-scale LNG plant, similar to the one operated by Énergir. The capacity of the Énergir plant is 436,000 m<sup>3</sup> of LNG that equates to approximately 200,000 tonnes per year compared to the total demand of all Quebec-based scenarios of around 50,000 tonnes per year.

## Arctic LNG Demand

The total potential demand for LNG in the Arctic is assumed to be required at the port of Iqaluit, as the only port facility in the Arctic planned at present. The calculated 22,520 metric tonnes of LNG that is required to supply icebreakers and cruise ships is assumed (as per above) to be supplied from a location in Quebec. This compares to the 30,000 m<sup>3</sup> storage tank considered in Case Study 1 of Chapter 4 that could accommodate approximately 15,000 metric tonnes of LNG. This case study assumed that a small LNG carrier would deliver multiple loads of fuel to replenish the supply of LNG in the storage tank.

## 7.6 Conclusions

Shipping in Canada's Arctic region is responsible for an estimated 0.27 megatonnes of CO<sub>2</sub>-e emissions each year from 169 individual vessels. The change in emissions due to a fuel switch to LNG was calculated for six common vessel types in the region: bulk carriers, general cargo ship, tankers, ice-going bulk carriers, icebreakers and cruise ships. These six implementation scenarios represent 50% of the ships and 80% of the emissions in the region.

Emissions analysis of these implementation scenarios showed significant SO<sub>x</sub> and particulate matter reductions. CO<sub>2</sub> emissions were also reduced in all cases as was black carbon, a powerful short-lived climate forcer with particularly significant effect in the Arctic. However, emissions of methane, a powerful short-term GHG, increased. The change in 100-year global warming potential CO<sub>2</sub>-e emissions in the Canadian Arctic region from the implementation scenarios is heavily dependent on which engine technology is used, with limited or no benefit from using the highest methane emissions engines and up to 29% reduction from the best available technology.

Fuel demand for LNG from these implementation scenarios was calculated and compares favorably with the available capacity in Europe and Quebec. New infrastructure would be required to supply vessels that require refuelling in the Arctic, such as CCG vessels and expedition cruise ships.



## 8.1 Introduction

This chapter outlines the potential environmental and economic impacts, both to Canada and to Arctic communities, that may be expected from a shift to the use of liquefied natural gas (LNG) in the marine sector in Canada's Arctic region. The primary focus is on the consequences – direct and indirect – if LNG is substituted as a fuel for shipping activity in Canada's Arctic region.

Conclusions from the previous chapters are brought together and integrated to provide clear facts for ship owners and operators and other impacted parties that include Arctic communities and industries in Canada.

## 8.2 Environmental Impact

This section provides a consolidated view of the environmental impacts of the use of LNG as a fuel in the Arctic. While the focus is on ship fuel, it also considers the impact of supplying LNG in place of diesel fuel that is currently delivered by tanker ship and used primarily for power generation in the Canadian Arctic region.

### Summary of Risks and Benefits

The emissions and pollution risk from shipping comes from a relatively small number of ships (169) that call on Canada's Arctic region each year. As noted in Chapter 7 (Implementation Scenarios), 80% of the emissions come from just six ship types, all of which are capable of being switched to LNG based on the modelling and analysis described previously.

Several positive environmental benefits were identified should these ships switch to LNG as a fuel, including benefits to human health and the environment from reduced sulphur oxides (SO<sub>x</sub>) and particulate matter emissions. These pollution reduction opportunities go beyond the reductions from implementation of the IMO global 0.5% sulphur emissions limit or even the contemplated Arctic Sulphur Emissions Control Area that would reduce sulphur emissions to 0.1%.

Emissions of black carbon, a powerful short-lived climate forcer with particularly significant effect in the Arctic, were likewise found to be reduced. CO<sub>2</sub> emissions from ship engine operations were reduced; however, the study identified a risk from increased methane emissions from ships using LNG. Methane is the main component of natural gas and is a powerful short-lived greenhouse gas. The level of methane emissions was found to be heavily dependent on the technology used to power the ships that switch to LNG fuel. In some cases the negative effects of methane emissions could outweigh the benefits from reducing CO<sub>2</sub> and black carbon emissions.

