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Canadian Marine Liquefied Natural Gas (LNG) Supply Chain Project - Arctic

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Since some of the accepted measures in the industry are imperial, metric measures are not always used in this report.

Un sommaire français se trouve avant la table des matières.

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17. Abstract

This report describes all aspects required for the development of a supply chain for LNG as a marine fuel in the Arctic region of Canada.

It describes the technologies involved, and the different types of investment required on land and on new and existing ships. The economics for different ship types are analyzed, to identify the most attractive candidates and the potential payback period for investments. Environmental benefits of switching from fuel oils to natural gas are quantified, taking the whole supply chain into account. Regulatory considerations are identified, and recommendations are provided as to how federal and provincial reviews and approvals can be facilitated. Human resource requirements and training needs are also taken into account. Potential implementation strategies are developed, taking the future needs of short sea and international services into account. The potential benefits of a move towards LNG fuel are discussed, examining a range of sectors and stakeholders.

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17. Résumé

Ce rapport décrit tous les aspects nécessaires pour la mise en place d'une chaîne d'approvisionnement en gaz naturel liquéfié (GNL) qui serait utilisé comme carburant marin dans la région de l'Arctique canadien.

Il présente les technologies nécessaires, ainsi que les différents types d'investissement requis tant dans les installations à terre que sur les navires existants et nouveaux. Les données économiques relatives aux différents types de navire sont analysées afin de déterminer les candidats les plus intéressants et d'évaluer la période de récupération potentielle pour les investissements. Les avantages pour l'environnement rattachés à la transition du mazout vers le gaz naturel sont également quantifiés, selon une approche qui englobe la chaîne d'approvisionnement dans son ensemble. Les facteurs relatifs à la réglementation sont signalés, et des recommandations sont formulées afin de faciliter le plus possible les approbations et les examens fédéraux et provinciaux. Les besoins en ressources humaines et en formation sont également pris en considération. Des stratégies de mise en œuvre potentielles sont présentées, qui prennent en compte les besoins futurs en services à courte distance et en services internationaux. Les avantages potentiels d'une transition vers le GNL comme carburant sont examinés, du point de vue d'un éventail de secteurs et d'intervenants.

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Inuvialuit Petroleum Corporation and Inuvialuit Regional Corporation

Inuit Tapiriit Kanatami

INOCEA

International Council on Clean Transportation

ITB Marine Group / Island Tug and Barge

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EXECUTIVE SUMMARY

The Canadian Natural Gas Vehicle Alliance has led a series of government/industry projects which released studies on the feasibility of liquified natural gas (LNG) as a marine fuel in Canada's West Coast in 2014, followed in 2016 by Canada's East Coast, Great Lakes and St. Lawrence regions. This latest phase delivers a similar study for the Canadian Arctic region.

Technology Readiness

The report provides a summary review of all the technologies that may be required, and those that are currently available, as part of a future LNG supply chain system for Canada's Arctic region, focusing on marine operations. It addresses some areas where development work is underway and identifies others where work may be required to enhance the performance of LNG-fuelled systems and/or to reduce their cost.

The scope of the review covers:

- The inherent characteristics of natural gas and the possible variations in gas properties;
- Liquefaction and bulk storage systems;
- Distribution systems such as bulk cargo and feeder vessels, barges, rail and road vehicles, local tanks;
- Bunkering systems;
- Onboard storage and fuel distribution technologies;
- Engine technologies for various types of dual-fuel and pure natural gas engines, including their characteristics and drawbacks;
- The integration of natural gas engines into propulsion packages using mechanical and electrical drive systems;
- Safety technologies associated with the transportation of natural gas and its use as a fuel;
- Technical standards available for the certification of equipment using LNG; and
- Ongoing research and development (R&D) activities associated with all the above.

Natural gas is predominantly methane but can contain smaller amounts of other gaseous hydrocarbons and other impurities that are mostly removed prior to liquefaction. LNG from worldwide sources is a reasonably consistent substance although variability can still lead to some combustion challenges. The emergence of small-scale liquefaction technology has helped to establish local LNG sources, and there have been considerable recent developments in storage systems for both shore-side and onboard installations.

A rapid increase in the number of bunkering vessels and barges is serving the needs of large deep-water vessels. Earlier adopters typically used truck supply, which is still common for low power or low endurance vessels. Bunkering system technology has become safer to use and more reliable.

Most ship installations continue to use dual-fuel technology in which a traditional liquid fuel is the pilot source for natural gas ignition, but it can also provide the main power if LNG is unavailable. Dual-fuel engines include "diesel" type engines operating on either the Otto or Diesel combustion cycles with either two- or four-stroke cycles, with the two-stroke mainly for larger engines. The Otto cycle tends to allow more methane slip (i.e., it releases more unburnt methane), particularly at part power. Reducing methane slip is a key challenge for engine design and operation, as the amount of methane slip can reduce or reverse the greenhouse gas benefits of using LNG.

LNG carriers have an excellent historical safety record, and there is a similar safety culture around LNG-fuelled vessels, with a comprehensive set of codes, rules, regulations and standards, and through the development of a range of safety equipment and systems, from gas-detection sensors to fail-safe transfer couplings. Risk assessments are mandatory for LNG-fuelled vessel design and operation to ensure that technical and procedural measures address their specific characteristics.

R&D is an ongoing effort in areas such as engine technology, fuel storage, boil-off gas (BOG) management, flow monitoring, and others.

Overall, the technological challenges of establishing LNG as a mainstream fuel for ships have been addressed and the technology is mature. Operation of LNG-fuelled ships in Canada's Arctic present no significant challenges while offering benefits compared to conventionally fuelled ships. There are no major technical challenges to refuel such ships in the Arctic but new processes and infrastructure are required to distribute and store bunker LNG fuel in the Arctic and to transfer it to a ship's tank.

Economics

The report explores the economic aspects of adopting LNG as a marine fuel, focusing on the vessel owner/operator's investment decision-making.

Findings confirm that the adoption of LNG can be economically attractive for vessel owners and operators, depending on the nature of their operations and the price of LNG and other fuels. The following key variables impact the payback period and economic feasibility of LNG for a vessel:

- Price differential between fuel oils and LNG
- Fuel Consumption
- Capital costs for LNG systems

This study focused on seven vessels that are representative of vessels operating within the Canadian Arctic. These include Canadian Coast Guard (CCG) Icebreaker, General Cargo, Tanker, Cruise Ship, LNG Carrier, Icebreaking Bulker and Icegoing Bulker. The vessels were modelled with different fuel options, including heavy fuel oil (HFO), marine diesel oil (MDO), and LNG. Most of the vessel case studies are newbuilds, with conversion options considered for the bulker types.

The low cost of HFO makes it the fuel of choice for many vessels. However, many vessel operators will soon face the decision of whether to switch to MDO or LNG in response to the HFO ban in the Arctic to be implemented between 2024 and 2029. For vessels now using HFO, the study analyzed three fuel options to cover both the current state and future options. For vessels already using MDO, the analysis compares MDO and LNG.

Key particulars were established for each of the studied vessels to determine the capital costs associated with each of the fuel options. Creating typical voyage profiles for time spent in the Arctic and outside the Arctic ensured that fuel consumption accounted for a complete year of service. The analysis used average fuel costs for 2021 to determine the current life cycle costs, which when analyzed together with the calculated capital costs, produced a payback period for each vessel.

The study determined that current LNG pricing results in significant payback periods that make the switch from HFO non-viable at this time. However, when comparing to MDO/ULSD, a switch to LNG has much shorter payback periods so vessel operators could realize significant savings in fuel costs through the life cycle of the vessel.

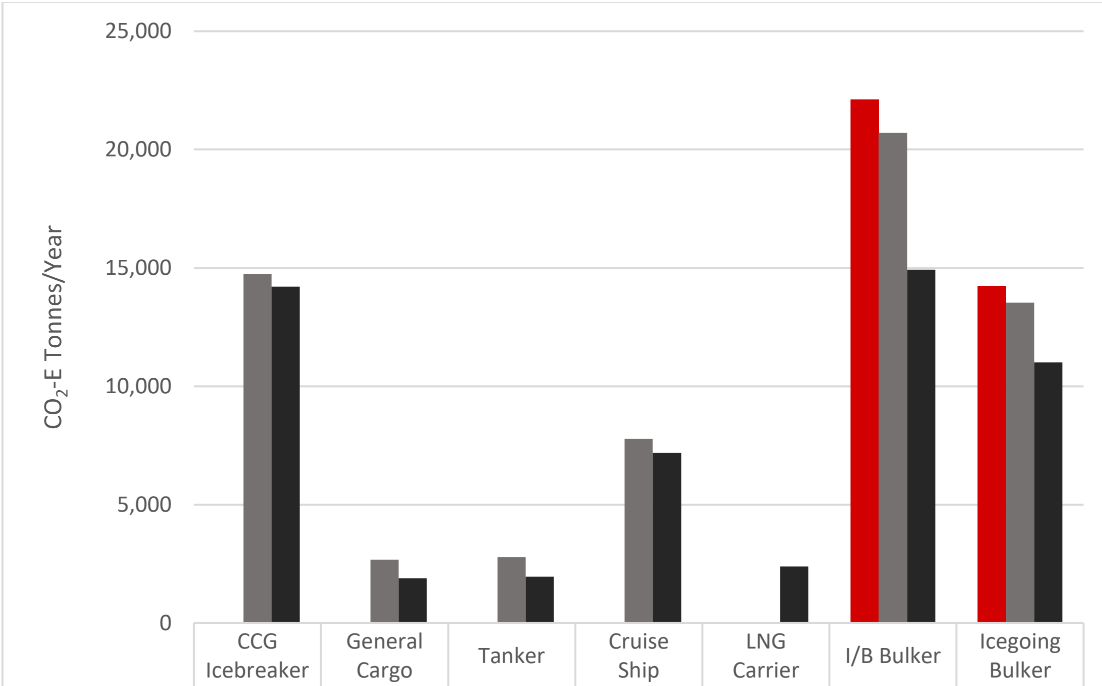
Environmental

This project explored the environmental aspects of adopting LNG as a marine fuel. The work addressed emissions generated at the ship level as well as the greenhouse gas (GHG) and other emissions from well to wake. The emissions benefits of using LNG were modelled for seven ship case studies, each using three different fuel options.

As the cleanest burning fossil fuel, LNG offers environmental benefits that include reductions in carbon dioxide (CO_2), sulphur oxides (SO_X), nitrogen oxides (NO_X), black carbon (BC), and particulate matter (PM). These reductions in emissions can help operators meet current environmental regulations from the International Maritime Organization (IMO) and related domestic legislation. Beyond current regulations, there are progressive regulatory changes that could drive the use of LNG as a marine fuel. The GHG benefit of LNG is recognized in IMO's Energy Efficiency Design Indices for new designs and existing ships (EEDI and EEXI respectively) and in the Carbon Intensity Index (CII) which are being applied progressively to reduce overall GHG emissions from the global shipping industry.

The potential life cycle emissions benefit of using LNG as a marine fuel, based on seven modelled vessel cases, ranged from 12-30% CO_2-equivalent (CO_2-e). The figure below shows the potential reduction of GHG emissions for the cases modelled, considering energy inputs for all aspects of natural gas production, liquefaction, and combustion. Actual environmental benefits are dependent upon the in-service operating profile of the vessels, engine performance, and LNG supply chain implementation.

While LNG can provide emissions benefits that support regulatory compliance, "methane slip" is an ongoing challenge. Methane is a potent GHG with a global warming potential (GWP) over a 100-year timeframe of 30. Methane slip is the term used to describe the release of unburned methane in the exhaust due to incomplete combustion. The amount of methane slip depends on whether the engine is operating on an Otto or Diesel combustion cycle. Otto cycle engines are more prone to methane slip compared to Diesel cycle engines. Manufacturers across the industry are working to improve engine performance. The Figure below incorporates current methane slip engine data.



	CCG Icebreaker	General Cargo	Tanker	Cruise Ship	LNG Carrier	I/B Bulker	Icegoing Bulker
HFO						22,114	14,235
MDO/ULSD	14,754	2,677	2,787	7,779		20,708	13,537
LNG	14,215	1,888	1,953	7,180	2,397	14,927	11,016

Lifecycle GHG emissions – Arctic Voyages Only

The amount of SO_X produced is directly proportional to the sulphur content of the fuel. As there is very little sulphur in LNG, SO_X emissions from an LNG-fuelled vessel are significantly less than from vessels consuming fuel oils.

The reduction in NO_X emissions depends on the type of gas engine used. Current LNG-fuelled medium-speed engines operate on the Otto combustion cycle, resulting in significant NO_X reduction and compliance with IMO Tier III requirements. By contrast, the direct injection slow-speed engine, used in the analysis, operates on the Diesel cycle and NO_X emissions reduction is non-existent. Engines that do not comply directly with NO_X limits will need to use supplementary NO_X emission control technologies.

PM emissions are the result of various impurities and incomplete combustion. Most PM emissions are harmful to humans, hence an increasing international focus to reduce them. Switching to LNG has significant PM benefits. BC emissions are a component of PM with a high GWP value. Switching to LNG significantly lowers BC emissions, in turn helping to reduce the CO_2-e GHG emissions.

Deep-sea shipping is responsible for most marine fuel consumption. These ships often use fuel oils with relatively high sulphur content outside the North American Coastal Emission Control Area (ECA), including Arctic waters. Until such time as LNG's availability, relative cost, and emission requirements allow for widespread adoption in the Arctic fleet, the use of LNG will have modest, though positive, effects on total emissions.

The analysis confirms that the adoption of LNG as a marine fuel can produce environmental benefits that include reduction in life cycle CO2e emissions by 4-32%. SO_X can be reduced by up to 99%, NO_X by up to 88%, BC by up to 95%, and PM by up to 99%. In addition, LNG's physical properties greatly reduce the potential for environmental damage such as oil slicks and residues from spills or shipping accidents.

Infrastructure

While natural gas itself is plentiful throughout Canada and the United States, there is currently very little LNG production or distribution capacity in the Arctic, with currently no capacity to support a fleet of LNG-fuelled marine vessels. For those vessels calling on the Canadian Arctic that originate in Europe, LNG bunkering is possible at a growing number of ports. For Canada, and the St. Lawrence Seaway in particular, expansion plans for domestic LNG production and various export-oriented projects are also under consideration.

Arctic communities and industries are heavily dependent on petroleum for power generation, resulting in high electricity prices and high levels of air pollution, GHG emissions and BC emissions. This study identified that 270 million litres of diesel fuel is delivered by sea annually to Arctic communities for combustion in diesel generators.

To illustrate what an Arctic LNG supply chain might look like, two case studies were analyzed for bringing LNG to two Arctic locations – Iqaluit and Cambridge Bay – for use as both a marine fuel and/or local domestic energy. From the case study analysis, the estimated price per gigajoule (GJ) of LNG is shown in the table below.

Case Study LNG Cost

	Location	LNG Cost ($/GJ)	DLE
Case Study 1	Iqaluit	$18.83	$0.69
Case Study 2	Cambridge Bay	$37.95	$1.39

The case studies look at two different ways that LNG could make an impact in the Arctic. With Case Study 1, the supply chain relies on southern infrastructure to do most of the feedstock processing. In Case Study 2, the supply chain is based solely in the Arctic, starting at the gas well. This describes a supply chain that could result in some level of energy independence for the Arctic. The costs and complexities of operating smaller scale Arctic-based LNG supply chains are reflected in the LNG price.

The overall conclusion is that it should be possible to develop an Arctic LNG Supply Chain at attractive prices ($/GJ) in comparison with fuel oil alternatives, as shown by the conversion of LNG prices to a diesel litre equivalent (DLE). DLE is a way to show the cost of LNG energy in terms that most people have an understanding of, the cost of diesel energy. However, LNG pricing is sensitive to many factors. Two key factors are the level of utilization of several capital-intensive assets, and the distances between the LNG production facility and the bunkering locations for the end users.

Human Resources

A complete LNG marine fuel supply chain relies on skilled personnel across all areas of the vessel life cycle. Relevant personnel for vessels designed and built or retrofitted in Canada include vessel designers, shipyards, original equipment manufacturers and certification and inspection authorities. For vessels in service, the personnel involved are seafarers, bunkering personnel, and emergency responders. Many of these personnel have ample experience with fuel oil-fuelled vessels, but all will need additional competencies to transition to LNG-fuelled vessels.

Since the previous LNG feasibility studies conducted for Canada's West Coast (2014), Canada's East Coast, Great Lakes and St. Lawrence regions (2016), there has been no significant change in competency requirements. The main change is that training courses have become more widely available, in Canada and elsewhere. The increasing number of LNG-fuelled vessels means that more personnel are gaining experience with LNG, which also streamlines the process for future vessels.

The competency requirements for personnel involved with the vessel in service have remained largely unchanged. For seafarers the key requirements come from the STCW Code, which has two levels: basic and advanced. Competency requirements for facility and shore-side bunkering personnel is largely detailed in (CSA, 2021) and the (NFPA, 2021).

Available training courses are identified for seafarers and bunkering and shore-side facility personnel as these are the main groups who need to undergo formal training for certifications. Consideration has been given to how training may be conducted for Arctic based facilities, although this is very situation specific. A combination of local training and travel to a main city are likely required.

Regulations

A regulatory framework is an essential element of a project involving the use of LNG as a marine fuel.

The number of LNG-fueled vessels worldwide and within Canada continues to grow. For these vessels the key requirements are detailed in the International Code of Safety for Ships using Gas Fuels (IGF), which is specifically focused on the use of gases or other low flashpoint fuels. Supplementary guidance and rules for LNG-fuelled vessels is also provided by classification societies and other bodies such as Society of International Gas Tanker and Terminal Operators (SIGTTO) and Society for Gas as a Marine Fuel (SGMF). Canada has developed policies that govern the approval and certification of LNG-fuelled designs. However, there are not yet similar policies, procedures or regulations for LNG carriers. These types of vessels will be needed to allow for bunkering of larger vessels with LNG, and for the local distribution of LNG in the Arctic if these are to become part of an implementation approach.

Another area of uncertainty is the approvals regime for small-scale LNG facilities covering transfer, storage, and (potentially) liquefaction in ports or at other locations in the Arctic and elsewhere. The approaches used for large-scale plants and terminals are onerous and time- consuming, and not appropriate to the types and levels of risk posed by smaller facilities.

There is an increasing body of knowledge within Canada and worldwide to address the hazards and risks posed by LNG design and operation, including bunkering operations. Currently all LNG-fuelled designs under the IGF Code and Canadian policies must have some elements undergo risk assessment, and bunkering operations are also reviewed in this way. Additional guidance from Transport Canada and/or other regulatory agencies would help with the quality and consistency of this work, and its extension to cover gas carrier (IGC Code) vessels.

Training programs are available for ship- and shore-side personnel, but formal approval of Canadian courses for compliance with Canadian and international standards is lagging.

Implementation Scenarios

To understand the impact of using LNG as a ship fuel in the Arctic, various implementation scenarios were developed and assessed against the emissions from past shipping in the Canadian Arctic region. This component draws on the case study results discussed in earlier sections to make an assessment of the fuel demand and emissions impact these scenarios would have. The implementation scenarios evaluate the impact if each type of vessel studied previously were to switch to LNG fuel.

The baseline for comparison was developed using data published by Environment and Climate Change Canada through the online Marine Emissions Inventory Tool (MEIT) for 2019, to determine the amount and type of emissions produced by the overall fleet of ships in the Canadian Arctic region in a typical year. The impact assessment assumes that the IMO 2020 sulphur cap and the HFO ban in the region are in force. As such, the economic and emissions impacts are assessed from a baseline of distillate fuels (MDO or ULSD), not heavy fuel oil.

Shipping in Canada's Arctic region is responsible for an estimated 0.27 Megatonnes of CO2e emissions each year from 169 individual vessels. The change in emissions due to a fuel switch to LNG has been calculated for six common vessel types in the region: bulk carriers, general cargo ships, tankers, icebreaking 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_X and PM reductions. CO2 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 the 100-year GWP CO2-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. Available capacity in Europe and Quebec should be sufficient to meet these demands. New infrastructure would be required to supply vessels that require refuelling in the Arctic.

Benefits to the Canadian Arctic

In conclusion, the study establishes the potential environmental and economic impacts, both to Canada and to Arctic communities, that may be expected from a shift to the use of LNG in the marine sector. 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. 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 cases where a risk to the potential greenhouse gas benefits due to higher methane emissions may negate the environmental benefits in some instances.

Environmental benefits include improvements to human health and the environment from reduced SO_X and PM emissions.

Emissions of black carbon, a powerful short-lived climate forcer with particularly significant effect in the Arctic, were found to be reduced. CO2 emissions from ship engine operation were also reduced. However, the study identified a risk from 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 CO2 and black carbon emissions reduction. Suppliers claim significant success in measures to reduce methane slip, while regulators are considering how to factor this into future 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. The same risk from methane emissions exists in this application.

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 more 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 LNG-fuelled ships remains significantly higher than that of conventionally-powered vessels, and conversions are particularly costly. The payback periods for these investments depend on the ship’s type and its operating profile, including any need for additional Arctic infrastructure. However, for some ships and services the use of LNG fuel is attractive on both an economic and an environmental basis.

RÉSUMÉ

L'Alliance canadienne pour les véhicules au gaz naturel (ACVGN) a dirigé une série de projets gouvernementaux et de projets industriels dans le cadre desquels des études ont été publiées sur la faisabilité du gaz naturel liquéfié (GNL) comme carburant marin sur la côte Ouest du Canada (2014) ainsi que sur la côte Est du Canada et dans les régions des Grands Lacs et du Saint-Laurent (2016). La phase en cours comportera une étude semblable pour la région de l'Arctique canadien.

Niveau de préparation technologique

Le rapport présente un examen sommaire de l'ensemble des technologies qui pourraient être nécessaires, et de celles qui sont actuellement disponibles, dans le cadre d'un futur système de chaîne d'approvisionnement en GNL pour la région de l'Arctique canadien, en mettant l'accent sur les opérations maritimes. Il traite de certains secteurs où des travaux préparatoires sont en cours et cible d'autres secteurs où des travaux pourraient être nécessaires pour améliorer la performance des systèmes alimentés au GNL ou réduire le coût de ceux-ci.

La portée de l'examen couvre les éléments suivants :

- les caractéristiques inhérentes au gaz naturel et les variations possibles des propriétés du gaz;
- la liquéfaction et les systèmes de stockage en vrac;
- les systèmes de distribution tels que les vraquiers et les navires collecteurs, les barges, les véhicules ferroviaires et les véhicules routiers, les réservoirs locaux;
- les systèmes de soutage;
- les technologies de stockage à bord et de distribution du carburant;
- les technologies de moteur pour divers types de moteurs bicarburants et de moteurs au gaz naturel pur, y compris leurs caractéristiques et leurs inconvénients;
- l'intégration des moteurs à gaz naturel dans des ensembles de propulsion utilisant des systèmes de transmission mécaniques et électriques;
- les technologies liées à la sécurité du transport du gaz naturel et à son utilisation comme carburant;
- les normes techniques disponibles pour la certification de l'équipement utilisant le GNL;
- les activités continues de recherche et de développement liées à tous les points énumérés ci-dessus.

Le gaz naturel est principalement composé de méthane, mais il peut contenir de petites quantités d'autres hydrocarbures gazeux et d'autres impuretés qui sont pour la plupart éliminés avant la liquéfaction. Le GNL provenant de sources mondiales est une substance raisonnablement homogène, bien que sa variabilité puisse néanmoins entraîner certains défis liés à la combustion. L'émergence de la technologie de liquéfaction à petite échelle a contribué à l'établissement de sources locales de GNL, et des avancées considérables ont été réalisées récemment dans le domaine des systèmes de stockage, tant pour les installations à terre que pour les installations à bord.

Une augmentation rapide du nombre de navires et de barges de soutage répond aux besoins des grands navires en eau profonde. Les premiers utilisateurs recouraient généralement à l'approvisionnement par camion, ce qui est encore courant pour les navires de faible puissance ou à basse autonomie. La technologie des systèmes de soutage est devenue plus sûre et plus fiable.

La plupart des installations à bord des navires continuent d'utiliser la technologie bicarburant, qui consiste à se servir d'un combustible liquide traditionnel comme veilleuse pour l'allumage du gaz naturel, mais qui peut également fournir l'énergie principale si le GNL n'est pas disponible. Les moteurs bicarburants comprennent les moteurs de type « diesel » fonctionnant selon le cycle de combustion d'Otto ou le cycle de combustion diesel, à deux temps ou à quatre temps. Le cycle à deux temps est principalement réservé aux plus gros moteurs. Le cycle d'Otto a tendance à produire davantage d'émanations de méthane (c.-à-d. qu'il libère plus de méthane imbrûlé), en particulier à puissance partielle. La réduction des émanations de méthane est un défi important de la conception et du fonctionnement des moteurs, car la quantité d'émanations de méthane peut réduire ou annuler les avantages que confère l'utilisation du GNL sur le plan de la production de gaz à effet de serre.

Les navires transporteurs de GNL affichent un excellent bilan de sécurité, et il existe une culture de sécurité semblable entourant les navires alimentés au GNL, reposant sur un ensemble complet de codes, de règles, de règlements et de normes, de même que sur la conception d'une gamme d'équipement et de systèmes de sécurité, allant des capteurs de gaz aux raccords de transfert à sécurité positive. Les évaluations des risques sont obligatoires pour la conception et l'exploitation des navires alimentés au GNL car elles permettent de garantir que les mesures techniques et les mesures procédurales soient adaptés aux caractéristiques uniques de chaque navire.

La recherche et le développement constituent une activité permanente dans des domaines comme la technologie des moteurs, le stockage du carburant, la gestion du gaz évaporé, la surveillance du débit, etc.

Dans l'ensemble, les défis technologiques liés à l'utilisation du GNL comme carburant principal pour les navires ont été relevés, et la technologie est parvenue à maturité. L'exploitation de navires alimentés au GNL dans l'Arctique canadien ne présente aucun défi important et offre des avantages par rapport aux navires alimentés de façon conventionnelle. Le ravitaillement en carburant de ces navires dans l'Arctique ne présente pas de défis techniques importants, mais de nouveaux processus et de nouvelles infrastructures sont nécessaires pour distribuer et stocker le GNL dans l'Arctique et pour transférer ce carburant dans le réservoir d'un navire.

Économie

Le rapport se penche sur les aspects économiques de l'adoption du GNL comme carburant marin et il est axé sur la prise de décisions en matière d'investissements du propriétaire ou de l'exploitant du navire.

Les résultats du rapport confirment que l'adoption du GNL peut être intéressante sur le plan économique pour les propriétaires et exploitants de navires, selon la nature de leurs activités et du prix du GNL et des autres carburants. Les variables principales suivantes ont une incidence sur la période de récupération et la faisabilité économique du choix du GNL pour un navire :

- la différence de prix entre le mazout et le GNL;
- la consommation de carburant;
- les coûts d'investissement pour les systèmes de GNL.

Cette étude a porté sur sept navires qui sont représentatifs des navires exploités dans l'Arctique canadien. Les sept navires comptent un brise-glace de la Garde côtière canadienne (GCC), un transporteur de marchandises générales, un pétrolier, un paquebot de croisière, un navire transporteur de GNL, un vraquier brise-glace et un vraquier équipé pour naviguer dans des eaux prises par les glaces. La modélisation des navires a été réalisée en fonction de plusieurs options de carburant, notamment le mazout lourd, le diesel et le GNL. La plupart des navires étudiés sont des constructions neuves; des options de conversion ont été envisagées pour les vraquiers.

Le faible coût du mazout lourd en fait le carburant de choix pour de nombreux navires. Cependant, de nombreux exploitants de navires devront bientôt prendre la décision de passer au diesel ou encore au GNL, étant donné l'interdiction du mazout lourd dans l'Arctique qui sera mise en œuvre durant la période allant de 2024 à 2029. En ce qui concerne les navires utilisant actuellement du mazout lourd, trois options de carburant ont été analysées dans le cadre de l'étude. Ces options tiennent compte à la fois de la situation actuelle et de la situation future. Quant aux navires utilisant déjà du diesel, une analyse comparative du diesel et du GNL est présentée.

Des éléments clés ont été ciblés pour chacun des navires étudiés afin de déterminer les coûts d'investissement associés à chacune des options de carburant. La création de parcours types (profils) représentant le temps passé dans l'Arctique et à l'extérieur de l'Arctique a permis de calculer la consommation de carburant pour une année complète de service. Dans le cadre de l'analyse effectuée, les coûts moyens du carburant pour 2021 ont été utilisés afin de déterminer les coûts actuels du cycle de vie. Ces coûts, analysés conjointement avec les coûts d'investissement calculés, ont permis d'établir la période de rentabilisation pour chaque navire.

D'après les résultats de l'étude, le prix actuel du GNL entraîne de longues périodes de rentabilisation qui font de l'abandon du mazout lourd une solution non viable pour le moment. Cependant, si l'on effectue la comparaison avec le diesel pur ou le diesel à très faible teneur en soufre, la transition vers le GNL offre des périodes de rentabilisation beaucoup plus courtes. Les exploitants de navires pourraient ainsi réaliser d'importantes économies sur les coûts de carburant tout au long du cycle de vie des navires.

Environnement

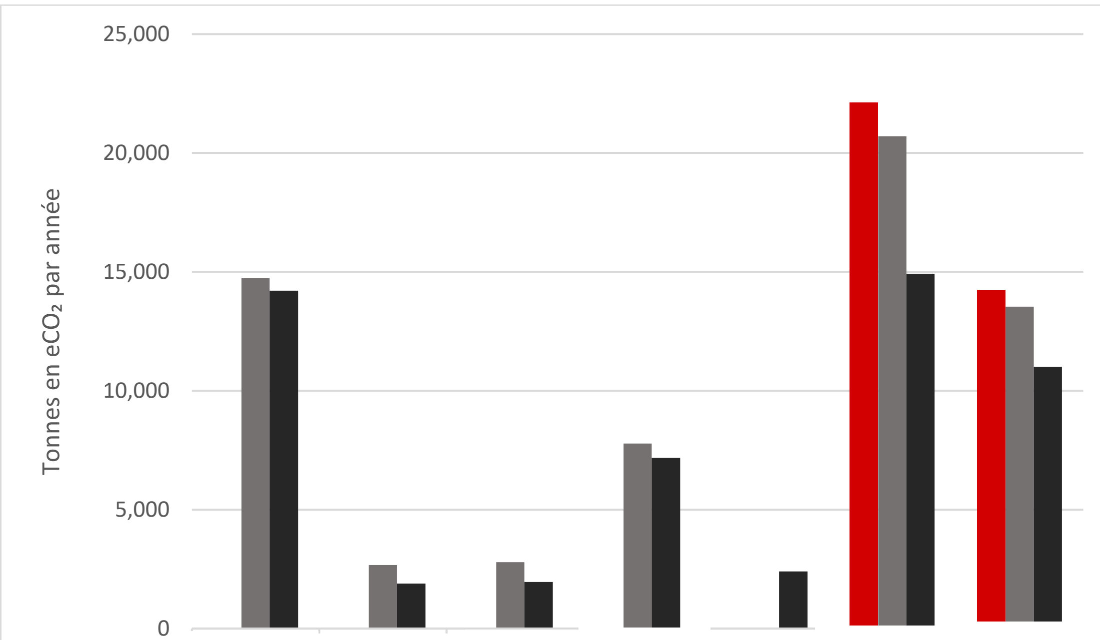
Ce projet a examiné les aspects environnementaux de l'adoption du GNL comme carburant marin. Les travaux ont porté sur les émissions générées par les navires ainsi que sur les gaz à effet de serre (GES) et autres émissions dégagés entre le début de la production jusqu'à l'utilisation (« du puits à la navigation »). Les avantages de l'utilisation du GNL relativement aux émissions ont été modélisés pour sept études de cas de navires. Chacune de ces études de cas a eu recours à trois options de carburant.

À titre de carburant à combustible fossile le plus propre, le GNL offre des avantages pour l'environnement, notamment des diminutions du dioxyde de carbone (CO_2), des oxydes de soufre (SO_X), des oxydes d'azote (NO_X), du carbone noir (CN) et de la matière particulaire (MP). Ces réductions d'émissions peuvent aider les exploitants à respecter la réglementation environnementale actuelle de l'Organisation maritime internationale (OMI) ainsi que la législation nationale correspondante. Outre la réglementation actuelle, des changements réglementaires graduels pourraient favoriser l'utilisation du GNL comme carburant marin. L'avantage du GNL relativement aux GES est reconnu dans les indices de l'OMI pour les nouvelles conceptions et les navires existants [l'indice nominal de rendement énergétique (EEDI) et l'indice de rendement énergétique des navires existants (EEXI)], ainsi que dans l'indicateur d'intensité carbone (CII). Ces indices et cet indicateur sont utilisés progressivement en vue de réduire les émissions de GES produites par l'industrie mondiale du transport maritime.

L'avantage potentiel de l'utilisation du GNL comme carburant marin sur le cycle de vie des émissions, établi à partir des sept études de cas de navires modélisés, représentait de 12 à 30 %

en équivalent dioxyde de carbone (eCO_2). La figure ci-dessous montre la réduction potentielle des émissions de GES pour les cas modélisés, en tenant compte des intrants énergétiques pour tous les aspects de la production, de la liquéfaction et de la combustion du gaz naturel. Les avantages réels pour l'environnement dépendent du profil d'exploitation en service des navires, du rendement des moteurs et de la mise en œuvre de la chaîne d'approvisionnement en GNL.

Bien que le GNL puisse offrir des avantages en matière d'émissions qui favorisent la conformité à la réglementation, les émanations de méthane constituent un défi. Le méthane est un puissant GES, dont le potentiel de réchauffement planétaire (PRP) sur 100 ans est de 30. Le terme « émanations de méthane » est utilisé pour décrire la libération de méthane imbrûlé dans l'échappement en raison d'une combustion incomplète. La quantité d'émanations de méthane varie selon le type de cycle suivi par le moteur, soit le cycle de combustion d'Otto ou le cycle de combustion diesel. Les moteurs à cycle de combustion d'Otto sont plus susceptibles de produire des émanations de méthane que les moteurs à cycle de combustion diesel. Les fabricants de l'ensemble de l'industrie travaillent à l'amélioration du rendement des moteurs. La figure suivante présente les données actuelles sur les émanations de méthane que produisent les moteurs.



	Brise-glace de la GCC	Marchandises générales	Navire-citerne	Navire de croisière	Méthanier	Varquir brise-glace	Vraquier navigant dans les glaces
Mazout lourd						22,114	14,235
MDO/DTF	14,754	2,677	2,787	7,779		20,708	13,537
GNL	14,215	1,888	1,953	7,180	2,397	14,927	11,016

Émissions de GES au cours du cycle de vie – Parcours dans l'Arctique seulement

La quantité de SO_X produite est directement proportionnelle à la teneur en soufre du carburant. Comme il y a très peu de soufre dans le GNL, les émissions de SO_X d'un navire alimenté au GNL sont nettement inférieures à celles d'un navire alimenté au mazout.

La réduction des émissions de NO_X dépend du type de moteur à gaz utilisé. Les moteurs actuels à vitesse moyenne alimentés au GNL fonctionnent selon le cycle de combustion d'Otto, ce qui entraîne une réduction importante des émissions de NO_X et permet la conformité aux exigences du niveau III de l'OMI. En revanche, le moteur à vitesse lente à injection directe, utilisé dans l'analyse, fonctionne selon le cycle de combustion diesel, ce qui n'entraîne aucune réduction des émissions de NO_X. Les moteurs ne respectant pas directement les limites de NO_X devront utiliser des technologies anti-émissions de NO_X additionnelles.

Les émissions de MP sont le résultat de diverses impuretés et d'une combustion incomplète. La plupart des émissions de MP sont nocives pour l'être humain, d'où l'intérêt croissant de la communauté internationale de les réduire. La transition vers le GNL présente des avantages considérables en ce qui concerne les MP. Les émissions de CN sont un composant de MP présentant un PRP élevé. La transition vers le GNL permet de réduire considérablement les émissions de CN, ce qui contribue à réduire les émissions de GES en eCO_2.

Le transport maritime en haute-mer représente la majeure partie de la consommation de carburant marin. Ces navires utilisent souvent du mazout à teneur en soufre relativement élevée en dehors de la zone de contrôle des émissions (ZCE) des eaux côtières de l'Amérique du Nord, ce qui comprend les eaux de l'Arctique. Jusqu'à ce que la disponibilité du GNL, son coût relatif et les exigences en matière d'émissions permettent une adoption généralisée au sein de la flotte de l'Arctique, son utilisation aura des effets modestes, bien que positifs, sur les émissions totales.

L'analyse confirme que l'adoption du GNL comme carburant marin peut présenter des avantages pour l'environnement, notamment une réduction des émissions en eCO_2 sur le cycle de vie allant de 4 à 32 %. Les émissions de SO_X peuvent être réduites dans une mesure maximale de 99 %, celles de NO_X dans une mesure maximale de 88 %, celles de CN dans une mesure maximale de 95 % et celles de MP dans une mesure maximale de 99 %. En outre, les propriétés physiques du GNL réduisent considérablement le potentiel de dommages environnementaux, comme les nappes d'hydrocarbures et les résidus de déversements ou d'accidents maritimes.

Infrastructure

Même si le gaz naturel comme tel est abondant au Canada et aux États-Unis, il y a actuellement très peu de capacité de production ou de distribution de GNL dans l'Arctique, et il n'y a actuellement aucune capacité à soutenir une flotte de navires alimentés au GNL. Pour les navires qui font escale dans l'Arctique canadien et qui proviennent d'Europe, le soutage en GNL est possible dans un nombre croissant de ports. Pour le Canada, et la voie maritime du Saint-Laurent en particulier, des plans de croissance pour la production nationale de GNL et divers projets axés sur l'exportation sont également à l'étude.

Les collectivités et les industries de l'Arctique sont fortement dépendantes des hydrocarbures pour la production d'énergie, ce qui entraîne des prix élevés de l'électricité et des niveaux importants de pollution atmosphérique et d'émissions de GES et de CN. Cette étude a montré que 270 millions de litres de carburant diesel sont livrés par mer chaque année aux collectivités de l'Arctique pour être brûlés dans des moteur à diesel.

Pour illustrer ce à quoi pourrait ressembler une chaîne d'approvisionnement en GNL dans l'Arctique, deux études de cas ont été analysées concernant l'acheminement du GNL vers deux endroits dans l'Arctique – Iqaluit et Cambridge Bay – où le GNL serait utilisé comme carburant marin ou comme source d'énergie locale. Selon l'analyse des études de cas, le prix estimé par gigajoule (GJ) de GNL a pu être déterminé. Voir le tableau ci-dessous.

Coût du GNL déterminé dans les études de cas

	Endroit	Coût du GNL ($/GJ)	Litres de diesel équivalents
Étude de cas n° 1	Iqaluit	18,83 $	0,69 $
Étude de cas n° 2	Cambridge Bay	37,95 $	1,39 $

Les études de cas examinent deux façons dont le GNL pourrait avoir des répercussions dans l'Arctique. Dans l'étude de cas n° 1, la chaîne d'approvisionnement compte sur l'infrastructure du sud du Canada pour effectuer la majeure partie du traitement des matières premières. Dans l'étude de cas n° 2, la chaîne d'approvisionnement est établie uniquement dans l'Arctique et commence au puits de gaz. Cette étude décrit une chaîne d'approvisionnement qui pourrait mener à un certain niveau d'indépendance énergétique pour l'Arctique. Les coûts et les aspects complexes liés à l'exploitation de chaînes d'approvisionnement en GNL à plus petite échelle dans l'Arctique se reflètent dans le prix du GNL.

La conclusion générale est qu'il devrait être possible de mettre en place une chaîne d'approvisionnement en GNL dans l'Arctique à des prix intéressants ($/GJ), comparativement aux alternatives à base de mazout, comme le montre la conversion des prix du GNL en litres de diesel équivalents. Les litres de diesel équivalents sont un moyen d'illustrer le coût que représente l'énergie au GNL en des termes que la plupart des gens comprennent, à savoir le coût de l'énergie au diesel. Toutefois, le prix du GNL est tributaire de nombreux facteurs. Deux facteurs sont particulièrement importants : la mesure dans laquelle plusieurs actifs nécessitant de grands investissements sont utilisés, et les distances entre l'installation de production de GNL et les lieux de soutage destinés aux utilisateurs finaux.

Ressources humaines

Une chaîne complète d'approvisionnement en carburant marin de GNL requiert du personnel qualifié dans tous les aspects du cycle de vie du navire. Les ressources nécessaires pour les navires conçus et construits ou modernisés au Canada comprennent les concepteurs de navires, les chantiers maritimes, les fabricants d'équipement d'origine et les autorités de certification et d'inspection. Pour les navires en service, les ressources concernées sont les marins, le personnel de soutage et les intervenants en cas d'urgence. Bon nombre de ces personnes ont une vaste expérience des navires alimentés au mazout, mais toutes devront acquérir des compétences supplémentaires pour faire la transition vers les navires alimentés au GNL.

Depuis les précédentes études sur la faisabilité du GNL réalisées pour la côte Ouest du Canada (2014) ainsi que pour la côte Est du Canada et les régions des Grands Lacs et du Saint-Laurent (2016), il n'y a pas eu de changement important dans les exigences relatives aux compétences. Le principal changement est que les cours de formation sont devenus disponibles à plus grande échelle, au Canada et ailleurs. Le nombre croissant de navires alimentés au GNL signifie que davantage de personnel acquiert de l'expérience en matière de GNL, ce qui simplifie également le processus pour les futurs navires.

Les exigences relatives aux compétences pour le personnel à bord d'un navire en service sont demeurées essentiellement inchangées. Pour les marins, les principales exigences proviennent du Code STCW, lequel comporte deux niveaux : formation de base et formation avancée. Les exigences relatives aux compétences pour le personnel de soutage des installations terrestres et des installations de bord sont présentées en détail dans la norme (CSA, 2021) et dans la norme (NFPA, 2021).

Les cours de formation offerts sont indiqués pour les marins et pour le personnel de soutage des installations terrestres et des installations de bord, puisque ce sont les principaux groupes qui doivent suivre une formation officielle pour l'obtention des certifications. Une réflexion a été menée quant à la formule qui pourrait être utilisée pour la formation sur les installations établies dans l'Arctique, bien qu'il s'agisse d'une situation bien précise. Il est probable qu'un mélange de formation locale et de formation dans un grand centre urbain soit nécessaire.

Réglementation

Un cadre de réglementation est un élément essentiel d'un projet d'utilisation du GNL comme carburant marin.

Le nombre de navires alimentés au GNL dans le monde et au Canada ne cesse de croître. Pour ces navires, les principales exigences sont détaillées dans le Recueil IGF (*Recueil international de règles de sécurité applicables aux navires qui utilisent des gaz ou d'autres combustibles à faible point d'éclair*). Des directives et des règles supplémentaires pour les navires alimentés au GNL sont également fournies par les sociétés de classification et d'autres organismes comme la Society of International Gas Tanker and Terminal Operators (SIGTTO) et la Society for Gas as a Marine Fuel (SGMF). Le Canada a élaboré des politiques qui régissent l'approbation et la certification des conceptions de navires alimentés au GNL. Toutefois, il n'existe pas encore de politiques, de procédures ou de règlements semblables pour les navires transporteurs de GNL. Ces types de navires seront nécessaires pour permettre le soutage en GNL de plus gros navires ainsi que pour la distribution locale de GNL dans l'Arctique, si cela doit faire partie d'une approche de mise en œuvre.

Le régime des approbations pour les installations de GNL à petite échelle, comprenant le transfert, le stockage et (potentiellement) la liquéfaction dans les ports ou à d'autres endroits dans l'Arctique et ailleurs, est un autre élément d'incertitude. Les approches utilisées pour les terminaux et les usines à grande échelle sont dispendieuses, demande beaucoup de temps et elles ne sont pas adaptées aux types et aux niveaux de risque associés aux plus petites installations.

Le bassin de connaissances est de plus en plus vaste au Canada et dans le monde pour gérer les dangers et les risques que présentent la conception et l'exploitation des navires alimentés au GNL, y compris les activités de soutage. À l'heure actuelle, toutes les conceptions de navires alimentés au GNL, conformément au Recueil IGF et aux politiques canadiennes, doivent faire l'objet d'une évaluation des risques pour certains éléments; il en va de même pour les activités de soutage. Des directives supplémentaires de Transports Canada ou provenant d'autres organismes de réglementation amélioreraient la qualité et l'uniformité de ce travail, ainsi que leur application élargie aux navires transporteurs de gaz (Recueil IGC [*Recueil international de règles relatives à la construction et à l'équipement des navires transportant des gaz liquéfiés en vrac*]).

Des programmes de formation sont offerts au personnel des installations de bord et des installations à terre, mais l'approbation officielle des cours canadiens visant à enseigner la conformité aux normes canadiennes et internationales tarde à venir.

Scénarios de mise en œuvre

Dans le but de comprendre les répercussions de l'utilisation du GNL comme carburant de navire dans l'Arctique, divers scénarios de mise en œuvre ont été établis et comparés aux émissions du transport maritime produites par le passé dans la région de l'Arctique canadien. Cette partie s'appuie sur les résultats des études de cas (dont il a été question dans les sections précédentes) pour évaluer les répercussions des scénarios sur la demande en carburant et la production d'émissions. Les scénarios de mise en œuvre évaluent les répercussions qui seraient engendrées si chaque type de navire étudié précédemment devait faire la transition vers le GNL comme carburant.

La base de référence aux fins de comparaison a été établie à l'aide de données publiées par Environnement et Changement climatique Canada par l'intermédiaire de l'Outil d'affichage d'inventaire des émissions marines (OAIEM) en ligne pour 2019, afin de déterminer la quantité et le type d'émissions produites par l'ensemble de la flotte de navires dans la région de l'Arctique canadien au cours d'une année type. L'évaluation des répercussions repose sur l'hypothèse que le plafond de soufre de l'OMI pour 2020 et l'interdiction du mazout lourd dans la région sont en vigueur. Ainsi, les répercussions sur l'économie et sur les émissions sont évaluées à partir d'une base de référence de carburants distillés (le diesel régulier ou le diesel à très faible teneur en soufre) et non de mazouts lourds.

Le transport maritime dans la région de l'Arctique canadien est à l'origine d'environ 0,27 mégatonne d'émissions en eCO_2 par an produites par 169 navires. La différence des émissions résultant de la transition du GNL a été calculée pour six types de navires typiques de la région : vraquiers, transporteurs de marchandises générales, pétroliers, vraquiers brise-glace, brise-glace et paquebots de croisière. Ces six scénarios de mise en œuvre représentent 50 % des navires et 80 % des émissions dans la région.

L'analyse des émissions liées à ces scénarios de mise en œuvre a montré des réductions importantes de SO_X et de MP. Les émissions de CO_2 ont également été réduites dans tous les cas, de même que les émissions de CN, lequel est un puissant polluant climatique de courte durée de vie dont les effets sont particulièrement importants dans l'Arctique. Toutefois, les émissions de méthane, un puissant GES à court terme, ont augmenté. D'après les scénarios de mise en œuvre, la variation des émissions en eCO_2 exprimées en PRP sur 100 ans dans la région de l'Arctique canadien dépend fortement de la technologie de moteur utilisée : pour les moteurs à fortes émissions de méthane, l'avantage serait limité ou nul, tandis que pour la meilleure technologie disponible, la réduction pourrait atteindre jusqu'à 29 %.

La demande en GNL comme carburant, selon ces scénarios de mise en œuvre, a également été calculée. La capacité existante en Europe et au Québec devrait être suffisante pour répondre à ces demandes. De nouvelles infrastructures seraient nécessaires pour approvisionner les navires qui doivent se ravitailler en carburant dans l'Arctique.