Similar environmental benefits are also available should the diesel generators used to generate electricity for Arctic communities be switched to natural gas engine power with LNG instead of diesel delivered by ship. The same risk from excessive methane emissions exists in this application; careful methane management in power generation is essential to achieve overall emissions reductions with an increased use of natural gas.

Although spills from oil cargo or fuel in the Arctic are rare, the environmental impact of such a spill was found to be basically eliminated if the substance spilled is LNG rather than residual fuel oil or diesel.

### **Air Pollution Impacts from Shipping**

The impact of air pollution on human health and the environment is well understood and documented. Particulate matter emitted in ship engine exhaust occurs from combustion of fuel in the ship engine and is exacerbated by the sulphur content in fuels. Additional particulates are formed through atmospheric chemical processes acting on the SO<sub>x</sub> and NO<sub>x</sub> gases also formed during combustion. These particulates are responsible for approximately 60,000 cardiopulmonary and lung cancer deaths annually on a global scale, concentrated in coastal areas near major shipping routes (Corbett et al 2007) and have been the subject of international attention through various pollution reduction measures. Shipping in the Canadian Arctic region also contributes to these harmful emissions that impacts the health of Northern residents and the natural environment in which they live.

This study has found that SO<sub>x</sub> and particulate matter emissions are reduced by ships burning LNG. These reductions are over and above the reduction achieved by the implementation of the 0.5% IMO sulphur emissions limit. Implementation scenarios in Chapter 7 found that 498 metric tonnes of SO<sub>x</sub> emissions were eliminated (a reduction of 94%). The remaining sulphur emissions come from sulphur in the pilot fuel used to ignite the natural gas in the gas engines. This could be further reduced by using ultra-low sulphur pilot fuel. Implementation scenarios indicated that 76 metric tonnes of particulate matter were eliminated (a reduction of 95%).

In most cases, NO<sub>x</sub> emissions remained similar even when ship engines are switched to natural gas fuel. Implementation scenarios did not find any NO<sub>x</sub> reduction below the current Tier II limits currently in place except when four-stroke medium-speed low-pressure dual-fuel engines are used. In these cases, NO<sub>x</sub> emissions below the more restrictive Tier III limits are achieved (an 88% reduction from the baseline). However, these engines also have the highest methane emissions which negatively impacts the GHG emissions reductions associated with switching to LNG fuel. More details on NO<sub>x</sub> emissions are provided in the Chapter 3 (Environment) and Chapter 7 (Implementation Scenarios).

A concern raised by a working group participant during a feedback session related to the future ban on HFO use is that ship operators may not switch to pure distillate fuels (MDO or ULSD) as is assumed in this study, but could potentially instead use other blended fuels compliant with the HFO ban that increase particulate matter emissions. A similar concern was raised at the IMO Pollution Prevention and Response sub-committee in February 2020 in relation to the increases in particulate matter from blended fuels used to comply with the IMO 2020 sulphur emissions limit. The use of natural gas as a fuel mitigates this risk.

### **Greenhouse Gas Emissions Impact from Shipping**

This study has found that greenhouse gas emissions from shipping can be reduced if LNG is used as a fuel for ships. CO<sub>2</sub> and black carbon emissions were found to be reduced in all cases but methane emissions increased. Combining these effects into a ship-level CO<sub>2</sub>-equivalent emissions calculation showed a wide range of results due to the range of methane emissions from different ship engine technologies. The engines with the highest methane emissions show an increase in CO<sub>2</sub>-equivalent emissions, while the best available technologies achieved a 31% decrease in emissions overall. A lifecycle assessment that includes the upstream emissions from fuel production and distribution conducted as part of Chapter 3 (Environment) showed a similar result, highlighting the impact methane emissions have on overall emissions.

CO<sub>2</sub> emissions reductions of between 21% and 28% were found, with implementation scenarios in Chapter 7 identifying 54 thousand metric tonnes of CO<sub>2</sub> emissions reduction potential. The variation in CO<sub>2</sub> emissions reduction benefit is due to the operating parameters of the vessels studied as part of Chapter 3 (Environmental), and the fuel efficiency of different natural gas engine technologies, with the largest benefits attributed to the most fuel-efficient engines.

Black carbon emissions reductions of between 77% and 95% were found as part of the emissions modelling. Implementation scenarios identified 5.4 metric tonnes of black carbon emissions reduction potential, noting that the baseline from which reductions were calculated may be under-reporting the total black carbon emissions from shipping.