Avantages pour l'Arctique canadien

En conclusion, l'étude établit les répercussions possibles sur l'environnement et sur l'économie que pourrait engendrer une transition vers l'utilisation du GNL dans le secteur maritime, tant pour les collectivités du Canada que celles de l'Arctique. L'étude met principalement l'accent sur les conséquences, directes et indirectes, de l'emploi éventuel du GNL comme carburant pour les activités de transport maritime dans la région de l'Arctique canadien. Des exemples de cas tirés de cette étude ont démontré les avantages pour l'environnement et l'économie qui pourraient résulter de l'utilisation par les navires de gaz naturel sous forme de GNL comme carburant plutôt que de carburants distillés à base de pétrole comme le diesel régulier ou le diesel à très faible teneur en soufre. L'étude a également permis de recenser des cas où la quantité supérieure d'émanations de méthane risquait d'annuler les avantages associés à l'utilisation du GNL quant à la production de gaz à effet de serre.

Les avantages comprennent des améliorations pour la santé humaine et l'environnement grâce à la réduction des émissions de SO_X et de MP.

Une réduction des émissions de MP, un puissant polluant climatique de courte durée de vie dont les effets sont particulièrement importants dans l'Arctique, a été constatée. Les émissions de CO_2 provenant du fonctionnement des moteurs des navires ont également été réduites. Cependant, l'étude a permis de cibler un risque d'augmentation des émissions de méthane provenant des navires utilisant du gaz naturel comme carburant. Il a été constaté que le niveau des émissions de méthane dépendait fortement de la technologie utilisée pour alimenter les navires effectuant la transition vers le GNL comme carburant; dans certains cas, les effets négatifs de l'augmentation des émissions de méthane pouvaient l'emporter sur les avantages de la réduction des émissions de CO_2 et de MP. Les fournisseurs affirment que les mesures visant à réduire les émanations de méthane ont donné d'excellents résultats, tandis que les organismes de réglementation se demandent comment en tenir compte dans les exigences futures.

Ces mêmes avantages pour l'environnement sont également réalisables si les génératrices à diesel utilisés pour produire de l'électricité à l'intention des collectivités de l'Arctique sont remplacés par des moteurs à gaz naturel et que du GNL est livré par bateau au lieu du diesel. Dans cette situation, le risque lié aux émissions de méthane est le même.

Même si les déversements de cargaisons de pétrole ou de carburant dans l'Arctique sont extrêmement rares, il a été constaté que les répercussions de tels déversements sur l'environnement étaient pratiquement éliminées si la substance déversée est du GNL plutôt que du mazout ou du diésel.

Le GNL constitue une solution de rechange intéressante et moins coûteuse que les carburants à base de pétrole, comme le diesel régulier ou le diesel à très faible teneur en soufre. Cette solution devra être plus largement utilisée lorsque l'interdiction du mazout lourd entrera en vigueur dans l'Arctique. Tous les navires examinés dans le cadre de cette étude profiteraient d'une réduction des coûts d'exploitation s'ils utilisaient le GNL comme solution de rechange. Cela entraînerait une baisse des coûts des marchandises transportées vers les collectivités de l'Arctique, une baisse des coûts d'exploitation pour l'industrie et le gouvernement, et une baisse du prix de l'électricité en raison de la diminution des coûts de transport du diesel pour alimenter les génératrices.

Le coût des navires alimentés au GNL reste sensiblement plus élevé que celui des navires alimentés de manière conventionnelle, et les conversions sont particulièrement coûteuses. Les périodes de récupération de ces investissements dépendent du type de navire et de son profil d'exploitation, ainsi que du besoin éventuel d'infrastructures supplémentaires dans l'Arctique. Toutefois, pour certains navires et services, l'utilisation du GNL est intéressante tant sur le plan de l'économie que sur le plan de l'environnement.

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GLOSSARY

AB	Alberta
ABS	American Bureau of Shipping
ASTM	ASTM International
ASSPPR	Arctic Shipping Safety Pollution Prevention Regulations
BASiL	Bunkering Area Safety Information LNG
BC	British Columbia
BOG	Boil off gas
BSEC	Brake Specific Energy Consumption
BV	Bunkering Vessel
CCG	Canadian Coast Guard
CH_4	Methane
CII	Carbon Intensity Indicator
CNG	Compressed Natural Gas
CMA CGM	Compagnie Maritime d'Affrétement and Compagnie Générale Maritime
CO_2	Carbon Dioxide
CO_2–E	Carbon Dioxide Equivalent
CP	Controllable pitch
CSA	Canadian Standards Association
CNGVA	Canadian Natural Gas Vehicle Alliance
DF	Dual fuel
DFO	Department of Fisheries and Oceans
DI	Direct injection
DLE	Diesel Litre Equivalent
DNV	Det Norske Veritas
DNV-GL	Det Norske Veritas – Germanischer Lloyd
DRMS	Design Requirement for Maritime Structures
ECA	Emission Control Area
ECCC	Environmental and Climate Change Canada
EEDI	Energy Efficiency Design Index
EEXI	Energy Efficiency Existing Ship Index

EGR	Exhaust Gas Recirculation
EMSA	European Maritime Safety Agency
EMD	Electro Motive Diesel
EPA	Environmental Protection Agency
ERS	Emergency release system
ESD	Emergency shutdown device
ESS	Energy Storage System
GHG	Green house gas
GTT	Gaztransport and Technigaz
HAZID	Hazard Identification (process)
HC	Hydrocarbons
HFO	Heavy fuel oil
HP	High Pressure
H_2S	Hydrogen Sulphide
ICCT	International Council on Clean Transportation
IEC	International Electrotechnical Commission
IFO	Intermediate fuel oil
IGC	International Gas Code
IGF	International Code of Safety for Ships using Gas Fuels
IMO	International Maritime Organization
IPCC	Intergovernmental Panel on Climate Change
ISO	International Standards Association
KR	Korean Registry
LEL	Lower explosive limit
LFO	Light Fuel Oil
LNG	Liquefied natural gas
LP	Low Pressure
LPG	Liquefied Petroleum Gas
LPV	Lattice Pressure Vessel
LSR	Liquefaction, Storage and Regasification
LR	Lloyd’s Register
MARPOL	International Convention for the Prevention of Pollution From Ships

MDO	Marine diesel oil
MEPC	Marine Environment Protection Committee
MGO	Marine Gas Oil
MR	Mixed Refrigerant
MSDS	Material Safety Data Sheet
MT	Metric Tonnes
MTRB	Marine Technical Review Board
NB	New Brunswick
NFPA	National Fire Protection Association
NG	Natural Gas
NK	Nippon Kaiji Kyokai (Class NK)
NO_X	Nitrogen oxides
OEM	Original Equipment Manufacturer
ON	Ontario
PBU	Pressure build up unit
PEI	Prince Edward Island
PM	Particulate Matter
PPM	Parts per million
PPMV	Parts per million by volume
PSV	Platform supply vessel
QC	Quebec
QC/DC	Quick connect / disconnect
RO	Recognized Organization
RPM	Revolutions Per Minute
SCR	Selective catalytic reduction
SGMF	Society for Gas as a Marine Fuel
SI	Spark Ignition
SIGTTO	Society of International Gas Tanker and Terminal Operators
SIMOPS	Simultaneous operations
SO_X	Sulphur oxides
SOLAS	International Convention for the Safety of Life at Sea

STCW	International Convention on Standards of Training, Certification and Watchkeeping
STQ	Société des traversiers du Québec
STS	Ship to ship
TC	Transport Canada
TCS	Tank Connection Spaces
TERMPOL	Technical Review Process of Marine Terminal Systems and Transhipment Sites
TEU	Twenty-foot equivalent unit
TPA	Tonnes per annum
ULSD	Ultra-Low Sulphur Diesel
US	United States
USCG	United States Coast Guard
V_2O_5	Vanadium Pentoxide
VARD	Vard Marine Inc
VFPA	Vancouver Fraser Port Authority
VDC	Volts Direct Current

GLOSSARY OF UNITS AND SYMBOLS

$	Dollar
%	Percentage
^0C	Degree Celsius
GJ/day	Gigajoules per day
hr	Hour
kg/L	Kilograms per litre
kW	Kilowatt
kVA	Kilovolt-ampere
m	Meter
m^3	Cubic meter
m^3/hr	Cubic meters per hour
m^3/min	Cubic meters per minutes
MJ/L	Megajoules per litre
MJ/kg	Megajoules per kilogram
mm	Millimeters
MW	Megawatt
rpm	Rotations per minute
t	Tonne
TPA	Tonne per annum
ug/Nm^3	Micro grams per normal cubic meter

CHAPTER 1 PROJECT OUTLINE

1 INTRODUCTION

This report is the results of a multi-participant study into the implementation of a Liquefied Natural Gas (LNG) marine fuel supply chain in the Arctic region of Canada. The project has been coordinated by the Canadian Natural Gas Vehicle Alliance (CNGVA), Transport Canada's (TC) Innovation Centre, Clear Seas and Vard Marine. This report is the continuation of similar work completed on the same subject dealing with Canada's West Coast, Great Lakes and East Coast, its outline is similar to those reports and its observations are in line with those found in the previous reports (2014 & 2016).

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 attractive in comparison to more traditional ship fuels; particularly for voyages within, to, and from North America.

The objective of this project has been to develop a comprehensive understanding of all issues relating to the introduction of natural gas as a marine fuel in the Arctic region of Canada, and to use this understanding to understand the economic and environmental impacts should this transition take place.

2 PROJECT PARTICIPANTS

The intention of the project was to engage a diverse set of potential stakeholders, covering all stages of a potential supply chain and the industry and government sectors which are most likely to be involved. This was accomplished successfully, and participants came from:

- Fuel suppliers;
- Ship operators;
- Ship designers;
- Shipbuilding and ship repair companies;
- Engine and equipment suppliers;
- Ports;
- Training organizations;
- Indigenous organizations;
- Regulators societies; and
- Governments.

Participating organizations included;

Canadian Natural Gas Vehicle Alliance

Chart Industries

Clear Seas Centre for Responsible Marine Shipping

Cryopeak

Distributed Gas Solutions Canada

Inuvialuit Petroleum Corp.

Enbridge Gas Inc.

Energir

Fortis BC

INOCEA

ICCT

Island Tug and Barge

Jenmar Concepts

Kivalliq Inuit Association

Nunavut Water Board

Oceans North

Petronav

Pollution Probe

Port of Halifax

Port of Montreal

Port of Vancouver

LNG Coalition

Top Speed Energy

Wartsila

World Wildlife Fund Canada

Vard Marine

3 PROJECT SCOPE

The work has been undertaken as a set of tasks, with task team membership drawn from the project participants, and they have addressed the following aspects of the use of LNG as a marine fuel:

1. Technology readiness for the use of LNG as a marine fuel.

2. Economic aspects and benefits of LNG as a marine fuel.

3. The environmental benefits of and concerns adopting of LNG in various sectors of the shipping fleet.

4. Infrastructure options will consider all aspects of the supply and distribution chain by Arctic natural gas.

5. Human resource challenges for the installation operation, and maintenance of LNG vessels and refueling systems, and developing strategies to meet these challenges.

6. Regulatory impediments to the introduction of LNG at the federal, provincial, municipal, and community levels, and formulating policies and procedures to address these impediments.

7. Implementation scenarios for the introduction of LNG-powered vessels, including quantification of investment requirements.

8. The potential benefits to Canada of an LNG marine strategy including environmental benefits, economic gains associated with the fuel and technology supply chain.

OVERVIEW OF THE REPORT

The final report is a consolidation of a series of documents prepared for each project task. These have been restructured into the chapters of the current report – Chapter 2 covers the analysis under Task 1, and so on for subsequent chapters. All substantive content is retained, though some duplication that was needed to ensure that the early reports could be read as stand-alone documents has been removed.

Throughout the report, “gas” can be taken to refer to natural gas, except where it is made clear that other gaseous substances are addressed. It is never used as an abbreviation for gasoline.

CHAPTER 2 TECHNOLOGY READINESS

1 INTRODUCTION

This report presents the outcome of the Technology Readiness Review (Task 1) of the Arctic Marine Natural Gas (NG) Supply Chain joint industry project.

This task is intended to provide a summary review of all the technologies that may be required, and those that are currently available, as part of a future LNG supply chain system for Canada's Arctic regions, focusing on marine operations. It also addresses some areas in which further development work is underway and identifies others in which work may be required to enhance the performance of NG-fuelled systems and/or to reduce their cost.

The scope of the review covers:

- Discussion of inherent characteristics of natural gas and the possible variations in gas properties;
- Liquefaction and bulk storage systems;
- Distribution systems such as bulk cargo and feeder vessels, barges, rail and road vehicles, local tanks, etc.;
- Bunkering systems;
- Onboard storage and fuel distribution technologies;
- Engine technologies for various types of dual-fuel and pure natural gas engines including their characteristics and drawbacks;
- The integration of natural gas engines into propulsion packages using mechanical and electrical drive systems;
- Safety technologies associated with the transportation of natural gas and its use as a fuel;
- Technical standards available for the certification of equipment using liquefied natural gas (NG); and
- Ongoing research and development (R&D) activities associated with all of the above.

Almost all the information provided in the report is readily available in the public domain. Supplementary information has been collected through direct contact with technology proponents, including but not limited to those who are project participants.

The layout of the report reflects the scope outlined above, except that where ongoing R&D has been identified it is discussed as part of the technology area to which it relates. An overall assessment of the state-of-the-art and of priorities for further development work is also included.

2 CHARACTERISTICS OF NATURAL GAS

2.1 OVERVIEW

"Natural Gas" is a term that is used to describe a wide range of gaseous mixtures of hydrocarbons (HC) and associated compounds found in below ground deposits. It is predominantly methane (CH_4), but will normally also include smaller amounts of ethane, propane, butane, and other heavier hydrocarbons. It can also contain nitrogen, oxygen, carbon dioxide (CO_2), hydrogen sulphide (H_2S), water and a variety of trace compounds.

The actual percentages of methane and other components of the natural gas vary based on the characteristics of where the gas is produced, as shown in Table 1.

Table 1: Typical Composition of Natural Gases by Percentage (FortisBC Energy Inc., 2015), (Nicotra, 2013), (Enbridge Gas, 2016)

Component	Production Area									
	Abu Dhabi	Alaska	Australia NW Shelf	Algeria – Arzew	British Columbia	Ontario	Brunei	Libya	Nigeria	Qatar
Methane	88.47	99.73	87.39	87.98	95.4	93.50	90.61	81.57	91.28	90.10
Ethane	13.22	0.08	8.33	9.00	3.46	4.58	4.97	13.38	4.62	6.23
Propane	1.63	0.01	3.35	1.99	0.73	0.47	2.89	3.67	2.62	2.32
Nitrogen	0.29	0.17	0.09	0.56	0.05	0.92	0.05	0.69	0.08	0.36
Heavier HC	0.09	0.00	0.84	0.47	0.36	0.46	1.48	0.69	1.40	0.99

Before most gas is exported from its region of origin, it is subjected to a range of processes that separate most of the substances, as shown schematically in Figure 1. “Pipeline gas” must have few contaminants and a low level of heavier hydrocarbons to ensure that the gas is “dry”. Pipeline gas standards are typically based on commercial arrangements between the natural gas producer and natural gas purchasers with no single industry-wide standard adopted in Canada. It should also be noted that the gas composition will likely change based on the composition of natural gas extracted from the ground.

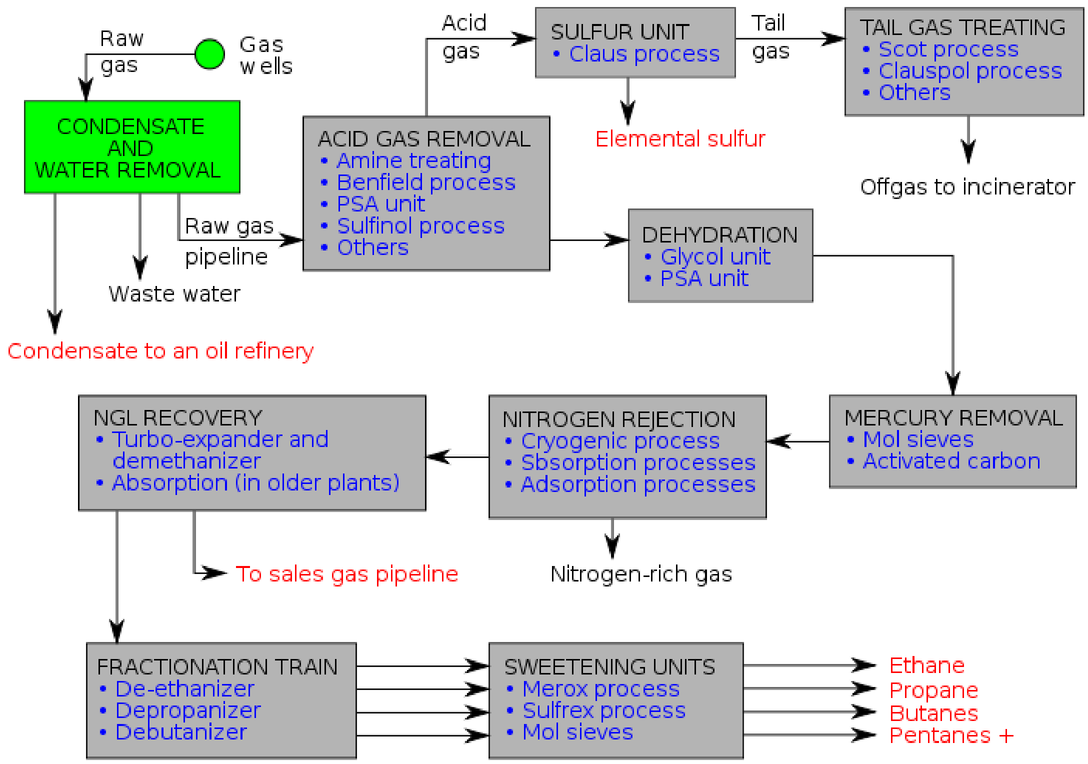

Figure 1: Natural Gas Processing (Wikipedia, 2008)

Due to the varying composition of NG, engine manufacturers may require that the fuel composition is known for a given application. Some engine manufactures optimize their engines specifically for expected gas supply composition. Specifically, the methane content is of high importance and must not fall below an agreed upon minimum value. Some engine manufacturers also require regular sampling of the NG in order to avoid operational problems such as corrosion, wear, and lubricating oil contamination.

The composition of NG can also cause problems when it comes to measurement and billing. If a litre of LNG has higher levels of ethane, then it will skew the actual energy and carbon and the weight. Currently "Methane Number" is the most frequently used metric to describe fuel quality, but this does not denote certain particulates individually and there is also frequently no public record of these fuel qualities.

For the purposes of this project, it can be assumed that the NG for use as a transportation fuel in Canada will have the same qualities as the natural gas composition produced in Canada (see Table 1). This will not necessarily be the case for all applications, and engine suppliers provide tolerances for gas fuel quality which are further incorporated in reference documents cited later in this report. None of the engine types or sizes identified will have any difficulty running on Canadian (or most United States (US)) natural gas.

2.2 LNG CHARACTERISTICS

Methane has a very low density, and 1 m^3 of gas is required to provide the energy content of a litre of diesel fuel (Corp, n.d.). The low energy density of natural gas at ambient pressure means that natural gas must be liquefied or compressed in order to store enough energy for transportation uses including marine applications.   LNG is natural gas that has been cooled to its liquid state at -161^{0}C and is stored in insulated vessels to keep it in a liquid form. LNG has roughly six hundred times greater energy density compared to natural gas itself.

Compressed natural gas (CNG) has also been used in some transportation fuel applications. CNG, when compressed to 200-250 bar has a storage density still only roughly 1/3rd of LNG, and although numerous technologies have been proposed for large scale systems none has reached a commercially viable level of maturity. For Arctic NG transportation and use it has therefore not been considered further at this time.

The general characteristics and properties of LNG can be summarized as follows:

- LNG has a specific gravity of about 0.45 (of water) with a density range of approximately 0.41 kg/L to 0.50 kg/L;
- LNG is 1/619th the volume of natural gas at standard conditions; and
- LNG is odourless, colorless, non-corrosive, and non-toxic.

(FortisBC, 2011) (ABS Pacific Division, 2003) (Contributors, n.d.)

The calorific value of LNG is dependent on the chemical composition of the natural gas and varies depending on the source, as shown in Table 1. The net calorific value of the British Columbian gas composition is approximately 49.5 MJ/kg. The values in Eastern Canadian markets are similar but more variable.

Unlike pipeline natural gas, LNG does not include mercaptan, an odorant which is added that gives a “rotten egg” smell to pipeline natural gas to facilitate leak detection. The low temperature demands of the LNG production process require mercaptan to be removed prior to liquefaction (if previously added).

LNG also has a limited hold time before, as it warms up, it returns to a gaseous state. This “dynamic” quality of LNG must be actively managed through systems to capture and use LNG boil-off gases, or by adding a re-liquefaction capability to the storage system.

2.3 NATURAL GAS AS A MARINE FUEL

Natural gas has been used as a marine fuel, albeit on a very limited basis globally over several decades. Bulk LNG carriers have used LNG boil-off gas to supplement onboard fuel storage for close to 50 years. There is an estimated population of 600 gas carriers which operate on natural gas. This number has also grown rapidly in the last few years as international trade in LNG itself has increased.

More recently, there has been a considerable surge in the number of vessels of all types and services that have adopted LNG as their main fuel, generally for new buildings but in some cases for retrofit. Norway was the initial leader in using LNG as a fuel for ships other than gas carriers. This has been promoted by nitrogen oxides (NO_X) related tax penalties that helped to incentivize the use of LNG for passenger ferries as well as export content financing. This has been followed by global tightening of emission standards (energy use standards) for commercial shipping and supported by economic considerations. These two components of rationale are addressed under Chapters 3 and 4 of this report.

Since 2010 the number of vessels fuelled by LNG has grown consistently by between 20% and 40% per annum (SEA-LNG, 2020). As well as approximately 600 gas tankers as mentioned above, at the start of 2020 there were 175 LNG-fuelled ships in operation and over 200 more on order. An estimated 10%-20% of the new order book is LNG-fuelled. Det Norske Veritas – Germanischer Lloyd (DNV GL) forecasts for 2050 that LNG will account for 41% of marine fuel portfolio. Almost every ship type is represented in the LNG-fuelled fleet, with early adopters in sectors such as ferries and offshore supply vessels having been joined by container ships, tankers, cruise ships, bulk carriers, vehicle carriers and others. The variety of LNG-fuelled ship types is shown in Figure 2.

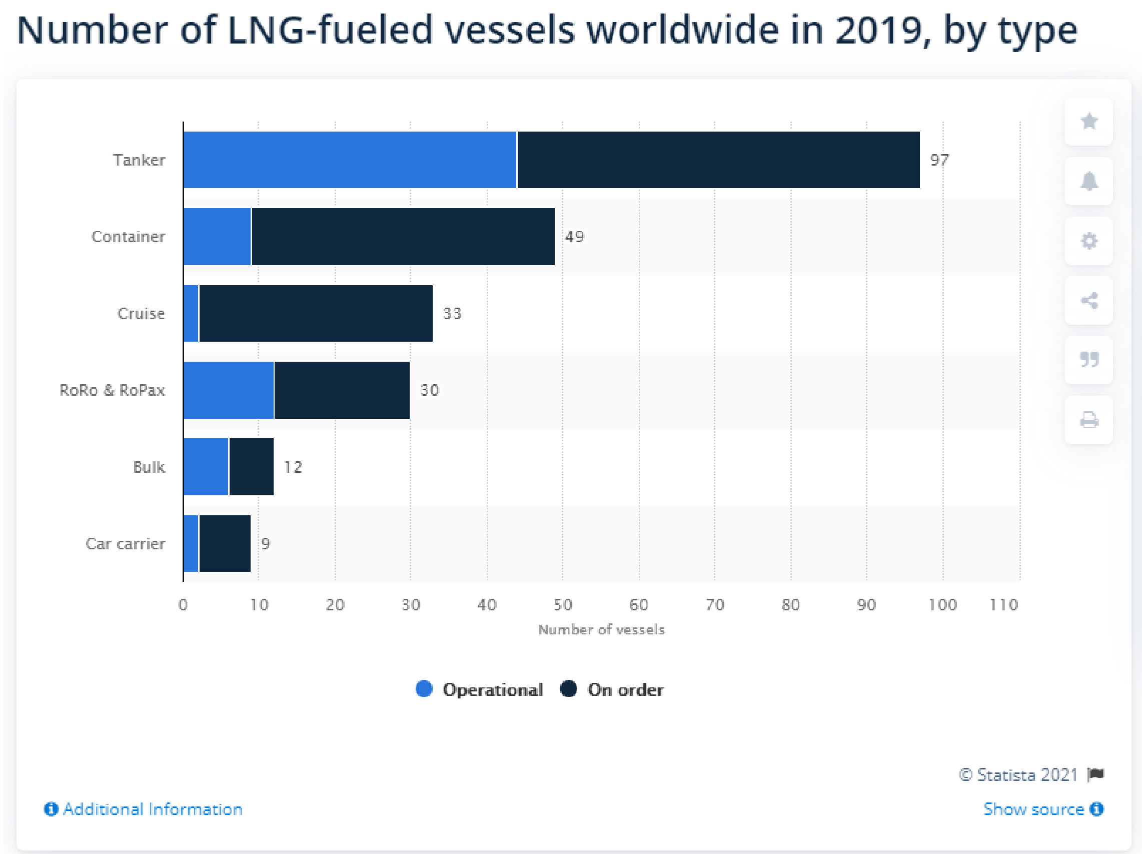

Figure 2: LNG Fuelled Ship Population 2019 (Statista Research Development, 2021)

A further 140 plus LNG-ready ships have been identified – these are vessels equipped with gas-capable engines and some other LNG systems components but not yet fully configured for LNG operation.

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

- Harvey Gulf operate the first US flagged LNG-fuelled vessels, offshore supply vessels in the Gulf of Mexico. They now have six vessels in service.
- The Société des traversiers du Québec (STQ) has three LNG-fuelled ferries in service.
- B.C. Ferries has three new LNG-fuelled vessels and retrofitted its two largest vessels to LNG.
- Desgagnes Group in Quebec have built a fleet of six vessels including asphalt carriers and product tankers.

- Seaspan Ferries in B.C. has two LNG-fuelled vessels in service and two more under construction.
- Some US operators (for example, TOTE) have commissioned LNG-fuelled container ships.
- Major cruise lines including Carnival are building LNG fuelled cruise ships, some of which will be home-ported in the US., and a number of which may call at Canadian ports such as Vancouver.

The growth of the fleet of LNG-fuelled vessels, and increasing LNG-fuelled vessel size, has created a need for bunker vessels that can supply relatively large volumes of LNG to ships during port calls. There are now several bunker barges in service in the US, and proposals to initiate bunker vessel services in the Port of Vancouver (Vancouver Fraser Port Authority, VFPA) by 2023. This specialized sector of the fleet is discussed in more depth at Section 7.

3 LNG SAFETY

The LNG carrier industry has an excellent safety track record. Over nearly 50 years of operating experience, there have been no fatalities onboard ships related to LNG (there have been some minor incidents related to loading and unloading of cargoes resulting in damage to vessels and injury to personnel). The LNG carrier industry's safety record can be attributed to several key factors (Foss, 2006) (International):

- An industry committed to risk management;
- The risks and hazards due to the chemical and physical properties of LNG are known and appreciated in LNG related technology and operations;
- International standards and codes developed by not only regulators but also the LNG industry provide a framework for safe LNG operations;
- Operational integrity and protocols, operator knowledge, training and experience;
- Technological advances in the LNG industry.

Gas carrier and terminal operators' industry established the Society of International Gas Tanker and Terminal Operators (SIGTTO) in which industry participants address common problems and derive agreed upon criteria for best practices and standards. In February 2013, SIGTTO formed a similar organization for gas-fuelled vessels; Society for Gas as a Marine Fuel (SGMF). SGMF has promulgated additional best practices and standards, including tools to help assess the potential impacts of accidental releases of LNG. Many Canadian stakeholders in marine LNG projects are members of SGMF, including B.C. Ferries, Seaspan Ferries, VFPA, FortisBC and others.

A major objective for the current project is to ensure that the use of LNG as a fuel achieves similar levels of safety, using an appropriate mix of standards, regulations, training and technologies. This is addressed in part at Section 13 of this Chapter, and in Chapter 7.

4 LIQUEFACTION PROCESS

4.1 OVERVIEW

Liquefaction of natural gas reduces the volume of the gas by a factor of more than 600, resulting in a proportional increase in the energy density of the fuel. Liquefaction processes are capital and energy intensive and can account for up to 50% of the cost for bringing LNG to the market (M.N. Usama, 2011); see also Chapter 3 (Economics) and Chapter 5 (Infrastructure Options). Liquefaction processes are undergoing continuous evolution in an effort to increase efficiency and decrease plant complexity and cost.

Prior to the increasing interest in LNG as a transportation fuel, there were two main types of LNG plants:

- Large-scale facilities used to prepare LNG for transhipment to remote (overseas) markets using LNG carriers.
- Small/medium facilities used by utilities in peak-shaving plants, where LNG storage can be used to level out fluctuations in demand.

The large-scale facilities typically use "raw" gas directly from extraction, with accompanying needs for processing and purification. The peak shaving facilities are close to consumers and therefore normally use pipeline gas of the quality supplied to end users.

More recently, the categorization of plants has been refined to distinguish more clearly between size rather than purpose. Large plants are as before used to prepare LNG for transhipment, and their maximum size has continued to increase. Mini, small and medium-scale plants are being developed for a much wider range of purposes, including supply to marine, truck and rail users. There is no standardized nomenclature for plant sizes, and so Table 2 is drawn from a range of suppliers and their own offerings (overlaps reflect differences in designations).

Table 2: Liquefaction Plant Size Ranges

Liquefaction Plant Type	Capacity Range	
	t/day	t/year
Mini	5 - 75	2,000 – 30,000
Small	55 - 900	20,000 – 300,000
Medium	600 - 3000	Up to 1,000,000
Large		Over 1,000,000

Mini, small, and in some cases medium size plants use standardized components and are either delivered to site as complete units or in modules for ease of assembly. The large plants have some components built on-site and have tended to suffer from cost overruns and delays in comparison, somewhat negating any economy of scale.

The following sections describe the liquefaction processes and technologies in greater detail.

4.2 PRE-TREATMENT

The purpose of pre-treatment is to eliminate constituents from the natural gas such as CO_2, H_2S, water, odorant, and mercury.

CO_2 and H_2S must be removed because they cause corrosion, reduce heating values, and may freeze and create solids in cryogenic processes. A maximum of 50 parts per million by volume (ppmv) CO_2 and a maximum of 4 ppmv H_2S is typically allowable.

Water must be removed as it will freeze in the cryogenic process. A maximum of 1 ppmv is allowable.

Mercury is generally not found in NG produced in Canada. If present in feed gas it can cause corrosion problems and must also be limited. Mercury is particularly damaging to aluminum heat exchangers. A maximum of 0.01 ug/Nm^3 can be tolerated. (Pettersen, 2012).

The pre-treatment process normally includes an acid gas removal step, a dehydration step, and (if required) mercury removal; generally in that order. Wet absorption (solvent based) is a common method of acid gas removal and adds to the water content. Dehydration then may involve an initial cooling stage followed by molecular sieves. Mercury removal is normally an adsorption process, employing chemicals that can be re-used (Klinkenbijl, 1999).

4.3 LIQUEFACTION

There are three main processes through which natural gas is liquefied, with variants on each. They can be categorized as (a) Cascade, (b) Mixed refrigerant and (c) Expansion. In extremely simplified form these are shown in Figure 3, (Zhang, 2020) with more detail available in the reference document.

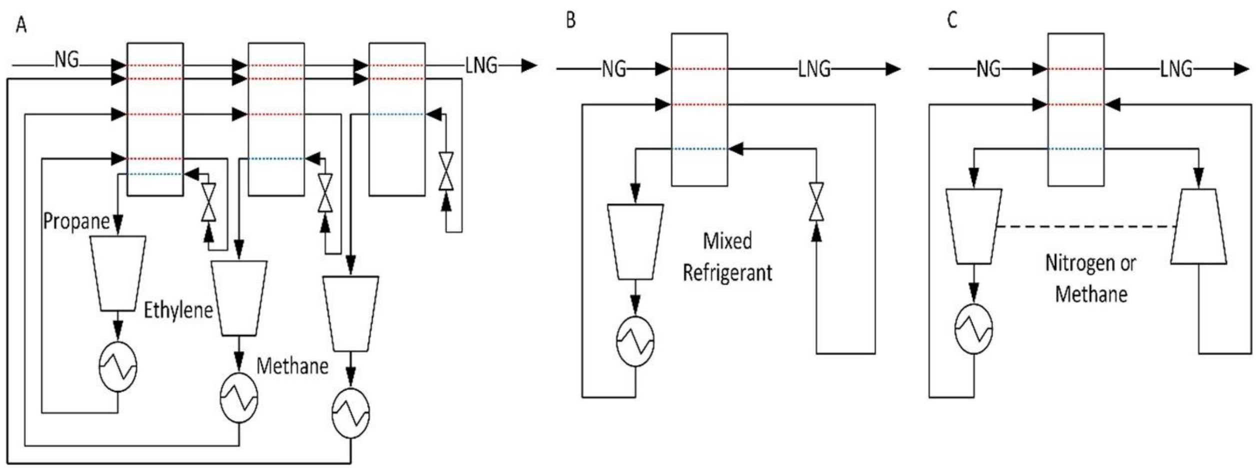

Figure 3: Liquefaction Processes

Each process has underlying characteristics which are summarized in Table 3. These make Cascade processes more suited to large-scale facilities and expansion to small-scale facilities, with Mixed Refrigerant being used at all scales. The large-scale plants achieve greater efficiency/lower energy use at the cost of complexity and (generally) higher capital cost per unit of production, as will be discussed in more depth in Chapter 3 of the report.

Table 3: Characteristics of Liquefaction Processes (Zhang, 2020)

Criteria	Cascade	Mixed Refrigerant	Expansion
Application	Large-scale	Large-scale and small-scale	Small-scale
Energy efficiency	High	Medium to high	Low

Equipment count	High	Low to medium	Low
Heat-transfer surface area	Medium	High	Low
Simplicity of operation	Low	Low to medium	High
Ease of start-up and line-up	Medium	Low	High
Adaptability of feed-gas compositions	High	Medium	High
Space requirement	High	Medium	Low
Hydrocarbon-refrigerant storage	High	Medium to high	None
Capital costs	High	Low to medium	Low

4.3.1 LARGE SCALE LIQUEFACTION SYSTEMS

As noted above, the two main alternatives used for large-scale liquefaction are Cascade and Mixed Refrigerant (MR). There are variants of each of these, as outlined in Table 4.

Table 4: Large-Scale Liquefaction Technologies

Technology	Process name and supplier	Abbreviation	Specific features
Cascade	ConocoPhillips Optimized Cascade	CPOC	Evolved Cascade technology
	Statoil/Linde Mixed Fluid Cascade	MFC	A closer matching NG cooling curve
MR	APCI Propane Precooled Mixed Refrigerant	AP-C3MR	Most utilized process
	APCI AP-X	AP-X	Nitrogen expander sub-cooling cycle (hybrid of MR and expander)
	Shell Dual Mixed Refrigerant	DMR	MR precooling cycle
Small Scale Technologies	Single Mixed Refrigerant	SMR	First single MR cycle
	Single Expander	SE	Simplest expander cycle
	Other Expander	OE	Either the precooled expander process or the dual expander process.

The installation sizes and installation dates for each of these are shown in Figure 4 and also drawn from (Zhang, 2020).

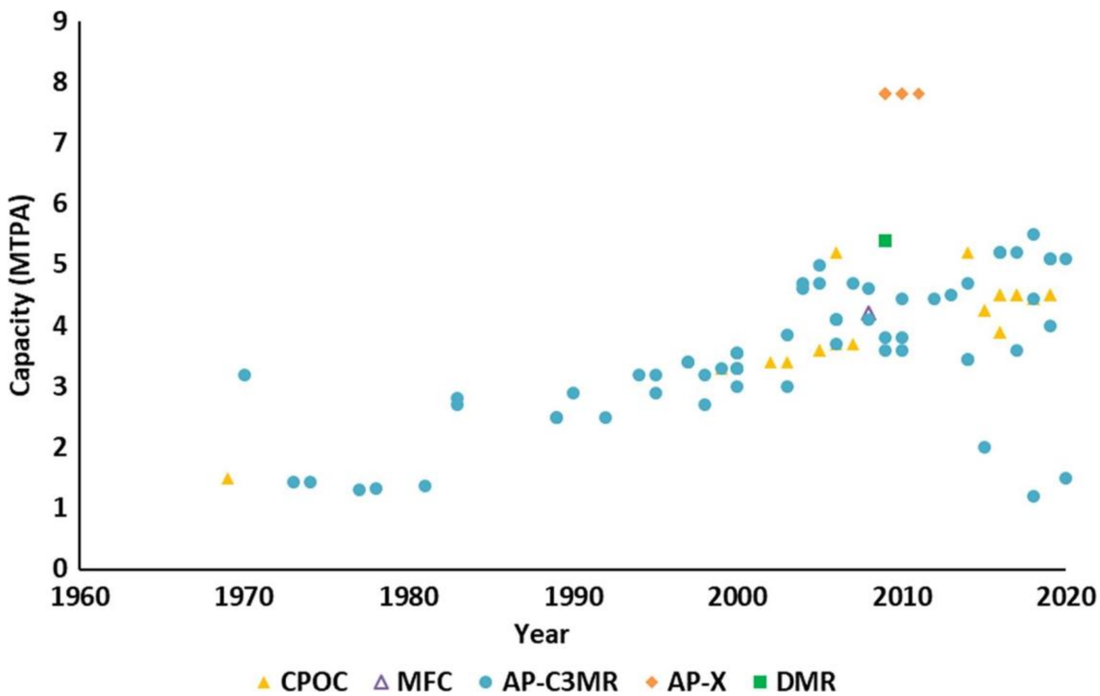

Figure 4: Large Scale Liquefaction Technology Usage (Commissioning Dates)

Detailed explanation of the technologies is beyond the scope of this report but can be found in the references cited and other data sources. Of most direct importance to the current project is the comparative performance in terms of energy consumption, which affects the well-to-wake emissions for LNG and the running costs of liquefaction. A consolidation of available information is provided in Figure 5 noting that part of the range of efficiencies depends on the source of power (note that more information for the smaller plants is provided in the following section). Many plants use gas turbines (fuelled by NG) to power their processes, whereas when electricity is available and either cheap or mandated then it is also used as the energy input.

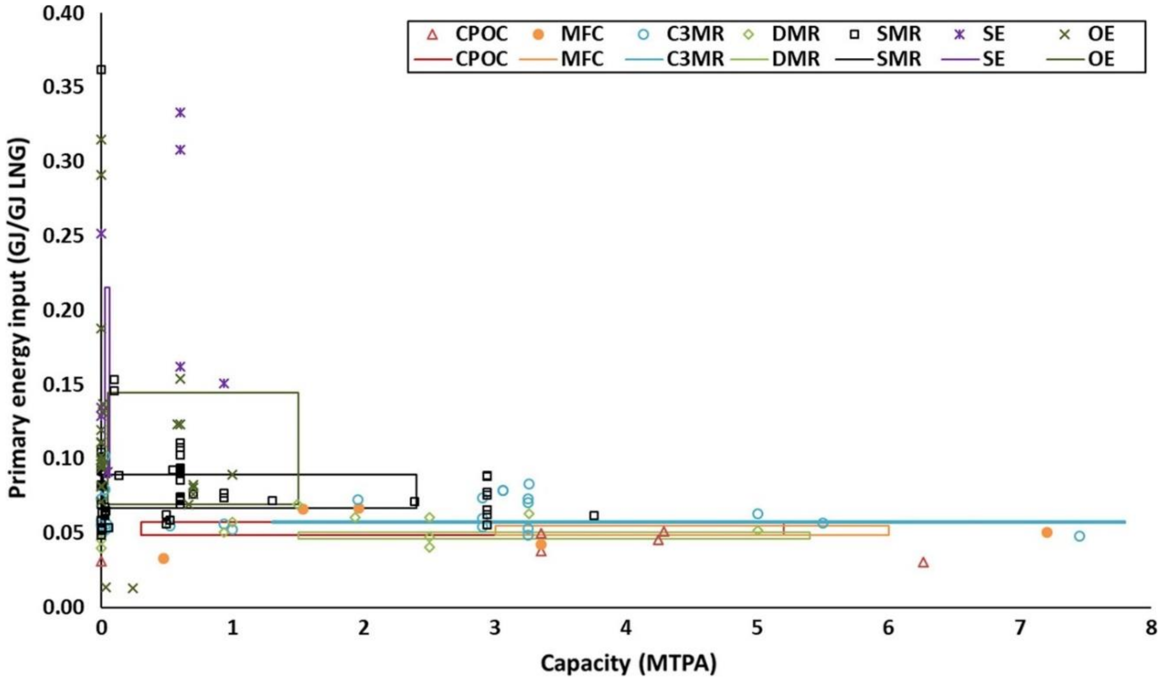

Figure 5: Comparative Energy Consumption of Liquefaction Processes

An example of a recent large-scale high Arctic LNG plant is shown in Figure 6. This takes up many square kilometers of land area and represents an investment of tens of billions of dollars.

Figure 6: Yamal LNG Plant

4.3.2 SMALL SCALE LIQUEFACTION FACILITIES

Much smaller than the Yamal plant in Figure 6, there are small scale facilities such as the Galileo Technologies Cryobox shown in Figure 7. Each liquefaction module is equivalent in size to a road tanker truck.

Figure 7: Cyrobox Nano LNG Station

As noted above, there is some cross-over in the technologies that are used for small scale with those used in larger plants, with mixed refrigerant types as well as expansion. There is also a range of variants for each, as summarized in Table 5.

Table 5: Small Scale LNG Technologies

Technology	Process name and supplier	Abbreviation	Specific features
MR	Black & Veatch Pritchard PRICO Process	PRICO	Simple single MR cycle
	Technip/Air Liquide TEALARC	TEALARC	MR precooled MR cycle
	APCI Single Mixed Refrigerant Process	AP-SMR	First single MR cycle
	Linde Multistage Mixed Refrigerant process	LIMUM	Three-stage single MR cycle
	Kryopak Precooled Mixed Refrigerant Process	PCMR	Precooled MR cycle
EXP	Single Expander process	SE	Simplest expander cycle
	Air Product AP-N process	AP-N	Optimized from AP-X

Types, sizes and years of commissioning for a number of smaller scale plants are shown in Figure 8.

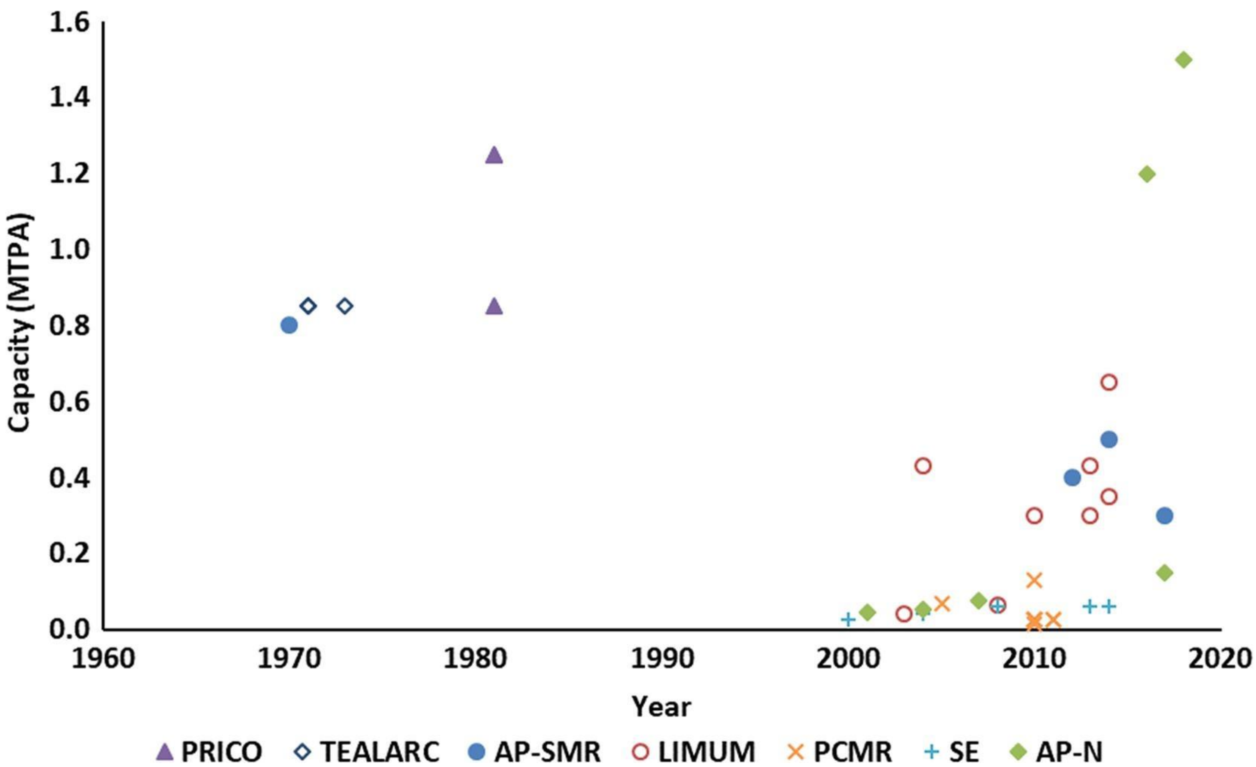

Figure 8: Small Scale Liquefaction Market Share by Type of Technology

Suppliers of modular small-scale plants and of standardized modules frequently use brand names to differentiate their offerings. The recent expansion of the FortisBC LNG plant in Tilbury, B.C uses the Chart IPSMR technology, a variant of mixed refrigerant, while the Energir plant in Montreal uses a Linde (LIMUM) multi-stage plant. The smaller scale market continues to see considerable research and development to bring compact plants closer to the efficiency of larger plants while retaining their capital cost advantage. Over the complete size range, Research & Development is underway to explore the potential for carbon capture of the fuel burn for liquefaction (Cocklin, 2020).

5 BULK STORAGE SYSTEMS

5.1 INTRODUCTION

This section provides an overview of storage tanks used in the LNG industry. Much of the tank technology has been developed for export/import of large volumes of LNG and would not be applicable to the smaller volumes of gas envisioned for either community or ship bunkering in Canada’s north. However, the full spectrum of tank sizes is discussed, and the section concludes with a summary of the likely application to Canada’s Arctic.

Most liquefaction systems, particularly those at export scale, are designed to be run more or less continuously to maintain efficiency and to reduce stress cycling. The LNG is then supplied in batches to tankers for export. This requires that plants include large storage tanks typically in the range of 8,000 – 200,000 m^3 to allow for rapid loading of the ships. As cargoes for export are carried at atmospheric pressure, these tanks are designed to store LNG below its atmospheric boiling temperature (approximately -161 ˚C). See Figure 9 for an example of bulk storage tanks.

Figure 9: Bulk LNG Storage Tanks (Courtesy of Gaztransport & Technigaz (GTT))

Another main use of LNG storage is to act as a buffer for local NG distribution systems, in which demand vary significantly with time of day, weather and other factors. LNG is produced and stored during periods of low demand, and then re-gasified and injected into the local pipeline system as and when required. These "peak shaving" facilities primarily supply gas to shore-based markets and typically include smaller liquefaction systems, and tanks. They also typically store LNG at close to atmospheric pressure.

A number of different tank technologies have been used for the storage of LNG. Primary considerations in the type of tanks used include environmental considerations, cost, design and safety, and operation and maintenance.

5.2 TANK TYPES

5.2.1 FLAT BOTTOM TANKS

Flat bottom tanks (Wartsila, 2021) can be divided into single containment, double containment or full containment tanks. In all cases, the primary tank is extensively insulated to minimize heat absorption into the LNG. Above-ground full containment tank technology is the preferred solution for storing large quantities of LNG with maximum safety in a limited site area. But depending on safety requirements and free space available around the tank, the single and double containment tanks can also be considered. Flat bottom tanks are built on site, which prolongs construction time.

Boil-off gas is approximately 0.05 % per day, which must be dealt with by consumption or re-liquefaction, since flat bottom tanks are not designed or rated for over-pressure.

Single containment: The first LNG tanks developed were single containment tanks. This type of tank has a cylindrical metal primary tank and an earthen dike or bund wall secondary containment. These tanks are now mainly used in remote locations.

- Primary container contains liquid and vapour;
- An outer shell of the primary tank retains insulation; and
- Bund around the tanks retains liquid (not vapour) if primary container fails. Consequently, failure of the primary containment results in release of any spilled gas to the atmosphere since the liquid gas will boil as it is warmed by the environment.

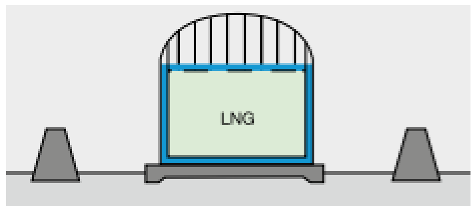

Figure 10: Single Containment Flat Bottom Tank (Wartsila)

<u>Double containment</u>: Similar to the single containment tanks, double containment types have a cylindrical metal primary tank. In addition to this an independent metal or reinforced concrete, open top secondary containment outer tank is implemented. Few double containment tanks have been built because the full containment type was soon developed.

- Primary container contains liquid and vapour;
- An outer shell of the primary tank retains insulation; and
- Secondary container is an open top tank that retains liquid (not vapour) if primary container fails. Consequently, failure of the primary containment results in release of any spilled gas to the atmosphere since the liquid gas will boil as it is warmed by the environment.

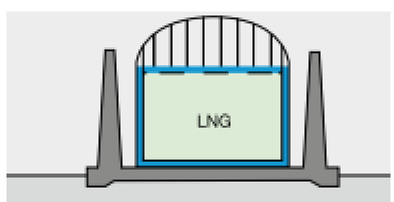

Figure 11: Double Containment Flat Bottom Tank (Wartsila)

<u>Full containment</u>: Today full containment tanks are most commonly used. Full containment tanks have a cylindrical metal inner primary tank and metal or pre-stressed concrete outer structurally independent secondary containment tank. Some tanks are built below grade, allowing the outer wall to be held in compression by soil pressure. Key characteristics include:

- Primary container contains liquid and vapour;
- Secondary container retains insulation and is also liquid and vapour tight; and
- Smallest footprint since no bund around the tanks is required.

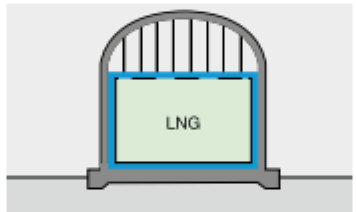

Figure 12: Full Containment Flat Bottom Tank (Wartsila)

A variant of the full containment tank is the membrane tank, which is now increasingly used. The primary metal tank is structurally light and cannot alone withstand the hydrostatic load of the LNG contained within it. The secondary tank (prestressed concrete or metal) surrounds and supports the primary tank as well as providing a secondary containment in the event of failure of the primary tank. If a membrane tank is built partially or fully below grade, soil pressure can contribute to the support of the LNG's hydrostatic load.

The Canadian Standards Association (CSA) Z276 Standard on LNG has included membrane tanks since its 2015 edition. This standard establishes essential requirements and minimum standards for the design, installation, and safe operation of LNG facilities. Previous editions had not included membrane tanks therefore the CSA technical committee formed a work group consisting of members representing LNG operators, membrane tanks designers, engineering firms and the relevant provincial industry regulator to develop the standard.

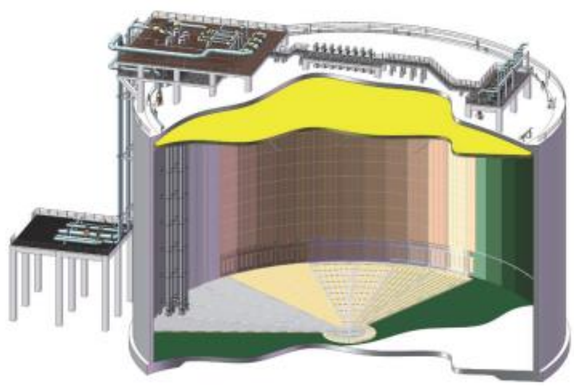

Figure 13: Membrane Tank (Courtesy of GTT)

Flat bottom LNG storage tanks are widely used, and there are no concerns over their ability to be incorporated into an LNG marine fuel supply chain. LNG tank costs for static use range from approximately $1,350 to $4,375 per m^3 of LNG stored (2015 data). Full containment tanks take over 36 months to design, construct and commission. Increases in shell plate thickness up to 50 mm through advances in materials have allowed for above-ground tank sizes to increase to 200,000 m^3. Limitations for further increases in tank sizes include the material availability (in particular, plate thickness) and the available welding technologies.

5.2.2 SPHERICAL TANKS

Spherical tanks have sometimes been used for LNG storage onshore but are more costly than flat bottom tanks and more limited in capacity. The spherical shape creates a strong structure because of the even distribution of stresses on the sphere's surfaces. Their main advantage is that they have a smaller surface area per unit volume than any other shape of tank, meaning less heat ingress and thus less boil-off gas (BOG).

5.2.3 BULLET TANKS

Bullet tanks are cost effective and suitable for storing smaller volumes of LNG. They are stainless steel pressure vessels, operating above 0.5 barg, insulated by vacuum and multilayer insulation materials such as pearlite. These tanks are modular, flexible, available in vertical or horizontal formats, and may be arranged in tank farms of any number tanks connected by manifolds to provide the desired amount of storage. Bullet tanks are prefabricated in factories, which reduces site costs. BOG is approximately 0.05–0.15 % per day, but the tank is capable of handling the increased pressure generated by boil-off for up to one month. Measures to handle BOG must be provided if prolonged periods of no demand are envisioned.

Vertical tanks characteristics:

- Small footprint compared to horizontal tank;
- Heavy foundations;
- Sizes up to approximately 300 m^3 per tank.

Horizontal tanks characteristics:

- Large footprint compared to vertical tank;
- Sizes up to approximately 1200 m^3 per tank.

The safety requirements are an important input for selecting the type of bullet tank system. Bullet tanks have an inner shell made of cryogenic steel and an outer shell of cryogenic or non-cryogenic steel. The tanks can have a bund around the whole tank farm area or only under the process area.

Figure 14: Bullet Type Storage Tank (Wartsila)

5.2.4 INTERMODAL (PORTABLE) TANKS

As discussed in Section 7, some LNG is transported (by truck, rail or sea) in intermodal Type-C tanks conforming to International Standards Associations (ISO) standards for 20- and 40-foot containers. Some ships are being designed to use such tanks as their on-board fuel tanks, exchanging them for full tanks when needed (see Section 9). For smaller demand applications, filled intermodal tanks can be delivered and used as the storage and supply tanks for service required.

Figure 15: LNG Tank Containers Embarked for Delivery to Northern China

5.2.5 ARCTIC COMMUNITY BULK STORAGE

In summary, onshore storage for LNG can be arranged using flat bottom tanks with storage capacity of »7500-160,000 m^3, spherical tanks of »1000-8000 m^3 or, for small LNG storage volumes, bullet tanks. Single Bullet tanks are available up to 1200 m^3, meaning that larger storage capacities (up to 20,000 m^3) are arranged with multiple bullet tanks. At even smaller volume requirements, intermodal tanks of up to 40 m^3 each can be used singly or in multiples.

It is conceivable that larger Arctic cities could warrant flat bottom tank LNG storage if the primary community energy source was switched from diesel to LNG. Any ship fueling demand at a coastal city such as Iqaluit, Nunavut could also be serviced by such a facility.

The volumes of gas required in all other communities for both local energy needs and ship bunkering are unlikely to warrant flat bottom storage tanks. Bullet tanks (single or multiple) are likely to be in the size range required, or for smaller needs, intermodal tanks may be the most cost-effective solution.

In any event, the technologies are ready and proven.

6 CURRENT AND PROJECTED LNG FACILITIES

6.1 OVERVIEW

Existing LNG facilities in Canada, and in North America as a whole were predominantly designed as peak shaving plants. A few larger plants were constructed as import terminals for LNG from overseas. More recently, the oversupply of gas available from North American fields has led to some import facilities being re-purposed for export, and a large number of new export terminals being developed or proposed. Meanwhile existing peak shaving plants have been adapted to provide supply for a broader range of end uses, and other smaller scale facilities have been built and planned.

The smaller scale LNG liquefaction facilities are frequently well-suited to supply fuel to transportation and other users, as they are typically located close to large population centers and other transportation hubs. Larger facilities are, increasingly, located well away from such areas due to public perceptions of risk. This can however make them well-suited to be part of a marine fuel supply chain, as they are on the waterfront due to their export orientation, and as their permitting will normally allow for supply to bunker vessels and other smaller scale LNG Carriers.

Outside North America, most liquefaction facilities are in the Middle East, Africa and Russia, which supply gas predominantly to Europe and East Asia. These export projects constitute the great majority of liquefaction capacity worldwide. The associated import terminals all incorporate bulk storage that reduces the need for dedicated peak shaving in the local grids.

6.2 PEAK SHAVING AND OTHER SMALL-SCALE LNG

6.2.1 CANADA

Generally, peak shaving plants were built to serve end-use markets connected to a highly integrated transmission pipeline system with physical constraints impeding the delivery of natural gas during peak demand periods. These periods are most pronounced during periods of cold weather when natural gas use for heating by end customers drives increases in demand. The construction of peak shaving plants in North America, most active in the 1970s and 1980s, was particularly significant in pipeline-constrained regions. It often occurred at “end of the pipeline” locations such as Vancouver and Montreal, where network flows of natural gas were unavailable to replace or supplement deficiencies from the single supply source or serving pipeline. In their design, North American peak shaving plants were generally optimized to the “200/20” rule of thumb, where approximately 200 days of liquefaction was installed to store LNG over the course of the calendar year in order to meet peak demands lasting up to 20 days for regasification to send out to the local distribution network.

Table 6 provides an overview of current Canadian LNG production facilities and their purpose. The difference between a regulated and non-regulated plant here relates to the tariff structure that is applied to the gas; in all cases these plants comply with all safety-related regulations and standards. The Energir and FortisBC plants supply for transportation purposes is covered by different arrangements and tariff structures compared with their use in peak shaving. Capacities are not reported consistently for these facilities, but for approximate purposes 1 tonne (t) is equivalent to 2.2 m^3 and 49.5 GJ of energy.

Table 6: Existing Canadian LNG Production Facilities

Location	Ownership	Purpose
Montreal, QC	Energir	436,000 m^3/year Regulated utility peak shaver
Hagar, ON	Union Gas	Regulated utility peak shaver
Grand Prairie, AB	Encana/Ferus	5,000 GJ/day non-regulated facility
Elmworth, AB	Ferus	190 m^3/day non-regulated facility
Dawson Creek, BC	AltaGas	27,000 gallons/day non-regulated facility
Tilbury, BC	FortisBC	250,000 t/year regulated utility peak shaver
Mt. Hayes, BC	FortisBC	Regulated utility peak shaver
Fort Nelson, BC	Cryopeak	27,000 gallons/day non-regulated facility

The Energir liquefaction, storage and regasification (LSR) facility is located in eastern Montreal, Quebec (QC) and has been in operation for 45 years. The facility was recently expanded to more than double its previous production capacity, which is now 436,000 m^3/year (255 million m^3 of NG). This expansion was intended to meet growing demand for NG for road and maritime transportation markets and power supply in regions remote from the gas network. Energir currently supplies marine consumers including STQ ferries and Groupe Desgagnes cargo vessels.

Union Gas's Hagar facility has a liquefaction capacity of 28.3 million m^3/year. This facility is located near Sudbury, Ontario (ON) and is mainly used for peak shaving. However, it also has sufficient spare capacity to offer approximately 416,000 GJ per year (500 to 700 truck loads) for other purposes.

The two FortisBC facilities both currently supply marine fuel to B.C. Ferries and Seaspan. Tilbury has a liquefaction capacity of 250,000 t/year and is in the planning stage for a major expansion including a marine jetty to supply both bunker vessels and LNG carriers (see below). Mount Hayes (Ladysmith) is a smaller plant which is also supplying transportation users by tanker truck.

The newest LNG facility, Cryopeak's Fort Nelson plant is intended to supply remote communities and mines using trailer distribution. The plant is scalable to 100,000 gallons/day under its existing permits.

Several additional smaller scale LNG plants are under consideration. In B.C., Skeena LNG and Port Edward LNG are each proposing to produce 150,000 t/year for domestic and overseas customers. Skeena is an inland location that would use a fleet of tanker trucks, while Port Edward is on the coast and is focused on supply to China. In the Arctic, the Inuvialuit Petroleum Corp and Ferus have teamed to propose a project near Tuktoyaktuk to use stranded natural gas to supply various consumers throughout the area.

6.2.2 UNITED STATES OF AMERICA

There are approximately 50 peak shaving LNG facilities in the US, fairly widely distributed though with the bulk located near the Eastern Seaboard and in the Upper Midwest. Their combined production is in the order of 1.3 billion gallons/year (close to 5 million m^3). As in Canada, an increasing number of these facilities are now supplying LNG to a variety of users in the transportation sectors. Recently (December 2020) LNG from a Pennsylvania LNG plant was used to refuel one of Groupe Desgagnes vessels while in Hamilton, ON. US LNG supply is being looked at more broadly as an option for shipping in the Great Lakes and St. Lawrence Seaway.

Figure 16 shows a 2013 map of all US facilities, including large scale import and export terminals. For the small-scale facilities this is still reasonably current, but the picture for larger-scale plants and operations has changed completely, as discussed in Section 6.3.2 below.

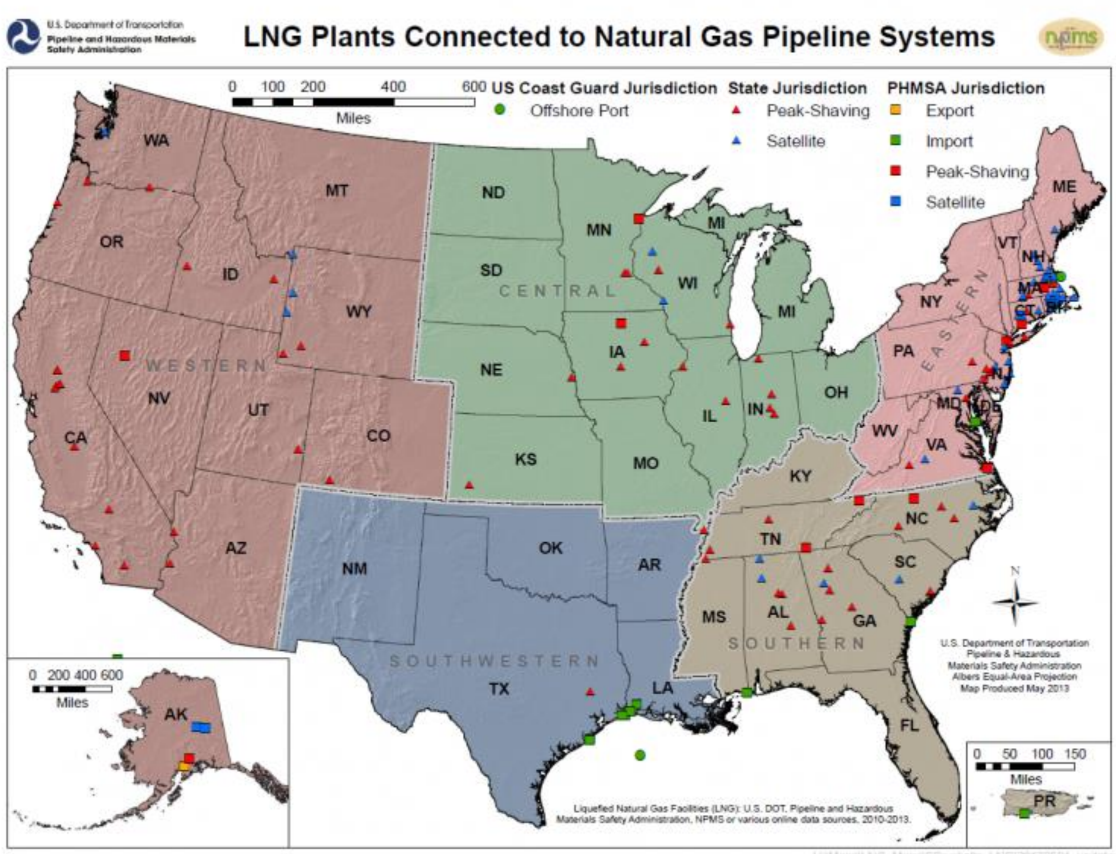

Figure 16: US LNG Facilities (2013)

6.3 LARGE SCALE LNG

6.3.1 CANADA

There is one large LNG plant in Canada, CANAPORT in Saint John, New Brunswick (NB). This plant has been in service as an import terminal since 2008. It does not incorporate a liquefaction capability but does store 950,000 m^3 of LNG for regasification and supply into the gas pipeline network. Following the surge in North American gas production in recent years, the terminal is currently being used at a fraction of its potential throughput.

With this rise in production, a large number of new liquefaction and export facilities have been proposed on both the West and East Coasts of Canada. The most recent listing available from Natural Resources Canada (NRCan) is provided at Table 7, with locations as shown in Figure 17.

Table 7: Proposed Large-Scale Canadian LNG Projects

Project	Export License	Capacity (Export Volume)	Cost ($billion)
West Coast Projects			
Kitimat LNG	20 Years	10 Mtpa - 1.3 Bcf/d	$15
LNG Canada	40 Years	26 Mtpa – 3.5 Bcf/d	$25-40
Cedar LNG Project	25 Years	6.4 Mtpa – 0.8 Bcf/d	
Orca LNG	25 Years	24 Mtpa – 3.2 Bcf/d	
New Times Energy	25 Years	12 Mtpa – 1.6 Bcf/d	
Kitsault Energy Project	20 Years	20 Mtpa – 2.7 Bcf/d	
Stewart LNG Export Project	25 Years	30 Mtpa – 4.0 Bcf/d	
Triton LNG (On Hold)	25 Years	2.3 Mtpa – 0.3 Bcf/d	
Woodfibre LNG	25 Years	2.1 Mtpa – 0.3 Bcf/d	$1.6
WesPac LNG Marine Terminal	25 Years	3 Mtpa – 0.6 Bcf/d	
Discovery LNG	25 Years	20 Mtpa – 2.6 Bcf/d	
Steelhead LNG: Kwispaa LNG	25 Years	30 Mtpa – 4.3 Bcf/d	$30
Watson Island			
East Coast Projects			
Goldboro LNG (Nova Scotia)	20 Years	10 Mtpa – 1.4 Bcf/d	$8.3
Bear Head LNG (Nova Scotia)	25 Years	12 Mtpa – 1.6 Bcf/d	$2-8
A C LNG (Nova Scotia)	25 Years	15 Mtpa – 2.1 Bcf/d	$3
Energie Saguenay (Quebec)	25 Years	11 Mtpa – 1.6 Bcf/d	$7

Project	Export License	Capacity (Export Volume)	Cost ($billion)
Stolt LNGaz (Quebec)	25 Years	0.5 Mtpa – 0.7 Bcf/d	$0.6

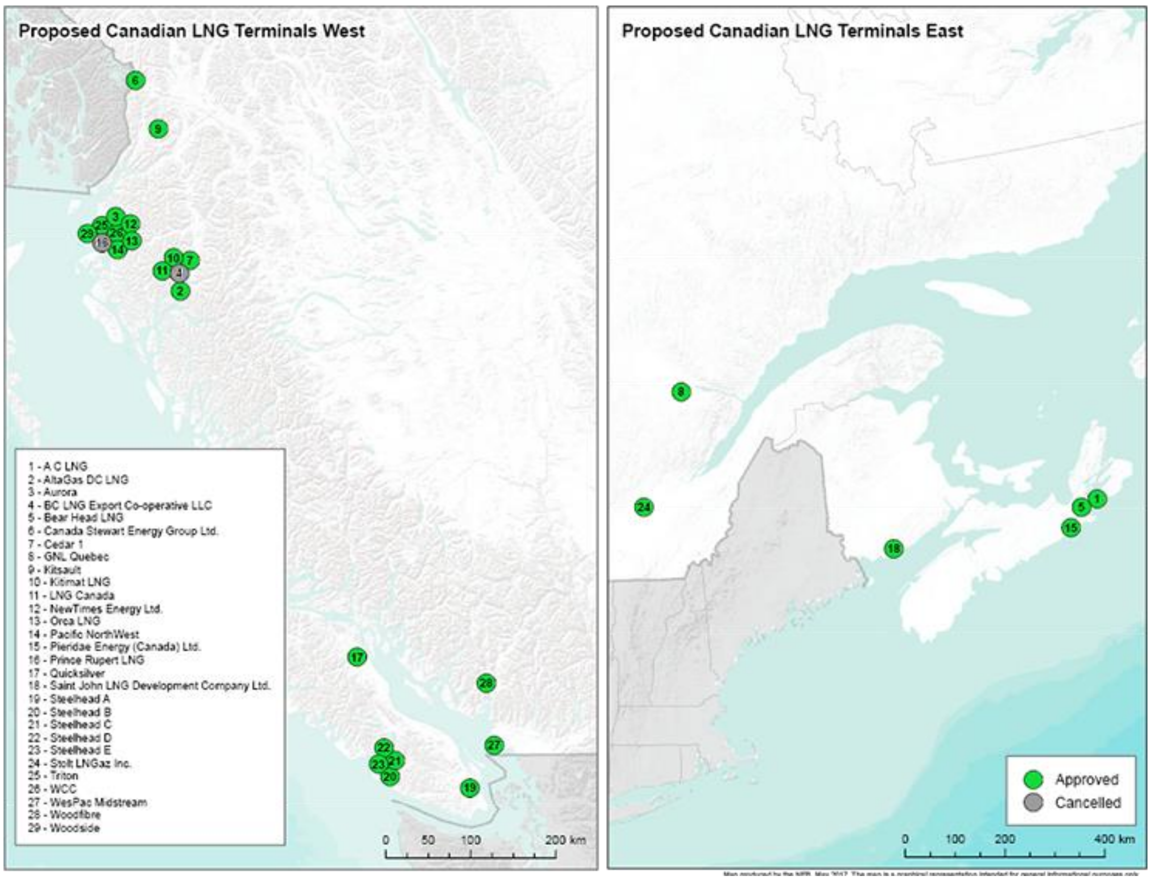

Figure 17: Proposed Canadian LNG Projects

There is considerable uncertainty as to how many and which of these will actually be built, those furthest advanced at present include LNG Canada and Woodfibre in BC. and Bear Head in Nova Scotia. The WesPac Terminal in Tilbury BC is now being advanced by the Tilbury Jetty Limited Partnership of FortisBC and Seaspan. This will include an export component and supply to bunker vessels, using production from a second phase of expansion of the FortisBC Tilbury plant. The proposed facility layout is shown in Figure 18.

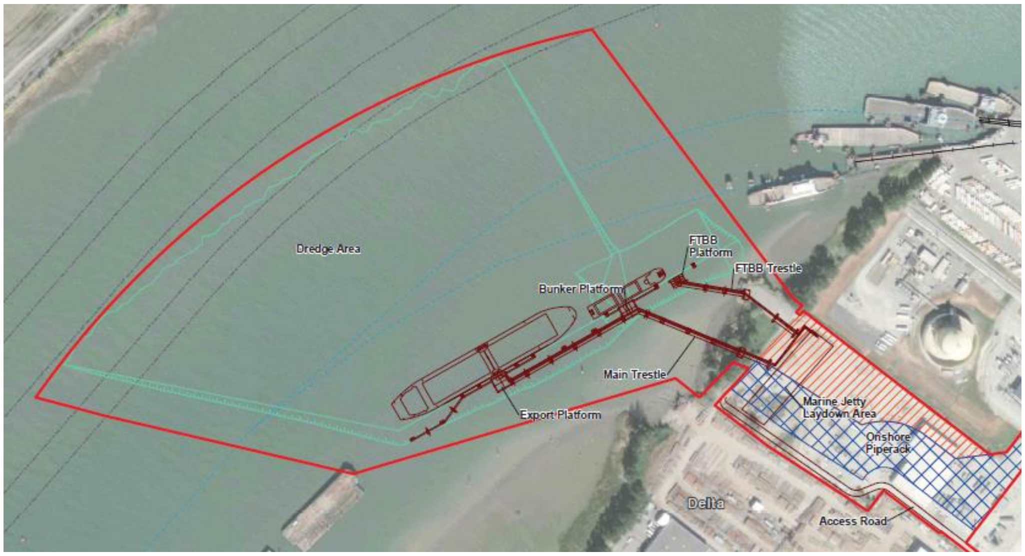

Figure 18: Tilbury Terminal

6.3.2 UNITED STATES OF AMERICA

The US has been ahead of Canada in the pivot from LNG Import to export, with many of the import terminals in Figure 19 having been re-purposed for export or closed completely. The status of many projects has changed rapidly even over the past several years due to economic factors (fuel prices, pandemic impacts) and domestic and international political ones. Domestically, approvals and rejections of both terminals and the pipelines supplying them have impacted many projects. Internationally, the effects of the Ukraine war have hugely increased the attractiveness of North American gas as an alternative to Russian supply. It is projected that the US will become the world's largest exporter of LNG in 2022.

Figure 19 shows the status of operational export plants as of 2020, and Figure 20 shows those under construction or approved; all data taken from the Federal Energy Regulatory Committee. Most relevant to the Arctic are the existing plant at Kenai, Alaska, and the Alaska Gasline and LNG, to be located in Nikiski, projected to enter service around 2028.

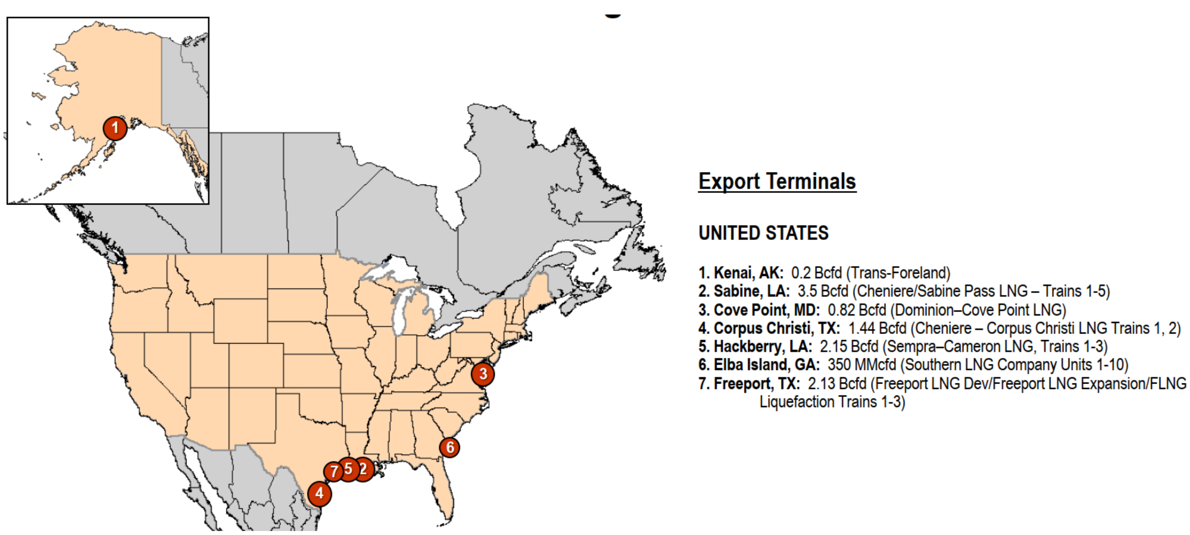

Figure 19: Current US LNG Export Terminals (2020)

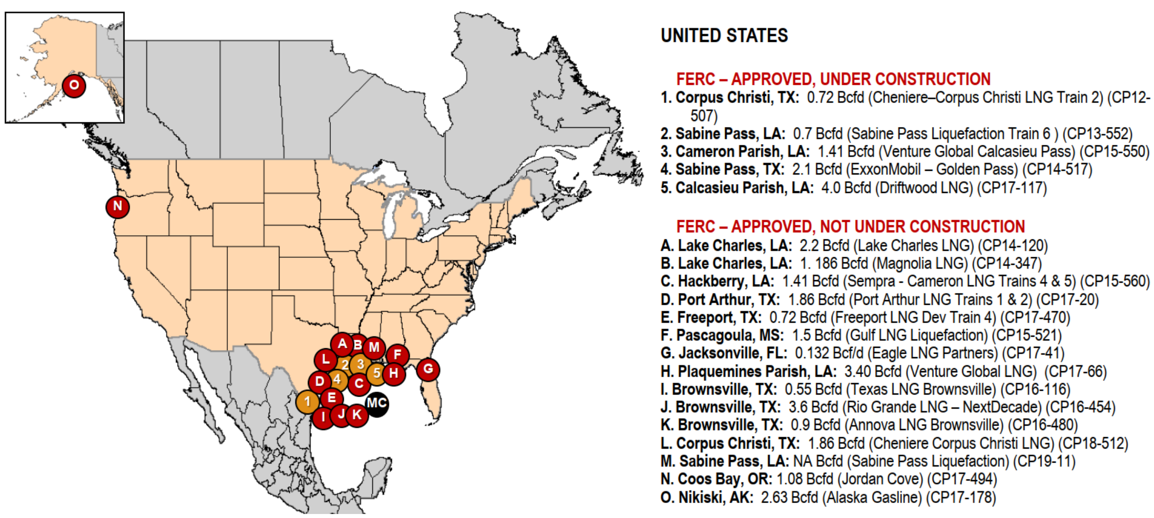

Figure 20: Pending US LNG Export Terminals (2020)

7 DISTRIBUTION SYSTEMS

7.1 OVERVIEW

LNG for export is loaded onto LNG carriers directly from the bulk storage tanks at the terminal associated with the liquefaction plant. Similar arrangements can be provided for supplying LNG at a smaller scale. For example, the Tilbury Marine Jetty project in B.C. intends to service both medium size LNG carriers serving larger markets and bunker vessels that will service LNG-fuelled ships in and around Vancouver and (potentially) smaller consumers on the B.C. Coast. Many projects are using or examining other distribution systems using trucks, railcars, intermodal containers and other options to move LNG from a liquefaction plant to a bunkering location. In some cases, fuel may be provided directly to the ship; in others the distribution system may replenish a local storage tank located alongside a dedicated berth. This is an option used, for example, by various ferry operations.

It may also be feasible in some locations to move LNG by pipeline to a local storage tank. This is most likely to be done as part of a large facility and over short distances. Long LNG pipelines are generally prohibitively expensive and demanding to fabricate and maintain given the cryogenic nature of the fuel. There are no current examples.

The type of LNG distribution system is dependent on the volume of the demand and the nature of the location to be serviced. In many parts of the world, initial relatively low demand from smaller coastal vessels or occasional larger vessels has been supplied by tanker trucks, which have then been supplemented or replaced by bunker vessels as the demand grows. This transition is well under way on Canada's West Coast and under consideration for the East Coast and St. Lawrence. For an Arctic LNG supply chain, supply of fuel to most ports, communities and other refueling sites will require some form of marine transportation, given the lack of road or rail infrastructure in almost all parts of the region.

The following sections discuss each of these distribution options in greater detail.

7.2 PERMANENT BUNKERING FACILITIES

Permanent shore side tanks and the associated pipework, pump equipment, and safety devices can be an element of supply for ships and potentially also a distribution hub for other local communities.

As an early example, since 2008 three LNG-powered ferries in Norway bunker from a fixed shore side system that includes two 500 m^3 tanks and 150 m of insulated pipework. This installation was designed for a bunkering rate of 100 m^3/hr (MAGALOG, 2008). Since then, other bunkering stations have been installed around the coast of Norway (and in neighbouring countries) as part of the supply chain for both shipping and other fuel users.

In the US, Harvey Gulf operates the first US LNG bunkering facility in Port Fourchon, Louisiana (Figure 21), to service its own fleet of LNG-fuelled offshore supply vessels. The facility has two 1000 m^3 storage sites and transfer rates of up to 100 m^3/hr. There is now a larger facility in Jacksonville, Florida which is mainly used to supply bunkering barges but has also fuelled other LNG-fuelled ships. The construction of a facility in Tacoma, Washington State to service container ships and other LNG-fuelled vessels is well-advanced and projected to come into service in the near future, replacing the tanker truck refueling currently in use.

Figure 21: Port Fouchon LNG Bunkering Terminal

In China, around 20 fixed and floating refueling stations have been put in place to service the river and coastal shipping communities; an example is shown in Figure 22 (Hongjun, 2018). Some of these also act as barges for local distribution.

a. 1st generation (cement cofferdam without refueling function)

b. 2nd generation (stainless steel cofferdam with refueling function)

c. 3rd generation (joint location with refueling function)

d. 3rd generation (liquid input/output at the top of the tank with refueling function)

Figure 22: China River Bunkering Stations (Fan, 2020)

More recently, China has announced plans to develop a larger bunkering station in Shenzen at Yantian Port to service international shipping (Si, 2020). This will have an initial capacity of up to 230,000 t/year of LNG, with potential expansion up to 10 times this supply volume. In Singapore, a 3,500 m^3 capacity fixed facility is under construction to service the smaller LNG-fuelled vessels using the port, while larger vessels are serviced by bunker vessels (see also below).

Studies for other "filling station" concepts have been conducted by ports as diverse as Busan in South Korea and Becancour in Quebec. However, in general ports with ambitions to become LNG bunkering hubs have generally preferred to adopt the approach of using bunker vessels (self-propelled vessels and barges) to allow for fuel supply while the customers are alongside and discharging or loading (simultaneous operations, or SIMOPS). Bunker vessel solutions are discussed below. This may still involve the construction of a storage facility as the source of supply for bunker vessels if the LNG is originally coming from a remote source, as in the case for many of the world's largest ports such as Singapore and Rotterdam. In these cases, the marine fuel supply needs are integrated with an LNG import terminal which will have its own storage capabilities.

7.3 TANKER TRUCK

LNG tanker trucks are used for distribution and directly for bunkering. In North America they typically have capacities between 35 to 56 m^3 or roughly 15 to 25 t, though Cryopeak in B.C. is now using Super B-train trailer combinations to transport roughly double these volumes (Figure 23). Trucks store LNG at pressures of around 5 bar, using cylindrical pressure vessels (Type C tanks).

Figure 23: Super B-Train Trailer (Courtesy Cryopeak)

LNG tanker trucks typically have the following basic components:

- Inner pressure vessel made from nickel steel or aluminum alloys exhibiting high strength characteristics under cryogenic temperatures;
- Several inches of aluminized mylar super-insulation in a vacuum environment between the outer jacket and the inner pressure vessel. An alternative to the vacuum insulation is polyurethane insulation. Vacuum insulation has the advantage of providing better insulation and as a result a reduced vaporisation rate (a daily rate of 0.13 % compared to 1.3 %) (Garcia-Cuerva, 2009);

- Outer tank made of carbon steel and not normally exposed to cryogenic temperatures; and
- Control equipment consisting of loading and unloading equipment (piping, valves, gauges, pump, etc.) and safety equipment (pressure relief valve, burst disk, gas detectors, safety shut off valves, etc.).

As many LNG-fuelled vessels require more than a single tanker truck to fill their own tanks, solutions have been developed to allow for multiple trucks to connect simultaneously through some form of manifold system. An example supplied by Groupe Desgagnes in Quebec is shown in Figure 24. This connects up to four trucks. Other systems have been developed for larger numbers of up to eight simultaneously.

Figure 24: truck Bunkering Manifold System

7.4 INTERMODAL TANKS

Intermodal tanks (Figure 25) can be transported via ship, rail and road and can act both as a distribution system and as an onboard storage system. Chart Industries, for example manufactures units which include the necessary equipment including for pressure transfers of LNG using vaporizers. To date, containerized LNG has not been used directly as a fuel source in Canadian marine projects, but FortisBC is shipping LNG by container to clients in China (Figure 26) and other Canadian land-based projects are receiving LNG by containerized tanks.

Figure 25: Chart LNG Intermodal Container

Figure 26: FortisBC LNG for China

Several vessels around the world use containers as their onboard tankage, for example Brittany Ferries in new buildings as shown in Figure 27. Recent work by VARD on behalf of Canadian Coast Guard has explored whether containerized fuel systems could be used on some of their existing and new vessels, during winter operations when working decks and cargo holds are not in use and when fuel use is high.

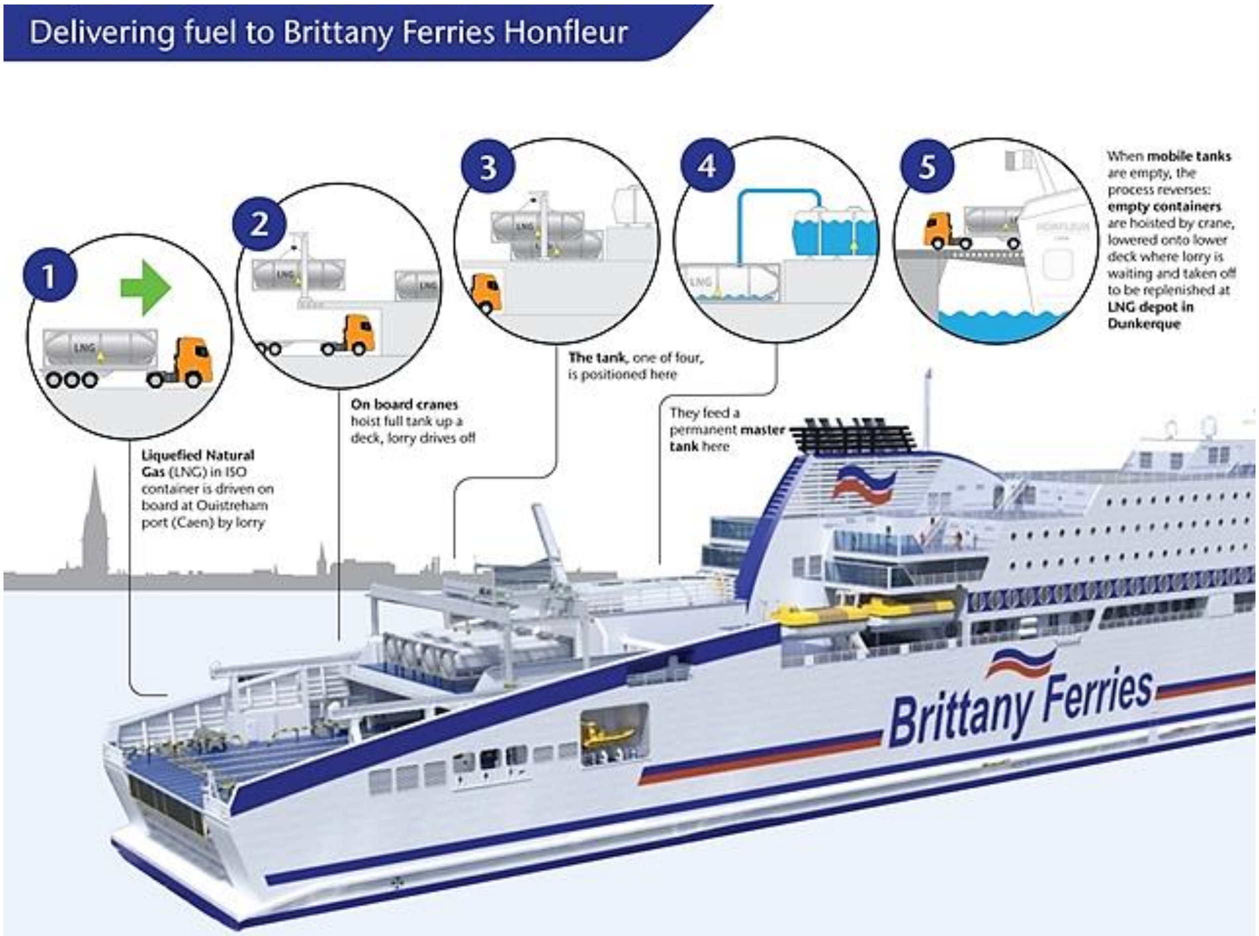

Figure 27: Containerized LNG Ferry Operation

Containerized LNG can be transported by rail as well as by other modes. Rail transport of LNG is an important component of local distribution in some countries, though not to date in North America. It is not likely to be an important component of any Arctic LNG supply chain, though the planned rail line on Baffin Island as part of the Baffinland Mine project could in time be used for this form of cargo.

7.5 BARGES AND TANKSHIPS

The first LNG bunkering vessel was a converted small ferry, adapted to deliver fuel to the ferry Viking Grace in Stockholm, Sweden. This used a retrofitted Type C storage tank and an early generation of LNG transfer system (Figure 28). This combination has now performed over 1,000 bunkerings.

Figure 28: Viking Grace and Sea LNG Bunker Vessel

In recent years bunker vessel designs and buildings have proliferated rapidly. Data from SEA-LNG notes that there were six in operation at the start of 2019, double this by 2020, and by March 2021 approximately 40 were in service or under construction worldwide. One recent delivery is the FueLNG Bellina, shown in Figure 29 (rendering prior to construction). This is a 7500 m^3 capacity vessel with high maneuverability and advanced control system characteristics to allow for operations in restricted waterways around the variety of large vessels it is intended to service in the Port of Singapore.

The illustration shows the large fenders that are typically deployed during bunkering operations. There is a need for mooring systems that can respond to changes in draft of both the bunker vessel and the receiving vessel during bunkering; this also applies to the transfer system itself which may use a loading arm or a crane to support transfer hoses. Numerous other safety systems must be installed on both vessels, and these must be capable of communicating with each other to allow for emergency shutdown in the event of an incident during bunkering. Prior to the first bunkering of any vessel, a compatibility study is normally undertaken to ensure that all systems will work successfully together. Hazardous zones around where gas could be present, such as the bunkering stations themselves and any tank and system vents should also not intersect with any areas where ignition hazards may exist. Ports will normally require a comprehensive risk assessment of all proposed types of LNG bunkering prior to the issuance of permits.

Figure 29: FueLNG Bellina (courtesy Keppel)

Self-propelled bunker vessels comprise the majority of new vessels, but there are also a significant number of barges coupled with different types of tugs, including Integrated/Articulated tow/push systems. These are particularly popular in North America, where US regulations in particular are adapted to barge operations and there is a large towboat industry. A recent barge example, Polaris New Energy is shown in Figure 30. It has similar design features to the Bellina bunker vessel described above, other than relying on power from the attached tug. Polaris undertook its first bunkering in Jacksonville in March 2022.

Figure 30: Polaris New Energy (courtesy Fincantieri)

A challenge for the design of bunker vessels is to determine the appropriate capacity for the unit. While many current LNG-fuelled vessels have total tankage in the range of 1-2,000 m^3, some of the large container vessels now entering service require up to 15,000 m^3 for a full refueling. These capacities allow for a return Trans-Pacific voyage, plus margin. Bunker vessels capable of providing this become quite large vessels in their own right (e.g. Figure 31, a recently launched 20,000 m3 vessel with length of 160m), which may compromise their ability to operate at close quarters with the vessels they are supplying and also drives up their cost. A number of operators of container ships and other large consumers are therefore tending to explore long-term relationships with LNG bunkering suppliers in several locations, to aim to ensure security of supply and to limit the volumes required at any location. This is quite different from the traditional oil fuel bunkering supply chain, in which much fuel supply is fairly opportunistic and assumes fuel availability in most ports of call.

Figure 31: Avenir Allegiance (courtesy CIMC)

Most bunker vessels are intended for fairly local use around a major port, but in some cases, they are intended to provide distribution over a wider area such as the Baltic, large areas of the Mediterranean, or long stretches of the European Atlantic coastline. This includes the Avenir class shown in Figure 31, which is intended both for bunkering and for regional LNG supply. Several recently delivered bunker vessels for the Baltic have moderate ice class (Baltic 1A and RMRS Arc 4, similar to PC 7) to allow for year-round deliveries throughout the Northern Baltic.

The economics of longer distance supply using bunker vessels are addressed in subsequent chapters; however, it can be noted that there are now a significant number of well-proven designs for vessels that could service any part of an Arctic LNG supply chain. Most bunker vessels are customized to a particular service (including the compatibility analyses noted above) but the increasing commoditization of the components is driving costs lower and build times are becoming quite short at 18 months or less.

8 BUNKERING SYSTEMS

8.1 OVERVIEW

The transfer of LNG from shore to ship was first undertaken by the Methane Pioneer in 1959 at an LNG terminal in Louisiana. Bulk transportation of LNG from source terminals to receiving terminals is now commonplace. In addition to ship-shore transfers, ship-to-ship (lightering) of LNG cargo is also conducted regularly. LNG cargo loading/unloading processes are well established. However, the operations, practices and training for refueling (bunkering) of LNG fuelled ships are still evolving.

The increase in numbers of LNG fuelled ships over the last decade has been accompanied by a modest increase in infrastructure for refueling (bunkering) of LNG. LNG bunkering facilities require considerably more infrastructure than those for conventional fuels, with accordingly higher capital and operating costs. Consequently, the global number of ship LNG bunkering facilities is still limited. LNG bunker facilities are (unsurprisingly) concentrated where demand has been established, such as terminals of LNG-fuelled ferry routes and major shipping ports (for example, Singapore and Rotterdam).

The immediate source of LNG for transfer to the ship's tanks (illustrated in Figure 32) may be:

1. Shore-side storage tank (which may be replenished by various means or may be immediately adjacent to a liquefaction plant, itself served by piped natural gas);
2. Road (or rail) tanker; or
3. Bunkering ship or barge.

An alternative replenishment approach is by portable tank transfer, whereby a filled LNG tank is loaded onboard the ship in exchange for a depleted tank (analogous to a backyard propane barbeque tank exchange).

This section briefly describes various bunkering approaches and considers their suitability and adaptations necessary for Arctic locations.