The baseline oil-based fuels like HFO, MDO or ULSD produce very small amounts of methane during combustion. The introduction of natural gas as a fuel creates methane emissions as small amounts of unburnt fuel pass through the engine into the exhaust, the levels of which vary significantly depending on the engine technology used. If only the implementation scenarios that use the best available technologies are implemented, 48 metric tonnes of methane emissions per year will be added to Arctic region emissions. However, the two additional implementation scenarios with high methane emissions engine technology add 344 metric tonnes of additional annual methane emissions from these two scenarios alone.

Both methane and black carbon are considered short-lived climate pollutants that have an amplified near-term warming impact on climate. In the low-methane emissions case examples, the reduction in black carbon emissions achieved by the switch to natural gas fuel more than offsets the increase in methane emissions, even if a short time-horizon of 20 years is used to evaluate the impact on global temperature increases. However, this is reversed in the high methane emissions cases as the short-term impact of methane emissions outweighs the benefits from reductions in black carbon emissions.

The risk of increased particulate matter emissions if oil-based fuels are permitted under the HFO ban also has greenhouse gas implication as a portion of these emissions are black carbon. Natural gas fuel would mitigate this potential risk.

The greenhouse gas emissions benefit from switching to LNG is dependent on the engine technology selected with little or no benefit derived from the use of high methane emissions engine technologies, while low methane emissions technologies can generate up to 30% reductions, even when taking into account upstream emissions from natural gas exploration and production.

### **Air Pollution Impacts from Diesel used for Power Generation Delivered by Ship**

Most of the electricity in the Canadian Arctic region is generated by diesel generators fueled by diesel delivered by tanker ship. Chapter 4 (Infrastructure) used Natural Resources Canada data to estimate these deliveries and found the volume of diesel delivered to the Canadian Arctic region by tanker ship to be approximately 272 million liters in 2017. Renewable electricity sources like wind and solar electricity have thus far had limited penetration in the region, and many communities are continuing to invest in diesel fuel storage and generation capacity. The high cost of delivered diesel contributes to the fact that Nunavut and Northwest Territories have the highest cost of electricity in all of Canada's territories and provinces.

The study identified the combustion of diesel delivered by ship to Arctic settlements and industries for generating electricity creates CO<sub>2</sub> emissions of approximately 757 thousand metric tonnes per year. This is more than double the emissions from all shipping in the Canadian Arctic region. Furthermore, black carbon emissions from the diesel engines used to power the generators are higher than those from ships because of the high ratio of black carbon to particulate matter in the four-stroke high-speed diesel engines used in these applications. Chapter 4 (Infrastructure) estimated black carbon emissions from this source to be 156 metric tonnes per year.

Natural gas presents an alternative to diesel for these applications and LNG could be transported by ship into the Arctic or manufactured in the Arctic from local gas reserves present. These scenarios were explored in more detail in Chapter 4. The environmental risks and benefits of replacing diesel generators with natural gas-fuelled generators are similar to those from shipping.

### **Oil Spill Risk**

Although the HFO ban that comes into effect between 2024 and 2029 will largely eliminate the use and carriage of persistent oil by ships in Canada's Arctic region, the risks presented by waivers and exemptions to these measures has been noted. And while distillate fuels that are compliant with the HFO ban, like diesel or MDO, present less of a persistent risk to the environment than HFO, a major diesel spill would nevertheless be very damaging because of the toxicity of diesel to marine life.

Chapter 3 (Environment) of this project considered the impact of an LNG spill; in general, while spills and other accidental releases of LNG are highly undesirable and do represent a safety risk, from an environmental standpoint they are far more benign than either HFO or diesel oil spills. After a release, LNG will vaporize and will become lighter than air and disperse rapidly as it warms. Although an LNG spill poses a safety hazard to equipment and personnel in the immediate area, and GHGs in the form of methane are released into the atmosphere, from an environmental standpoint it is more benign than conventional fuel oil spills as LNG releases do not require any clean-up effort. The GHG impact of the probable number of spills is considerably less than that created by the combustion of conventional fuel.

## 8.3 Economic Impact

This section provides a consolidated view of the economic impacts of the use of natural gas as a fuel in the Arctic with a focus on ship fuel, but also considering the impact of diesel fuel delivered by tanker ship used primarily for power generation in the Canadian Arctic Region. The conclusions are drawn primarily from the work conducted on Economics, Infrastructure, Human Resources, Regulations, and Implementation Scenarios for this project.

### Summary of Risks and Benefits

LNG represents an attractive lower-cost alternative to petroleum-based fuels like MDO or ULSD that will be required to be used widely as the HFO ban comes into effect in the Arctic. All the ships examined as part of this study would benefit from operating cost reductions should they use LNG as an alternative fuel and this would result in lower cost of goods transported to Arctic communities, lower operating costs for industry and government, and lower electricity prices from lower costs of transporting diesel to fuel generators.

However, Chapter 2 has documented that LNG-fuelled ships are more expensive to build and converting existing ships to use LNG fuel is also a significant investment. The best available technology that has the lowest methane emissions is the high-pressure dual-fuel engine technology. But these engines are currently only available for larger ships, and this technology is more expensive and far less common. Low-pressure technology (Otto cycle) is available for low, medium, and high-speed engines. The less expensive but high-methane emissions low-pressure dual-fuel engines are far more common; however, their use is likely to face greater scrutiny as lifecycle methane emissions become factored into clean fuel standards and energy efficiency index calculations. Engine manufacturers continue to work on methane emission reduction measures, which may lead to some increase in the cost of future models.

### Opportunities for Arctic Community Cost of Living Reduction

A report titled, "Assessment of the benefits and impacts associated with a ban on the use and carriage of heavy fuel oil as fuel by ships operating in the Arctic" prepared by the Government of Canada in 2019 for submission to the IMO sub-committee on Pollution Prevention and Response indicated that the compounding impact of the IMO 2020 sulphur emissions cap and the HFO ban would increase shipping costs for delivering goods to Arctic communities by between 13% and 20% because of the higher cost of distillate fuel like MDO. This impact of the passthrough of these cost increases on a representative household in Nunavut was found to be between \$248 and \$679 a year. The analysis did not consider the potential increase in the price of electricity because of the increased delivery cost of diesel.

Chapter 2 (Economic) analysis concluded that LNG prices in Quebec are comparable to heavy fuel oil prices on an energy equivalent basis, so that ships using LNG instead of distillate fuel to comply with the HFO ban would have operating costs comparable to the original baseline before IMO 2020 sulphur limits or the HFO ban came into place. However, Chapter 2 analysis also highlighted the incremental investment required and found that payback periods for shipowners could range from 4 to 13 years depending on fuel prices. However, the ongoing health and economic benefits for communities should be taken into consideration for policy development.

## **Opportunities for Canadian Mining Company Operating Cost Reduction**

Mining operations in Canada's Arctic region are heavily reliant on ships to transport in supplies and transport out ore for processing. Many of the case examples developed for this study are relevant to mining operations in the Canadian Arctic region. In particular:

- › Ice-going bulk carriers (Case A7) collect ore and export it for processing overseas
- › Icebreaking bulk carriers (Case A6) bring fuel and supplies to mines and collect ores for delivery to processing plants in Canada

The annual savings to mining companies from these two vessel cases was calculated to be approximately \$12.8 million; however, the Economic analysis in Chapter 2 also determined that the payback period for converting these vessel types was the longest of all those considered, between 16 and 25 years.

## **Opportunities for Canadian Coast Guard Operating Cost Reduction**

The Canadian Coast Guard provides icebreaking services annually with between 5 and 7 icebreakers active in the region in any one season. Some of the operating costs of these vessels are passed on to commercial ship operators in the categories above as a fee for service. Using LNG as a fuel for icebreakers (Case A1) instead of diesel was calculated to deliver an annual savings of \$3.5 million. However, the only engine technology currently available for this application is the high methane emissions engines, which if used for this application, resulted in an increase in CO<sub>2</sub>-equivalent emissions.

## **Opportunities for Exploitation of Local Natural Gas Reserves**

Chapter 4 (Infrastructure) identified that the Inuvialuit Petroleum Corporation's proposed Inuvialuit Energy Security Project will involve the construction of a small-scale LNG plant connected to a gas supply near Tuktoyaktuk, NT. As part of Case Study 2 – Tuktoyaktuk to Cambridge Bay – this chapter further examined the feasibility and cost competitiveness of transporting LNG to a location to be used for marine applications such as bunkering or for local power generation instead of diesel. Even after absorbing the cost of infrastructure described in Case Study 2, the delivered cost of LNG was found to be attractive. Should implementation scenarios develop that require bunkering of LNG in the Arctic (see Chapter 7), this proposed Inuvialuit Energy Security Project could contribute to local demand for gas in the Canadian Arctic Region.