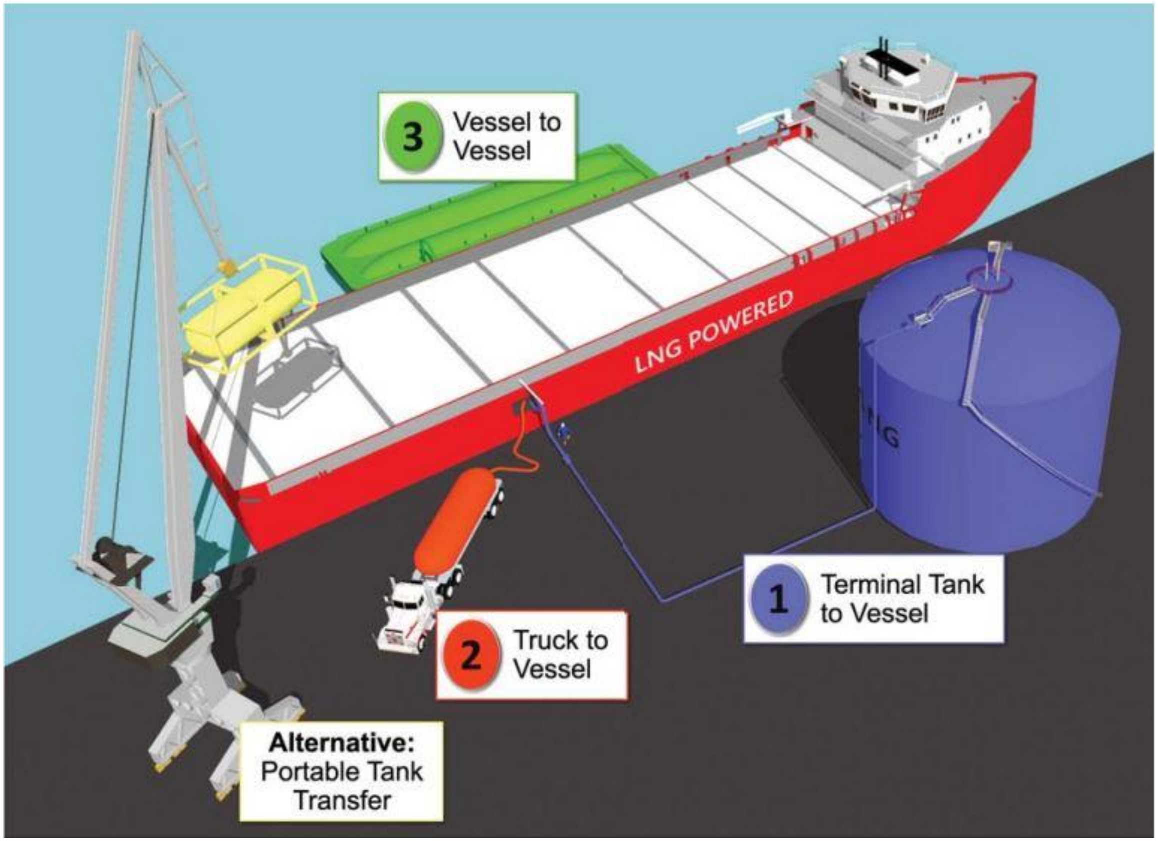

Figure 32: LNG Bunkering (ABS, 2015)

8.2 BUNKERING CHALLENGES

The extremely low temperatures associated with handling LNG raise material property issues and safety requirements that differ considerably from those associated with normal marine fuel operations. The nature of the receiving arrangements on the ship side requires relatively precise control of the fueling process. Purging the fueling lines before and after fuel transfer poses challenges in avoiding contamination and in minimizing any emissions.

Although LNG bunkering is relatively new in the non-LNG carrier market, transfer procedures and systems are well established in the LNG carrier industry. In addition to shipping LNG cargo on established long-term routes, the LNG spot market sector has been a major influence on the development of technology, equipment and operations in order to efficiently and safely undertake ship to ship LNG cargo transfer and lightering operations. Lightering is the process of transferring cargo from a large ship which cannot enter a port due to draft restrictions or narrow entrances to smaller vessels which discharge cargo to port facilities.

Established LNG transfer evolutions address:

- Control of operations;
- Safety (checklists, mitigation);
- Communications;
- Manoeuvring/mooring/connection;

- Procedures for ship to ship (STS) or ship to jetty (STJ) transfers;
- Vapour management;
- Measurement / metering;
- Shutdown/drainage/purging/disconnection;
- Emergency disconnection/release; and
- Personnel training.

The equipment, operational procedures, and personnel training can be used as the main reference for issues related with LNG bunkering operations.

The amount of LNG transferred during a bunker operation for an LNG fuelled vessel when compared to an LNG carrier will be less, however the bunkering operation may be more frequent. In addition to the type of distribution used, the selection of bunker locations is also of high importance. Factors to be considered when evaluating potential bunker locations include:

- Impact on existing quay side area dedicated for the movement of cars and passengers;
- Impact on the Hazardous Area Class due to potential sources of ignition during bunkering;
- Port Authority requirement for risk assessment of the bunker operations/system; and
- Local Legislation impact on road/transport safety due to the truck traffic.

Additional training and certification of personnel both on shore and onboard LNG fuelled vessels will be required which will be addressed in Chapter 6 (Human Resources).

8.3 SHIP-BOARD BUNKERING FACILITIES

8.3.1 BUNKER STATION

The requirements for the bunkering facilities onboard a vessel are dictated by the classification society and International Maritime Organization (IMO) requirements, as interpreted by the flag state (country of ship registry). While the specific requirements may vary between different regulatory bodies, in principle the bunkering facilities will consist of the same main components and safety arrangements.

The piping arrangement of the bunkering manifolds for gas-fuelled vessels are in general similar to a typical LNG carrier's manifold although smaller in size. For the bunker station, the following critical issues need to be addressed:

- LNG liquid and vapour return manifolds;
- Spill protection system at manifolds;
- Spill protection system ship's side shell (at bunker station);
- Manifold piping position to enable drainage operations;
- Relief and purging connection;
- Lifting equipment over manifold to facilitate/support hose connection;
- Elimination of ignition sources throughout bunker station (area class Zone-1);
- Minimization of personnel presence during bunkering;

- Separate control room with panel;
- CCTV at bunker station;
- Emergency shutdown devices; and
- Gas detection and ventilation systems for certain bunker station applications.

8.3.2 CONNECTING SYSTEMS

Quick connect/disconnect couplings (QC/DC) are used to connect the supply hose to the ship's pipework to provide an emergency release system (ERS) or equivalent as required by both SIGTTO and EN 1474 (for STS LNG). Insulating flanges are used to prevent electric flow through a hose.

The following systems, depending on bunker capacity/flow rates/hose diameter, may be adopted:

- Combination of marine dry coupling with QC/DC;
- ERS system activated by emergency shutdown (ESD).

8.4 SHORESIDE BUNKERING FACILITIES

There are three main types of LNG bunkering solutions for supply LNG to marine vessels: LNG terminal with land-based storage tank, tanker trucks, tanker ships / barges (ship to ship bunkering). Choosing a suitable bunkering method is dependent on a variety of factors such as:

- LNG tank capacity;
- Location; and
- Frequency of bunkering.

This section discusses these in a general context. Arctic applicability is examined further in Section 8.6.

8.4.1 LNG TERMINAL / LAND BASED STORAGE TANKS

An LNG terminal will incorporate similar equipment and safety arrangements to those found onboard LNG fuelled ships. Valves, fittings, and pipelines used are installed and maintained in accordance with the appropriate standards and codes of practice (SIGTTO, 2000). A pipeline is used to transfer the LNG from the storage tanks to the ship. Discharge pumps may be used, or transfer of LNG may be accomplished by pressurizing the vapour space of the storage tank.

The vapour return facilities installed at an LNG terminal will be dependent on factors such as economics, filling rates, and the distances between the tanks and the ship connection.

8.4.2 TANKER TRUCKS

As previously noted, tanker trucks are also a viable method of LNG bunkering. LNG tanker trucks typically carry approximately 35 to 56 m^3 of LNG in one trip. Transfer pumps may be fitted to the trucks, pump trailer units, shore side, or on the receiving vessel. The LNG ferry operations in Norway typically bunker with the tanker truck remaining shoreside (see Figure 33).

Figure 33: LNG Bunkering (Elbehafen)

On the West Coast of Canada several ferry operators bunker their LNG by having the LNG tanker truck drive aboard the vessel for fuel transfer. This type of bunkering is necessary when vessels do not have dockside berths, as is the case for many ferries. Figure 34 shows the onboard LNG tanker truck bunkering used by Seaspan Ferries in British Columbia.

Figure 34: Onboard LNG Tanker Truck Bunkering (Seaspan Ferries, 2015)

Current experience with LNG tanker truck bunkering has identified the following critical issues when considering delivery via tanker truck:

- Pumps fitted on tanker trucks need to be matched to the required capacity to achieve flow into a pressurised system such as the Type C tank;
- Numerous tanker trucks are required to bunker larger vessels (bunker volumes 150 m^3 and above);

- An ESD must be in place.

Truck-on-deck bunkering removes relative motion problems and can simplify communications procedures. However, additional safety measures are required to mitigate risks associated with LNG releases onboard.

8.4.3 TANKER SHIP / BARGE (SHIP TO SHIP) BUNKERING

Organizations including SGMF, SIGTTO and numerous classification societies (Section 13) have published guidelines for LNG STS transfer. They cover bunker vessel to receiving vessel bunkering, and side-by-side STS transfer operations of LNG between commercially trading LNG carriers at anchor, alongside a shore jetty or while underway.

Critical issues for this delivery method include:

- Selection of appropriate hose system for STS in order to meet fuel transfer requirements;
- Addressing compatibility issues with bunker barge transfer system and bunker station lay-out;
- Ensuring regulatory requirements for hose certification are complied with;
- Ensure manifold spools, valves, equipment have been typed approved by the regulatory bodies;
- Address type of ERS, QC/DC arrangement. Certification/test requirements for a new system will have cost, schedule, and risk impacts. Also, the complexity of a standalone or an integrated ERS system will potentially have technical/cost impact on the ship's specification; and
- Address impact that system operation may have especially on manifold arrangement, control operation, ESD system and Port Authority safety requirements. Insufficient integration may have cost/time impact and/or may not meet with safety criteria of operations.

Existing vessels use flexible cryogenic hoses, which are arguably less sensitive to adverse swell or weather conditions for STS transfer than rigid arm technology. An alternative to the rigid arm technology is a hose handling crane and pumping of LNG using high pressure (Swedish Marine Technology Forum).

There are numerous existing and proposed systems which can be easily adopted for bunkering operations:

- Cryogenic air hoses;
- Cryogenic floating hoses;
- Crane/articulated supported hoses; and
- Rigid arm systems.

8.4.4 MEASUREMENT / METERING TECHNOLOGIES

Measurement technologies are not consistent across the different distribution systems, and different regulatory regimes have different metering schemes (e.g., for tax calculations). The following LNG measurement challenges have been identified:

- Changes in tank volumes due to continual temperature cycling;
- Errors related to ship loading and offloading dynamics (list, trim and tank corrections);
- Unaccounted for boil-off gas and flared gas;
- Calibration of meters to actual operating conditions due to the lack of large-scale cryogenic flow laboratories; and
- Due to LNG being stored close to its boiling point it may become a two-phase liquid if there are any hot spots in the system.

In addition to being suitable for cryogenic applications, metering devices should:

- Have few or no moving parts;
- Have the proven accuracy required;
- Allow for calibration and testing; and
- Cause low or no pressure drop to avoid LNG vaporization.

For tanker truck to ship bunkering, the preferred method of determining amount of LNG supplies is through scale tickets. Ultrasonic and Coriolis metering devices are two potential systems.

8.5 PORTABLE (INTERMODAL) TANK TRANSFER

Portable fuel storage can be achieved using portable tanks which can be lifted or driven on and off a vessel for refueling. These tanks are contained in the form factor of 20- and 40-foot ISO containers. A 40-foot tank has a capacity of approximately 40 m^3 of LNG. Although this concept could be well suited for replenishment at locations with limited infrastructure, there is a relative scarcity of ships designed for portable tanks, either built or on order. Section 7 includes a description of the MV Honfleur which was nearing completion for Brittany Ferries in 2020 before its order was cancelled. Honfleur was to use four 20-foot intermodal tanks which connected to a permanent master tank.

8.6 ARCTIC LNG BUNKERING APPROACHES

Marine activity along Canada’s north coast interfaces with rudimentary shore infrastructure. Alongside moorings for vessels of moderate draft are available in very few locations such as the Nanisivik, Nunavut deep water jetty (scheduled for completion in 2022 and the deep-water port under construction at Iqaluit, Nunavut.

Sea supply to northern communities is generally provided via “barges” (shallow-draft landing craft) to beaches or slipways from anchored ships. Cargoes including ISO containers can be transferred to shore by this method. In some locations fuel oil is pumped from anchored vessels through floating hoses to shore storage tanks. Most ships servicing the north have sufficient range to complete their voyages using fuel embarked in the south and do not require bunkering in northern locations but some bunkering of liquid fuel to ships from shore tanks is undertaken using floating hoses. Canadian government agencies (Coast Guard and Royal Canadian Navy) annually pre-position fuel barges at anchor in northern locations for replenishment of vessels participating in Arctic programs and is in the process of (re)establishing conventional liquid fuel storage and bunkering systems at Nanisivik.

LNG has been proposed as an energy source for various northern communities but has not yet been implemented. If it does so, sea delivery of LNG to community shore storage tanks may become established. Outside of deep-water jetty locations, this will probably be by buoyant floating hoses, but regulations and processes will need to be developed. If LNG shore storage tanks are built to serve any Arctic locations, they could potentially be sources for bunkering LNG-fuelled ships. Supply to such tanks could be by floating hoses from anchored LNG transport vessel, but as yet such processes have not been developed. There is also a future possibility of using small-scale liquefaction plants fed by the Arctic's abundant, but un-exploited, natural gas reserves. Such plants could also be suppliers of LNG to ships' bunkers.

It is also possible that LNG for coastal communities' energy needs could be delivered in intermodal ISO 20- and 40-foot tanks, as is being done in China (CIMC, 2018). These tanks themselves could be used as bunker (exchange) tanks for suitably designed LNG-fuelled ships operating in Arctic waters. However, the scarcity of alongside berths and cranes would necessitate such ships to have their own lifting capability to embark such containers, probably from barges.

As one of the north's largest communities and as the (imminent) site of a deep-water berth, Iqaluit could be a feasible candidate for adoption of LNG as a community energy source for power generation stations. LNG stored in that city could also service an LNG bunkering port. Either piped supply or tanker truck supply (both described above) could be used to service LNG fuelled ships berthed alongside.

In the absence of any shore storage of LNG, and pending development of ships using portable/exchange LNG fuel tanks, the remaining option for bunkering in the Arctic is ship-to-ship. LNG supply chains from both east and west coasts of Canada (or the US) may acquire bunker vessels (ships or barges) to service LNG fuelled ships in the Arctic.

9 ONBOARD STORAGE AND DISTRIBUTION SYSTEMS

9.1 GENERAL

The design codes for LNG Carriers and LNG fuelled vessels (Section 13, and Chapter 7) allow for considerable flexibility in the technologies that can be used in most aspects of the design, from the propulsion systems to storage arrangements. The focus of all areas is ensuring that acceptable levels of safety are achieved and can be demonstrated through analysis and testing. This section of the report covers the available options for onboard storage and distribution systems, while propulsion prime movers and systems are discussed in Sections 10 and 11 respectively.

9.2 LNG TANKS

Conventional ship (liquid) fuel tanks are typically integral tanks enclosed by the ship's structure. However, LNG tanks used for gas-fuelled ships are expected to be independent as per the IMO Resolution MSC 285(86) and the IMO IGF Code. Section 2.8.1.1. of the IMO guidelines states that the storage tank used for liquefied gas should be an independent tank designed in accordance with the International Code for the Construction and Equipment of Ships Carrying Liquefied Gases in Bulk (IGC) Code, chapter 4. This chapter of the IGC code categorizes independent tanks into three types, types A, B, and C, and the same designations are used for LNG-fuelled vessels in the IGF Code. The primary differences between the tanks are types A and B are non-pressurized while type C tanks are pressure vessels. Furthermore, type A and B require full or partial secondary barriers, respectively. Type C does not require any form of secondary barrier.

Other tank types include membrane tanks and lattice tanks. Membrane tanks are non-self-supporting prismatic tanks while lattice tanks are box shaped tanks with lattice type structures which increase the load the tank can accommodate.

All LNG tank options require more space than conventional fuel oil tanks to provide the same range and endurance, due to the lower volumetric energy density of LNG.

9.3 TYPE “A” INDEPENDENT TANKS

These are tanks designed primarily using recognized standards of classical ship-structural analysis procedures (shown in Figure 35). Type A tanks, which are prismatic tanks, are independent of the ship’s structure. They are classified as independent tanks because there is no metal-to-metal contact between the structure of the tank and that of the vessel. Instead, the space between the tank and vessel is filled with layers of insulation consisting of timber, glass fiber, and balsa panels. This allows for expansion and contraction of the tank. Furthermore, type A tanks require a secondary barrier which can contain the entire tank volume at any heel angle for 15 days in the event of a leak (Chakraborty, 2021). These tanks are non-pressurized and can withstand a vapour pressure not exceeding 0.7 bar. They are designed with longitudinal bulkheads which reduce sloshing. One advantage of type A tanks is that they have a volume efficiency 30-40% greater than that of the more common type C tanks (Tutturen, 2019). These tanks may be used for LNG-fuelled vessels; however, there are no recent LNG vessels with this kind of cargo containment system due to the necessity of a complete structural secondary barrier.

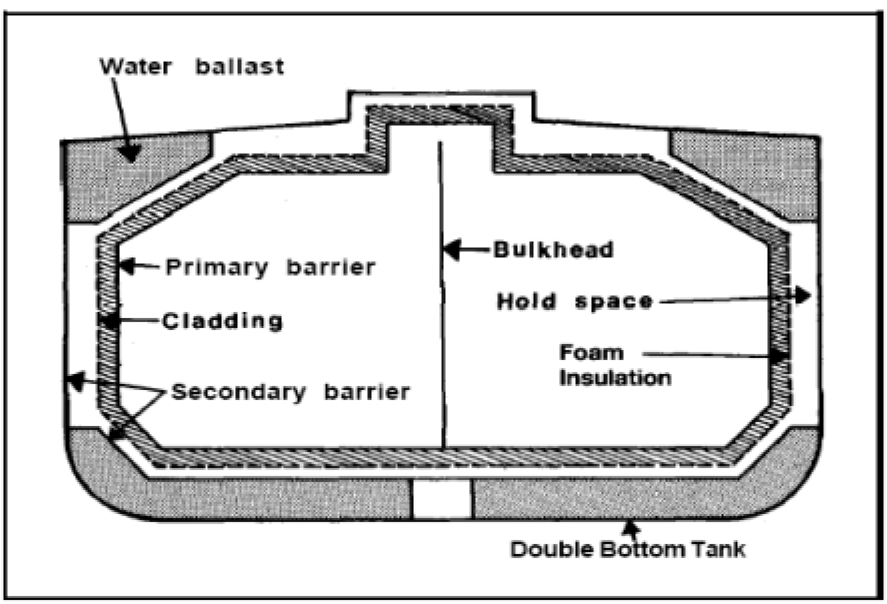

Figure 35: Prismatic Self-Supporting Type A Tank (Liquified Gas Carrier, 2021)

9.4 TYPE "B" INDEPENDENT TANKS

These are tanks designed using model tests, refined analytical tools and analysis method to determine stress levels, fatigue life and crack propagation characteristics. Similar to type A tanks, type B tanks are non-pressurized and can carry loads having a vapor pressure not exceeding 0.7 bar and any boiling temperature. Type B tanks require a partial secondary barrier which consists of a drip tray as well as a series of sensors that can detect the presence LNG. They do not require a full secondary barrier because they are designed for early crack detection so that failure is very rare. Type B tanks, which are traditionally spherical in shape, are often installed with about half of the tank below deck and half above (Maritime, DNV-GL, 2015). In that scenario the above deck portion is weather proofed. The tank has a flexible foundation to allow for expansion and contraction (Chakraborty, 2021). A type B tank is shown in Figure 36.

Type B tanks may be used in larger or longer endurance vessels, as they can maximize the amount of storage volume in an internal installation on the ship. Several LNG-fuelled vessels with Type B tanks are now under construction, notably for EPS Lines container vessels, constructed by HHI in Korea. The first of these entered service in September 2020. Their tanks are essentially cubic in design.

A case study performed by Japan Marine United Corporation examined the feasibility of fueling an 10000 Twenty-foot equivalent unit (TEU) container ship with a IHI-SPB type B tank. The proposed fuel capacities for the ship are 2000 m^3 of LNG and 10000 m3 of heavy fuel oil. The ship would run on LNG in emission control areas and fuel oil outside of these areas. The case study found that in order to implement this fuel system it would result in a loss of 200 TEU or less (Nagata, Tanoue, Kida , & Kawai, 2015).

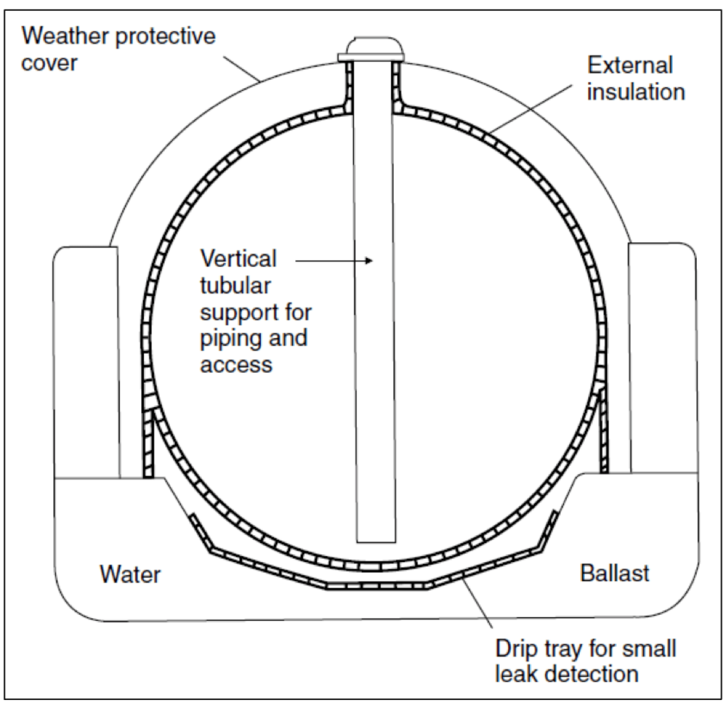

Figure 36: A Spherical Type B Tank (Chakraborty, 2021)

9.5 TYPE “C” INDEPENDENT TANKS

These are tanks which are designed in accordance with Classification society pressure vessel design requirements and are essentially the same as the bullet tanks described at Section 5.2.3. Examples are shown in Figure 37 and Figure 38. The maximum allowed cargo vapour pressure of these pressurized tanks is a function of many factors, such as density of cargo, tank dimensional ratios, tank material allowable stresses, etc. however, it is typically in the range of 10 bar. Type C tanks can be a variety of shapes although, the most common are cylinders and bi-lobes (Figure 39). Bi-lobe tanks are preferred where space is a limiting factor as they can accommodate a greater volume of LNG in the same amount of space as cylindrical tanks. The configuration of the tanks depends upon their shape and size as well as the physical constraints of the vessel. The holding space for these tanks is filled with inert gas or dry air and sensors so that if there is an LNG leak it can be easily detected. For that reason, type C tanks do not require a secondary barrier (Chakraborty, 2021).

Figure 37: Type C Tank

Figure 38: Type C Installation, Viking Grace

Figure 39: Bi-lobe Type C tank (courtesy Wartsila)

Initially the majority of LNG-fuelled vessels, other than LNG carriers, were designed using Type C tanks including all vessels currently operating in Canada as described in Section 2. An example from the US Harvey Gulf's platform supply vessels (PSV) is shown in Figure 40.

Figure 40: LNG Powered PSV with Type C Tank

The storage tank is one of the single most expensive components of an onboard system. Recent improvements in Type C tanks have been the introduction of lighter, thinner insulation materials which allow for smaller gaps between the double wall. Further improvements include both the mechanical design with even more integration of the complete gas supply system and the control system based on operator feedback.

9.6 MEMBRANE TANKS

Membrane tanks are superficially similar to Type A prismatic tanks but differ in that membrane tanks are of relatively light construction and require to be fully supported by surrounding ship structure. Membrane tanks such as GTT's Mark III and NO96 systems are commonly used on LNG carriers. Membrane tanks typically consist of two independent and liquid tight barriers and two layers of insulation to protect the hull from the low temperatures and to limit boil-off, as shown in Figure 41. Such tanks can make more efficient use of space than cylindrical or spherical tanks. These tanks are designed for modular construction so that they can easily fit different shapes and tank capacities. Their prefabricated components allow for mass production and easy assembly. The boil off rates for the range of Mark III tanks vary between 0.15 % to 0.07 %V/d (Gaztransport & Technigaz, 2021).

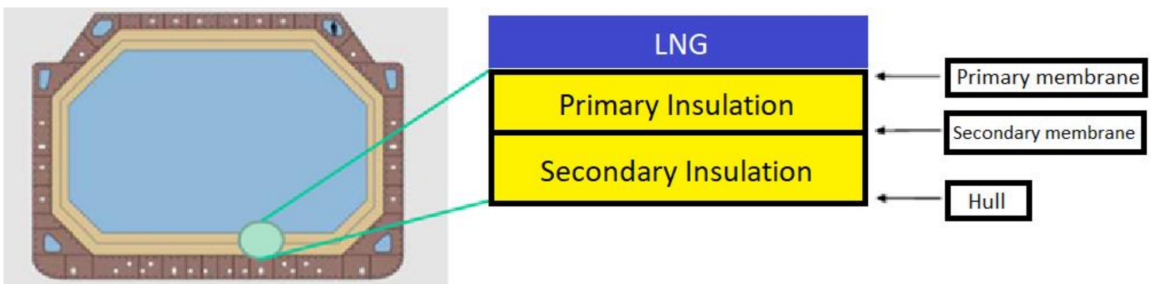

Figure 41: Membrane Tanks (Courtesy of GTT)

Membrane tanks are also being installed in gas-fuelled large vessels that perform long-range voyages. One such concept design was developed by DNV-GL in partnership with Hanjin Shipyards and GTT for a gas-fuelled large container vessel equipped with membrane fuel tanks. This project looked at a 16,300 TEU container vessel with the fuel storage for a 15,000 nautical mile journey thanks to two membrane tanks with capacity of 11,000 m^3 of LNG, concept shown in Figure 42. This joint project demonstrated that this concept can be feasible for large ships.

The Compagnie Maritime d'Affrétement and Compagnie Générale Maritime (CMA CGM) Jacques Saade, delivered in 2020, is the first of nine large LNG powered container sister ships to be completed for CMA CGM by Shanghai Jiangnan-Chanxing Shipyard. It is currently the largest LNG powered container ship in the world, carrying a maximum of 23,000 TEU, and is fitted with a single 18,600 m^3 membrane tank (Kalyanaraman, 2020). In 2019, Jiangan Shipyard placed an order with GTT for five additional LNG-fuelled 15000 TEU container ships for CMA CGM. The ships will use the Mark III Flex membrane tanks with a capacity of 14,000 m^3 per ship (GTT, 2019). Furthermore, in 2018, GTT received an order from the Norwegian shipyard, VARD, for two MARK III membrane tanks to be installed in a hybrid cruise icebreaker, Le Commandant Charcot (Figure 43) was delivered **in 2021**. This cruise ship is the world's first luxury ship with Ice Class PC2 and the first with an electric hybrid engine propelled by LNG. The vessel's expeditions will range from two weeks to one month in length. The vessel, which will be installed with two 4500 m^3 tanks, will be capable for completing its entire voyage on LNG (GTT, 2018). The overall design of this system provides for higher tank pressures of up to 2 bar, increasing the flexibility of operation.

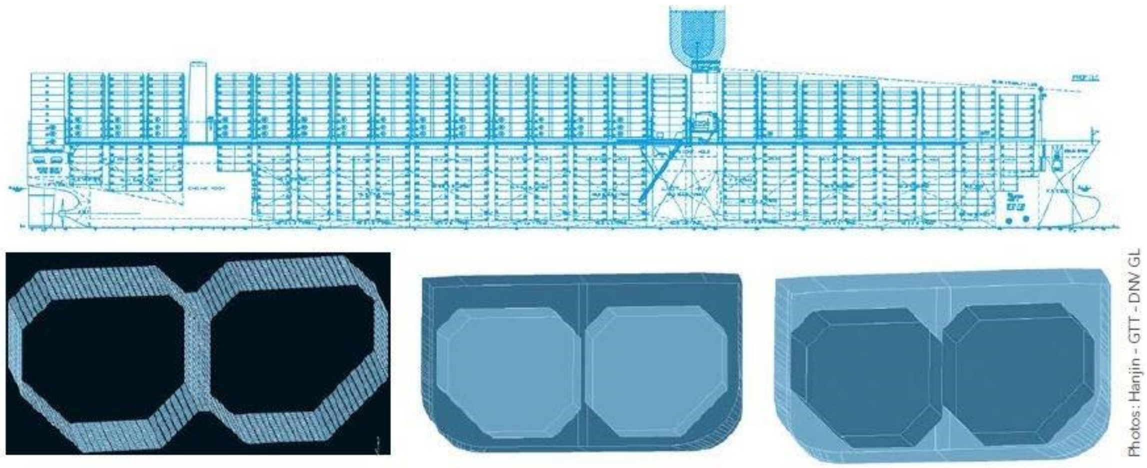

Figure 42: Container Vessel with Membrane Tank (Maritime, DNV-GL, 2015)

Figure 43: LNG Fuelled Expedition Cruise Vessel *Le Commandant Charcot*

9.7 LATTICE PRESSURE TANKS

A recent innovation in onboard NG storage is the Lattice Pressure tank. The Lattice Pressure tank is box shaped, and therefore space efficient. To bear structural load, it has an internal, load carrying lattice type structure. The lattice structure is modular in all three spatial directions (connecting opposite walls and base to top) which balances the pressure forces on the external walls, therefore scaling the tank to larger sizes does not increase the wall thickness of the tank. The Lattice Pressure tank offers vessels high volume efficiency with its prismatic shape with flexible dimensions and scalability in any direction. Figure 44 shows the benefits of the Lattice pressure tank on a container ship, with space savings and system simplification due to using a single tank.

In 2018, LATTICE Technology, a start-up established in 2012 by two KASIT University professors, signed a contract with the Ulsan Port Authority to install their Lattice Pressure Vessel (LPV) in a

150 tonne port cleaning ship. The LPV's internal lattice structure allows it to support a pressure load 50 % greater than the pressure load that a cylindrical tank can support. The LPV has a modular structure which is scalable in any direction. Furthermore, it has a negligible fatigue risk because it mitigates sloshing (ed_news, 2018).

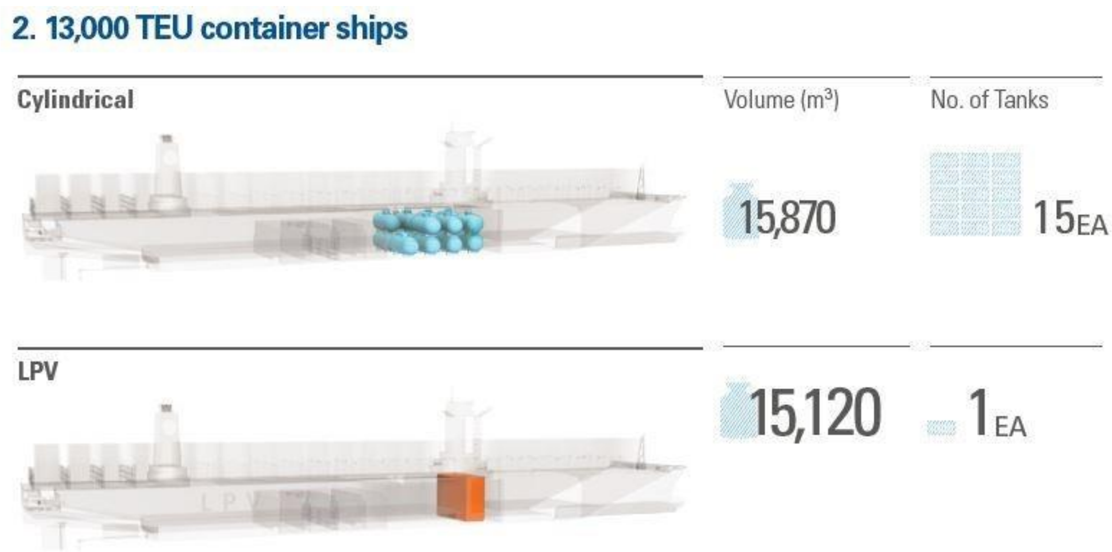

Figure 44: Lattice Pressure Tank Comparison (Lattice Technology, 2015)

9.8 ADDITIONAL ELEMENTS OF THE ONBOARD STORAGE SYSTEMS

All storage tanks for LNG are highly insulated and various industry standards specify minimum hold times for LNG. Nonetheless, gradual heating is unavoidable, resulting in gradual boil-off gas (BOG) which has to be managed. For vessels fitted with type C tanks, the BOG can be managed up to a point by allowing the pressure to increase. BOG is also managed by using the gas for fuel in a gas engine, or by combustion in an auxiliary system such as a boiler. LNG carriers are sometimes fitted with gas combustion units or reliquefication plants for managing BOG.

The significance of boil-off and property variation depends on the application (e.g., long term storage, carriage of gas and its use in a fuel system). For fuel systems the turn-over time for the storage tank will typically be quite rapid, and the boil-off rate needs to be boosted in order to provide a sufficient supply of gas fuel. At the other extreme, the boil-off vapour may need to be managed by either recirculation through a liquefier or by consuming the fuel. A boil-off gas utilization system is used to control gas fuel storage tank pressure and to maintain it below the maximum allowable tank relief valve setting.

LNG must be allowed to vaporize to gaseous state before being supplied to an engine. Ancillary equipment is necessary to condition the gas for engine supply. As described in Section 10, different engine technologies require either low- or high-pressure gas fuel supply. Additional key elements are required to complete the onboard fuel distribution system depending on whether the system is a high- or low-pressure fuel system and whether it uses pumps or a pressure build up unit (PBU).

PBUs are used for low pressure systems (~5 bar operating pressure) and incorporate a heat exchanger for heating the LNG inside of a storage tank. The resulting pressure build up inside the tank is used for supplying the fuel to the engines. Variations exist on this concept which incorporate centrifugal pumps for circulating the LNG through the PBUs. An alternative low-pressure system may use a centrifugal pump for supplying the gas pressure for the engines which results in a lower tank pressure.

High pressure systems such as those used on the MAN ME-GI engines incorporate cryogenic pumps to supply LNG to the injectors at pressure up to 300 bar.

A tank room is required if the LNG storage tank is located within the ship's structure. These tank rooms must be arranged with fuel containment provisions and secondary barriers to reduce the risk of gas or liquid release from the tanks.

The gas valve unit is a system of block and bleed valves for regulation / control of pressure and flow to the engine(s). The supply valve arrangement consists of a series of manual and automatic valves that allow for the isolation of the gas supply to each gas utilization unit in an emergency. These valves are normally located outside of the space containing the gas utilization unit.

Due to different boiling points of each of the LNG components the vaporization of LNG results in a change in composition. The nitrogen component of LNG has the lowest boiling point and vaporizes first, followed by methane. This leads to a higher concentration of nitrogen in the boil off gas early during storage. The longer LNG is stored, the more the nitrogen content decreases, and the hydrocarbon concentration increases.

Most designs require tank connection spaces (TCS). The TCS is a gas tight second barrier for all the connections to the tank, the vaporizer, pressure build up unit, and pressure relief system. In the event of a connection failure the TCS captures any potential liquid gas leaks (Chorowski, 2015).

The ventilation systems in LNG-fuelled ships play an important role in the safety of the vessel. They prevent explosions in the case of a gas leak. Inlet and outlet locations, flow velocities, and equipment specifications must all be taken into consideration when designing ventilation systems for hazardous zones. The IGF code provides regulations for ventilation on LNG fuelled ships.

9.9 FUEL SUPPLY ARRANGEMENTS

IMO IGF Code requires a fully redundant system. For single-fuel installations (gas only), the fuel storage should be divided between two or more tanks of approximately equal size. Dual fuel engines may use a single gas tank and have liquid fuel as a backup. There are some interpretations of this rule, and some applications may allow a single-fuel, pure gas system to have only one fuel storage tank provided that there is redundancy in the fuel delivery systems.

9.10 CONVERSIONS AND NEWBUILDINGS

LNG tank locations onboard a vessel are key considerations when considering a new design or a conversion of an existing diesel-powered vessel to LNG. The challenge is greater for conversions, due to the constraints imposed by the existing vessel and the general unsuitability of fuel oil tank locations to use for LNG storage. The size of the LNG tanks depends on the desired bunkering frequency of the LNG and are specific to each application, however to maintain the same vessel range after conversion a larger tank volume will be required due to the lower energy density of LNG. Pure gas engine applications do not require both liquid fuel and gas fuel storage tanks, whereas dual fuel engines need both; however, redundancy considerations also need to be addressed.

Vessel operators considering engine replacements for existing vessels must also consider upcoming emission requirements when operating in emission control areas. Depending on the sulphur content of the liquid fuel being consumed, scrubbers for the removal of sulphur as well as selective catalytic reduction systems to reduce NO_x may be required in order meet allowable limits. LNG-fuelled engines are able to comply with all of the marine emission regulations coming into effect in the near future. In many applications, no catalytic or scrubber systems are required for LNG engines to meet sulphur oxides (SO_x) and NO_x emission restrictions.

There have been a number of LNG conversions in recent years. Ferries constitute a large portion of the conversion projects which have been completed or are underway, including two of the BC Ferries Spirit class. In 2019, the Spirit of Vancouver Island, the second ship in the class to be converted, returned to British Columbia after being installed with four new dual fuel engines and an LNG tank in Poland. The Spirit of British Columbia underwent a similar conversion at the same shipyard in 2018 (Safety4Sea, 2019). Similarly, there have been several recent projects to convert container ships to LNG fuelled systems. For example, the Sajir, a 15000 TEU ship owned by Hapag-Lloyd, began conversion in Shanghai 2020. The vessel was built in 2014 and designed to accommodate a potential conversion. It is the largest conversion of its kind to date. The vessel has been fitted with a 6,700m^3 tank which reduced the ship's cargo capacity by 350 containers. The Sajir has 16 sister ships which were also designed for possible LNG conversion although, their conversion has not been ordered yet (The Maritime Executive, 2020).

10 ENGINE TECHNOLOGIES

10.1 OVERVIEW

There are several approaches to using natural gas as the main fuel for prime movers (engines). The focus of this project is on internal combustion reciprocating (piston) engines, which have become by far the predominant engine technology for marine applications. Turbines – steam or gas (referring to the working fluid rather than the fuel) – continue to be used, especially gas turbines and nuclear-heated steam plant in warships and submarines. Steam plants remained in use for LNG tankers long after they were phased out for most other ship types, due to the simplicity of using gas as a fuel for these ships. However, the much higher fuel efficiency of marine internal combustion engines makes them the selection of choice for new construction and for major conversions. Sections 10.2 to 10.4 review a range of the engine options that are currently available.

Marine internal combustion reciprocating engines are broadly categorized as high speed, medium speed and slow speed. Speed definitions vary slightly, but the engine manufacturer Wartsila categorizes high speed as more than 1,400 revolutions per minute (rpm), medium speed as 400 – 1,200 rpm and slow speed as less than 200 rpm. Engine size and power output bands have considerable overlap, but slow speed engines are physically largest and deliver the highest power outputs. High speed engines are the most compact and are capable of quick response to changes in power demand. Typical propulsion applications are presented in Table 8.

Table 8: Engine Category by Ship Type

Ship type (examples)	High speed	Medium speed	Slow speed
Warships	X	X	
Fishing vessels	X	X	
Ferries	X	X	
Cruise ships		X	
Coastal cargo vessels		X	
Icebreakers		X	
Offshore supply vessels		X	
Trans-ocean – bulk carrier			X
Trans-ocean – container ship			X
Trans-ocean – tanker			X

Large ships with slow speed engines typically also utilize high speed or medium speed engines as electrical generators.

10.2 GAS FUELLED ENGINE TECHNOLOGIES

Unlike diesel or heavy oil fuel, natural gas does not ignite at temperatures achieved by the compression ratios feasible in reciprocating internal combustion engines. Therefore, gas engines require an ignition source. Two technologies are currently used: spark ignition (similar to spark plugs in a gasoline automotive engine) and dual fuel (injection of a small quantity of pilot diesel fuel, which does ignite by compression and then ignites the main gas fuel). Four main configurations are used in natural gas engines – lean burn spark-ignition (SI) pure gas and three types of dual fuel (DF): direct injection 4-stroke, high-pressure direct injection 2-stroke and low-pressure gas 2-stroke. Engine designs using Otto cycle (rapid combustion at approximately constant volume at the beginning of the power stroke) and Diesel cycle (slower combustion at approximately constant pressure throughout the power stroke) are available. Table 9 below provides an overview of these technologies.

Table 9: Natural Gas Engine Technologies

	Lean burn spark ignition (SI) pure gas (Figure 45: Bergen B35:40 Spark Ignition Gas Engine)	Dual fuel (DF) with diesel pilot (Figure 46: MaK DF Medium-Speed Engine)	High Pressure Direct gas injection (HP gas) with diesel pilot (Figure 47: MAN 9-Cylinder HP Gas Slow-Speed Engine)	Low pressure gas (LP gas) with diesel pilot (Figure 48: WinGD 10 Cylinder LP Gas 63MW Engine)
Thermodynamic cycle	Otto (4-stroke cycle)	Otto (4-stroke cycle)	Diesel (2-stroke cycle)	Otto (2-stroke cycle)
Fuel introduction	LP gas pre-mixed in intake or port injection	LP gas/air pre-mixed in intake	HP gas direct in cylinder head	LP 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

Figure 45: Bergen B35:40 Spark Ignition Gas Engine

Figure 46: MaK DF Medium-Speed Engine

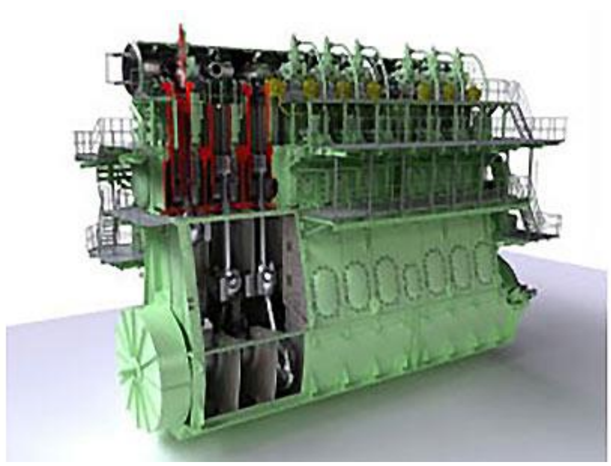

Figure 47: MAN 9-Cylinder HP Gas Slow-Speed Engine

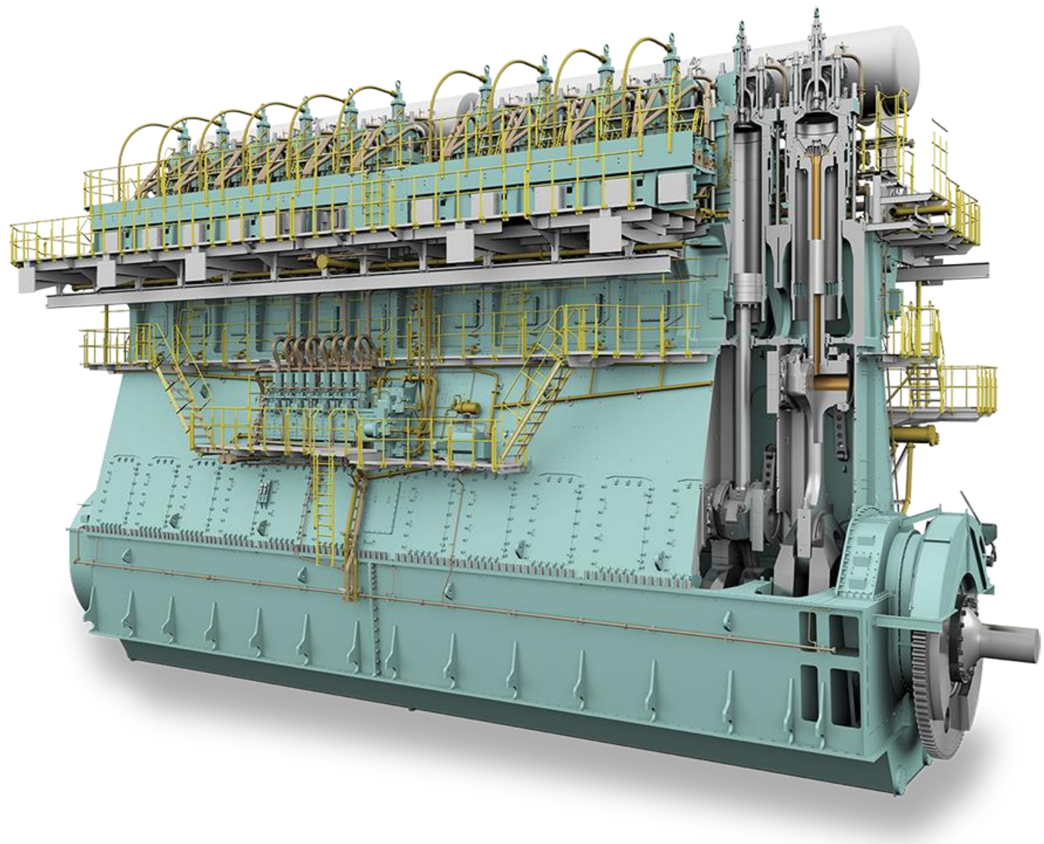

Figure 48: WinGD 10 Cylinder LP Gas 63MW Engine

10.3 ENGINE TECHNOLOGY CONSIDERATIONS

Some considerations are:

1. Use of a pre-mixed air/fuel charge has two main consequences that are not observed in direct injection (HP gas) engines:
    a. Sensitivity to gas quality: Lower-methane-number fuels (common in some parts of the world) increase the susceptibility to knocking, which can only be managed through advanced control systems to de-rate the engine and prevent damage.
    b. Methane slip: Unburned fuel (methane – a potent greenhouse gas (GHG)), from incomplete combustion, will escape through the engine exhaust valve reducing the GHG benefit of the reduced CO_2 output of a natural gas engine.
2. SI engines have a single-gas fuel system as opposed to pilot-fuelled engines. Although this has logistical advantages, the internationally agreed code for gas fuelled ships (IGF Code) requires gas fuelled ships to have two independent fuel supplies. In Dual fuel installations, the necessary pilot oil fuel doubles as a second fuel supply, but a pure gas engine requires a second set of LNG fuel delivery equipment (such as "cold boxes" wherein LNG is re-vaporized for delivery to the engine) and usually a second storage tank (see Section 9.9).

3. The pilot-fuelled engine types require a liquid fuel system for the pilot injection. They typically have the built-in capability to operate on 100% liquid fuel as an alternative to the gas fuel. However, for engine designs that optimize gas combustion on the Otto cycle (e.g., reduced compression ratio), then the engine's efficiency and emission performance when operating solely on fuel oils are unlikely to match the original base diesel engine from which the LNG engine was derived.
4. In the cases where a vessel is fitted with DF engines and the intention is to operate fuel oil only mode for extended periods, the lubricating oil properties may need to be adjusted if the engine is to consume fuel oils with higher sulphur content. However, the lubricating requirements for engines running on ultra-low sulphur diesel (ULSD) are similar to LNG operation. The lubricating oil for an SI engine can be optimized for use with only natural gas fuel.
5. Both DF and SI engines operating on the Otto cycle have decreased transient load responsiveness while DI engines respond basically the same as Diesel engines operating on fuel oil. DI engines have higher NO_x emissions in comparison to the DF and SI engines. However, the NO_x emission levels are not to the level observed in engine operating on fuel oils.
6. Natural gas engines have minimum requirements for methane number. Below these limits original equipment manufacturers (OEMs) typically need to review the gas specification to determine whether the gas can be used or not without any de-rating.

10.4 GAS ENGINE DEVELOPMENT TRENDS

LNG fuelled engines are considered mature, but design refinement continues. Examples are:

I. Reduction of amount of pilot fuel required in DF engines (trending from 5% to 1% for most types, 0.1% claimed for some).
II. Continuous refinement to reduce Methane Slip. Some engines adopt "skip firing", whereby one or more cylinders are de-activated at lower power demand levels, resulting in the active cylinders being run at more efficient and cleaner-burning load. Examples of other measures being developed to reduce methane slip are shown in Figure 49.