## **Opportunities for LNG Fuel Sales in the Arctic**

Should cruise and Canadian Coast Guard ships convert to using LNG instead of diesel fuel, there is an opportunity for Arctic-based businesses to provide refuelling services to these vessels that are active in the Arctic region. The annual revenue from fuel sales to ships requiring refuelling in the Arctic could be as high as \$14.4 million per year according to calculations performed as part of the Implementation Scenarios in Chapter 7.

## **Opportunities for LNG Infrastructure Construction**

The infrastructure required to support vessels that convert to using LNG fuel represents an opportunity through increased local investment. International bulk carriers calling on Canadian ports do not require any additional investment in Canada, however, the other cases considered could require additional

investment in LNG liquefaction, storage and refuelling if the full volumes of fuel considered in the implementation scenarios were required. The implementation scenarios indicated that a small- to medium-scale LNG plant could adequately supply all of the domestic shipping needs. An LNG refuelling jetty similar to the one described in Chapter 1 (Technological Readiness) would also be required.

If the two ship types that require refuelling in the Arctic (cruise ships and CCG icebreakers) did convert to LNG fuel, then LNG storage and bunkering facilities would also be required at a convenient location in the Arctic. Chapter 4 (Infrastructure) provides further detail on the infrastructure required.

## 8.4 Conclusions

Case examples from this study have demonstrated the environmental and economic benefits that could result if ships use natural gas in the form of LNG as a fuel rather than petroleum-based distillate fuels like MDO and ULSD. The study has also identified a significant risk in certain cases to the potential greenhouse gas benefits due to excess methane emissions.

This study identified a number of positive environmental benefits should these ships switch to natural gas as a fuel, including benefits to human health and the environment from reduced SO<sub>x</sub> and particulate matter emissions.

Emissions of black carbon, a powerful short-lived climate forcer with particularly significant effect in the Arctic, were found to be reduced. CO<sub>2</sub> emissions from ship engine operation were also reduced. However, the study identified increased methane emissions from shipping using natural gas fuel. The level of methane emissions was found to be heavily dependent on the technology used to power the ships that switch to LNG fuel, and in some cases the negative effects of increased methane emissions could outweigh the benefits from CO<sub>2</sub> and black carbon emissions reduction. Suppliers claim significant progress in measures to reduce methane slip, but the best available technology is still not widely available for different ship types. Regulators are considering how to factor this into future policies and requirements.

These same environmental benefits are also available should the diesel generators used to generate electricity for Arctic communities be switched to natural gas engine power with LNG delivered by ship instead of diesel, with the same risk from methane emissions. Careful management of methane emissions is essential to achieve GHG emissions reductions from the use of natural gas for power generation.

Although spills from oil cargo or fuel in the Arctic are extremely rare, the environmental impact of such a spill was found to be basically eliminated if the substance that is spilled is LNG rather than residual fuel oil or diesel.

LNG represents an attractive lower-cost alternative to petroleum-based fuels like MDO or ULSD that will be required to be used widely as the HFO ban comes into effect in the Arctic. All the ships examined as part of this study would benefit from operating cost reductions should they use LNG as an alternative and this would result in lower costs of goods transported to Arctic communities, lower operating costs for industry and government, and lower electricity prices from lower costs of transporting diesel to fuel generators.

The cost of building an LNG-fuelled ships remains significantly higher than a conventionally fuelled vessel. Converting existing ships to be LNG-fuelled is also a significant investment. The payback

periods for these investments depend on the ship type, operating profile (including any additional Arctic infrastructure), and fuel prices.

The best available technology that has the lowest methane emissions is the high-pressure dual-fuel engine technology. But these engines are currently only available for larger ships, and this technology is more expensive and far less common. The less expensive but high methane emissions low-pressure dual-fuel engines are far more common; however, their use is likely to face greater scrutiny as lifecycle methane emissions become factored into clean fuel standards and energy efficiency index calculations. However, for some ships and services, the use of LNG fuel is attractive on both an economic and environmental basis.

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