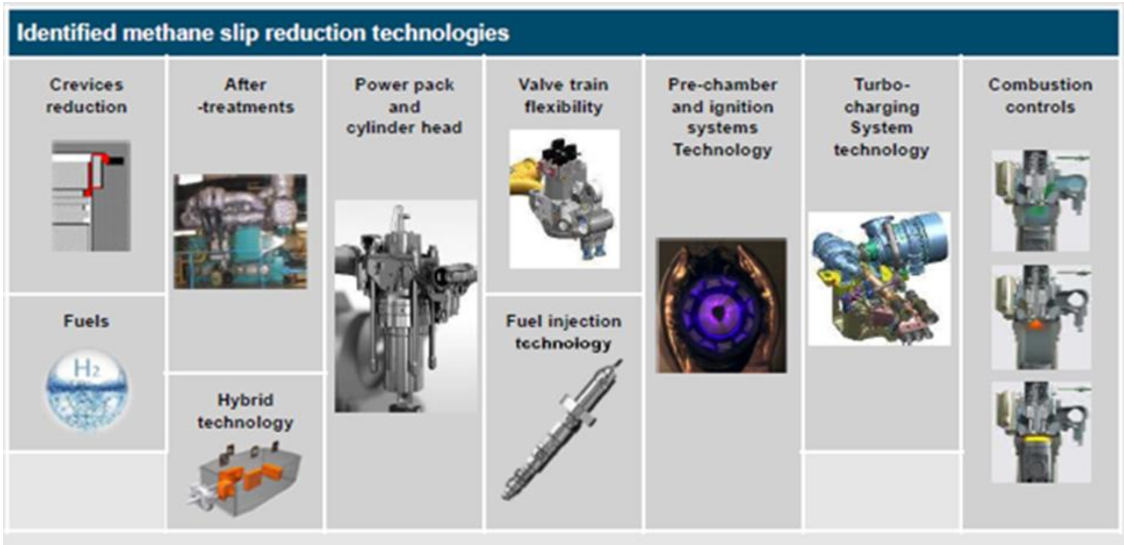

Figure 49: Methane Slip Reduction Technologies (courtesy Wartsila)

Engine manufacturers and researchers are also pursuing use of lower/zero-carbon fuels such as hydrogen and ammonia. For example, MAN plans to run a test engine on ammonia in 2021 and a full-scale slow-speed engine in 2024. However, carbon free marine power is not anticipated to be mature or widely available in the near future, and fully carbon-free chains to produce and supply zero carbon fuels are as yet limited in capacity.

10.5 GAS ENGINE TECHNOLOGY READINESS

Several OEMs have accumulated several million operating hours on their gas fuelled engines both in land and marine applications. While there are a limited number of marine gas engines available with power ratings below 1,000 kW, numerous options are available for higher horsepower engines. Gas-fuelled engines are now fully available to support the adoption of LNG as a marine fuel.

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

11 PROPULSION SYSTEMS

11.1 GENERAL

Any prime mover (engine) installed in a ship has to transmit its power into the water through a propulsion train, whose final element is the propulsor – typically a propeller, but potentially other options ranging from waterjets to paddle wheels. The performance of the propulsion system must be adequate to meet a full range of voyage requirements, including acceleration, cruise and maximum speed, deceleration, manoeuvring, and load fluctuations due to ship motions in waves, power take offs for ship services, and other types of variability. As discussed in Section 10, the response characteristics of gas-fuelled engines differ between engine types and also from those of more standard marine diesels. This may affect the preferred selection of engine and requires consideration during vessel design.

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

11.2 DIRECT DRIVE

In direct drive systems the engine(s) either drive the propeller shaft(s) directly or through a speed reduction gearbox depending on the engine speed. Deep sea vessels typically use highly efficient slow speed engines well suited to continuous steady speed applications, directly coupled to fixed-pitch propellers. With a fixed pitch propeller, the engine speed will need to change across a broad range to suit changes in thrust requirements. Examples are shown in Figure 50, Figure 51 and Figure 52.

Figure 50: TOTE Isla Bella Dual Fuelled Marline Class Containership with Direct Drive Slow-Speed Engine

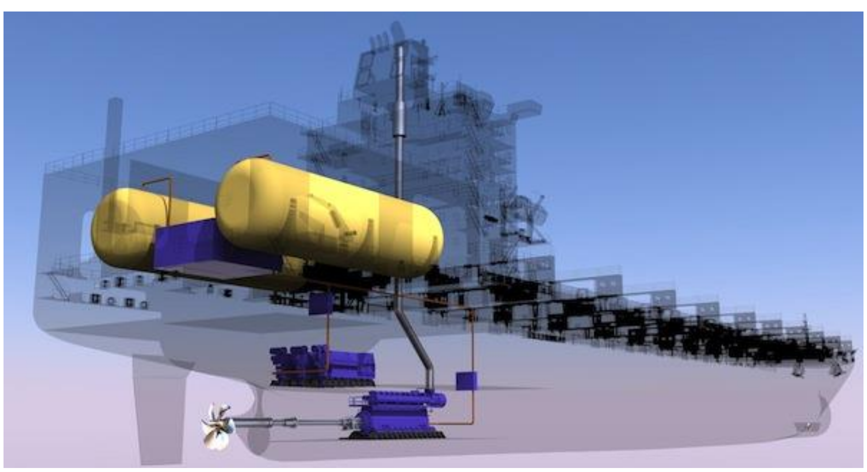

Figure 51: Direct Drive LNG Fuelled Propulsion System of Isla Bella

Figure 52: CMA CGM Jacques Saade, LNG-Fuelled 23,000 TEU Containership

Medium and high-speed engines are more typically found in ships requiring more frequent demand changes such as ferries and smaller vessels. Such installations often use controllable pitch (CP) propellers to allow the engines to run in a relatively narrow speed range when ship speed demands vary. Engines that can respond quickly to thrust/load changes are favoured for these types of drive arrangements. An example is shown in Figure 53.

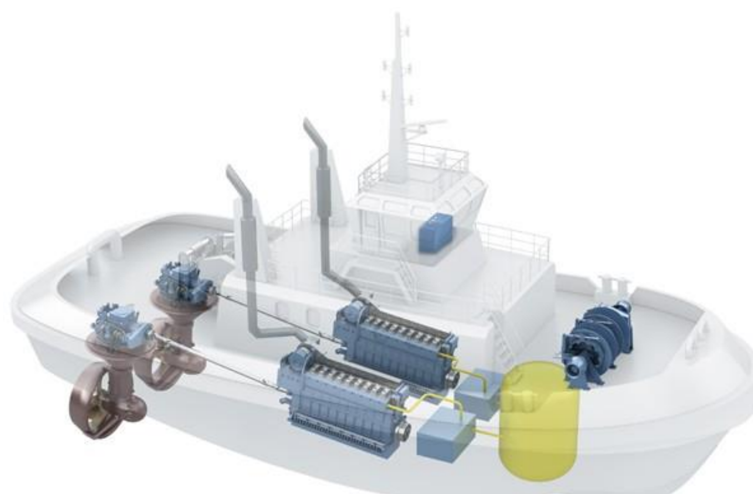

Figure 53: Bergen LNG Fuelled Propulsion Arrangement for Direct Drive Tugs Borgov and Bokn (built 2013)

11.3 ELECTRIC DRIVE

Electric propulsion systems generally consist of a set of internal combustion engine driven generators combined with electric propulsion motors which are used to drive either propellers, azimuthing thrusters, or a combination thereof. The advantages of such an arrangement include increased flexibility in multi-engine load optimization, allowing the appropriate number of engines to be run to match the power demand. It may also allow for maintenance to be completed while the vessel remains in service, if there are sufficient gensets available both to meet the propulsion requirements as well as provide adequate redundancy so as not to jeopardize ship safety. An electric drive system also allows for greater flexibility to designers for arranging machinery spaces and vessel configuration because there is no requirement for a mechanical connection between the power production and the power delivery to the propulsion equipment.

Electric drive systems are well suited to ships with high non-propulsion energy needs, in particular cruise ships and some warships, in which the engines and generators serve as a central power station for all the ship's electrical energy needs. Electric propulsion systems require sophisticated power management systems, but these are mature technologies.

The Viking Grace (shown in Figure 54) is a passenger ship which incorporates an electric propulsion plant with dual fuel generator engines. Four dual fuel gensets deliver 8,200 kVA each to two 10.5 MW propulsion motors.

Figure 54: Viking Grace

The Harvey Gulf LNG powered Platform Supply Vessels (PSV) (shown in Figure 55) also utilize electric drive and dual fuel generating sets, with azimuthing thrusters for propulsion. Several of these vessels have recently been retrofitted with battery banks, to assist with load management during certain operations (see also Section 11.4 below)

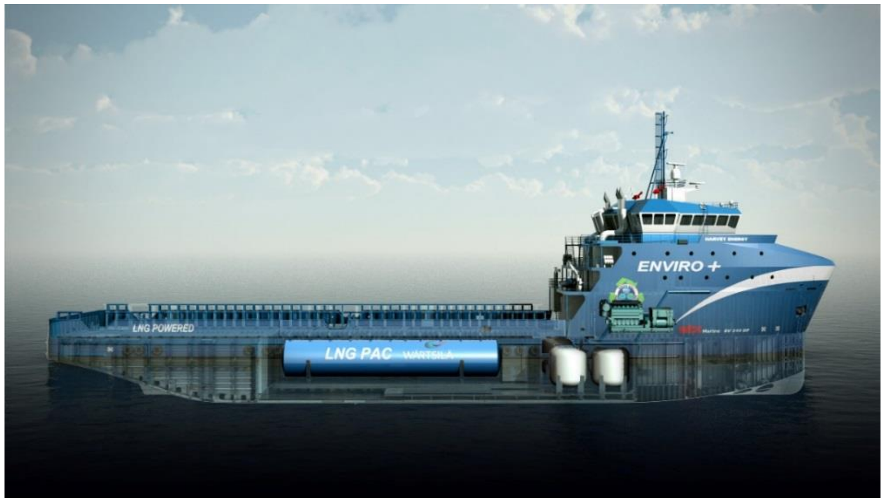

Figure 55: Harvey Gulf LNG Powered PSV

A number of LNG-fuelled large cruise ships are now in service and others are on order. For example, Carnival Corp is building nine 180,000 gross ton ships for its various brands. Each ship has four medium speed dual fuel engines generating a total of 57MW electrical power. The ship's two propulsion motors together are rated at 37 MW. The second of these ships is shown in Figure 56.

Figure 56: Costa Smeralda, 180,000gt LNG Fuelled Cruise Ship

11.4 HYBRID SYTEMS

Hybrid power systems are a relatively new technology in the marine industry that use a combination of engine power and batteries. A hybrid system offers significant efficiency improvement by running the engines on optimal load and absorbing many of the load fluctuations through batteries. Wartsila developed a Low Loss Hybrid system and in 2014 installed this system on the platform supply vessel *Viking Lady* which is powered by four LNG-powered 32DF engines. Depending on the type of engine, configuration and mission profile this system can see yearly fuel saving of between 10% and 20%. A hybrid system may also satisfy the IGF requirement for secondary power source in gas-fuelled ships.

Seaspan Ferries have installed a hybrid power system on their new trailer ferries (shown in Figure 57) which entered service in 2016. The new vessels operate with 84 Corvus Energy AT65000 advanced lithium polymer batteries creating the 1050 Volts Direct Current (VDC), 546 kWh Energy Storage System (ESS) (Corvus Energy, 2015). The propulsion system which is powered by DF engines is integrated with the ESS, with the ESS responsible for spinning reserve and power for harbour maneuvering. The spinning reserve allows for the rapid reaction to the application of load, very high redundancy in the event of any type of mechanical failure, a seamless transition to auxiliary power and instant switching from hydrocarbon fuel to electrical power at port. Optimization of engine selection also helps with overall fuel economy. The success of the first two vessels led to a second batch of two being ordered with much larger battery capacity.

Figure 57: Seaspan Hybrid Ferry with Storage Battery and Dual Fuel Engine Propulsion

12 SAFETY TECHNOLOGIES

12.1 OVERVIEW

The equipment and some aspects of the systems discussed in earlier sections have been developed to meet "normal" expectations for safety standards, as defined by relevant regulations, codes and standards. None of the technologies involved are inherently novel, and all have successful track records in other applications. However, their application in LNG-fuelled ships and the support systems for these is quite recent, and some aspects of the tailoring of requirements for LNG fuel systems remains a work in progress, as discussed in Section 13 and in the work under Task 6.

This section of the report provides an overview of some of the safety technologies that mitigate risks associated with system installation and operation under normal and emergency conditions. The focus is on the types of selection and customization decisions for LNG applications, as in all cases the basic technologies are readily available.

12.2 MATERIALS

LNG is stored at very low temperatures (at -161^{0}C). This is not uniquely demanding, as a number of other substances are often transported and handled at similar temperatures, examples being liquid nitrogen (-196^{0}C) and liquid oxygen (-183^{0}C). There is therefore a considerable body of experience in producing and assembling piping, valves and other system components that can resist these temperatures without embrittlement, leakage, or other adverse effects.

Common materials selected to withstand service conditions imposed by LNG are aluminum, 9% nickel steel, and austenitic stainless steel. These materials have high resistance to brittle fracture at cryogenic temperatures below -200°C.

A concern with shipboard (and other installations) is whether leakage of LNG due to breaks or from spills during fueling operations may reduce the temperature of more standard steels to a point where they are at risk of brittle fractures. This is typically mitigated by using drip trays at potential spill or leakage points and by using double-walled piping systems. Double walled piping provides a second barrier against leakage, and the interstitial space between the walls can be monitored to detect any failure of the primary (inner) barrier.

Flexible hoses are needed for various types of connections in LNG systems, most notably for bunkering operations. Flexible double-walled cryogenic hoses are available from multiple suppliers in any size likely to be necessary for bunkering operations. Recent developments include floating cryogenic hose systems, that have the potential to offer easier transfer arrangements where there is limited shore-side infrastructure and/or large tidal ranges, both of which apply in most of the Canadian Arctic (Lagarrigue).

Seals and gaskets are also readily available, using a variety of materials including silicones, graphite, and more exotic options. LNG-qualified options can be sourced from various suppliers.

12.3 FIRE AND EXPLOSION PREVENTION

The biggest perceived risk associated with LNG is that an accidental leakage (or a deliberate act of sabotage) will create a mixture that can be ignited or that may explode. Methane will only combust within a quite limited range of concentrations in air with a Lower Explosive Limit (LEL) of 5% gas in vapour and an Upper Explosive Limit of 15%. Rapid dispersion by natural or engineered mechanisms are effective means of mitigating risk. However, other techniques can and will also be applied.

Isolating potential leaks from potential ignition sources can be achieved by isolation, by using inherently safe equipment, and/or by using sensor and control technologies to shut down hazardous equipment in the event of a gas leak. Several of these measures will typically be used in combination in any installation.

The IMO Code for Gas Fuelled Ships recognizes two alternative approaches to system design, Inherently Safe Systems and Emergency Shutdown (ESD) Protected Systems. The first of these involves isolation measures. Isolation creates "gas safe" machinery spaces with arrangements in the machinery space such that the spaces are considered highly unlikely to experience gas leakage under any conditions, normal or emergency/accident. To achieve this, LNG supply piping within the machinery space boundaries is enclosed in a gastight enclosure, which is typically achieved by using double wall piping, to remove possibility of gas leaking into the engine room should the inner pipe containing gas fail. The gas supply system is contained within a ventilated double walled containment system from the LNG tank to the engine cylinders. All system components are located away from the outer hull to reduce the risk that a collision will breach tanks, piping, or other components.

The location measures also apply (under IMO and related rules and standards) to ESD protected machinery spaces. With this approach, arrangements in the machinery spaces are non-hazardous under normal conditions, but under certain abnormal conditions may have the potential to become hazardous. If these arise, they are detected through some form of sensor technology and ignition sources are automatically shut down. Any equipment or machinery required to remain in use or active during these conditions must be of a certified safe type – this is not uncommon in various shipboard applications for vessels ranging from tankers to ferries, which may have to cope with flammable or explosive mixtures due to the nature of their cargoes.

Under IMO's approach, with ESD systems, single wall LNG piping can be used in the machinery space. However, engines for generating propulsion power and electric power must be located in at least two machinery spaces and cannot have any common boundaries unless the boundary is explosion proof.

On LNG-fuelled vessels, the engine exhaust system is required to be fitted with explosion relief ventilation in case of incomplete combustion or misfiring allowing gas mixture to enter the exhaust system. Rupture discs or other safety valves must reliably discharge the overpressure and the discharged media to a safe place and must be suitable to be used in an explosive atmosphere. Engines must also be fitted with exhaust gas ventilation units to purge the exhaust piping of unburned gas prior to start-up and after low power/idle periods.

Classification societies require gas detection systems to be installed in several key areas of a gas-fuelled ship. Compartments/locations include the secondary pipe/duct of a double walled gas/LNG piping, enclosed and semi enclosed bunkering stations, tank rooms, pump rooms, and machinery spaces containing gas-fuelled engines. These gas detectors typically have two limits, 20% and 40% of the LEL. The lower limit typically triggers an alarm in the bridge and control room while the higher limit triggers automatic shutdown or isolation of gas systems.

12.4 GAS DISPERSION

Ventilation of enclosed or semi-enclosed spaces into which gas may leak or be spilled is used to remove the gas, using inherently safe fans or other means. One of the most probable sources of a gas leak is considered to be over pressurization of the storage tank(s), due to overfilling or to excess boil-off. Design and operational measures will also be used to mitigate this risk, but IMO and other standards require the installation of a vent mast, which must itself be at least 10 metres from the nearest air intake, air outlet, opening to accommodations, gas safe spaces, machinery exhaust outlets, and other ignition sources.

IMO defines three levels of hazard associated with spaces on a ship and prescribes both isolation and ventilation measures to prevent any escalation of risk levels. In any situation where there is direct access required from a hazardous area to a non-hazardous area, an airlock must be installed at the entrance. The airlock has exhaust ventilation to prevent gases from travelling between the hazardous and non-hazardous area. The ventilation system for hazardous spaces must be independent of non-hazardous spaces. In addition, ESD-protected machinery spaces have ventilation that provides at least 30 air changes per hour when gas is detected in the space. Ventilation openings for non-hazardous spaces are located outside of hazardous areas.

These regulations require gas dispersion analysis, in which are modelled: the dispersion of gas resulting from an LNG leak occurring during bunkering; a release due to over pressurization; or in some cases a more catastrophic release from an accident. Results identify the extent of the lower and upper explosive mixture zones, which will allow the Hazardous Zones around a bunkering station, vent or vessel to be defined. Gas dispersion analysis can be conducted using a number of different techniques and software that analyze the potential risk with vapour and liquid releases. One such software is PHAST by DNV-GL. This is a process industry hazard analysis software that can measure the amount of LNG rainout percentage from a LNG release, but does not take geometry into account. FLACS which is a computational fluid dynamics software package used for vapour dispersion modelling, includes the effects of obstacles and geometry on the flow of liquid and vapour. Other commercial CFD codes are used for similar purposes. Dispersion modelling is a complex and developing field, and an area of ongoing research and development. The SGMF (see Section 13) has developed a preliminary gas dispersion tool, BASiL (Bunkering Area Safety for LNG) for use by its members. This tool uses simplified parameters to generate rapid estimates of safety zones. Depending on the location, this may often be sufficient to demonstrate acceptable levels of risk.

12.5 PERSONNEL PROTECTION

Personal protection is required when handling LNG due to its cryogenic nature. Table 10 is an excerpt from the personal protection section of FortisBC’s LNG MSDS.

Table 10: Personal Protection

Personal Protection	
Equipment:	Ensure use of proper personal protective equipment at all times when handling this product.
Eye/face:	Face shield with other eye protection (safety glasses)
Skin:	Insulated gloves, safety work boots, Nomex coveralls.

Personal Protection	
Respiratory:	Supplied air respiratory protection to be used (airline or self-contained breathing apparatus) in cases of oxygen deficient atmospheres
Other Considerations:	Use extreme care in handling due to high flammability and risk of cryogenic burns.

13 TECHNICAL STANDARDS AND BEST PRACTICES FOR LNG

13.1 GENERAL

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 can be applied to the design and operation of systems throughout the supply chain. This will be addressed in more detail under Chapter 7 of the project, so the material below is intended as an introduction to the main areas in which useful documentation currently exists.

This can be envisaged as constituting a safety pyramid, as promoted under the IMO's "Goal Based" standards approach. In principle, International Codes and their implementation through national regulations establish goals, based on a society's level of tolerance of risk. Industry standards set performance requirements or prescribe particular solutions that allow the goals to be met. Inspection and monitoring activities ensure that measures are implemented and that operations are conducted properly. Educational and training standards cover the human factors aspects that are critical to safety. In practice, the separation is rarely clean. The top-level Codes often mix goals with performance and prescriptive requirements, as is the case in the current IMO Guidelines and Code for gas-fuelled ships.

13.2 INTERNATIONAL CODES

The basic requirements for vessels using LNG either as a fuel or as a cargo are set by the IMO. IMO has adopted a "one ship, one Code" philosophy so that all requirements for gas-fuelled ships are covered under the IMO International Code of Safety for Gas-Fuelled Ships (IGF Code), while those with LNG cargoes, whether bunker vessels or large-scale carriers are under the International Code for the Construction and Equipment of Ships Carrying Liquefied Gases in Bulk (IGC Code).

Other relevant IMO Codes cover Safety Management systems (ISM) and the training and certification of mariners (Standards of Training, Certification and Watchkeeping, STCW), plus the basic requirements for all internationally operating vessels for design, construction and pollution prevention. Any international vessels operating into Canada will comply with all of these as a minimum.

13.3 CANADIAN REGULATIONS

Transport Canada has adopted (almost) all IMO Codes by reference under the Canada Shipping Act, with supplementary requirements in certain areas; for example, for gas-fuelled ships. As there are currently no Canadian LNG carriers, there are no national provisions for these vessels, but their design and operation will need to demonstrate safety through a risk-assessment process.

For shore facilities, the approval process is complex and is often dependent partly on federal and also on provincial/territorial legislation and procedures. The Environmental Assessment Agency will often have a lead role. For larger projects, the Transport Canada TERMPOL process may be applied (Transport Canada, 2019). This is always voluntary in theory though mandatory in practice. Consultation with local communities and particularly with any First Nations who may be impacted is always essential. This will be discussed further in the Chapter 7 of the report.

13.4 STANDARDS

A range of standards bodies have developed standards for ships and onshore facilities, and for the systems and equipment these utilize.

Standards/Rules for ship design are set by Classification societies and accepted by national administrations as part of the overall regulatory system. All the major classification societies accepted by Transport Canada as Recognized Organizations have Rules for gas-fuelled and gas-carrying vessels, and often also offer guidance on aspects of operations. Classification societies also provide approvals and certification for equipment installed onboard, ranging from LNG storage systems (tanks) and dual fuel engines to the layout of ventilation and venting systems.

The shore facilities and marine terminals are addressed by several industry standards, most notably:

- CSA Z276-15 – Liquefied Natural Gas (LNG) – Production, Storage, and Handling;
- CSA EXP276.1 – Design requirements for marine structures associated with LNG facilities (DRMS) ISO/DTS 18683 Guidelines for systems and installations for supply of LNG as fuel to Ships (draft);
- ISO 28460:2010 Petroleum and natural gas industries - Installation and equipment for liquefied natural gas - Ship-to-shore interface and port operations; and
- ISO/DTS 18683 Guidelines for systems and installations for supply of LNG as fuel to Ships (draft).

ISO, CSA, ASTM, IEC and other industry standards are available for system layout and system components. These provide a comprehensive basis for equipment selection, although the pace of change in LNG technology remains high.

13.5 BEST PRACTICES

Best practices that complement regulations and standards are available from many sources, including Classification Societies and standards organizations. Other valuable sources include industry associations and other bodies.

The Society of International Gas Tanker and Terminal Operators (SIGTTO) is a long-established body dealing with LNGCs and the terminals they use. More recently, the Society for Gas as a Marine Fuel (SGMF) has been formed to determine best practices for IGF vessels. Both societies have developed a range of guidance for designers and operators, including tools for preliminary calculation of gas dispersion from a leak or spill.

Other organizations and associations offering guidance on best practices include the European Maritime Safety Agency (EMSA), the US Coast Guard, and Port Associations and individual ports. In general, a range of projects worldwide have undertaken risk assessments of LNG transfer operations, voyages, and incidents likely to occur on or to LNG vessels and have concluded that safety levels which follow best practices can achieve societally acceptable levels of risk.

14 TECHNOLOGY READINESS

As described in Sections 3 - 13 of this report, all aspects of LNG use as a marine fuel utilize technologies that are well proven in marine applications. In many of the aspects that have been reviewed, there has been rapid development of products and technologies over the last decade due to the upsurge of interest in NG as a substitute for more environmentally harmful hydrocarbon fuels.

The cost of LNG itself is driven principally by the market price of gas and the cost of liquefaction. The first of these is dictated by regional supply and demand factors, but the latter is an area where recent technology developments are highly significant. The emergence of small-scale liquefaction plants removes several of the major barriers to the use of LNG as a fuel (marine and other) by reducing capital investment requirements and offering the freedom to locate close to markets.

New distribution systems and technologies have addressed the scaling and location issues, as part of the overall bunkering challenge. Initially, and still for smaller volumes, road tanker trucks are a convenient distribution option that can be coupled with local storage to improve utilization. For larger volumes, many ports and/or their fuel suppliers are investing in bunker barges/ships which can service their ports and add the flexibility to service LNG customers elsewhere on their coasts. Bunkering is an area of the LNG supply chain where there has been much focus in the last few years, with innovative approaches to meeting the needs of particular ship/terminal combinations. Safety issues have been addressed by the development of improved connection and quick release systems, emergency shutdown and first response systems, improved hose design and gas capture and return systems. Rigorous safety assessment processes have been developed and have matured to support implementation of new bunkering port/ship combinations.

LNG bunkering for ships in the Arctic does present new challenges. Most established LNG bunkering takes place with the receiving ship secured to a harbour wall and supplied from the wharf side (tanker truck or piped from storage) or from an LNG supply vessel tied alongside the receiving ship. The absence of alongside berths in the Arctic will require bunkering processes to be developed using either an LNG supply vessel rafted alongside the receiving ship (for which processes have been developed, such as for lightering LNG cargo) or by hose from a shore tank. Floating hoses are currently used to deliver diesel fuel from shore to ships in Canada's north, and floating hose supply of LNG is not technologically challenging. However, the development and approval of processes and procedures to do so would be a new undertaking.

In general, there are no technological barriers to the use of LNG under Arctic conditions. The fuel itself must be stored at cryogenic temperatures well below the worst lows ever recorded, and all fuel system components are designed to cope with stringent demands. There is now a large fleet of dual fuel LNG carriers operating year-round on the Russian Northern Sea route to the Yamal operation (see above) and LNG icebreakers in service in the Baltic. Appropriate safety and personal protective equipment are also available; recognizing that human factors issues must always be given particular attention for Arctic winter operations.

The move to greater adoption of LNG fuel has been driven primarily by increasingly stringent air emission requirements through the first decades of the 21st century. The marine industry has had to either transition away from relatively inexpensive Heavy Fuel Oil or add remediation equipment to clean up the emissions from HFO combustion. The next thrust towards decarbonization can be assisted by adoption of lower carbon fuels, of which NG is one. Societal expectation of owners to clean up their environmental footprint adds to the pressure introduced by regulation. Another incentive to adopt LNG is the relative fuel cost compared to refined conventional fuels such as Ultra Low Sulfur Diesel.

The capital cost of on-board components of NG, whether engine, storage and distribution systems, and associated components is a barrier to adoption. In recent years, the costs of NG systems have decreased but most NG engines continue to be more expensive than traditional equivalents. Some of the increased price is a result of the greater number and complexity of the systems required, particularly for the dual fuel options. Although system manufacturing costs are reducing as order volume increases, technology investment costs are still being amortized over what are still relatively early production runs for gas-fuelled engines, tank designs and other system components. Engine efficiency has been developed to the stage where there is little difference to traditional marine diesel engines (which themselves face efficiency challenges due to emission reduction requirements). Engine manufacturers continue to make great strides in reducing methane slip in several engine types and to reducing the pilot fuel (conventional fuel) consumption in dual fuel engines.

It can be concluded that the technological challenges of establishing LNG as a commonplace fuel for ships have been addressed and the technology is mature. Operation of LNG fuelled ships in Canada’s Arctic present no significant challenges, and offer benefits compared to conventionally fuelled ships. The technical challenges of refueling such ships in the Arctic are not major but will require the development of new processes and infrastructure to distribute and store bunker LNG fuel in the North and to transfer it to ships’ tanks.

CHAPTER 3 ECONOMICS

1 INTRODUCTION

1.1 GENERAL

This chapter presents the outcome of the Economic Aspects and Benefits (Task 2) of the Marine Natural Gas (NG) Supply Chain project, covering the Arctic region of Canada.

The project as a whole is intended to address various aspects of the use of LNG as a marine fuel throughout Canada. There is a general appreciation in the marine industry that, in comparison with other fuels, LNG is an option that can facilitate compliance with current and future MARPOL requirements, including the Energy Efficiency Indices for new and existing ships (EEDI and EEXI respectively), Annex VI sulphur oxide (SO_X) and nitrogen oxide (NO_X) limits, and black carbon emissions. LNG may offer economic benefits as well. As of 2020 vessels operating worldwide must use fuel oils not exceeding 0.50% sulphur as opposed to the previous 3.50% limit. These changes have had major impacts on capital and equipment costs due to the higher costs of lower sulphur content fuel oils and/or the need to use expensive exhaust treatment systems; both of which also increase the difficulty of EEDI and EEXI compliance.

Shipping activity in the Arctic has increased over the past decade, coinciding with declining areas of sea ice. Between 2013 and 2019 there was a 25% increase in the number of unique vessels entering the Polar Code region. During the same time period the distance sailed increased by 75% from 6.1M to 10.7M nautical miles (PAME, 2020). The impending HFO ban being introduced by IMO will drive many of these vessels to consider alternative fuels. Should the diminishment of sea ice continue at a similar rate, shipping in the Arctic will likely correspondingly increase, particularly as there becomes increased viability for new trade routes through the Arctic Ocean (Wei, 2021).

This chapter focuses only on economic aspects of LNG. It provides a range of individual vessel case studies based upon vessels frequenting the Arctic. Chapter 5 on infrastructure options focuses on the implementation and investment requirements related to the supply and distribution of LNG to support different demand scenarios. Chapter 4 addresses environmental issues, including emissions and other risk factors.

The Chapter 3 team consisted of representatives from a number of the project participants, who provided essential input in areas ranging from ship operating profiles, price forecasting, Arctic fleet data, case study selection, and engine data.

It is important to acknowledge that the results presented in here are the product of data and assumptions provided by the study participants, and the specific methodologies that have been applied. Actual economic results will be dependent upon the in-service operating profile of the vessels, engine performance and LNG supply chain implementation.

1.2 OVERVIEW

The objective of this economic feasibility study was to determine the potential economic benefits of using LNG as a marine fuel for the Arctic marine industry. To determine these benefits, a model was developed and used to analyze seven vessel case studies operating within or visiting the Arctic.

NG can be used in transportation applications in two forms, compressed (CNG) and Liquefied (LNG). As discussed in Chapter 2, CNG has not been considered well-suited to Arctic marine applications and therefore the focus is on LNG.

This chapter presents the economic modelling methodology, its capabilities and limitations, and the seven individual case studies. Each case study is highly specific with assumptions for a number of variables which directly impact the feasibility of LNG as a marine fuel for a vessel. The results indicate that LNG may be feasible as a marine fuel depending on the following critical variables:

- Price differential between HFO[1], MDO[2], ULSD[3] and LNG;
- Fuel consumption; and
- Capital and operating costs for LNG supply and distribution systems.

Even with the instability in energy prices, the North American natural gas market provides a favourable environment for increasing the use of LNG as a transportation fuel due to its lower cost in comparison to diesel (MDO/MGO or ULSD) and reasonable competitiveness with heavy fuel oil (HFO). With the significant increase in production of natural gas throughout Canada and the United States, the price for natural gas is lower in North America than in Asian and European markets. By contrast, the price for marine distillates in Canada is quite high compared to other global markets.

The availability of LNG as a marine fuel is continually growing. Around 100 ports currently offer LNG worldwide which covers most of the main bunkering ports. Over 50 ports are also in the process of introducing LNG bunkering to their operations (SeaLNG, 2020). Within Canada truck-ship LNG bunkering is available in major ports including Vancouver and Montreal, both with plans to expand their capabilities.

Bunkering availability makes LNG a feasible option for some major trade routes along which ports have invested in LNG infrastructure, however it becomes less feasible outside of these routes so further investment would be required. This may include, for example, additional bulk and local storage facilities, increased liquefaction capacity, and higher capacity distribution systems. The additional investments in larger scale LNG infrastructure may increase the end user price of LNG, at least in the short term, as LNG fuel providers recover the cost of additional capital investments. However, there may also be economies of scale as production capacity increases to meet demand. This is further investigated in Chapter 5.

Using LNG will require significant ship-side investment by vessel operators. LNG engines and fuel storage system are more expensive, and the use of LNG may lead to loss of cargo capacity. There will also be training costs for operators moving their fleets to LNG and costs associated with modifying operating and emergency procedures for LNG vessels.

Due to rounding, numbers presented throughout this report may not add up precisely to the totals provided and percentages may not precisely reflect the absolute figures.

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[1] HFO – Heavy Fuel Oil
[2] MDO-Marine Diesel Oil, MGO-Marine Gas Oil
[3] ULSD – Ultra Low Sulphur Diesel

2 ANALYSIS APPROACH

2.1 CASE STUDY SELECTION

Not all vessel types are well suited to operation on LNG. LNG storage and systems take up much more volume than traditional fuel oils, and so small, densely packed vessels are difficult to adapt; as are vessels with very long range and endurance requirements. Also, LNG poses handling and safety challenges in comparison to traditional fuels, and LNG vessel operators need to have robust safety systems to manage the resulting risks. For these reasons, certain vessel types which are reasonably common in the Canadian Arctic have not been considered in any depth in this study. This includes fishing vessels, tugs and recreational vessels such as motor yachts. For larger vessels with long range and endurance needs, subsequent tasks in the project explore how the development of additional Arctic infrastructure could enhance the attractiveness of LNG.

Seven cases were selected as a representative cross section of ships operating within the Canadian Arctic. This includes the types of vessels providing supplies to Arctic communities, those supporting major mining projects such as the nickel mines in Northern Quebec and the iron ore mine on Baffin Island, and the type of expedition cruise ship which has become increasingly popular for Arctic and Antarctic experience tours. A Canadian Coast Guard (CCG) icebreaker is also included. Each summer, CCG provides escort and other services throughout the Arctic typically with six or seven vessels. Most of these are scheduled for replacement in the coming decade. Other icebreaker operators in Finland and Russia are currently operating or building LNG-powered icebreakers, though Canada has not yet moved in this direction.

Large LNG carriers comprise a large part of the traffic on the Northern Sea Route through Russian Arctic waters, exporting LNG from megaprojects on the Yamal peninsula. The LNG carrier considered here is however a much smaller vessel bringing LNG to the Arctic from southern ports, or potentially distributing smaller-scale Arctic LNG to other Canadian Arctic locations. LNG carriers of any size are a new vessel type for Canada, and so this vessel is not covered by comparative analysis in this Chapter. However, its construction and operational costs feed into the analyses under subsequent project tasks. Ship types such as container ships, vehicle carriers and ferries which were examined in previous phases of the work are not currently found in the Canadian Arctic, and so have not been considered at this time.

An overall summary of the cases analysed is provided in Table 11 and each case is further described in Chapter 2 of this report.

Table 11: Summary of Cases

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	I/B Bulker	22,000	Conversion	Slow Speed Diesel 2 Stroke Dual Fuel
A7	Icegoing Bulker	14,500	Conversion	Slow Speed Diesel 2 Stroke Dual Fuel

The LNG engine types selected were intended to cover options that are appropriate to the ship type in terms of engine speed. All vessels are assumed to use dual-fuel engines that can run on LNG with pilot fuel. This reflects both the available technology, and also the probability that these types of vessels will not adopt pure gas engines until a complete worldwide network for LNG bunkering becomes available. Although LNG is becoming more widely available as a marine fuel, most vessel operators still prefer dual-fuel engines to provide flexibility for routes where LNG is not available. The differences between Otto and Diesel combustion cycle engines are discussed in Chapter 2. This has limited effects on costing but somewhat more significance for emission estimates.

A combination of new build and conversion scenarios were selected as both options are being likely to be considered by vessel operators. Vessels capable of extended Arctic operations are specialized and expensive to build and operate, with strengthened hulls, powerful propulsion systems and systems rated for cold temperature service. They are also likely to remain in service for longer than comparable open water vessels – for example, the M.V. Arctic, a well-known Arctic bulk carrier has recently been retired after over 45 years of service. While conversion to LNG is generally more expensive than including the capability in a newbuild, for high-value and specialized ships such as these, conversion may still be cost-effective. LNG conversions have been undertaken for vessels ranging from B.C. Ferries to container ships, specialized tankers and others where combinations of special influences have made this an attractive option.

These case studies were analysed to determine the capital costs required to implement LNG systems as well as the life cycle costs for each of the vessels. The following sections describe the methodology used and key assumptions made.

2.2 METHODOLOGY

This study analysed the ship side investment and life cycle operational cost of three different fuel options and for the seven vessels. The ship side investment considered the costs associated with engines, LNG tanks, LNG system equipment and installation for newbuild and conversion. The life cycle cost considered the ship type, route information, installed power, operational profile, energy costs and crew training.

Another important aspect of cost is the shore side investment; however this is investigated at Chapter 5. Here, it was assumed that bunkering would take place primarily in major ports, the fuel costs and required tank sizes were established on this basis.

2.3 LIMITATIONS AND MODEL ASSUMPTIONS

The model incorporates several variables as described in the previous section. For all LNG options, it has been assumed that auxiliary engines for supplying the ship and hotel services would also be dual-fuel engines or that most/all power would be drawn from the main engines through power take-off (PTO) or other systems. While efforts have been made to make the model comprehensive, there are some limitations and assumptions which the reader should be aware of, and which should be considered when evaluating the presented case study results. Aspects not covered include:

- 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 maintenance for the engines;
- costs associated with having a vessel out of service while undertaking a conversion; and
- project-specific variables impacting capital costs.

The impact of LNG systems on cargo capacity has not been included in the modelling as it is highly variable and would involve numerous project-specific assumptions. Due to the increased footprint required for LNG storage, the cargo capacity may be impacted by selecting LNG as a fuel. For example, the impact of cargo-capacity loss for tankers and dry cargo carriers is dependent on whether the cargo capacity limitations are volume or weight related. For ship types that do not carry cargo and have irregular routes and operations, the loss of cargo-capacity may be irrelevant.

For the purposes of this analysis, it is assumed that the LNG tanks are accommodated in the design by increasing the vessel size or by integrating the LNG tanks into the vessel with no impact on cargo carrying capacity. These options/assumptions may be less valid for conversions than for new builds, and actual projects will always need to be assessed in more detail.

For new build vessels, the ship size may be increased, which will impact capital costs and may have some influence on operating costs due to reduced cargo capacity and/or increased propulsive power requirements. This is most likely to affect smaller and higher-powered vessels such as the icebreaker; for the larger vessels the size impacts are relatively unimportant effects. Other implications of installing LNG tanks onboard a vessel include maintaining visibility from the bridge, limits on air draught, and stability implications, depending on tank location.

The loss of operational time associated with a conversion to LNG has also not been included in the modelling. The time needed for a conversion could be significant considering the scope of work which would include the replacement of existing engines, installation of LNG storage tanks and distribution systems, and testing and trials. The location of LNG tank(s) and the availability of free and suitable deck space will impact the duration of a conversion, as well as the accessibility of the existing propulsion plants for removal of existing machinery, and installation of new equipment. In cases where vessels are already due for an extended period out of service for other maintenance, it may be possible to coordinate these efforts and thereby reduce the overall number of days a vessel is out of service for a conversion to LNG. In the case of multiple medium speed engine propulsion arrangements, it may be possible to stagger the conversion of the propulsion plant in stages.

The LNG vessel capital cost calculations were based on:

a. a dollar per kilowatt (kW) factor for the capital costs associated with fuel oil and LNG engine, auxiliary system, LNG system equipment and estimated installation; and

b. a dollar per LNG tank volume (m^3) for the capital costs associated with an LNG tank and associated equipment. New build estimated installation costs have been modelled as 30% of the equipment cost. For a conversion project the cost of installation is increased by a factor of x4 (120% of equipment cost), this takes into account the added expenses of a conversion, as well either the Canadian yard cost or the cost of diverting a vessel in domestic service to an overseas yard.

The model also does not account for additional operating costs which may be encountered by vessel operators due to limited LNG bunkering facilities. Operating a vessel with LNG may require additional travel time to bunkering facilities or additional bunkering time due to the necessity of bunkering two fuel types for vessels fitted with dual-fuel engines. Another consideration of time would be whether simultaneous operation (SIMOPS) of bunkering and loading/unloading vessel is allowed. These costs would be project and site-specific.

2.3.1 FUEL OPTIONS

IMO 2020 reduced the maximum sulphur content of fuels from 3.5% to 0.5% when operating outside of an ECA. The main options for compliance were switching to lower sulphur fuels, installing scrubbers or converting to an alternative fuel. To date the adoption rates of low sulphur fuels have been the highest, due to the relative ease of this fuel switch. Around 5% of vessels have scrubbers installed to enable them to continue utilizing the cheaper higher sulphur fuels (IMO, 2021). The option with the least uptake is switching to an alternative fuel, due to expensive conversion costs. However, in the newbuild market, the number of LNG fuelled vessels is consistently growing. At the start of 2020 there were 175 LNG vessels (excluding the 600 LNG carrier vessels which are mostly LNG fuelled), with another 200 LNG vessels on order (SeaLNG, 2020a).

Despite scrubbers currently being a viable option for continued use of HFO (>0.5% sulphur content) whilst complying with the IMO 2020, higher sulphur fuel has not been considered as part of this study. This is due to it not being a sustainable option with the impending HFO ban in the Arctic. It has been assumed that this ban will also extend to cover HFO (0.5% sulphur content) due to its density and viscosity.

To account for the future changing fuel regulations in the Arctic, this study has included three different fuel cases presented in

Table 12. Firstly, is HFO which only two vessels currently use, secondly MDO (ULSD for the CCG, which they currently use) and finally LNG with MDO being used as pilot fuel.

Table 12: Fuel Cases

	HFO	ULSD/MDO	LNG
A1 - CCG Icebreaker	-	ULSD	LNG
A2 - General Cargo	-	MDO	LNG
A3 – Tanker	-	MDO	LNG
A4 - Cruise Ship	-	MDO	LNG
A5 - LNG Carrier	-	-	LNG
A6 - I/B Bulker	HFO	MDO	LNG
A7 - Icegoing Bulker	HFO	MDO	LNG

As discussed below, a number of operating costs are considered to be essentially identical for LNG and traditionally fuelled ships:

- Maintenance;
- Lube oil;
- Crewing (No increase in manning levels or the associated costs are included for LNG propulsion systems; however additional training cost are considered as discussed further below).

2.3.2 SHIP SIDE INVESTMENT

The objective of the capital cost analysis is to estimate ship side investment for an LNG new build or for the conversion of an existing vessel to LNG. For a new build, deciding how to treat capital cost is straightforward. For conversions, additional assumptions are necessary.

Depending on the specific details of a conversion scenario, the capital investment for continuing operations with MDO rather than HFO may be quite low if the intention is to retain the original engines throughout the life of the vessel. Fuel supply and engine control systems will require some modifications to allow for switching from heavy to distillate fuels when the Arctic HFO ban is implemented. For the two conversion cases (A6 I/B Bulker and A7 Icegoing Bulker) analysed in this model, the assumption has been made that the engines would not have been replaced when switching from HFO to MDO and therefore the capital cost is effectively zero. This is a conservative assumption in terms of showing economic benefits for LNG.

Table 13 and Table 14 show the values used in calculating the capital costs for the different engine systems. As capital cost impact refers to the ship as a whole, the calculations include both the cost of equipment and the installation labour cost. Labour costs will be much higher in Canada, as discussed below for the specific case of the CCG icebreaker.

Table 13: HFO/MDO Equipment Capital Costs

Factor	Equipment	Multiplier
Main kW	Engine (Slow)	402 $/kW
Main kW	Engine (Medium)	300 $/kW
Aux kW	Auxiliaries	350 $/kW
Main & Aux kW	Installation	158 $/kW

Table 14: LNG Equipment Capital Cost

Factor	Equipment	Multiplier
Main kW	Engine (Slow)	493 $/kW
Main kW	Engine (Medium)	394 $/kW
Aux kW	Auxiliaries	494 $/kW
Main & Aux kW	Installation – Newbuild	158 $/kW
Main & Aux kW	Installation - Conversion	238 $/kW
m3 of LNG	LNG Tank	5,000 - 38,000 $/m3
Capital costs	Installation – Newbuild	15% of equipment cost
Capital costs	Installation - Conversion	30% of equipment cost

The capital costs presented in this study only relate to the propulsion power related costs and do not include overall vessel costs. The overall impact on vessel cost will be highly dependent on the size and complexity of the vessel as well as shipyard labour rates and productivity.

The following items of equipment are required for an LNG fuel system and have been included in the modelling along with their associated costs for installation and integration into the vessel:

- Engines
- Auxiliary systems
  - Gas detection
  - Control systems
  - Piping and other components
- Fuel supply systems
  - LNG tanks
  - Cold box

- Bunkering station

It should be noted that the quoted costs are approximate and budgetary numbers and do not account for all considerations – for example, certain installations may also require abatement systems for nitrogen oxide (NOx) emissions, and there is generally a cost difference between Diesel cycle and Otto cycle dual fuel engines.

2.3.2.1 INVESTMENT VARIABLES

The project specific capital costs are significantly influenced by the factors including type of propulsion arrangement, number of tanks, regulatory requirements and shore side infrastructure.

The type of propulsion arrangement will significantly impact the capital costs. A diesel electric propulsion system with numerous engines will have a higher capital cost at the same power level than a propulsion system consisting of a single screw mechanical drive arrangement. Many natural gas-fuelled vessels use electric transmission systems as these are popular options for many short-sea vessel types such as ferries and offshore supply and support vessels which were early adopters of LNG. More recently larger deep-sea vessels such as container ships, tankers and large LNG carriers have been built with mechanical drive propulsion arrangements. Diesel electric installations are inherently more expensive than mechanical drives and are normally selected only for compelling operational reasons. It can be expected that this same rationale will apply to future LNG installations. Another cost driver for propulsion systems is the selection of engine speed – low-, medium- and high-speed. Lower engine speeds are associated with larger but more fuel-efficient operations, whether operating on LNG or on traditional fuels. Vessel size constraints and through-life cost will drive speed selection.

The number of tanks and cold boxes will have a significant impact on capital cost. Pure gas installations require redundancy in the fuel supply which may be either two tanks and two cold boxes or one single tank and two cold boxes. This is dependent on the classification society and flag state requirements. Dual-fuel installations only require one LNG tank and one cold box. The vessel types considered here are all assumed to be dual-fuel, and tank size and number are driven by arrangement and reliability considerations.

The regulatory requirements for LNG-fuelled vessels are somewhat more onerous than those for conventionally fuelled designs and require both additional equipment and analyses. As experience with LNG grows, this cost is decreasing.

Additional shore side bunker infrastructure costs may be borne in whole or part by the operator depending on supply agreements. In addition to this, the regulatory approval and permitting required for developing bunkering locations and processes may result in additional costs.

Differences in shipyard labour rates depending on where the conversion work is done will impact the installation costs for both the conversion and the new build cases. Shipyard pricing may also vary depending on the economic climate and the perception of risk when dealing with new technologies. Based on past feasibility studies completed by the team members 15% of the total costs are attributed to shipyard profit, insurance and contingency costs. The main cost component of an LNG propulsion system is in the material/equipment costs.

In the case of new build vessels, removal of existing engines as well as integrating new systems with existing systems is not required, resulting in a reduction in man hours required. The ratio between labour and material/equipment costs will vary depending on shipyard location, labour rates, shipyard efficiencies, and project specifics and will impact the payback period of a project.

As mentioned previously the capital investment costs for the seven cases have been developed based on several other assumptions that are detailed in Section 2.2.

In some parts of the world, operators have been incentivized to adopt LNG by government programs aimed at reducing emissions or by LNG suppliers themselves supporting the creation of new markets. In Canada, Fortis B.C. provided support for several of the ferry operators in British Columbia. Currently, there are no such programs available for Canadian Arctic ship operators.

2.3.3 LIFE CYCLE OPERATIONAL COSTS

A life cycle analysis was used to determine the differentials in operating costs of the various ship types operating on HFO, MDO and LNG. It is assumed that the power, route, and vessel life requirements are essentially constant regardless of the fuel bunkered. The vessel life for each of the seven cases is assumed to be 25 years. A delivery date of 2023 was selected for both the new build cases and conversions.

The power requirements of the vessels shown in Table 11 were used to calculate the installed power. The ship's expected number of operational days per year, and the engine operating load profile were used to calculate the annual fuel consumption for the vessel.

Engine load profiles for any vessel type are assumed to vary due to factors such as operation on ballast voyages, specific route requirements, and vessel operation particulars. In the case of multiple propulsion engines and diesel electric propulsion vessels, these load conditions reflect overall power plant loading rather than individual engine loading in order to limit the complexity of the model.

The auxiliary power is assumed to be provided by generators operating on MDO for the HFO/ULSD/MDO fuel and LNG for the LNG fuel option. The engine capacity, the number of hours of operation, and the average load on the auxiliary engines have been derived from the 2009 Second IMO Greenhouse Gas (GHG) Study (Buhaug, 2009), as carried forward into subsequent IMO studies.

Life cycle parameters considered in this analysis are:

- Cost of fuel and energy per metric tonne (MT)
- Fuel price inflation rates
- Diesel & LNG engine information
- Load conditions
- Vessel type specific input
    - Power requirements
    - Route particulars
    - Endurance requirements
    - Expected vessel life
    - Bunkering profile

- Crew training costs.

For the purposes of this analysis, the maintenance cost differential between LNG-fuelled vessels and ULSD/MDO/HFO vessel is assumed to be zero. In reality, a number of factors should be evaluated when considering the maintenance costs, many of which are OEM-specific. The through-life spare and replacement part costs for an LNG-fuelled vessel are expected to be greater than those for conventional engines. This is due in part to the demanding operating conditions some components must operate in, reflecting the cryogenic nature of LNG, the increased complexity of the systems found onboard, and the comparably limited demand for LNG-specific parts in comparison to their diesel counterparts. Service costs may be greater for LNG vessels due to the specialized technicians needed to service some LNG related systems which are not found on a ULSD/MDO/HFO vessel. LNG vessels preparing for dockings for inspection, maintenance, repair will need to be gas free and inerting procedures will add costs that not typically required for a ULSD/MDO/HFO ship.

To balance this, LNG vessels may save on operational costs with a decrease in lube oil consumption and also a longer lube oil life due to the cleaner burning nature of NG when compared to HFO and distillate. This is due to the fuel having almost no sulphur, trace metals, or particulates which degrade the engine's components. The filtration costs are also less for NG and no purifiers are required for pre-treatment of the fuel before use in the engine. If HFO is replaced with LNG, the heating load required for fuel processing will be substantially reduced if not effectively eliminated. This heating of HFO storage, settling and service tanks, purification and injection preheating is typically provided by steam heating which may be generated by exhaust gas waste heat recovery, but if waste heat is insufficient, it is supplemented by steam from oil-fired boilers. Sludge disposal related to fuel oil purification also incurs costs for HFO engines. Some dual-fuel and NG engine OEMs state that maintenance intervals for their LNG-fuelled engines can be one third longer than for liquid-fuelled engines if a condition-based maintenance is taken. Fjord 1, who have been operating LNG-fuelled vessels in Norway for several years, states that the maintenance costs have been about the same for the LNG fuelled vessels when compared to comparable fuel oil powered ferries (Bergheim, 2013).

It should be noted that the requirements of the IMO Energy Efficiency Design Index (EEDI) for new ships, and the comparable EEXI for existing ships may allow a ship operating on LNG to have a different power level from one using distillate or HFO (see also Chapter 4); however, this is better treated on a case-by-case basis by an owner/designer than in a general study such as the current project.

Additional LNG crew training costs have been included in this analysis. These is investigated in greater detail in Chapter 6, but training costs assumed for this task are summarized in Table 15. The total number of each vessel's complement was estimated for each case and the average training costs were included for each of the positions. Overhead costs such as crew salaries, travel, and accommodation are not included in the model.

Table 15: Crew LNG Training Cost Estimate

Positions	Average Training Cost
All Crew	$928
Officers and crew with gas fuel related responsibilities	$2,783
Engineers and deck officers responsible for gas operations	$4,695
Engineers	$4,186

2.3.3.1 ENERGY COST PARAMETERS

It should be highlighted that the purpose of this analysis was not to predict the future costs of fuel, but rather to provide an overview of the potential fuel cost savings and the economic feasibility of using LNG as a marine fuel based on current representative costs. A limited sensitivity analysis is provided at Section 4.

Table 16 shows the energy cost parameters used for the life cycle cost analysis. The cost parameters are the averages for 2021 (1st January - 30th September 2021). Fuels include ULSD, which is the primary marine distillate for the CCG, HFO in Montreal and Rotterdam, MDO, and two LNG costs for Montreal and Rotterdam.

All prices are in Canadian Dollars.

Some dual-fuel engine manufacturers have the capability to use alternative distillate fuels or heavier fuel oils for the pilot fuel. However, this analysis assumes MDO is used as the pilot fuel for all vessels, except where ULSD is used as both fuel and pilot.

Table 16: Energy Costs

Fuel	Port	Current ($/MT)
MDO	Montreal	$800.00
ULSD (0.01% S)	Montreal	$888.00
HFO (0.5%)	Montreal	$559.00
HFO (0.5%)	Rotterdam	$488.00
LNG	Montreal	$720.00
LNG	Rotterdam	$801.37

Delivery of the LNG to the bunkering location may also be a significant cost component of LNG depending on the delivery method. Delivery costs are highly dependent on the mode of transportation, the distance, and the utilization of the assets required for delivery. In Chapter 4 this is analyzed in more depth, particularly for any options that involve bunkering in the Arctic rather than at Southern ports. Currently, LNG bunkering on both Canada's East and West coasts uses tanker trucks and small delivery volumes.

The bunkering of the larger and longer-range vessels will require additional infrastructure such as bunker vessels or shore side bunkering facilities. The LNG cost implications of these different delivery systems vary and are very project specific. LNG bunker vessels (which can double as small-scale LNG carriers) are expensive in comparison to traditional fuel bunkering vessels and barges and investing in a vessel of this type typically needs to be backed up by an assurance of a critical mass of demand. This is explored further in Chapter 5

The taxation of marine fuels varies depending on whether they will be used internationally, in which case no taxes are normally applied, or domestically, in which case provincial policy will dictate tax treatment. For example, in the tax rate on clear gasoline is applied to LNG for domestic marine use. This includes motor fuel tax, the B.C. carbon tax, and Provincial Sales Tax (PST).

The baseline approach taken in the analyses is to assume no taxes on either LNG or traditional fuels. This will affect absolute costs but will have a relatively limited impact on the relative attractiveness of the different options. The implementation of carbon pricing at a provincial, national or international level will be of more importance, as the carbon content of LNG is lower than that of traditional fuels on a unit energy basis. With a 25% lower carbon level, at a carbon price of $100/tonne emitted an LNG-fuelled vessel will realize an additional $20 saving (approximately) for every tonne of fuel burned.

Other than CCG Icebreaker, the LNG tank size for all vessels has been calculated so that they have sufficient range to allow them to bunker LNG once per round trip. This allows these vessels to have flexibility in bunkering in a main port. Chapter 5 reviews the infrastructure options which may enable the vessels to bunker during a voyage. If there is opportunity to bunker mid voyage, then this would reduce capital costs for tanks and increase cargo capacity. However, these benefits would have to be weighed up against the potential premium of Arctic bunkering.

2.3.3.2 LOAD CONDITIONS AND ENGINE DATA

The load conditions detail the operational profile of the various ships and are incorporated into the analysis using percentages of the propulsion engine's maximum continuous rating. Values used range from 10% to 100% in 10% increments. As most of the vessels distribute their time each year between Arctic and non-Arctic voyages as detailed in Table 17, average load profiles have been used for each of those scenarios. Auxiliary engine fuel consumption has been also included for all diesel mechanical cases.

Table 17: Operational Months

	Arctic (Months)	Non-Arctic (Months)	Non-Operational (Months)
A1 - CCG Icebreaker	4	4	4
A2 - General Cargo	3	8	1
A3 - Tanker	3	8	1
A4 - Cruise Ship	3	8	1
A5 - LNG Carrier	3	8	1
A6 - I/B Bulker	9	0	3
A7 - Icegoing Bulker	4	7	1

The product of the load conditions and the specific fuel consumption (SFC) for diesel engines (or brake specific energy consumption (BSEC) in the case of the dual-fuelled engines) at each of the load intervals is used to determine the fuel consumption of the vessel daily and annually. The SFC and BSEC vary depending on the engine type and the fuel used. For the purposes of this analysis, typical SFC and BSEC values were calculate using equations presented in the IMO 4th GHG study and used for the engine types analysed.

3 CASE STUDIES

3.1 NEW BUILD

3.1.1 CASE 1 – CCG ICEBREAKER

The CCG Icebreaker detailed in Table 18 is a representation of the Program Icebreakers which are intended to replace the current set of vessels that undertake most Arctic missions – the CCGS Louis S. St. Laurent, Terry Fox, Henry Larsen, and the three "R" class vessels. These are smaller than the proposed CCG Polar icebreaker, but will be larger than the current vessels (other than the Louis) due to increased performance requirements and the need to comply with modern international and Canadian regulations for segregation of fuel tanks, etc. The baseline propulsion plant is diesel-electric, with a set of generators supplying both propulsion and ship services. The Coast Guard plans to acquire up to six of these vessels.

Table 18: CCG Icebreaker Vessel Particulars

Type	CCG Icebreaker
Overall Length (m)	110.00
Beam (m)	23.00
Draft (m)	8.00
Gross Tonnage	7000
Deadweight (t)	3,000
Speed (kts)	16
Power (kW)	20,000

In a typical Arctic operating season from late June to late October each of these vessels will sail around 20,000 nm on missions including escort icebreaking, resupply, search and rescue, science and hydrography. The set of ship tracks for the CCGS Henry Larsen shown in Figure 58 is representative of the areas of operation.

The vessels are used in a variety of icebreaking roles in southern Canadian waters during the winter season. At other times, they are available as required or in maintenance.

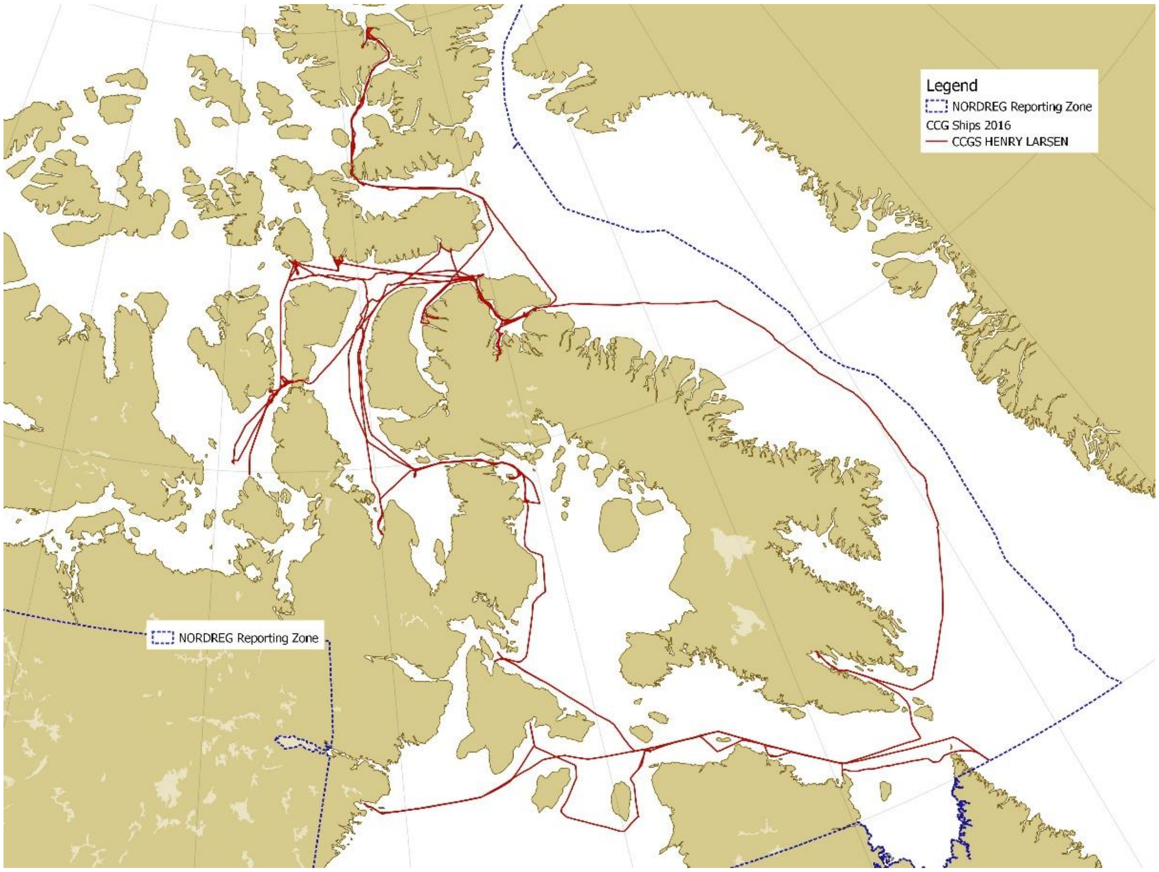


Figure 58: CCG Icebreaker Vessel Arctic Routes

3.1.2 CASE 2 – GENERAL CARGO

General cargo vessels are used to resupply Arctic communities and may also move supplies to mining and other northern operations during the summer operating season from July to September. The vessel used to illustrate this ship type is as shown in Table 19. Due to the lack of shore infrastructure all these vessels are "geared"; i.e., they have considerable crane capacity which is used to handle the boats and barges used to ferry cargo ashore, and also to handle the cargo itself. The vessels have some ice capability to reduce the risk of hull damage, but do not generally break significant amounts of ice independently, relying on CCG icebreakers to break track in more severe conditions. Propulsion plants are normally direct drive diesel mechanical, with a slow or medium speed engine driving a single propeller.

Table 19: General Cargo Vessel Particulars

Type	General Cargo
Overall Length (m)	140.00
Beam (m)	21.00
Draft (m)	8.00
Gross Tonnage	10,000
Deadweight (t)	15,000
Speed (kts)	15
Power (kW)	6,000

A typical set of routes for a cargo vessel is shown in Figure 59. A number of operators have contracts to deal with different Arctic communities, so other operators would be servicing other parts of the Arctic but with reasonably similar voyage profiles. Operations are labour intensive and also subject to frequent weather delays, and so considerable time is spent at anchor. Many transits between communities are at reduced speed, though at some times full power may be required for ice transit.

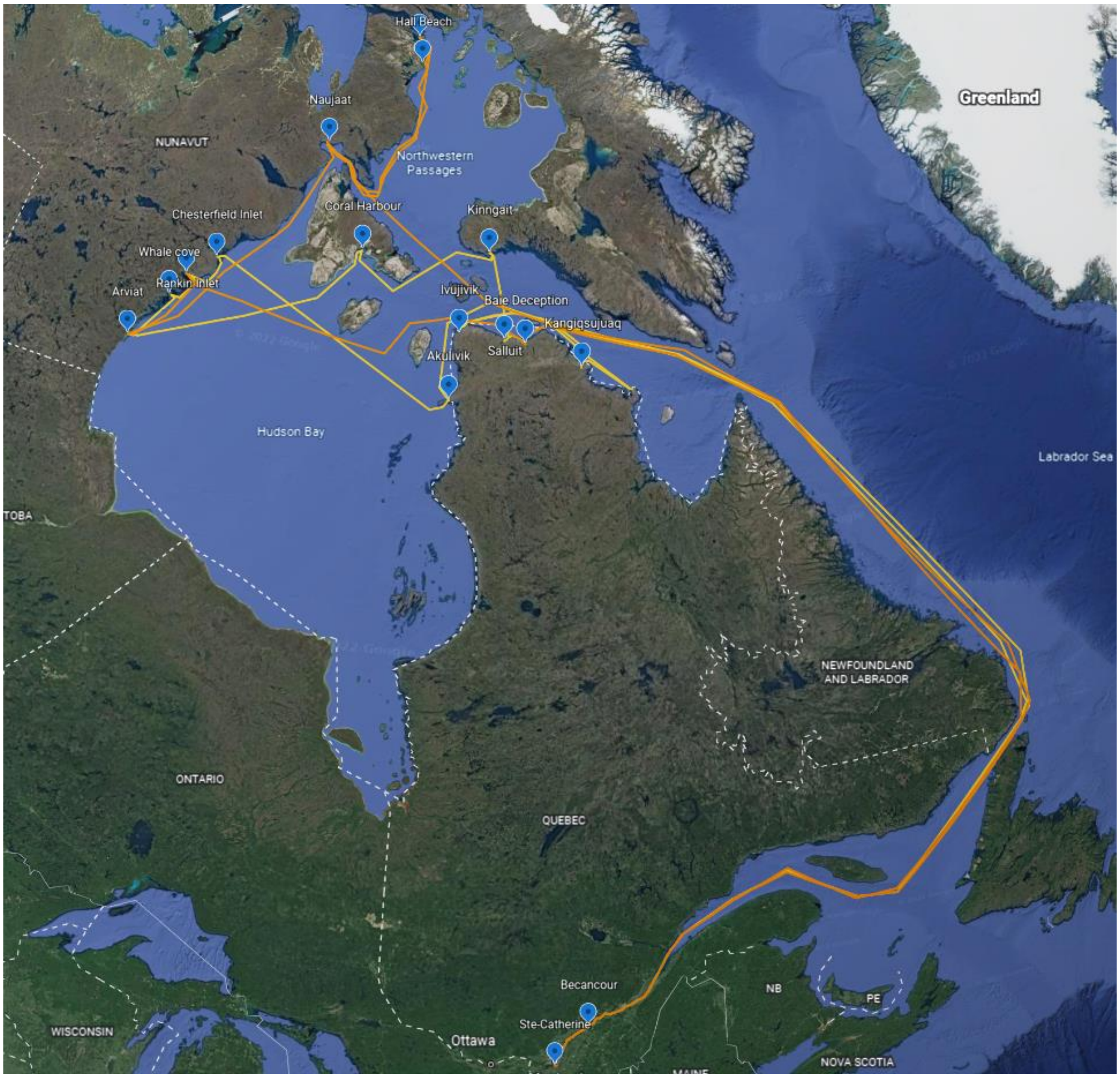


Figure 59: General Cargo Vessel Arctic Routes

3.1.3 CASE 3 – TANKER

Product tankers are used to supply diesel and other fuels to Arctic communities, mines etc. in a similar manner to the cargo resupply described above. Again, the vessels have some ice capability to reduce the risk of hull damage, but do not generally break significant amounts of ice independently, relying on CCG icebreakers to break track in more severe conditions. Propulsion plants are normally direct drive diesel mechanical, with a slow or medium speed engine driving a single propeller. Particulars of the vessel used for this study are detailed in Table 20.

Table 20: Tanker Vessel Particulars

Type	Tanker
Overall Length (m)	135.00
Beam (m)	23.50
Draft (m)	8.00
Gross Tonnage	12,000
Deadweight (t)	15,000
Speed (kts)	14
Power (kW)	5,500

A typical set of routes for a tanker is shown in Figure 60. A number of operators have contracts to deal with different Arctic communities, so other operators would be servicing other parts of the Arctic but with reasonably similar voyage profiles. Operations are subject to frequent weather delays, and so considerable time is spent at anchor. Many transits between communities are at reduced speed, though at sometimes full power may be required for ice transit. Most fuel transfer ashore uses floating hoses, with lengths of up to several kilometers. Small boats are used to keep ice away from the hoses, and a variety of other safety measures are used to mitigate the risk of spills.

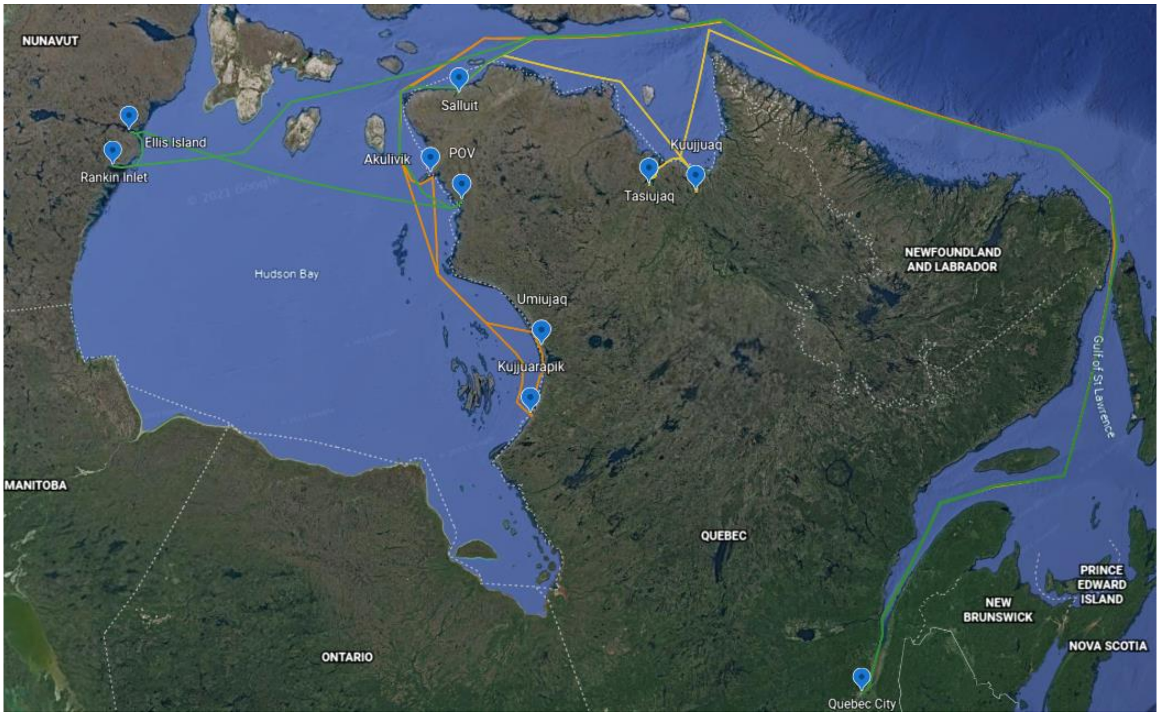


Figure 60: Tanker Vessel Arctic Resupply Routes

3.1.4 CASE 4 – CRUISE SHIP

Expedition cruises in polar waters are increasingly popular, and a new generation of ice-capable vessels have been built to service this market. The illustrative example detailed in Table 21 is typical of these ships. They have centralized diesel-electric power plants to provide both propulsive power and also the fairly high demand for hotel services for the passengers and crew. As shown, these vessels normally have a large number of small craft carried on board for excursions and wildlife observations.

Table 21: Cruise Vessel Particulars

Type	Cruise Ship
Overall Length (m)	138.00
Beam (m)	22.00
Draft (m)	5.60
Gross Tonnage	15,500
Deadweight (t)	2,000
Speed (kts)	16
Power (kW)	11,200

The route profiles developed for this vessel are synthetic. Currently, no cruise voyages originate or terminate in Canada, and ships tend to spend relatively brief periods in Canadian waters, mainly due to regulatory and jurisdictional challenges. The assumed voyages here start and end in Iqaluit, with passengers arriving and departing by air. The itineraries cover locations that have been popular in past years and that would offer a variety of Arctic experiences, these are shown in Figure 61.

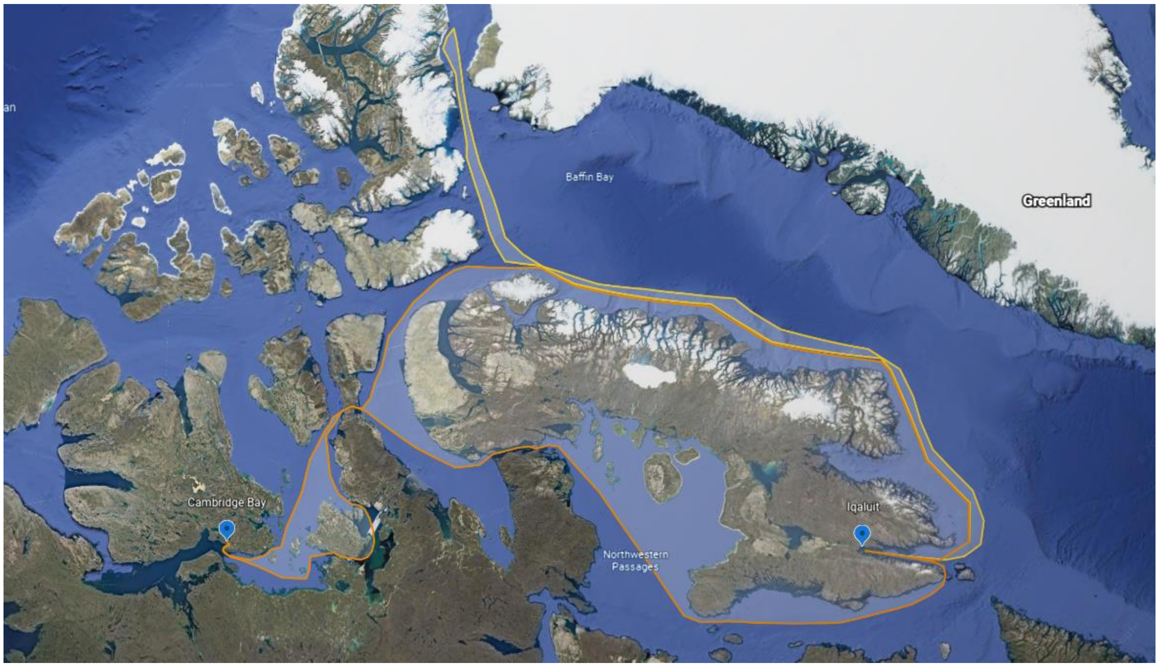


Figure 61: Cruise Vessel Arctic Routes

3.1.5 CASE 5 – LNG CARRIER

The LNG Carrier (LNGC) is a special case, as no vessels of this type currently operate in the Canadian Arctic, or elsewhere in Canada. Large LNG carriers transport LNG worldwide, with the only current Canadian port being the Canaport terminal in Saint John, NB. Smaller vessels are used for local distribution in countries such as Norway, and a new generation of vessels is being built to service the rapidly increasing demand for bunker fuel for LNG-powered ships of various types. These are referred to as LNG Bunker Vessels. Any bunkering vessel can also act as a local distribution vessel, as most of the equipment required is essentially identical. A bunkering vessel will also have supplementary safety systems to address aspects of ship-to-ship transfer.

The example in Table 22 is fairly typical of high-end LNG Carrier/Bunker Vessel now being built worldwide. This is a diesel-electric vessel, with ice class similar to the product tanker and excellent maneuverability and station-keeping capabilities. Its capacity is on the order of 10,000m^3 of LNG.

Table 22: LNG Carrier Vessel Particulars

Type	LNG Carrier
Overall Length (m)	115
Beam (m)	20
Draft (m)	5.5
Gross Tonnage	5,000
Deadweight (t)	4,000
Speed (kts)	13
Power (kW)	4,000

For illustrative purposes, the LNG Carrier/Bunker Vessel has been analyzed for a set of voyages based on another from the product carrier fleet. This includes Milne Inlet, for mine supply, passage close to Iqaluit, allowing for community supply, and other potential stops at locations where LNG-fuelled vessels may benefit from local bunkering. This is shown in Figure 62.

Figure 62: LNG Carrier Arctic Routes

3.2 CONVERSION

3.2.1 CASE 6 – ICEBREAKER BULKER

There are a number of high value ores in Canada’s Arctic (and in Russia and other countries) which have limited shelf lives after initial processing. These cargoes have therefore generated year-round transportation systems using highly capable icebreaking ships. The illustrative example in Table 23 is typical of the current generation of Canadian vessels. It has a relatively high ice class (PC 4), and a mechanical propulsion system with a single ducted propeller. The cargo carried has high density, and so the conversion would place LNG tanks in a cargo hold that is normally only partially filled as weight capacity is reached before volumetric capacity.

Table 23: Icebreaker Bulker Vessel Particulars

	Type	I/B Bulker
	Overall Length (m)	190.00
	Beam (m)	26.50
	Draft (m)	12.00
	Gross Tonnage	22,000
	Deadweight (t)	32,000
	Speed (kts)	13
	Power (kW)	22,000

The voyage profile for these ships includes voyages over most of the year, with a break during the period when First Nations most rely on and use the ice for hunting and transit. The route to and from the Arctic changes with the season, as vessels avoid ice as much as possible by keeping to the Greenland coast of Baffin Bay. Also, during the winter vessels will normally avoid the Strait of Belle Isle between Newfoundland and the mainland, which can also clog with difficult ice. Various potential routes are shown in Figure 63.

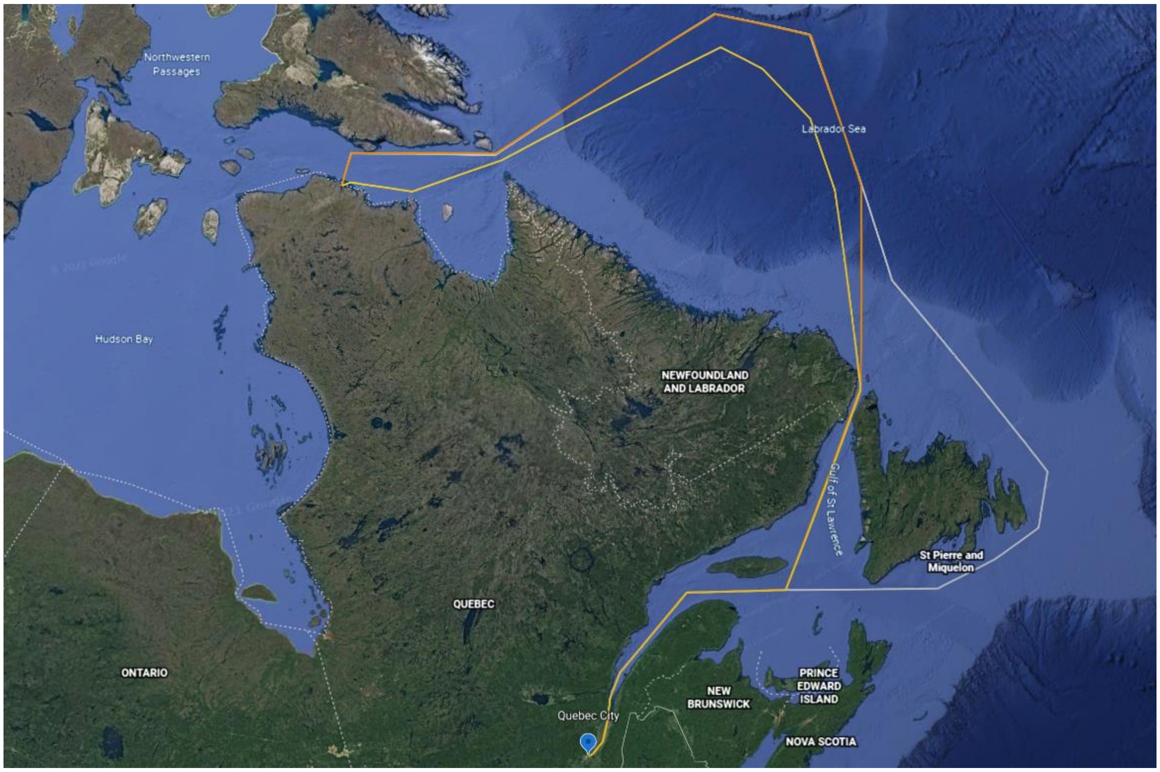


Figure 63: Icebreaker Bulker Arctic Routes

3.2.2 CASE 7 – ICEGOING BULKER

The Icegoing Bulker detailed in Table 24 is typical of the vessels currently transporting most of the iron ore from the Mary River mine on Baffin Island to ports in Europe. These are ships of Baltic ice class which operate in the Baltic during the winter months and in the Arctic over a four-month season extended at the start and finish by (private) icebreaker escort. The conversion approach will again use the fact that the cargo holds have spare volume when carrying high density ore. The power plant is mechanical drive from a slow speed engine to a single propeller.

Table 24: Icegoing Bulker Vessel Particulars

Type	Icegoing Bulker
Overall Length (m)	225.00
Beam (m)	32.00
Draft (m)	14.50
Gross Tonnage	40,000
Deadweight (t)	75,000
Speed (kts)	13
Power (kW)	14,500

The routes taken will again be influenced by the presence of ice particularly at the start and end of the season, and so a number of alternatives are shown in Figure 64.

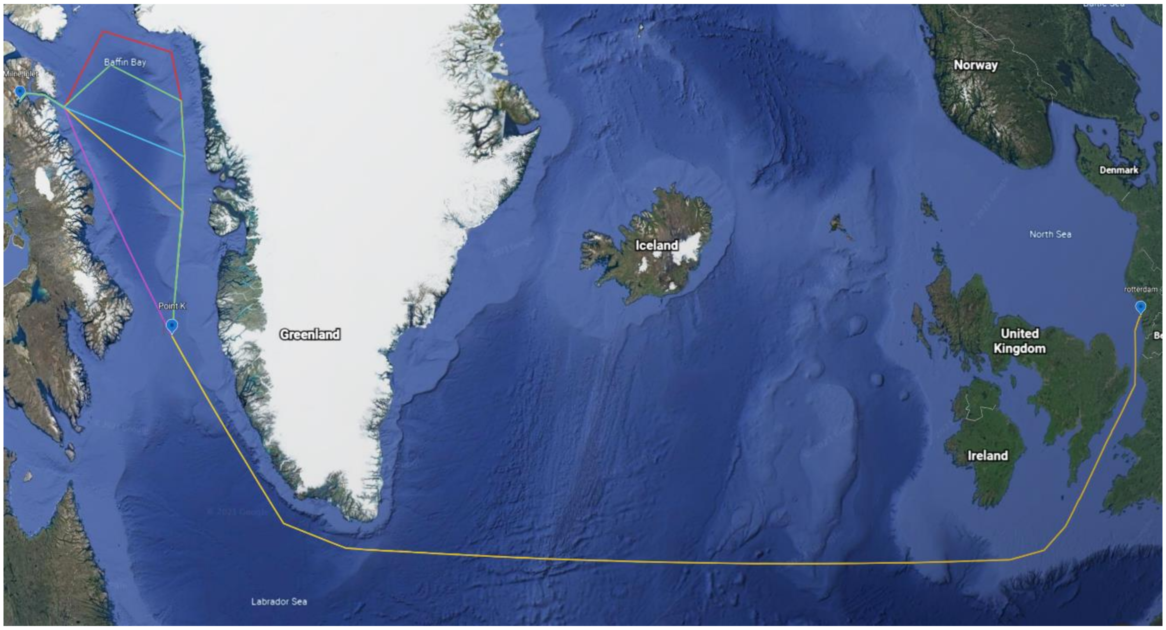


Figure 64: Icegoing Bulker Arctic Routes

4 ANALYIS AND RESULTS

The following sections provide an overview of the results which show the life cycle costs of using LNG as well as the initial capital costs associated with an LNG propulsion system.

4.1.1 PROPULSION SYSTEM CAPITAL COSTS

The results of the propulsion system capital cost analysis illustrated in Figure 65 show 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. As discussed earlier in the report, only LNG fuel has been considered for A5 – LNG Carrier so there is no comparative capital cost included. Additionally, as A6 – I/B Bulker and A7 – Icegoing Bulker are the conversion options they do not have capital cost associated with switching from HFO to MDO as the equipment is presumed to be suitable for both.

For this analysis the costs for the traditional fuel options are assumed to be equal. As mentioned previously, the modelled results do not include the capital costs associated with sulphur (SO_X) scrubbers due to the impending HFO carriage ban in the Arctic. It is probable that all costs for the CCG icebreaker will be higher than those shown, as Canadian government vessels are by policy required to be built in Canadian yards, where costs are considerably above world shipbuilding prices, particularly for the labour component. As no information to quantify this is available in the public domain, world pricing has been used for all vessels.

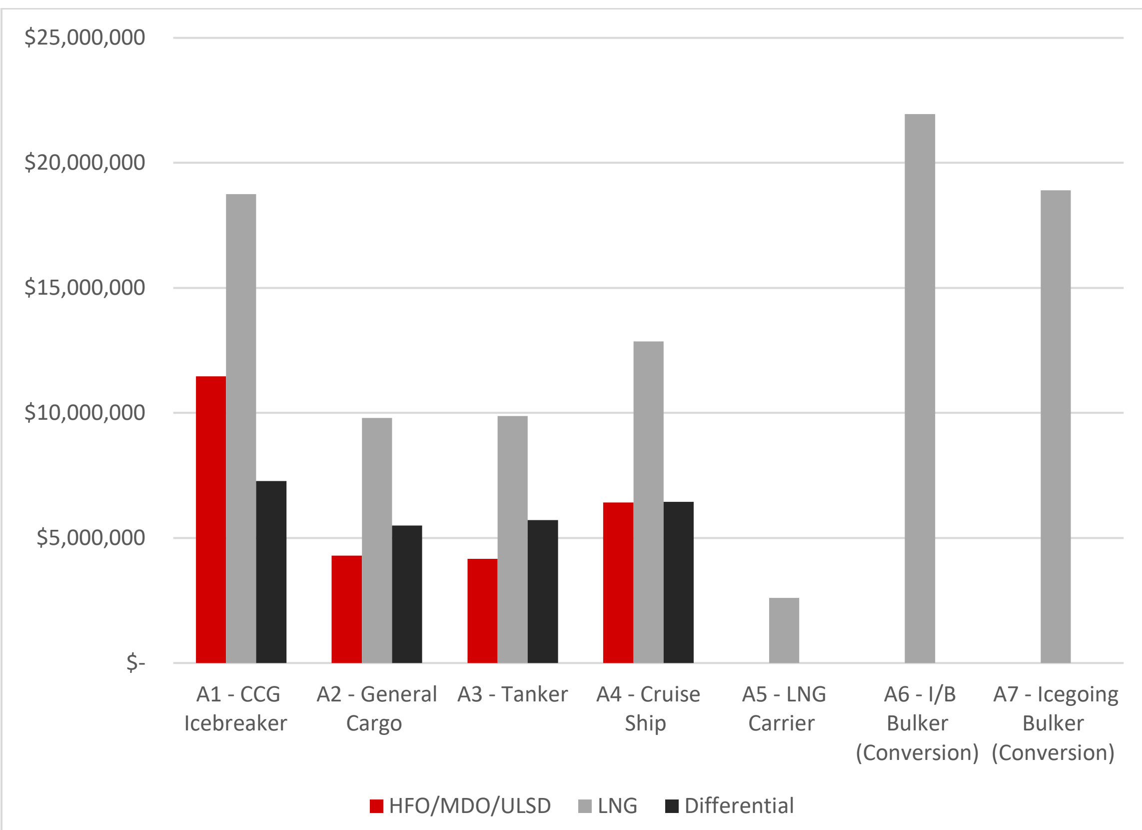


Figure 65: Propulsion System Capital Costs

4.1.2 ENERGY COSTS

Table 25 shows the annual fuel consumption (of all annual voyages) for each of the cases including both the LNG and the pilot fuel consumption. All of the vessels are assumed to bunker in Canada, other than the Icegoing Bulker which bunkers in Europe. For the HFO option, HFO is used for the main engines and MDO when only the auxiliary engines are being run.

Table 25: Annual Vessel Fuel Consumption

	HFO		MDO/ULSD	LNG	
	HFO – Main Engines (MT)	MDO – Aux Engines (MT)	MDO (MT)	LNG (MT)	Pilot Fuel - MDO (MT)
A1 - CCG Icebreaker	-	-	3,557*	3,171	6*
A2 - General Cargo	-	-	3,952	3,286	146
A3 - Tanker	-	-	4,029	3,291	115
A4 - Cruise Ship	-	-	6,712	5,086	57
A5 - LNG Carrier	-	-	-	2,823	-
A6 - I/B Bulker	5,202	611	5,515	4,845	44
A7 - Icegoing Bulker	10,444	898	10,745	8,978	281

*CCG Icebreaker uses ULSD

Figure 66 shows the annual fuel cost for the two vessels using HFO and LNG. The cost differential is shown to clearly illustrate the difference in cost at the current fuel pricing. The fuel prices are detailed in Section 2.3.3.1. The A6 - I/B Bulker would pay marginally more in fuel costs for LNG, the A7 - Icegoing Bulker would pay much more due to the higher cost of LNG when bunkering in Europe.

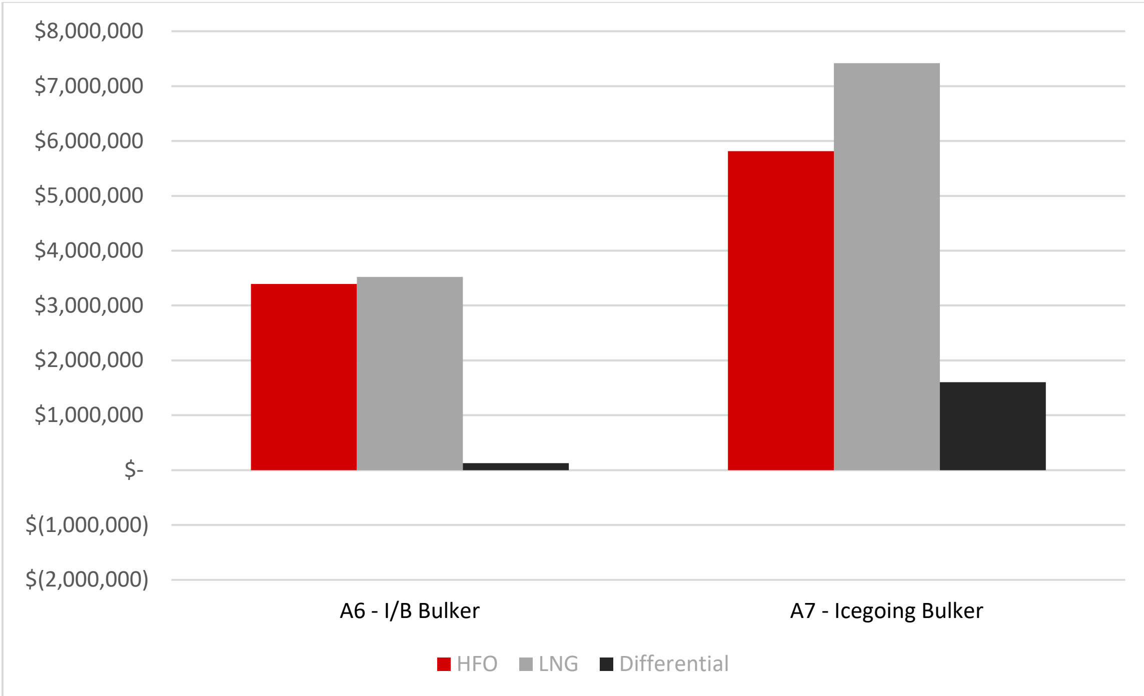
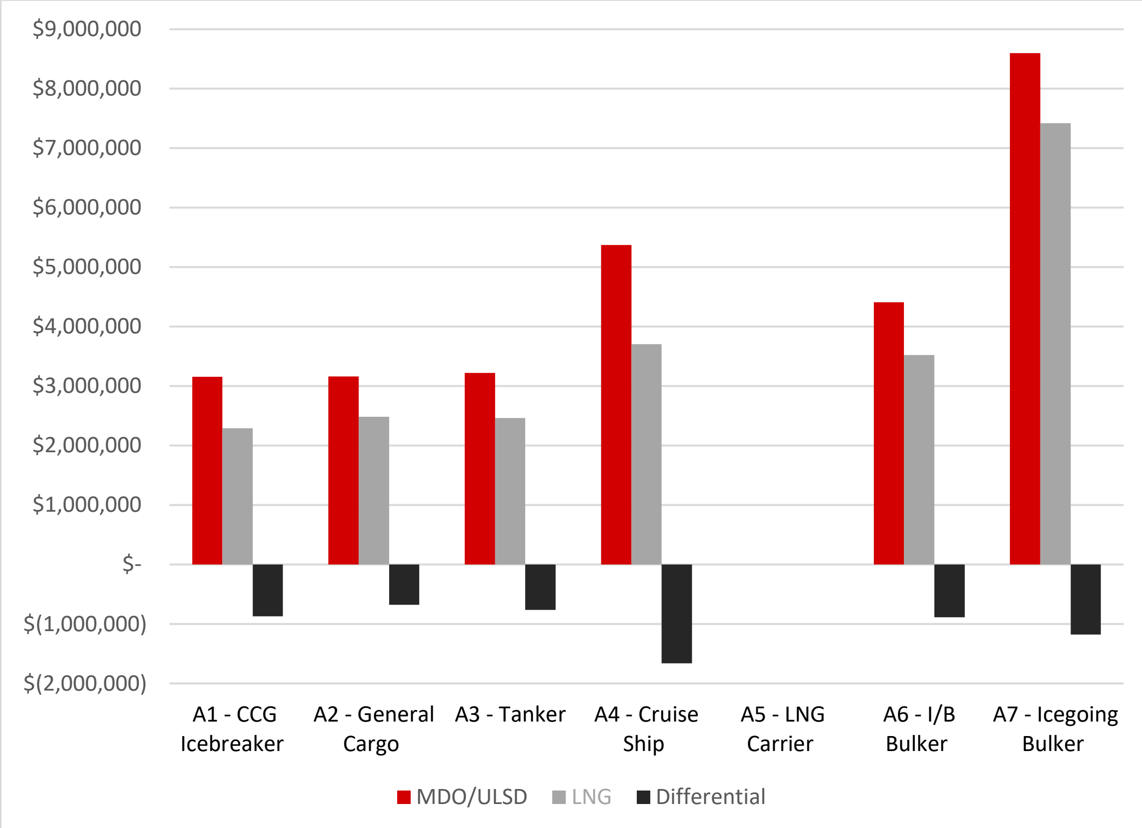


Figure 66: Annual Energy Costs - HFO & LNG

*Note *that case A1 (CCG) uses ULSD.*

Figure 67 presents the same information but instead comparing MDO/ULSD and LNG. The only vessel to use ULSD is CCG Icebreaker, all others presented use MDO. In this comparison, all vessels are projected to save if they switched to LNG. The potential savings will be heavily influenced by the evolution of pricing for LNG, HFO and MDO.



**Note that case A1 (CCG) uses ULSD.*

Figure 67: Annual Energy Costs – MDO/ULSD & LNG

4.1.3 PAYBACK PERIOD

Typically, a shipowner will want to see a payback period for a capital investment of 5-10 years (at most), though other factors may also influence this – for example, improved environmental performance. An outlier to this is A1 - CCG Icebreaker, as this does not have a revenue generating role there is no payback period as such and so the acquisition cost is a much bigger decision driver. The estimated payback period has still been included for completeness.

Only vessels A6 I/B Bulker and A7 Icegoing Bulker currently use HFO. These vessels are the conversion cases, so for HFO there is no associated capital cost as engines are already installed. The payback period therefore considers the capital costs associated with converting to LNG and calculates the payback period based on fuel consumption and cost. The payback period in years is shown in Table 26, at the current LNG price of $720/MT (Montreal) and $800/MT (Rotterdam) and HFO prices of $559/MT (Montreal) and $488/MT (Rotterdam), the payback period is significant.

When the price per tonne of LNG is varied in $100/MT increments the effect which this has on payback period is shown. The price of LNG would need to drop significantly for it to be financially viable to convert an HFO fuelled vessel into LNG fuelled.

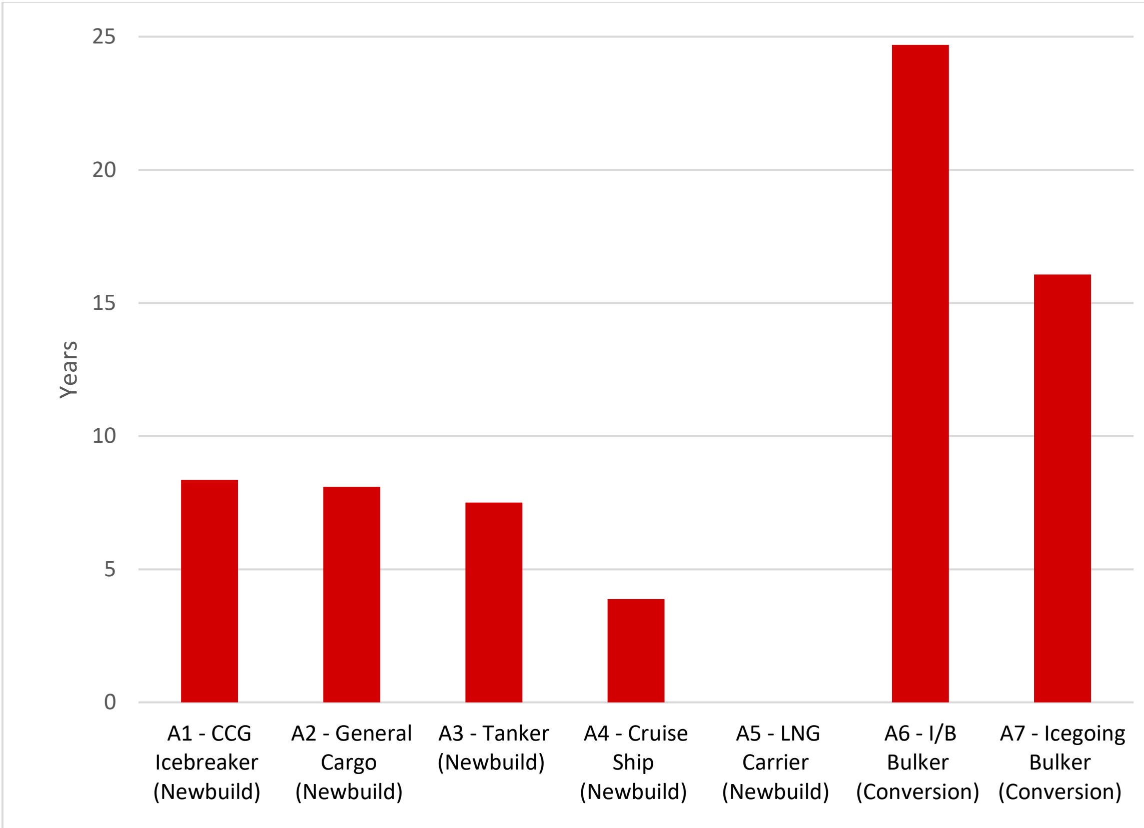
Table 26: LNG vs HFO Payback Period

Payback Period	$400/MT	$500/MT	$600/MT	$700/MT	$800/MT	$900/MT
A6 - I/B Bulker	8	10	13	19	34	159
A7 - Icegoing Bulker	5	6	7	10	18	75

However, with the impending HFO ban, a more pertinent comparison is between MDO/ULSD and LNG which is shown in Figure 68. The payback period for the CCG Icebreaker is comparing ULSD and LNG. As this vessel is assumed to be newbuild there are capital costs associated with both ULSD and LNG. As the capital costs for LNG are higher, the payback period estimates the time taken to recover these costs based on the variation in fuel costs and consumption of LNG vs ULSD.

The payback period is shorter for the General Cargo, Tanker and Cruise vessels. As these are all assumed to be newbuild, both the MDO and LNG options include the 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 vs MDO/ULSD.

For the conversion vessels (A6 - I/B Bulker and A7 - Icegoing Bulker), the payback periods are significantly longer as there are no capital costs associated with the MDO option, as it is assumed the original HFO engine would still be used and for the LNG option the conversion installation costs are substantial. The graph therefore portrays how long it would take to recoup the capital costs based solely on the difference in fuel costs and consumption of LNG vs MDO. Should those vessels be considered for newbuild instead, the payback period for each would be around 5 and 8 years respectively.



*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 68: Payback Period – MDO/ULSD vs LNG

4.1.4 PAYBACK PERIOD SENSITIVITY ANALYSIS

A number of payback period sensitivity analyses were completed in order to determine what key variables influence the viability of LNG as a marine fuel. Initially LNG fuel price sensitivity was analyzed for all cases with a fixed MDO/ULSD cost, followed by the reverse where the LNG cost was fixed and MDO/ULSD varied. The results of each price sensitivity are presented in the following sections. The results of varying both are presented in Appendix A.

It can be noted that the application of some form of carbon tax will tend to increase the price of MDO/ULSD relative to LNG, due to the higher relative carbon content. As the future of such market-based measures for marine fuel supplies is unclear this report does not attempt any forecast.

4.1.4.1 LNG PRICE SENSITIVITY

Figure 69 shows the payback period sensitivity to LNG prices decreasing or increasing in 10% increments from the current price of $720/MT, against a fixed cost of $800/MT for MDO/ULSD for the seven cases. The chart only presents up to an increase of 10%, if the price increases further then payback period increases significantly making LNG unviable.

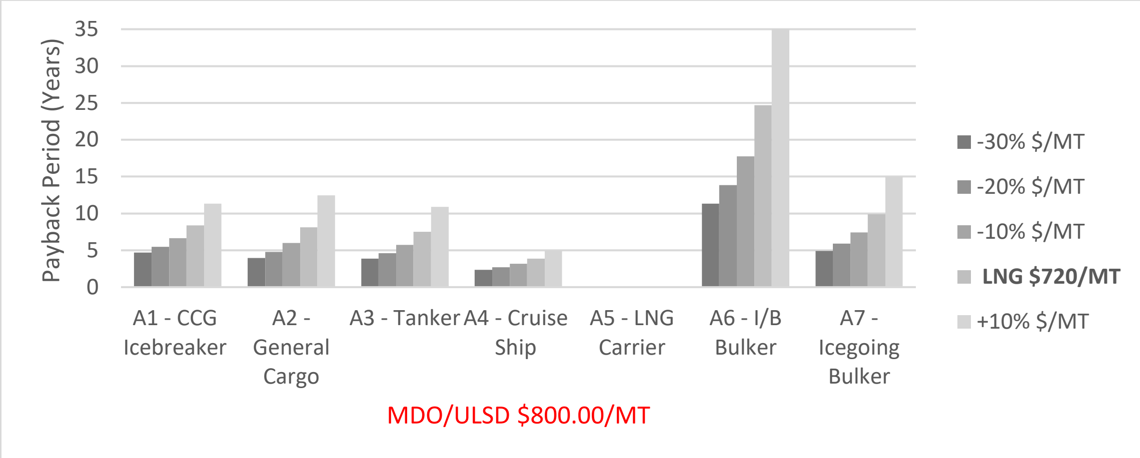


Figure 69: LNG Price Sensitivity

4.1.4.2 MDO/ULSD PRICE SENSITIVITY

Conversely, if the price of LNG remains steady at $720 per tonne and the price of MDO/ULSD increases or decreases, the effect of this is shown in Figure 70. Although MDO/ULSD has a less significant impact versus fluctuating LNG pricing, any increase in pricing would help strengthen the viability of LNG.

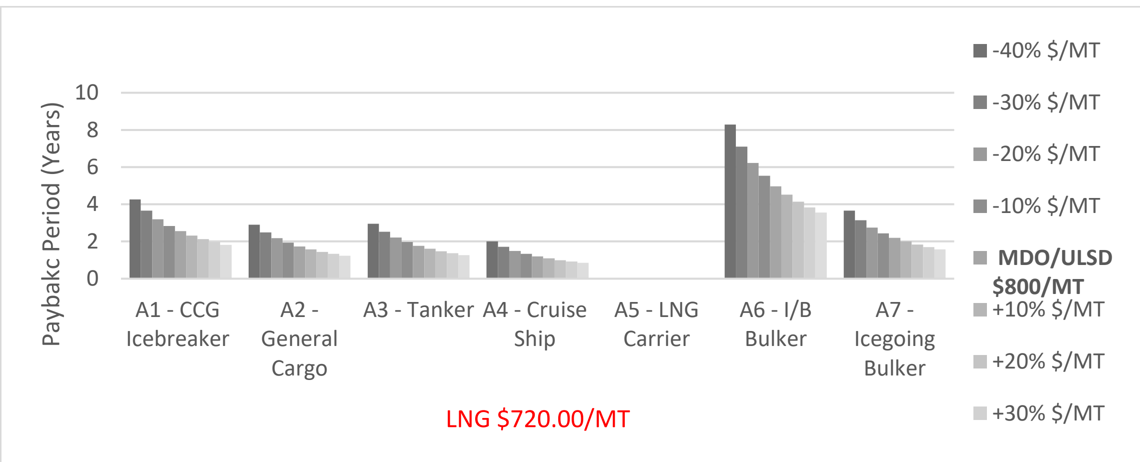


Figure 70: MDO Price Sensitivity

4.1.4.3 OTHER CONSIDERATIONS

An additional consideration for sensitivity is the capital expenditure required, which includes engine, tank and system costs and installation costs as assumed in Table 27. Should these costs reduce then the payback periods would be shorter. The differential in engine costs has tended to reduce in recent years, as dual-fuel engines become more common and initial investments in the technology are amortized.

4.1.5 LIFECYCLE COSTS

Whilst the payback period is a critical consideration for vessel operators. It is also important to compare the fuel costs for the life of the vessel to provide a complete picture of the investment.

With an inflation rate of 2.5% applied to MDO/ULSD and LNG over a 25-year period, Table 27 presents the savings that would be achieved.

Table 27: 25 Year Fuel/Energy Costs with Inflation

	MDO/ULSD	LNG	Differential
A1 - CCG Icebreaker	$107,898,566	$78,166,670	$(29,731,895)
A2 - General Cargo	$107,988,710	$84,817,984	$(23,170,727)
A3 - Tanker	$110,097,343	$84,085,104	$(26,012,239)
A4 - Cruise Ship	$183,420,068	$126,626,565	$(56,793,503)
A5 - LNG Carrier	$-	$69,426,015	$-
A6 - I/B Bulker	$150,704,823	$120,339,126	$(30,365,697)
A7 - Icegoing Bulker	$293,615,633	$253,420,143	$(40,195,490)

5 SUMMARY & CONCLUSION

The purpose of task 2 has been to investigate the economic feasibility of using LNG as a marine fuel for the Arctic maritime industry. An economic model has been developed and used to analyze the economics of LNG propulsion systems for seven different vessels. The model incorporates the capital costs associated with LNG propulsion plants, the vessel operational profiles, and the vessel fuel consumption.

Predicted payback period and life cycle costs have been calculated for each of the vessels to provide an indication of the economic feasibility of LNG as a marine fuel alternative. Sensitivity analyses were then completed on several variables. The results of these analyses indicate the following key variables impact the economic feasibility of LNG for a vessel:

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

The LNG cost itself is a function of multiple variables. For LNG to be available in sufficient quantity in the Arctic, new infrastructure will be required, including liquefaction plants and delivery systems. The delivered cost of LNG will depend on the feedstock gas costs, the location and scale of the liquefaction plants, the distance to bunkering locations, the method of delivery used, and the intensity of utilization of all the components of the supply chain. For this study the cost of LNG in Montreal and Rotterdam was used, Chapter 5 explores the infrastructure options for the Arctic.

The study has identified that when comparing LNG to HFO, at current prices, the payback periods are lengthy making it unviable in most cases, particularly for vessel conversions. However, with the impending HFO ban in the Arctic, vessel operators will be faced with two main fuel choices, MDO or LNG. When comparing these two, LNG becomes an attractive option, with reasonable payback periods followed by reduced costs through the life of the vessel.

CHAPTER 4 ENVIRONMENTAL

1 INTRODUCTION

1.1 GENERAL

This Chapter presents the outcome of the Environmental Aspects and Benefits (Task 3) of the Marine Natural Gas (NG) Supply Chain project, covering the Arctic region of Canada.

There is a general appreciation in the marine industry that, in comparison with other fuels, LNG is an option that can facilitate compliance with current and future International Maritime Organization (IMO) greenhouse gas reduction targets and with MARPOL Annex VI emission limits and may offer economic benefits as well. Vessels operating in the North American Emission Control Area (ECA) must use fuel oils not exceeding 0.10% sulphur. In addition, new (or re-engined) ships in this ECA must meet Tier III nitrogen oxides (NO_X) standards. Many LNG engines can also comply with these, unlike standard marine diesels which require some form of aftertreatment. Compliance with the ECA restrictions is not necessarily required for all Arctic going vessels, an exemption for Arctic vessels preforming sealifts has been granted which waives the ECA emissions restrictions. The ECA also does not extend into Arctic waters, so vessels primarily operating in arctic waters (sealift or not) will not need to comply with the ECA emissions restrictions.

This chapter is intended to provide an understanding of the potential reductions in pollutants/emissions and other environmental implications of moving to LNG as a marine fuel. In this regard, the report includes comparisons with current marine propulsion options and with other alternatives for meeting upcoming regulatory requirements.

The Task 3 team included representatives from a number of the project participants. Task 3 is closely aligned with several of the other tasks; particularly with Task 2 on economic aspects, as some of the same scenarios that were used for the economic modelling were also used for the emissions modelling.

It is important to acknowledge that the results presented in this chapter are the product of data and assumptions provided by the study participants, and the specific methodologies that have been applied. Actual environmental benefits will be dependent upon the in-service operating profile of the vessels, engine performance and LNG supply chain implementation.

1.2 OVERVIEW

The report is organized to provide readers with a general understanding of marine propulsion covering the fuels used and the nature of the engine technologies. Following this is a general review of emissions from marine engines. Current, pending and potential emission control requirements are then discussed, as are compliance options including a switch to LNG. Accident scenarios are reviewed, highlighting the differences in potential impacts from the liquid fuels now in general use compared to the impacts with LNG use as a marine fuel.

The report then provides calculations of relative operational emissions, on a ship basis, to indicate how individual operators can use LNG to achieve regulatory compliance and reduced emissions.

LNG is widely known as the cleanest-burning fossil fuel. Its use in the global marine sector has been very limited to date but is attracting increasing interest. Task 3 models the lifecycle emissions of LNG use based on the fuel production and supply chain through to 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 in order to determine the potential all-in CO_2-E benefit of marine LNG use. The report also identifies the potential environmental risks associated with LNG-related accidents in order to provide a complete picture of all aspects of LNG use.

In Canada, marine diesel fuel used by vessels fitted with Category 1 and 2 engines (less than 7 liters per cylinder and 7-30 liters per cylinder) must be ultra-low sulphur diesel (ULSD) as of 2012. Vessels fitted with Category 3 engines (greater than 30 litres per cylinder) are subject to ECA restrictions on fuel sulphur content when operating within an ECA. Larger vessels such as those covered by this report will normally have Category 3 engines, and so the only vessel Case Study (Refer to Section 8) analyzed in this report using USLD is the Canadian Coast Guard (CCG) ice breaker, by policy rather than requirement. None of the other vessel Case Studies analyzed in this report use ULSD, they use other fuels as noted in Section 8. Arctic vessels that use diesel for main or auxiliary engines must be prepared to comply with ECA requirements if operating within an ECA without an exemption.

The combustion processes in marine diesel engines also creates environmental challenges. The diesel combustion cycle is highly fuel efficient in comparison with, for example, gasoline engines. However, diesel combustion involves high peak temperatures that promote the formation of NO_X. In turn, NO_X emissions form acidic precipitates that can degrade or destroy natural ecosystems.

The most significant greenhouse gas resulting from marine transportation is carbon dioxide (CO_2). Fundamental chemistry means that LNG produces less CO_2 per unit of energy than heavier liquid hydrocarbons. However, LNG is primarily made up of methane (CH_4) which is itself a potent greenhouse gas (high global warming potential). Switching in whole or part from oil to LNG can have benefits in reaching greenhouse gas reduction targets provided increases in methane emissions are more than offset by reductions in CO_2 emissions.

In recent years, national and international standards have focused more attention on the contribution of marine transportation to local and global levels of pollution. As a result, new standards are coming into effect, which will lead to fundamental changes in both marine fuels and marine engines. As noted above, compared to traditional marine fuels, LNG can substantially mitigate many pollution problems, including SO_X, NO_X, BC and particulate matter (PM), as well as reducing carbon dioxide CO_2 equivalent (CO_2–E) emissions.

This project task is intended to quantify the potential environmental benefits of LNG fuel and – in combination with Task 2 – to show how environmental regulations may affect the economic aspects of investment decisions.

Due to rounding, numbers presented throughout this report may not add up precisely to the totals provided and percentages may not precisely reflect the absolute figures.

2 MARINE PROPULSION OPTIONS

2.1 MARINE FUELS

In order to provide the basis for the environmental benefits that LNG offers, it is useful to review the commercially available alternatives; i.e., the fuels now typically utilized in shipping in the Arctic and worldwide. There are a wide variety of marine fuels in use but, for simplicity, the remainder of this section will outline the characteristics of heavy fuels and marine distillates.

2.1.1 HEAVY FUEL OIL

Some of the information in this and the subsequent sections is derived from "Everything You Need to Know About Marine Fuels", Chevron Global Marine Products, 2021. (Vermeire, 2021)

A significant percentage of polar shipping has traditionally operated on heavy fuel oil (HFO). This is also often referred to as bunker or residual fuel and includes intermediate fuel oils (IFO). In all cases this fuel type is a residual product: it is taken from what is left after more valuable components of the stock crude oil have been extracted by some form of refining process. As such, it is normally less expensive than the crude oil from which it is derived. As refining processes have become more efficient, the quality of the residuals has declined in terms of lower calorific values and a higher concentration of impurities.

There are specifications that marine fuels are required to meet, but HFO will typically include a wide range of contaminants, including:

- Ash
- Water
- Sulphur
- Vanadium
- Aluminum
- Silicon
- Sodium
- Sediment
- Asphaltenes

Some of these will be present in the crude oil itself and tend to become more concentrated in the residuals; others can be introduced by the refining process. In all cases, what ends up going through the combustion processes in the ship's power plant will affect the composition of the combustion exhaust gases. Elements of the combustion exhaust are generally dangerous to the environment and detrimental to human health (CAREX, n.d.). In 2012 the World Health Organization has classified diesel engine exhaust as carcinogenic to humans (World Health Organization, 2012).

The use of HFO will be banned in polar waters by the IMO as of July 1, 2024, however many ships will be exempt from this ban until July 1, 2029, if they comply with certain IMO regulations. (Bryan Comer, 2020)

2.1.2 MARINE DISTILLATES

Marine distillates can be divided into two categories: marine diesel oil (MDO) and marine gas oil (MGO). Distillates are derived from crude oil by some form of a distillation (differential boiling) process rather than by chemical cracking. MDO is quite different from the type of diesel fuel used by cars and trucks. Internationally available marine diesel may be more viscous and have more impurities including significantly higher levels of sulphur. The slow and medium-speed diesel engines in widespread use in the marine industry (see Section 3) do not operate at the same speed (revolutions per minute) as road engines, and can, therefore, use fuels with lower cetane number (a measure of the ease of ignition).

MDO will typically be a blend of distillates with a fractional amount of HFO. While MDO has normally contained lower concentration levels of undesirable contaminants such as sulphur, permissible levels have remained quite high until the recent advent of new national and international standards. MGO is similar to MDO in that it is a distillate fuel, derived from crude oil by distillation. However, MGO will not contain any HFO or residual fuels.

2.1.3 NATURAL GAS

Natural gas must be either compressed (CNG) or liquefied (LNG) in order to be used as a transportation fuel due to its low energy density by volume. Approximately twice as much space is needed to store the same amount of energy in LNG as compared to diesel. By contrast, the volume required to store CNG is approximately double that of LNG, so its use in the marine sector is most likely to be in short range coastal operations.

As required by Canadian regulations, pipeline gas (and CNG) must be odorized with a chemical called mercaptan. This is added to give natural gas a rotten egg smell which is easily identified in the event of any leaks. LNG does not include mercaptan, because the low temperature demands of the LNG production process prevent its use. As a result, methane detectors are required for all LNG applications. Pre-treatment of natural gas eliminate constituents from the natural gas such as CO_2, H_2S, water, odorant, and mercury.

North American pipeline natural gas used to make either CNG or LNG has a relatively narrow range of chemical constituents and properties, making it a cleaner-burning fuel compared to oil-based fuels. The analyses detailed later in this report provide comparisons with the other marine fuels described above.

2.2 MARINE PROPULSION

This task does not involve a detailed analysis of engine technology, but it is useful to have a general understanding of the characteristics of marine power plants in order to understand some of the terminology and also why some engines are easier to adapt to alternative fuels than others. More detailed descriptions of natural gas and dual-fuel engines are included in Chapter 2; the material below covers “conventional” marine engines and summarizes the adaptations made for natural gas fuel.

2.2.1 DIESELS

Various types of diesel engines are the mainstay of 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, although there are substantial overlaps. High and medium speed engines are usually four stroke, while slow speed are two stroke; this again is not a universal rule.

The four stroke cycles in these engines are intake, compression, power and exhaust. The combustion air is compressed resulting in a rise in temperature. As the piston reaches top dead center, fuel is injected and combustion takes place, driving the piston down, followed by exhaust through cylinder valves.

In a two stroke engine, these stages are combined and overlapped. In the first (upstroke) the working fluid (air) is drawn in and compressed, and fuel is injected and ignites in a single stroke. The second (down stroke) drives the piston with the combustion energy and exhausts the hot air and combustion products to initiate the start of the next cycle.

Modern diesels are complex machines which incorporate a range of approaches and auxiliary equipment to boost power and efficiency levels. At the same time, they have a remarkable ability to burn a wide variety of fuels; care has to be taken to match these with appropriate lubricating oils and other additives to avoid damage. Slow speed engines will work with any grade of diesel fuel, as will most medium speed engines. High speed engines tend to require the more refined diesel.

The high cylinder temperatures and pressures in modern diesels mean that if anything in the fuel can burn (oxidize), it will. Therefore, the exhaust streams contain oxide forms of fuel and contaminants, most notably SO_X. The combustion process also generates nitrogen oxides from the nitrogen in the air which are also considered pollutants. Changes in fuel standards and engine emissions regulations have typically focused on reducing SO_X, NO_X, and PM emissions.

2.2.2 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 in this case refers to the operating fluid rather than the fuel itself. Gas turbines can run on natural gas fuel, but the marine industry normally uses some grade of distillate.

2.2.3 STEAM

Steam reciprocating engines were, historically, the first marine power plants; they have now almost entirely disappeared. Steam turbines' last major market sector was with LNG tankers. These propulsion plants were able to use LNG boil-off gas from the cargo in the boilers. Even in this sector, diesels or dual-fuel gas engines are now the most common type of prime mover due to their significant advantages in efficiency. With shrinking market shares, steam plants are increasingly expensive to buy, operate and maintain.

2.2.4 NATURAL GAS ENGINE TECHNOLOGY

Three basic technologies are used in marine natural gas engines – spark-ignition (SI) pure gas, dual-fuel (DF) with diesel pilot, and direct injection (DI) with diesel pilot. Table 28 provides an overview of these technologies.

Table 28: Natural gas engine technologies

	Lean burn spark ignition (SI) pure gas	Dual fuel (DF) with diesel pilot	Direct injection (DI) with diesel pilot
Thermodynamic Cycle	Otto	Otto	Diesel
Fuel introduction	Pre-mixed in intake or port injection	Pre-mixed in intake	Direct in cylinder
Ignition source	Spark plug pre-chamber	Liquid fuel pilot	Liquid fuel pilot
Technology providers & products (examples)	Mitsubishi Rolls-Royce	Wartsila MAN MAK	MAN

Both SI and DF engines use a pre-mixed air/fuel charge, which tends to result in methane slip. Methane slip is the term used to describe the release of methane in the exhaust from incomplete combustion. Methane slip reduces the greenhouse gas (GHG) benefit of the engine, as methane is a potent GHG. Some SI engines use port injection which manufacturers assert reduces methane slip.

In addition to the gas supply, DF and DI engines also require a liquid fuel system for the pilot injection. SI engines have a single gas fuel system which incorporates redundant fuel supply machinery.

DF engines typically have the in-built capability to operate on 100% oil-based fuel as an alternative to LNG fuel operation. However, it should be noted that, if the engine has been modified to optimize LNG combustion on the Otto cycle (e.g., reduced compression ratio), then the engine's efficiency and emission performance are unlikely to match the original base diesel engine from which the LNG engine was derived when operating on purely fuel oil.

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

3 EXHAUST EMISSIONS FROM MARINE ENGINES

Three main types of emissions are created from the diesel combustion process depending on the fuel type used: CO_2, NO_X, and SO_X. CO_2 is a GHG that is among those responsible for global warming. NO_X is formed due to high temperature during the combustion process and contributes to the formation of smog as well as contributing to the formation of ground level ozone. SO_X causes acid rain and is directly related to the amount of sulphur present in the fuel. Secondary SO_X and NO_X also contribute to PM formation through a series of chemical and physical reactions resulting in sulphate and nitrate PM.

PM and black carbon are solid pollutants created from the combustion process. PM results from various impurities and incomplete combustion processes. Most PM emissions are harmful to humans and may have contributing factors to global warming. The accumulation of black carbon on glaciers and polar icecaps may accelerate the melting rate by increasing the absorption of sunlight (United States Environmental Protection Agency, 2010). There is an increasing focus on black carbon emissions and its impact on environment and its contribution to global warming.

There is considerable literature on emissions from "standard" marine engines, and this is utilized in the comparative analyses presented later in the report. The remainder of this section describes the emission profile of pure LNG - as well as dual-fuel and direct injection LNG engines of various types.

3.1 GREENHOUSE GASES (CO_2, METHANE)

CO_2 emissions are related to the carbon content of fuel and the amount of fuel consumed. They can be reduced by creating more efficient engines, transitioning to fuels containing less carbon per unit energy, or by reducing energy demand (e.g., reducing speed, or improving ship hull forms). Factors which influence engine efficiency include mechanical efficiency, operating speed, type of cycle (Diesel, Otto, or Miller) and whether the engine is a two stroke or four stroke.

The majority of the LNG-fuelled marine engines in use in the marine market are medium speed, Otto cycle engines. The slow speed LNG engines in the marine market are direct injection two-stroke engines operating on the Diesel cycle. Regardless of the operating cycle, method of LNG ignition (spark ignited or diesel pilot), or the engine operating speed, using LNG rather than fuel oils results in a reduction in the amount of CO_2 produced by the engine itself as a result of the lower carbon content.

This reduction in CO_2 production may be partially offset or more than offset by methane slip, the term to describe the fraction of natural gas that passes through the engine without burning. Methane slip is more prevalent in engines operating on the Otto cycle. The amount of methane released by LNG engines operating on the Diesel cycle is less than the Otto Cycle, however it is still more than operation on conventional liquid fuel. Manufacturers of Otto cycle LNG engines are continuing to make advances in reducing the amount of methane slip by making design modifications and using a lean-burn principle. According to Rolls-Royce, there is the potential to reduce methane emissions by up to 80% as a result of enhanced engine design, integration of methane-related controls, and the use of methane-targeted oxidation catalysts (D. Lowell, 2013).

Environmental organizations and authorities have differing opinions on what figure should be used to calculate the greenhouse effect of methane in comparison to CO_2. The results presented in this report use a GWP100 factor of 30, which is in alignment with the Intergovernmental Panel on Climate Change (IPCC) 6th Assessment Report (AR6). The United Nations Framework Convention on Climate Change (UNFCCC) and Environment Canada currently use an older GWP100 value of 25 for Methane. It is uncertain when or if the UNFCC or Environment Canada will adjust their figures to become aligned with the IPCC.

It should be noted that short-lived greenhouse gases such as Methane may not have their effects best represented on a 100-year timeline. In the case of Methane, there is a case to be made that a 20-year timeline be used, known as GWP20. While this report will focus on GWP100, the reader should understand that if GWP20 were analysed the GWP of Methane would be about 3 times higher.

Results later in the report show that the net effect of methane slip from current LNG engines reduces their overall GHG benefits.

3.2 SO_X EMISSIONS

The amount of SO_X produced is a function of the sulphur content of the fuel. Equation (1) can be used to calculate the SO_X produced on a g/kwh basis (International Maritime Organization, 2020):

SO_X (g/kWh)

$$SO_X = 2 * 0.97753 * S \tag{1}$$

(S is the sulphur content on a percentage basis)

There is very little sulphur in LNG, so when compared to crude oil-based fuels with sulphur content equal to the International Maritime Organization (IMO) limits, the amount of SO_X is significantly reduced. Table 29compares the sulphur content of LNG and common marine fuel oils.

Table 29: Sulphur content: LNG compared to ISO 8217 marine fuel limits

	LNG	ULSD	MDO	RMG 180 (HFO)	RMG 380 (HFO)
Sulphur content (max) % m/m	0.0	0.0015	0.1	3.5	3.5

While diesel ignition dual-fuel or direct injection LNG engines may potentially use higher sulphur content fuel oils for pilot fuel, the SO_X emissions from these types of engines are the sum of the contributions from the LNG and pilot fuel. While the amount of pilot fuel required varies depending on the engine technology, the primary source of energy for these engines is LNG. There are next to no SO_X emissions for a spark-ignited Otto cycle engine.

3.3 NO_X EMISSIONS

NO_X is primarily a function of the combustion temperature. The higher the cylinder temperatures during combustion, the more NO_X is produced.

Engines operating on the Diesel cycle, regardless of whether they are fuelled by LNG or by fuel oils, have higher NO_X emissions compared to engines operating on the Otto cycle. This is due to the higher combustion temperatures with Diesel cycle engines. Compliance with the IMO Tier III NO_X limits, as shown in Table 30, will require after treatment such as Selective Catalytic Reduction (SCR) or Exhaust Gas Recirculation (EGR) for marine engines operating on oil-based fuels. For LNG-fuelled marine engines operating on the Diesel cycle, SCR or EGR may be required, although the specific emissions management strategy will vary depending on the engine manufacturer.

For LNG-fuelled marine engines operating on the Otto cycle, neither SCR nor EGR are required to comply. In fact, current generation Otto cycle LNG engines already comply with Tier III NO_X limits.

Table 30: IMO NO_X Emission Limits

Tier	Ship Construction date on or after	Total weighted cycle emission limit (g/kWh) n = engine's rated speed (rpm)		
		n < 130	130 ≤ n < 2000	n ≥ 2000
Tier I	1 January 2000	17.0	$45 \times n^{-0.2}$	9.8
Tier II	1 January 2011	14.4	$44 \times n^{-0.23}$	7.7
Tier III	1 January 2016*	3.4	$9 \times n^{-0.2}$	2.0

*Tier III controls apply only to the specified ships operating in established ECA to limit NO_X emissions, outside such areas the Tier II controls apply.

3.4 PM EMISSIONS

PM emissions can be attributed to incomplete combustion of fuels. High cylinder temperatures and pressures can cause some of the fuel injected into a cylinder to break down rather than combust with the air in the cylinder space. This breakdown of the fuel can lead to carbon particles, sulphates and nitrate aerosols being produced.

Fuels with higher sulphur contents result in higher PM emissions because some of the fuel is converted to sulphate particulates in the exhaust (United Nations Environment Fund). However, sulphur is not the sole source of particulate matter.

The formula used for calculating the PM produced for the fuel oil base line cases analyzed is as listed in Equations (2) & (13) (International Maritime Organization, 2020):

HFO PM (g/kWh)

$$PM = 1.35 + (SFC * 7 * 0.02247 * (S - 0.0246)) \tag{2}$$

(S is the sulphur content on a percentage basis & SFC is specific fuel consumption in g/kWh)

MDO & MGO PM (g/kWh)

$$PM = 0.23 + (SFC * 7 * 0.02247 * (S - 0.0024)) \tag{3}$$

(S is the sulphur content on a percentage basis & SFC is specific fuel consumption in g/kWh)

These formulas are not appropriate when considering PM emissions from LNG. Based on the "Fourth IMO GHG Study 2020" (International Maritime Organization, 2020) LNG PM emissions are 0.01 g PM/kWh for diesel cycle engines and 0.02 g PM/kWh for Otto cycle engines.

3.5 BC EMISSIONS

The most damaging component of PM is Black Carbon (BC). BC by definition is a distinct type of carbonaceous material, formed primarily in flames during combustion of carbon-based fuels. It is distinguishable from other forms of carbon and carbon compounds contained in atmospheric aerosol because of its unique physical properties as listed below; (Bond et. al, 2013)

- Strongly absorbs physical light
- Is refractory with a vaporization temperature near 4000k
- Exists as small aggregate spheres
- Insoluble in water and other organic solvents

BC emitters in the Arctic being especially damaging due to the impact that BC has on glaciers and polar icecaps. The 100-year GWP for BC is 900 with a range of (120 to 1800) (Bond et. al, 2013). The effects of BC on climate change is still not completely characterized, and as such a large range is provided for the GWP. This study will use a GWP of 900 for BC emissions.

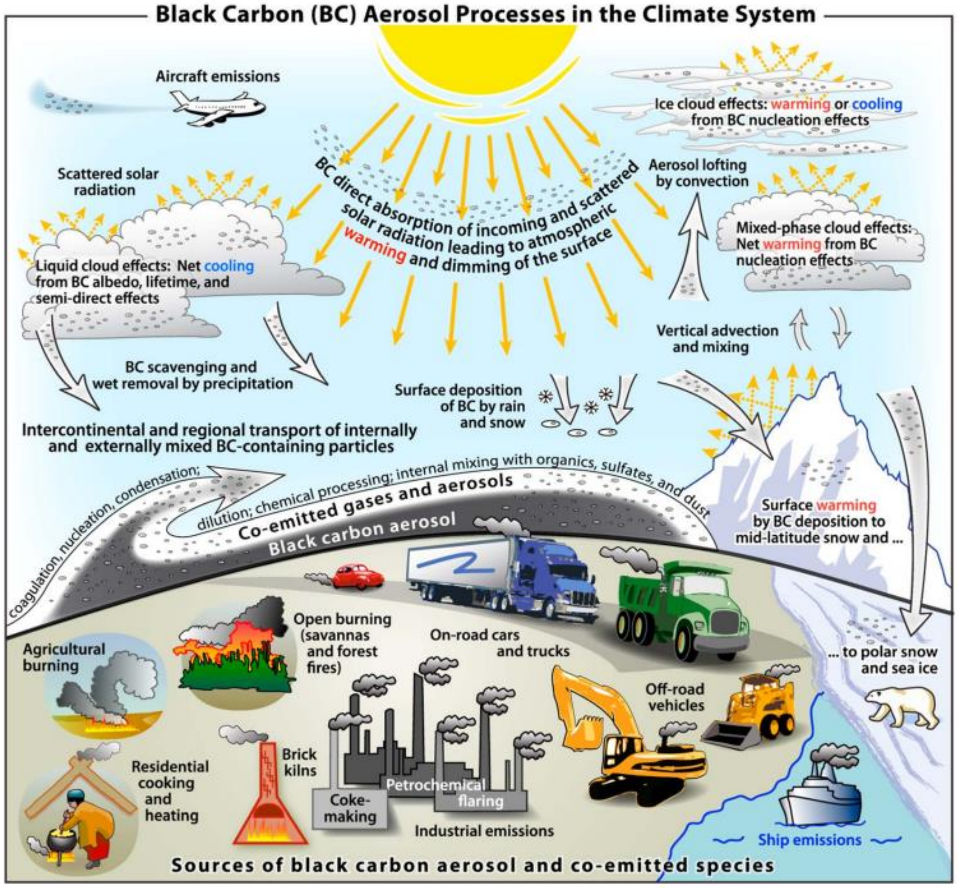


Figure 71: BC lifecycle (Bond et. al, 2013, p. 5390)

> "The black-carbon climate forcings from the direct effect and snowpack changes cause the troposphere and the top of the cryosphere to warm, inducing further climate response in the form of cloud, circulation, surface temperature, and precipitation changes." - (Bond et. al, 2013, p. 5387)

As detailed from the paper above and referenced in Figure 71, BC has a direct effect on global warming and is a key emission that should be reviewed when analyzing emissions from Polar marine traffic. The banning of HFO in polar waters by July 1, 2029, is a step made partly to decrease the BC emissions from Polar marine traffic (Comer, 2017).

The following formulas are used to calculate BC emissions (International Maritime Organization, 2020);

2 Stroke HFO BC (g/g fuel)*

$$BC = 1.500 * 10^{-4} * (Load^{-0.359}) \quad (4)$$

2 Stroke MDO/MGO BC (g/g fuel)*

$$BC = 3.110 * 10^{-5} * (Load^{-0.397}) \quad (5)$$

4 Stroke HFO BC (g/g fuel)*

$$BC = 2.500 * 10^{-4} * (Load^{-0.968}) \quad (6)$$

4 Stroke MDO/MGO BC (g/g fuel)*

$$BC = 1.201 * 10^{-4} * (Load^{-1.124}) \quad (7)$$

Diesel LNG BC (g/kWh)

$$BC = 0.002 \quad (8)$$

Non-Diesel LNG BC (g/kWh)

$$BC = 0.003 \quad (9)$$

* Load is the hourly main engine loading given as a proportion (i.e., from zero to one)

4 LEGISLATED EMISSIONS COMPLIANCE REQUIREMENTS

4.1 MARPOL ANNEX VI

Since the 1990s, there has been a particular focus on limiting SO_X emissions from ships. In the absence of controls, the sulphur content of the residual fuel oil used by the majority of international shipping has been in the range 2.0-4.0%. In the case of distillate fuels, as used in many auxiliary engines and by smaller ships, the Sulphur content has been in the range 0.2-0.8%.

The principal SO_X control regime worldwide is the International Convention for the Prevention of Pollution From Ships (MARPOL) Annex VI. The MARPOL Convention is one of the principal regulatory instruments produced by the IMO. The original MARPOL Convention was adopted in 1973 and addressed five areas of marine pollution from ships under the following Annexes: oil, bulk chemicals, packaged chemicals, sewage and garbage. In the 1990s concern over air pollution from ships resulted in the development of an additional annex, Annex VI. Annex VI deals with a range of air pollutant streams potentially produced as a result of ship operations.

MARPOL provides for the designation of “Special Areas”, in which environmental and other concerns are considered to justify the introduction of more stringent limits on various types of discharges and emissions. Under Annex VI, the equivalent of a Special Area is the Emission Control Area (ECA). Currently, Arctic waters are not designated as an ECA.

The adoption of Annex VI means that the permissible levels of Sulphur in fuel have been reduced quite drastically over the past decade. The reductions required in ECAs are larger and more rapid than those that will be required in non-ECA areas as detailed in Table 31. The IMO sulphur limits are applicable to both new and existing vessels.

Table 31: SO_X reductions - outside & inside ECAs

Locations	Dates	Fuel Oil Maximum Sulphur Content
Outside ECA-SO_X	From 1 January 2020	0.50%
Inside ECA-SO_X	From 1 January 2015	0.10%

4.2 POLAR CODE AND IMO PPR COMMITTEE

The International Code for Ships Operating in Polar Waters has been developed to supplement existing IMO instruments in order to increase the safety of ships' operation and mitigate the impact on the people and environment in the remote, vulnerable and potentially harsh polar waters. The Polar Code does not add any supplementary requirements for emissions from ships operating in Polar waters, which continue to be governed by MARPOL ANNEX VI.

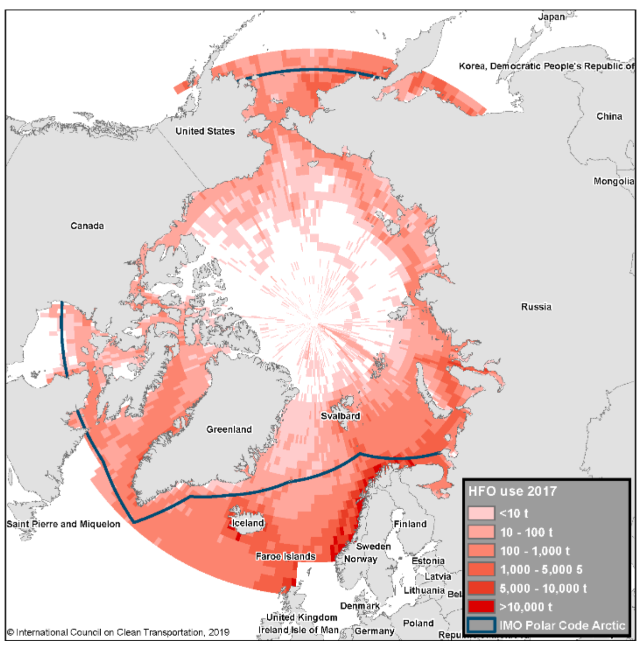


Figure 72: Polar Code Area and HFO use (Bryan Comer, 2020)

The IMO's Pollution Prevention and Response (PPR) subcommittee has banned the use of HFO in Polar waters in two phases. (IMO, Sub-Committee on Pollution Prevention and Response (PPR 7), 2020) Phase one will ban the use of HFO with two exemptions;

- Vessels that have double hulls with a gap of at least 760 mm between the outer hull and fuel tank
- Vessels that fly an Arctic flag (Canada, USA, Russia, Denmark and Norway)

Phase two will ban the use of HFO with no allowances for exemptions or waivers. The polar HFO ban is summarized in Table 32.

Table 32: Polar HFO Ban

HFO Ban	Dates	Exemptions and Waivers
Phase 1	From 1 July 2024	Yes
Phase 2	From 1 July 2029	No

4.3 IMO ENERGY EFFICIENCY REQUIRMENTS

Another requirement under MARPOL is the Energy Efficiency Design Index (EEDI), and more recently the Energy Efficiency Existing Ship Index (EEXI) and Carbon Intensity Indicator (CII). The objective of these indices is to reduce the environmental impacts of shipping through the adoption of thorough enhanced energy efficiency measures that reduce GHG emissions.

The EEDI is mandatory for new builds of various ship types including bulkers, tankers and container ships and is intended to be a requirement for a wider range of ships in the future. The formula for attained EEDI is shown in Equation (10) (IMO, MEPC 308, 2018). A full explanation of all of the terms is contained in various IMO documents[4] and will not be reproduced here.

EEDI Formula

$$\frac{\Big((\prod_{j=1}^{M} fj) * (\sum_{i=1}^{nME} P_{ME(i)} * C_{FME(i)} * SFC_{ME(i)}) + (P_{AE} * C_{FAE} * SFC_{AE}) + \Big((\prod_{j=1}^{M} fj * \sum_{i=1}^{nPTI} P_{PTI(i)} - \sum_{i=1}^{nME} f_{eff(i)} * P_{AEeff(i)}\Big) * C_{FAE} * SFC_{AE}\Big) - (\sum_{i=1}^{neff} f_{eff(i)} *}{(f_i * Capacity * V_{ref} * f_n)} \tag{10}$$

The key to the application of the EEDI is derived from the simpler formula:

EEDI Application Formula

$$Attained\ EEDI\ <\ Required\ EEDI\ =\ (a * b^{-c})(1 - x/100) \tag{11}$$

Values of a, b and c are ship-type specific. The values for bulk carriers are:

a = 961.79

b = ship deadweight

c = 0.477

x = reduction factor, depending on ship type, deadweight, date of construction

The values of a and c have been derived by regression analysis of the vessels in service worldwide. The final term, (1-x/100), is used to reduce the required value of EEDI with time. The initial regression curve is intended to represent the average current world fleet; new ships are expected to be no worse than this average. In Phases 1, 2 and 3 of future implementation, x rises to 10, 20 and finally 30; i.e., a phase 3 ship must have an EEDI 30% lower than the initial regression value.

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[4] MEPC 308, 2018 Guidelines on the Method of Calculation of the Attained Energy Efficient Design Index (EEDI) for New Ships, October 2018

Figure 73 shows this graphically. These reductions may be achieved by improvements in design or engine technology, reducing ship speed, or various combinations of these measures (see Section 5).

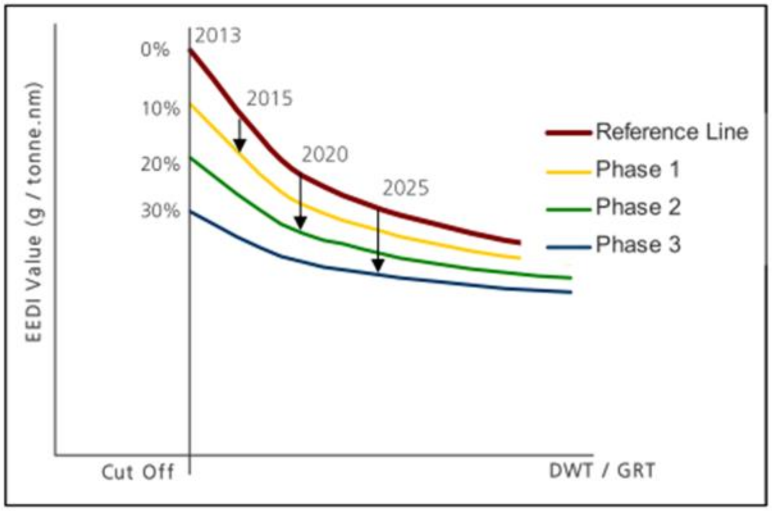

Figure 73: Progressive implementation of EEDI

Meeting EEDI targets will be challenging for many vessels and services. Switching to "cleaner" crude oil-based fuels can actually make it more difficult to meet EEDI targets as distillate fuels have higher calculated carbon values as shown in Table 34 below. In addition, the use of exhaust treatment systems (scrubbers, etc.) to remove SO_X and NO_X will further aggravate the problem due to the efficiency losses (higher fuel consumption) related to these systems.

As of June 2021, the IMO now requires that existing vessels over 400 GT meet the required EEXI value, this will come into effect in 2023. The EEXI is similar to the EEDI in a number of ways, note the similarities in the governing formulas between Equations (10) and (12) (IMO, MEPC 333, 2021). The EEXI for an existing ship must be equal to or less than the required EEXI value, which is relative to the EEDI reduction factor. A full explanation of the EEXI is contained within various IMO documents[5] and will not be reproduced here.

EEXI Formula

$$\frac{\left((\prod_{j=1}^{M} fj) * (\sum_{i=1}^{nME} P_{ME(i)} * C_{FME(i)} * SFC_{ME(i)}) + (P_{AE} * C_{FAE} * SFC_{AE}) + \left((\prod_{j=1}^{M} fj * \sum_{i=1}^{nPTI} P_{PTI(i)} - \sum_{i=1}^{nME} f_{eff(i)} * P_{AEeff(i)}) * C_{FAE} * SFC_{AE}\right) - (\sum_{i=1}^{neff} f_{eff(i)} * P_{eff(i)} * C_{FME} * SFC_{ME})\right)}{(f_i * f_c * f_l * Capacity * f_w * V_{ref} * f_m)} \quad (12)$$

In addition to the EEXI for existing ships, ships now must also comply with the Carbon Intensity Indicator (CII) starting in 2023. A CII rating will be given to each ship as shown in Table 33 (IMO, MEPC 339, 2021). Should a ship receive D or E ratings, certain actions will need to be taken to improve the rating of the vessel to the minimum of a C rating. A full explanation of the CII and how it is calculated is contained within various IMO documents[6] and will not be reproduced here.

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[5] MEPC 333, 2021 Guidelines on the Method of Calculation of the Attained Energy Efficiency Existing Ship Index (EEXI), June 2021

[6] MEPC 339, 2021 Guidelines on the Operational Carbon Intensity Rating of Ships (CII Rating), June 2021

Table 33: CII Rating

CII Rating	Description
A	Major Superior
B	Minor Superior
C	Moderate
D	Minor Inferior
E	Major Inferior

The use of LNG rather than crude oil-based fuels simplifies the compliance challenge as LNG has the lowest Carbon Factor (C_F) as shown in Table 34. The use of LN helps comply with the various IMO resolutions listed above (EEDI, EEXI & CII). Table 34(IMO, MEPC 339, 2021) is taken from IMO documentation[7] and shows how the C_F in the EEDI formula varies with fuel type.

Table 34: EEDI and EEXI fuel C_F values

Type of fuel	Reference	Lower Calorific Value (kJ/kg)	Carbon Content	C_F (t-CO_2/t-Fuel)	Normalized Emissions (Kg-CO_2/GJ)
Diesel/Gas Oil	ISO 8217 Grades DMX through DMB	42,700	0.8744	3.206	75.082
Light Fuel Oil (LFO)	ISO 8217 Grades RMA through RMD	41,200	0.8594	3.151	76.481
Heavy Fuel Oil (HFO)	ISO 8217 Grades RME through RMK	40,200	0.859	3.114	77.463
Liquefied Petroleum Gas (LPG)	Propane Butane	46,300 45,700	0.818 0.826	3.000 3.030	64.795 66.302
Liquefied Natural Gas (LNG)	-	48,000	0.750	2.750	57.292
Methanol	-	19,900	0.375	1.375	69.095
Ethanol	-	26,800	0.5217	1.913	71.381

[7] MEPC 339, 2021 Guidelines on the Operational Carbon Intensity Rating of Ships (CII Rating), June 2021

As shown in Table 34 a switch from HFO to LNG provides a 35% reduction and from diesel a 33% reduction in assessed emissions when normalized for specific energy available in the fuel.

4.4 EMISSIONS

As discussed in the previous sections, the main emissions from the internal combustion processes are CO_2, NO_X, SO_X, and PM. The following sections outline the current solutions available to vessel owners and operators to control these emissions.

4.4.1 FUEL SWITCHING

When sailing outside of ECAs (i.e., Polar waters), commercial vessel operators are able to consume less costly, higher emission residual fuels. When the vessel begins to approach the ECA, operators can switch to cleaner fuels with lower sulphur content to meet the emission restrictions. Unfortunately, some operators are experiencing difficulties switching HFO burning engines to distillates. For older vessels, fuel switching can be difficult and labour intensive and the mix of potentially very different fuels has adverse effects. When the fuels are mixed, heavy sludge is produced from asphaltenes of HFO precipitating causing filters to become clogged. Furthermore, the low sulphur and low viscosity characteristics of distillate fuels can cause problems in engines that were not meant to operate with these fuels. These issues can result in higher maintenance costs, changes in fuel oil handling and storage systems, and decreases in plant reliability during critical manoeuvring operations. (U.S. Coast Guard, 2011)

An alternative to using distillates to meet SO_X restrictions is to use an LNG/HFO engine. Using the same premise as described above but instead of low sulphur distillates, the engines are converted to burn LNG with all of the benefits discussed in this study. Once an LNG engine is fitted, LNG could be used 100% of the time to take advantage both of the cost differential of the fuel and the reduced emissions. However, if the vessel is travelling long distances, it may not be feasible to fit an LNG tank large enough to cover the whole voyage (especially until LNG bunkering becomes more widely available). Therefore, the vessel may remain with crude oil-based fuels when operating outside of ECAs and switch to LNG when necessary to meet emission restrictions.

4.4.2 SO_X REDUCTION OPTIONS

In order to reduce SO_X emissions there are two alternatives:

1. Reduce sulphur from the fuel; or
2. Scrub the sulphur from the exhaust.

Unlike NO_X emissions, SO_X emissions cannot be reduced by modifying the processes inside the engine. All of the sulphur contained in the fuel is output in the exhaust gas (MAN Diesel and Turbo, n.d.).

Wet exhaust gas scrubbers are capable of reducing the SO_X content by 90 to 95%. They typically function by spraying sea water over the exhaust gas stream, although other technologies have also been used as described below. The sea water and sulphur react to form sulphuric acid which is neutralized with alkaline components in the sea water. Filters separate particulates and oil from the wash water before this water is either re-used with the addition of chemicals such as sodium hydroxide for pH control (closed loop) or returned to the ocean (open loop). (Lloyd's Register, 2012)

One disadvantage of this type of system is the large space requirements for the scrubber and water system. An open loop scrubber operation requires a capacity of 40 to 50 m^3 of sea water per megawatt-hour of engine power. Operating the scrubber also involves significant power consumption, which itself boosts GHGs. In some jurisdictions (for example, Canadian Arctic waters) existing open loop systems are not allowed, as they discharge unacceptable pollutants to the water. Closed loop systems are more costly, complex and consume more energy than open loop systems and incur additional costs and challenges for discharging residues ashore.

In addition to the wet scrubbers described above, there is the potential for dry scrubbers. Dry scrubbers use granulated limestone which combines with sulphur to form gypsum which can be disposed of on land. The sulphur becomes locked in chemically and will not disturb the environment any further; however, a large amount of granulated limestone needs to be stored on board and refreshed during the operation. Manufacturers of these systems assert that these systems can remove more than 99% of the SO_X (Couple Systems).

4.4.3 NO_X REDUCTION OPTIONS

Diesel engine manufacturers are attempting to control NO_X emissions as extensively as possible with internal, on-engine changes, rather than using exhaust after treatment. However, use of exhaust aftertreatment is often required because the ability to reduce NO_x solely though internal, on engine changes is limited. External after treatment will incur additional costs, space limitations, and extra consumables such as urea and power, for example.

When designing an engine, there are trade-offs between fuel efficiency and emissions. Reducing fuel consumption by increasing combustion temperatures results in lower CO_2 and PM emissions, but higher NO_X emissions. The ability to reduce NO_x emissions solely through optimised combustion in the engine, however, is limited (MAN Diesel and Turbo, n.d.). Therefore, additional on engine treatments such as fuel/water emulsions, humid air, and EGR are used. The first two methods introduce fresh water, either in liquid form or as a vapour, to the combustion process. The evaporation of the water and subsequent heat absorption results in an overall lower combustion temperature.

Exhaust Gas Recirculation (EGR) introduces recirculated exhaust gas into the charge air. By doing so, the oxygen content is reduced and the specific heat capacity of the intake gas mix is increased, which reduces the combustion temperature. Although this method has the potential to reduce the NO_X by 80%, the process carries risks because any sulphur in the fuel will cause fouling and increased corrosion of components.

Figure 74 quantifies the potential NO_X reductions from internal, on-engine changes as well as off-engine technology options including EGR, Selective Catalytic Reduction (SCR) (described below in Section 4.4.4), and DF engines. The “potential” values indicate expectations with further development of the current technology.

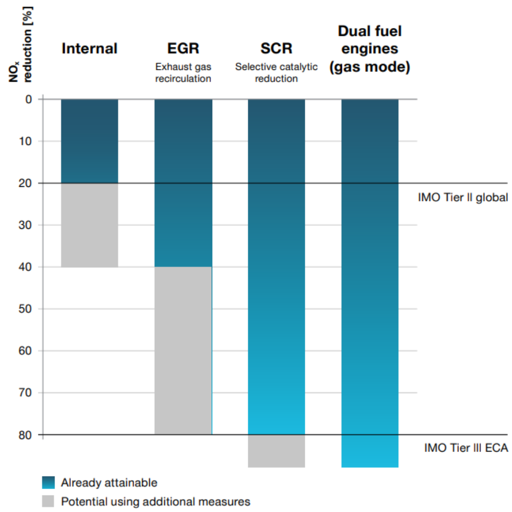


Figure 74: Effectiveness of NO_X reduction measures (MAN diesel and turbo)

4.4.4 SELECTIVE CATALYTIC REDUCTION (SCR)

To meet IMO Tier III NO_X, an emissions after-treatment system will be required for engines operating on the diesel cycle (any fuel). Assuming that low sulphur fuel is used to comply with SO_X restrictions, the primary method of meeting the Tier III NO_x requirements will be the use of SCRs. SCRs can achieve NO_X reduction rates up of to 90%. (MAN Energy Solutions)

The description below is taken from Wartsila's Environmental Product Guide (Wärtsilä Finland Oy, 2014):

> *The SCR system reduces the level of nitrogen oxide in the exhaust gas from the engine by means of catalyst elements and a reducing agent. In the process a reducing agent of an urea water solution is added to the exhaust gas stream. The water in the urea solution is evaporated as the solution is injected into the hot exhaust gas. The high temperature also induces thermal decomposition of the urea ($(NH_2)2CO$) into ammonia (NH_3) and CO_2:*
>
> $(NH_2)2CO + H_2O \rightarrow 2NH_3 + CO_2$
>
> *Exhaust gas NO_x emissions are thereafter transformed into molecular nitrogen (N_2) and water (H_2O), as they react with the ammonia at a catalytic surface:*
>
> $4NO + 4NH_3 + O_2 \rightarrow 4N_2 + 6H_2O$
>
> $6NO_2 + 8NH_3 \rightarrow 7N_2 + 12H_2O.$
>
> *The catalytic elements are located inside a metallic reactor structure located in the exhaust gas line. The end products of the reaction are pure nitrogen and water, i.e. major constituents of ambient air. No liquid or solid by-products are produced.*

The SCR equipment is comprised of a pump unit to transfer and regulate urea to the dosing unit located in the exhaust pipe. The dosing unit will also require compressed air to atomize the urea from the injector into the exhaust stream. The urea is injected into the reactor via a mixing pipe where the catalytic reduction takes place. The reactor houses the catalyst elements, soot blowing outlets, and NO_X monitoring equipment. The catalyst elements are rectangular shaped honeycomb structures made up of Vanadium pentoxide (V_2O_5) or metal substituted zeolites of different operating windows (ABS, 2015). The efficiency of the catalyst decreases with time, mainly due to thermal load and small amounts of catalyst poisons. When the catalytic activity has decreased too much, the catalyst must be changed. The lifetime of the catalyst depends on the fuel type and other operating conditions. The typical lifetime is 4 - 6 years. (Wärtsilä Finland Oy, 2014).

How to dispose of spent catalysts is a complex topic. In general, the material is considered hazardous and is returned to the manufacturer for disposal. If operators choose to dispose of the catalyst themselves they must confirm with the reception facility that they are able accept this type of hazardous waste. Part of the catalyst is documented in the MSDS but the coating on the catalyst (poisons and heavy metals) which are retained by the catalyst during operation is an unknown dependent of the initial fuel quality, and itself is often also hazardous.

As with SO_X scrubbers, adding an SCR system involves weight and volume impacts, and incurs running costs that include increased energy consumption, urea supply, and maintenance costs.

4.5 ENERGY EFFICIENCY IMPROVEMENTS

In addition to switching to a lower carbon fuel as discussed in section 4.3, other changes can be made to lower the EEDI or EEXI number for any particular vessel.

4.5.1 VESSEL DESIGN ENHANCEMENTS

There are a wide range of potential vessel design enhancements that can be utilized regardless of the fuel type used that will increase energy efficiency by reducing fuel consumption and GHG emissions. A majority of these vessel enhancements must be adopted when the vessel is designed and before ship construction. The main areas of vessel design enhancement are improvements in the hull form, propulsion efficiency and propulsion machinery. It is beyond the scope of this study to describe all of these potential improvements in detail; however, this report will provide an overview of the main methods of improving energy efficiency. For a more detailed study of energy efficiency enhancements please consult the Fourth IMO GHG Study 2020 (International Maritime Organization, 2020).

The main source of energy consumption onboard a ship is the energy required to propel the ship through the water. The energy is required to overcome the drag forces caused by friction of the water, air flowing over the hull and pressure drag caused by the generation of surface waves. By streamlining the ship's hull, superstructure and appendages it is possible to significantly reduce the drag of the ship and improve energy efficiency. This is not much different than what is done for other types of vehicles such as aircraft or land vehicles except that ships have to also deal with the additional drag caused by wave making. Optimization of the hull requires iterative improvement of the ship's form and extensive prototype testing either experimentally using towing tanks and wind tunnels or using computational fluid dynamics. Often proven hull forms from existing ships are further refined during each design iteration. The challenge with hull form optimization is that there are many conflicting design requirements that constrain the hull form optimization to non-optimal solutions. Typical design constraints are: flat straight sides for construction and docking; maximization of cargo capacity; draft, beam and length limits in order to access various ports and building cost constraints.

Ships are in a vast majority of cases propelled through the water with either propellers or in rare cases waterjets. Propellers or waterjets create a thrust force that propels the ship. The propulsive efficiency is the ratio of the thrust force to the energy required to generate that thrust. The propulsive efficiency of ships is typically between 50 and 65%. Any improvements in propulsive efficiency will result in a corresponding increase in energy efficiency. In recent times there has been considerable research and development of ways to improve propulsive efficiency. Some of the most significant ways to improve propulsive efficiency include: larger diameter and slower turning propellers; contra-rotating propellers; podded pulling propulsors; and ducted propellers. These measures can achieve from 5 to 15% improvements in propulsion efficiency.

Finally there are numerous ways to make the propulsion machinery more energy efficient. The main focus for improving propulsion machinery efficiency has been to lower the specific fuel consumption of diesel engines. The list of potential technologies is quite extensive and diesel suppliers have been making very good progress in achieving improved energy efficiency. A number of the technologies are described in other sections of this report. In addition to improving diesel efficiency, some other significant technologies for improving energy efficiency are: waste heat recovery, integrated diesel electric propulsion plants, and hybrid propulsion plants.

4.5.2 SLOW STEAMING

In addition to the ship design aspects, there are numerous operational practises that can be used to reduce energy consumption of ships. The most significant operational practice to reduce energy consumption is the reduction of vessel speed. Energy consumption for ship propulsion is roughly proportional to the cube of ship speed; therefore, relatively small reductions in ship speed can yield relatively large reductions in energy consumption. When the financial crisis hit in 2008 there were suddenly too many ships for the amount of cargo that needed to be carried worldwide. As a result, the freight rates dropped dramatically and ship owners were forced to reduce costs. Many owners ordered their vessels to operate at slower speeds to reduce fuel consumption. This trend continues today as freight rates continue to be low and slow steaming has proven to be very effective in reducing energy costs. A challenge with slow steaming is the fact that ships are being operated at speeds where their main engines are not fully loaded. Engines operate most efficiently at higher loads. While the overall effect of slow speed steaming is a reduction in vessel fuel consumption, the power being produced is not in the most efficient range of the engine. This causes higher energy consumption in terms of g/kwh and also results in increased diesel engine maintenance costs. Many new ships are now being designed to have lower ship service speeds to meet EEDI requirements and to reflect recent market forces. These designs ensure that their propulsion machinery is better matched to their operating speeds. This approach is not practical for some vessel types such as ferries and other short-sea operations, for which maintaining schedules is critical. However, for many existing ships compliance with EEXI and CII requirements is likely to involve lowering operating speeds.

Ships in the Arctic may operate at lower speeds due to the presence of ice; either as a safety measure or due to the need to break ice in order to proceed. In the latter case, power levels and fuel consumption will be high. To account for this, correction factors are built into the IMO EEDI, EEXI and CII formulae, but these are still becoming very challenging for icegoing vessels.

4.6 LEGISLATIVE ALTERNATIVES

Introduction of emission controlling legislation (or regulations) has sometimes been accompanied by measures that permit existing non-compliant infrastructure to remain in use, either temporarily or indefinitely. Such measures recognize that the gross quantity of emission reduction will be achieved if the average of the emissions of all sources is at or below the target level, i.e., that non-compliant emitters are offset by those that perform better than the standard.

Therefore, some regulators in industries have allowed for aggregation of emission performance. One such approach is market-based measures (MBM), an example of a MBM is where owners whose assets produce less emissions than they are allowed can sell their surplus emissions capacity to asset owners whose inventory would otherwise exceed their permitted ceiling. Such trading can be within or beyond a single industry or sector. MBM has been considered for the shipping sector, and there currently is ongoing discussion and proposals to establish MBM's.

It should be noted that there are a number of measures mandatory under the IMO regulatory framework to reduce GHGs. These measures include the EEDI addressed above, as well as the obligation for each ship to develop a Ship Energy Efficiency Management Plan (SEEMP).

5 ACCIDENTAL POLLUTION SCENARIOS

Arctic waters are perceived as being uniquely vulnerable to pollution not only from operational discharges, but also to accidental spills or deliberate dumping of pollutants from shipping and other sources. Canada has had Arctic-specific regulations to mitigate these risks since the early 1970s, with the Arctic Waters Pollution Prevention Act (AWPPA) and Arctic Shipping Pollution Prevention Regulations (ASPPR, now ASSPPR with the addition of "Safety and" to the original title). The ASSPPR now incorporate by reference the International Maritime Organization (IMO) Polar Code requirements under the SOLAS and MARPOL conventions, which apply construction standards and operational requirements to vessels in Arctic and Antarctic Sea areas.

Liquid hydrocarbons, whether fuel oils or cargoes, have always been the greatest concern for spills in all sea areas, due to their highly visible effects on the environment. The most recent international initiative has been the agreement to adopt a ban on both the use and carriage of heavy fuel oils in the Arctic. This will start to take effect in 2024 and will be fully implemented by 2029. The HFO ban will have the effect of forcing operators to use fuels other than HFO, but will not reduce the quantities of oil or the risk of a spill. The consequences of spills may be somewhat reduced due to the lower persistence of distillates compared to heavy fuels.

A pivot towards the use of LNG in the Arctic will affect the spill risk profile as discussed in Section 5.2.

5.1 LIQUID HYDROCARBONS

Oil spills into the sea are one of the most societally unacceptable forms of pollution.

Operational discharges, which can result from pumping out oily bilge water or residues from fuel and cargo tanks, now have to be treated to a point where they do not leave any visible sheen on the water. Canada has put considerable effort into monitoring and enforcing its regulations in this area due to public concerns.

Small accidental spills can result from fuelling and cargo transfer operations, and much larger ones from collisions or groundings. The environmental damage resulting from spills relates directly to the volume and type of oil involved. HFOs are persistent and can contain numerous toxic substances in addition to the hydrocarbons. Distillate fuels evaporate and weather somewhat more rapidly, but are also contain a range of toxic chemicals, notably polycyclic aromatic hydrocarbons (PAH) which can be water-soluble and therefore migrate within the water column rather than being confined to the surface layer[8]. Any spill of liquid HCs is likely to be fatal or highly

[8] Environmental Contaminants Encyclopedia, 1997

injurious to mammals, birds and other marine life which encounters the slick, either at sea or if and when it washes ashore.

Over the decades since the sub-Arctic Exxon Valdez spill, there has been considerable progress in adding safety measures to reduce the risk of accidents and to mitigate the consequences. For example, the use of double hull construction helps to reduce the risk of oil spills related to collision or grounding. Double hull construction started with large oil tankers for the cargo hold area and has been progressively extended. For new ships, even large fuel tanks now require double hull protection. A combination of design and operational measures has been successful in reducing the number and average size of spills, as shown for example in Figure 75 (International Tanker Owners Pollution Federation, n.d.). 700 tonnes (somewhat less than 1000 m^3) has been taken as the boundary between large and medium spills for many years. The figure does not include small spills of less than 7 tonnes, as it is generally considered that many of these are not properly reported. However, it is generally believed that the number of small spills has also dropped substantially in recent decades.

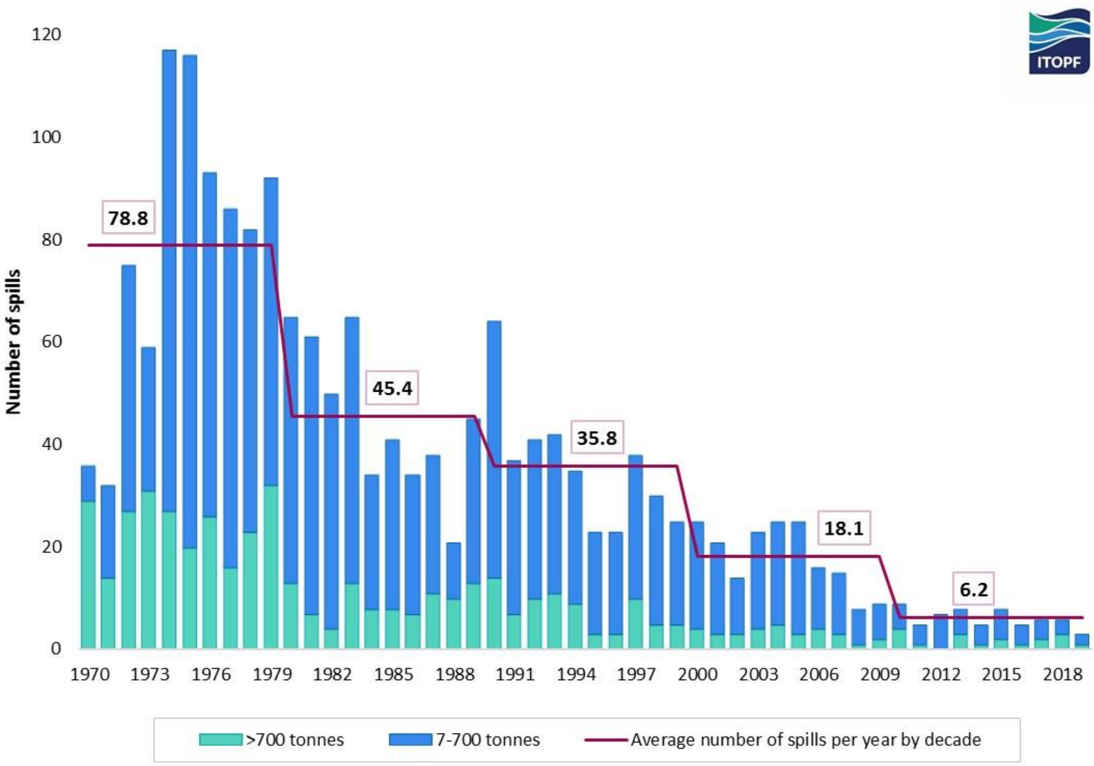


Figure 75: Accidental oil spills 1970 to 2019

Spills in the Canadian Arctic are not uncommon, but no major spills have occurred. A compendium of Arctic accident data was compiled for the Arctic Council's Protection of the Arctic Marine Environment (PAME) panel and reported in 2021. A copy of the background data for this was provided by TC to VARD to assist in earlier risk modelling work in support of the IMO work on the HFO ban. Figure 76 shows all incidents in Canadian waters over the period 2005 - 2017. Those shown as red dots all have the potential for pollutant release due to structural damage, as do the small number of additional incidents recorded as discharge/release of pollution. Actual spill volumes are not included in this data set.

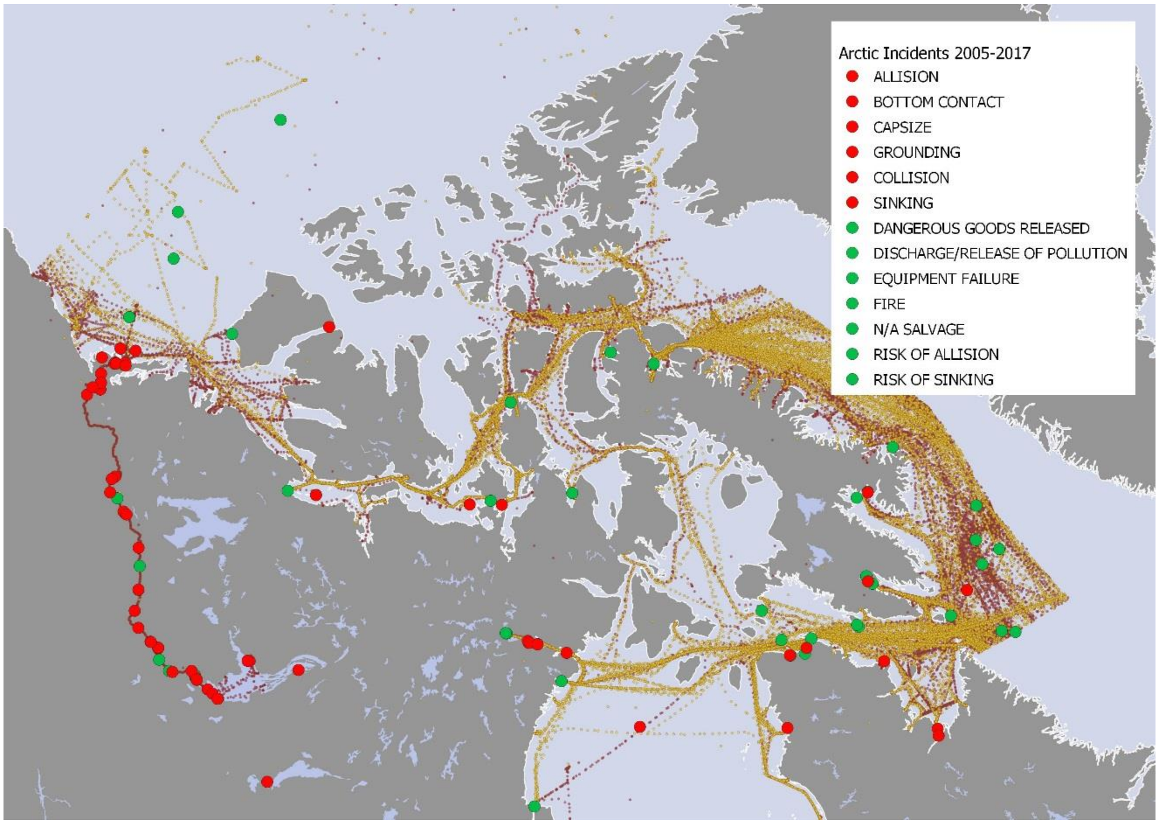


Figure 76: All Incidents in Canadian Arctic Waters from 2005 to 2017

VARD used this data to calculate an annual expected total spill volume of 3,600 litres of HFO, for vessels using HFO fuel and generating accidental spills due to rupturing fuel tanks. This average would be expected to include some years with no spills and a smaller number with a spill event. The grounding of the cruise ship, Akademic Ioffe in 2018 (after the PAME data set was compiled) is believed to have released up to 16,000 litres of intermediate fuel oil (diesel/HFO blend), the largest incident in recent years[9]. Little of this oil was traced after the incident.

Diesel spills were not estimated for this project, but the methodology would have generated a somewhat higher number based on the relative number and types of ships carrying diesel both as a fuel and as a cargo. It was not completely clear whether the data accounted for spills during cargo transfer ashore, but it can be assumed that these would give some further increase in overall spill volume.

This type of analysis, which is based on actual incidences of relatively minor incidents also does not fully account for the potential for a low probability but high consequence event, such as major damage to or the complete loss of an oil tanker (product tanker) while on an Arctic voyage. Such incidents occur globally once every few years. While some recent academic studies have tried to quantify the potential effects of large spills, Vard considers that the assumptions involved are of

[9] Transportation Safety Board of Canada Marine Investigation Report M18C0225

very dubious validity and the accident scenarios are not credible. Tanker safety requires constant vigilance, but current risk levels are societally tolerable.

5.2 LNG AND NATURAL GAS

The design standards for vessels using LNG as a fuel are stringent, with double-hulling in way of tanks of any size, and safety systems to provide rapid detection of any leaks or spills. Similar measures are applied to LNG carriers if these are used in the Arctic. The inherent likelihood of a damage event leading to fuel spill is therefore considerably smaller for an LNG ship than for a conventional equivalent, and the severity of the consequences will be very much less.

LNG is lighter than water, so in the event of a release, it will float on the surface of the water. As a cryogenic gas with a temperature of -161 °C, LNG will immediately start to vaporize after a release and disperse rapidly depending on the local wind conditions. LNG vapour typically appears as a visible white cloud, because its cold temperature condenses water vapour present in the atmosphere (even under Arctic conditions). If an ignition source is available, there is a risk that the natural gas at the edge of the vapour cloud could ignite and that a pool fire or an explosion could occur. The right conditions for a pool fire or explosion involve gas mixing with air in a ratio of 5-15%. Without the right mix of air, the LNG will not burn. Vapour cloud dispersion is highly influenced by atmospheric conditions, so potential hazards will be very site-specific. No clean-up effort will be required in the event of an LNG release (Foss Ph.D, 2003).

A major spill into water may dissolve some gas into the surface layers, and will also have some localized cooling effect. The most dramatic consequence could be rapid phase transitions – a form of flash evaporation that can produce noise and energy, but which is considered unlikely to lead to significant damage. (Sandia National Laboratories, 2004) If a pool fire or an explosion occurs, there will be more severe consequences but these are not considered to be primarily environmental, and are discussed in more detail under Chapter 7 .

As the gas itself is non-toxic, unless it is present in high enough concentrations and for long enough to cause asphyxiation, there is limited direct risk to either marine or airborne organisms. Methane emissions are undesirable from a GHG perspective, as discussed earlier in the report, however, occasional accidental spills are unlikely to represent a significant component of overall GHG emissions.

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.

6 UPSTREAM EMISSIONS MODELING

6.1 GENERAL APPROACH

Many analyses of the environmental benefits of alternative fuels, or other emission reduction options, consider only fuel combustion impacts. For this project, it was agreed that the analyses of GHGs in particular should consider the full lifecycle impacts, encompassing all aspects of the fuel supply from source (the well) through processing and distribution to the eventual use on board the ship.

Various different sources for fuels we analyzed as presented in Table 35 below. Since it is not realistic to account for every GHG emitted during the extraction, processing and transportation of all fuels, a CO_2-eq value is presented that accounts for all GHGs emitted.

Table 35: Upstream Emissions

Upstream Emissions	g CO_2eq/GJ (LHV)	Source
HFO - Canada	18,800	Sphera 2021 *
MGO - Canada	17,900	Sphera 2021*
VLSFO - Canada	18,700	Sphera 2021*
HFO - Europe	12,900	Sphera 2021*
MGO - Europe	13,300	Sphera 2021*
VLSFO - Europe	14,100	Sphera 2021*
LNG - Europe	17,900	Sphera 2021*
LNG - Canada	11,968	GHGenius 2016**

*Upstream GHG emissions were calculated with Sphera Environmental Impact Calculation software

** Upstream GHG emissions were calculated with GHGenius lifecycle analysis model software

The fuel source for each vessel case study has been selected based on the geographical route, ports of call and fuel availability. The upstream emissions can be calculated based upon fuel consumption and fuel source for each vessel. These upstream emissions are added to the ship emissions to provide a complete lifecycle emissions estimate (typically on an annual basis). The emissions presented in this chapter are reflective of voyages that navigate the Arctic region. Emissions generated from voyages not navigating the Arctic region are not presented in this chapter.

As detailed further in Section 9.1.2, the full lifecycle emissions of a marine fuel source is often described as Well-Wake (WTW). These emissions combine the Well-Tank emissions for a fuel source (noted above in Table 35)and the Tank-Wake (TTW) emissions. The TTW emissions account for all the emissions that come from using a fuel within a marine engine.

7 EMISSION MODELLING METHODOLOGY & KEY ASSUMPTIONS

The modelling of lifecycle emissions for each of the case study vessels included CO_2, CO_2-E, NO_X, SO_X, PM, CH_4 and BC for baseline scenarios and LNG as a marine fuel scenario. The basis for emissions modeling is the Fourth IMO GHG 2020 Study. The emissions are a function of the type of fuel consumed by the vessel, operating profile and of the engine type and size. The modelling approach used normalized emissions for various combinations using the metric of grams of emission per kilowatt hour of engine power supplied; g/kWh.

While the IMO NO_X limits are imposed on only new builds after the date they take effect, the IMO SO_X limits are applicable to both new and existing vessels. There are different SO_X limits depending on whether the vessel is operating within an ECA zone or outside. IMO's sulphur restrictions when operating within an ECA are 0.1%. The resulting gram per kilowatt hour limit for SO_X which must be achieved either by using low sulphur fuels or using after treatment is 0.42 g/kWh while operating in an ECA. However, outside of an ECA the sulphur limit is 0.5%.

Arctic vessels preforming sealifts are exempt from the ECA restrictions even when transiting through an ECA. However, discussions with operators of Sealift vessels confirms that many of these now operate on MDO by corporate policy. Up until the Arctic HFO ban takes full effect, most other commercial vessels will burn the most economical fuel available, very likely HFO for large cargo vessels. No fuel switching (HFO to MDO or LNG) when entering or exiting ECAs, is considered in the vessel route analysis.

For this analysis it has been assumed that, for the LNG scenarios, vessels would be operating exclusively in gas mode, regardless of whether they are within or outside an ECA. This results in next to no sulphur emissions. LNG availability is a key factor impacting the validity of this assumption. If the vessel is travelling long distances it may not be technically or economically feasible to fit an LNG tank large enough to cover the whole voyage, especially until LNG bunkering becomes more widely available. Therefore, vessels may remain with crude oil-based fuels when operating outside of ECAs (including Arctic waters) and switch to LNG when necessary to meet emission restrictions. Several economic factors will play into the fuel usage decision.

For each case the emissions were calculated based on load, voyage and fuel. For the purposes of this analysis, the specific emission data shown in Table 36 can be used as a sample. This data is not representative of every vessel case study as emissions are to a certain extent a function of the operating load (% of MCR) of an engine. This is representative of sample engines operating at various loads.

Table 36: Emissions by engine type

	HFO	ULSD	LNG		Units
Engine Type	Slow Speed	Medium Speed	Medium Speed DF	Slow Speed DF	
CO_2	566	583	446	406	g /kWh
NO_X (Tier II)	14.9	10.9	1.3	14.9	g /kWh
SO_X	1.777	0.053	0.003	0.014	g /kWh
PM	0.83	0.18	0.02	0.01	g /kWh
CH_4	0.01	0.01	5.50	0.20	g /kWh
BC	0.038	0.008	0.003	0.002	g /kWh

The importance of methane slip (essentially "CH_4" in Table 36) can be seen when comparing the CH_4 values for the different engines technologies and fuels. The quantities of methane are multiplied by the global warming factor of 30 when converted to CO_2-E.

As detailed in Table 36, use of LNG as a fuel at the ship level results in reductions in CO_2, NO_X (when considering Otto cycle engines), PM and BC. A reduction in the amount of SO_X is also achieved, especially in the cases where higher sulphur content fuels are used. Analysis of the seven case studies has provided a quantification of these reductions over the life cycle of the vessels. Section 8 describes each of the cases and the results in greater detail.

The basis for emissions modeling is the Fourth IMO GHG 2020 Study – Chapter 2. The study details the procedure for analyzing and quantifying various emissions for different engine types, loads and fuels. However, given the rapid development in some areas of emissions, particularly CH_4 or methane slip, the latest engine manufacturer methane slip figures may be lower than the IMO study figures. It is expected that methane slip will continue to be reduced over time and the methane slip figures quoted in this report may be quickly outdated when compared to the latest engine technologies.

8 VESSEL CASE STUDIES

Arctic marine activity is set to increase in the future as the ice sheets continue to melt, paving a way for easier transiting of Arctic waters. While the Northwest Passage through Canadian waters is not expected to become a popular transit route due to its complexity and navigational challenges, growth in economic activity and in local populations will lead to increases in destination traffic for resource development and for community supply.

Seven vessel case studies were selected as a representative cross section of ships operating within or making port calls on Canada's Arctic Coast. An overall summary of the cases analysed is provided in Table 37 below. For a complete description of each vessel including a route profile, refer to Chapter 3.

Table 37: Summary of vessel cases modelled

No	Vessel	Power (kW)	Fuel Option 1	Option 1 Engine	Fuel Option 2	Option 2 Engine	Fuel Option 3 Engine (LNG only)
1	CCG Icebreaker	20,000	-	-	ULSD	Medium Speed Diesel 4 Stroke	Medium Speed Otto 4 Stroke Dual Fuel
2	General Cargo	6,000	-	-	MDO	Slow Speed Diesel 2 Stroke	Slow Speed Diesel 2 Stroke Dual Fuel
3	Tanker	5,500	-	-	MDO	Slow Speed Diesel 2 Stroke	Slow Speed Diesel 2 Stroke Dual Fuel
4	Cruise Ship	11,200	-	-	MDO	Medium Speed Diesel 4 Stroke	Medium Speed Otto 4 Stroke Dual Fuel
5	LNG Carrier	8,000	-	-	-	-	Medium Speed Otto 4 Stroke Dual Fuel
6	I/B Bulker	22,000	HFO	Slow Speed Diesel 2 Stroke	MDO	Slow Speed Diesel 2 Stroke	Slow Speed Diesel 2 Stroke Dual Fuel
7	Icegoing Bulker	14,500	HFO	Slow Speed Diesel 2 Stroke	MDO	Slow Speed Diesel 2 Stroke	Slow Speed Diesel 2 Stroke Dual Fuel

The case studies were analysed to determine the CO_2, CO_2–E, SO_X, NO_X, HC, BC, and PM produced on an annual basis for voyages navigating the Arctic region. The results presented are intended to be generally reflective of the performance that is available from different prime mover types and ship applications, but should be taken as indicative, rather than precise values. For specific projects, additional engineering effort would be needed to develop true "predictions" of fuel consumption, emissions, and other aspects of comparative performance.

For each vessel case study, three fuel options were analyzed where applicable. The three fuel options are summarized below in Table 38. With respect to upstream emissions described in Section 6, all case studies use Canadian fuel sources, except for Case #7 which fuels in Europe.

Table 38: Fuel Options

Fuel Case	Typical Fuels
Heavy Fuel Oils	HFO
Diesels	ULSD, MDO
LNG	LNG, MDO (Pilot)

Not all vessel case studies use each type of fuel. As discussed above some vessel case studies for example do not use HFO – even prior to the HFO ban.

9 ANALYSIS AND RESULTS

Emission results for each of the case studies are presented below. Most of the results are provided for the ship itself which is of importance when considering regulatory emission compliance for a vessel. The total GHG emissions, i.e., CO_2-E, section 9.1.7 also provides results that combine the downstream and upstream components which present the overall potential emission aspects of LNG as a marine fuel.

9.1.1 SHIP LEVEL CO_2 EMISSIONS

Figure 77 and Table 39 provides an overview of the CO_2 results. The 21-29% reduction in CO_2 emissions in the LNG (Fuel Option 3) options is primarily due to the lower carbon content of the fuel.

Table 39: CO_2 emissions (Baseline fuel is 100%)

	Fuel Option	Case A1	Case A2	Case A3	Case A4	Case A5	Case A6	Case A7
		CCG Icebreaker	General Cargo	Tanker	Cruise Ship	LNG Carrier	I/B Bulker	Icegoing Bulker
CO2	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%	71.5%	71.3%

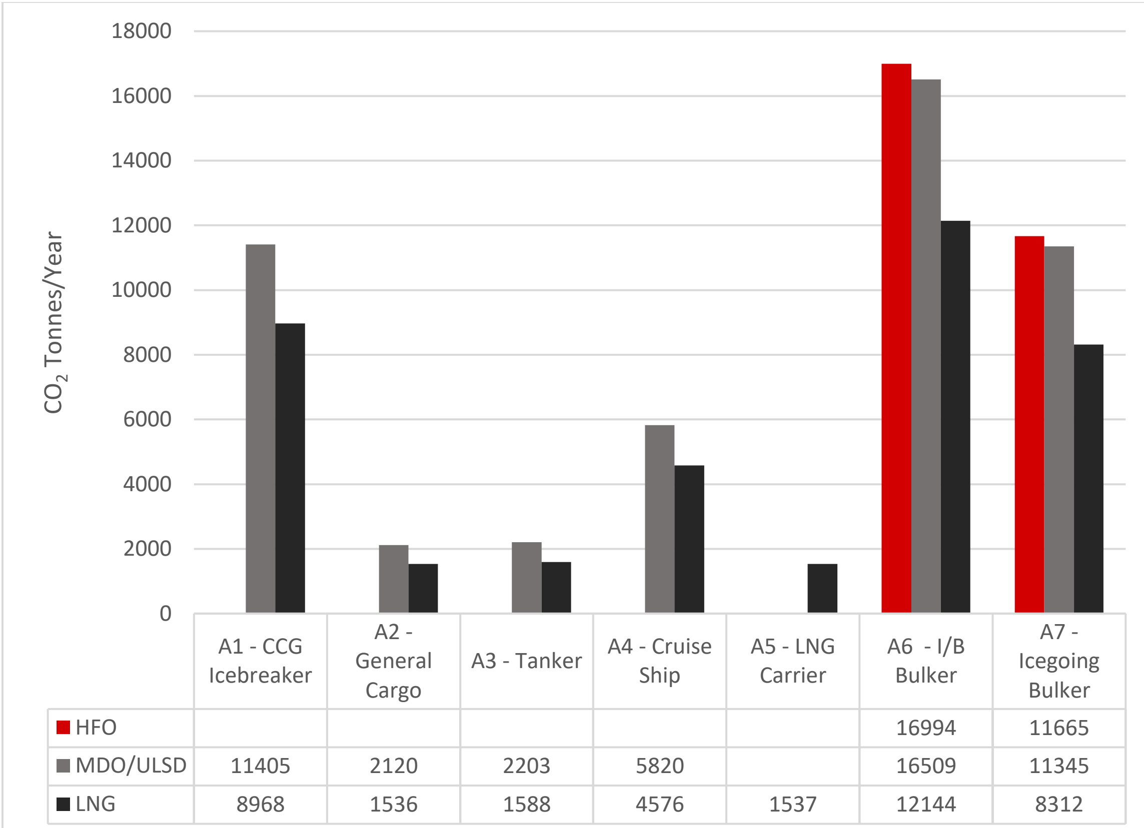


Figure 77: CO_2 emissions

9.1.2 SHIP LEVEL GREENHOUSE GAS PRODUCTION

The reduction in GHGs at the ship level for each of the cases is shown in Table 40 and Figure 78. For some LNG cases the reductions are significantly lower than for CO_2 alone (see Figure 77) due principally to the contribution of methane slip during the combustion process. In some cases they are slightly higher due to the reduction in black carbon. This analysis includes CO_2, CH_4 and BC but does not include N_2O which is a minor component of vessel emissions. The GHG emission reductions are up to 31% depending on the engine technology and type. However in some scenarios switching to LNG can actually increase the GHG emissions. This can be the case if Otto cycle engines are used extensively at low engine loads, which lead to high methane slip. As shown previously in Table 39, the vessel case studies operating on an LNG Otto Cycle are A1, A4 and A5. In principle, all of these could use diesel cycle engines, which would reduce their GHG's.

Table 40: CO_2-E emissions (Baseline fuel is 100%)

	Fuel Option	Case A1	Case A2	Case A3	Case A4	Case A5	Case A6	Case A7
		CCG Icebreaker	General Cargo	Tanker	Cruise Ship	LNG Carrier	I/B Bulker	Icegoing Bulker
CO2-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%

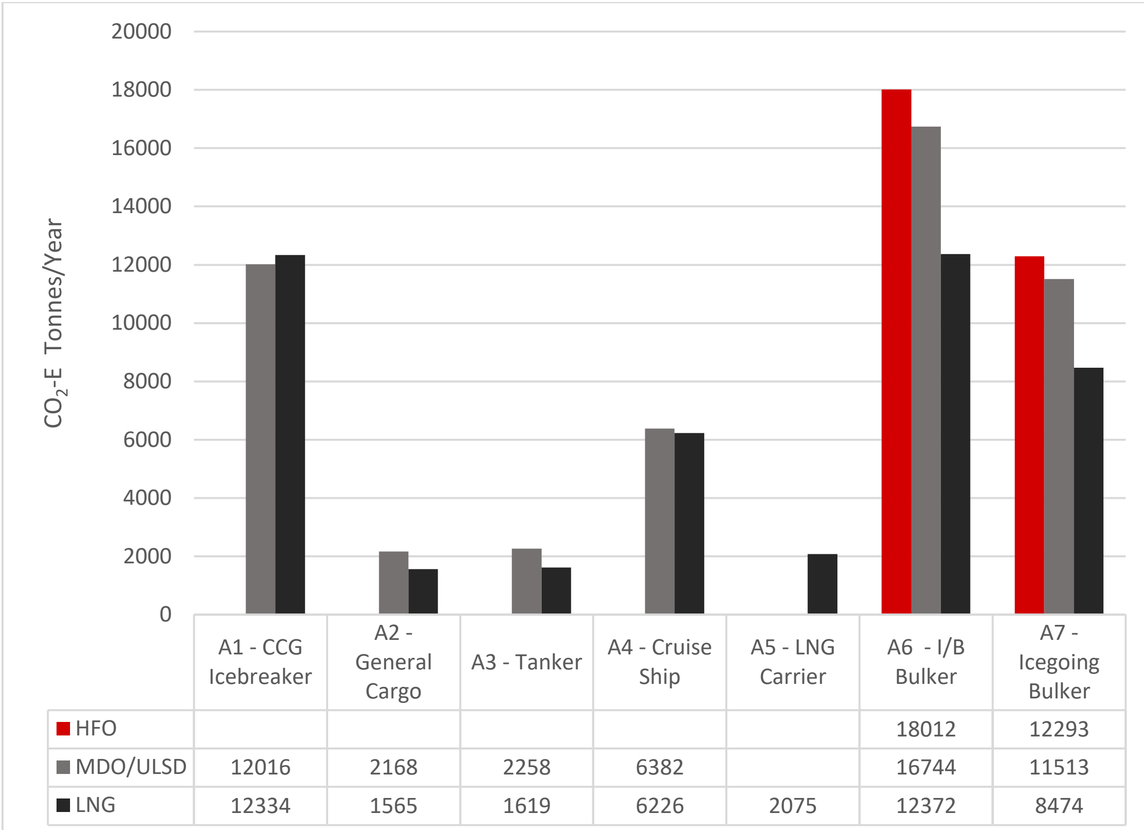


Figure 78: CO_2-E emissions

9.1.3 SHIP LEVEL NO_X EMISSIONS

The results of this analysis shown below in Table 41 and Figure 79 indicate a limited reduction in the amount of NO_X produced by LNG vessels compared to their liquid fuel counterparts. The amount of reduction is dependent on the engine cycle, either Otto or Diesel. This reduction assumes the use of after- treatment for the fuel oil baseline cases and LNG Diesel cycle cases which results in the maximum possible Tier II NO_X emissions for these cases. LNG engines operating on the Diesel cycle will require after- treatment and will have similar NO_X emissions compared to their fuel oil counterparts. The only LNG engines operating on the Otto cycle are vessel case studies A1, A4 and A5, these cases will have significantly lower NO_X emissions due to the lower temperatures in the combustion chamber.

Table 41: NO_X emissions (Baseline fuel is 100%)

	Fuel Option	Case A1	Case A2	Case A3	Case A4	Case A5	Case A6	Case A7
		CCG Icebreaker	General Cargo	Tanker	Cruise Ship	LNG Carrier	I/B Bulker	Icegoing Bulker
NOX	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%	100.0%

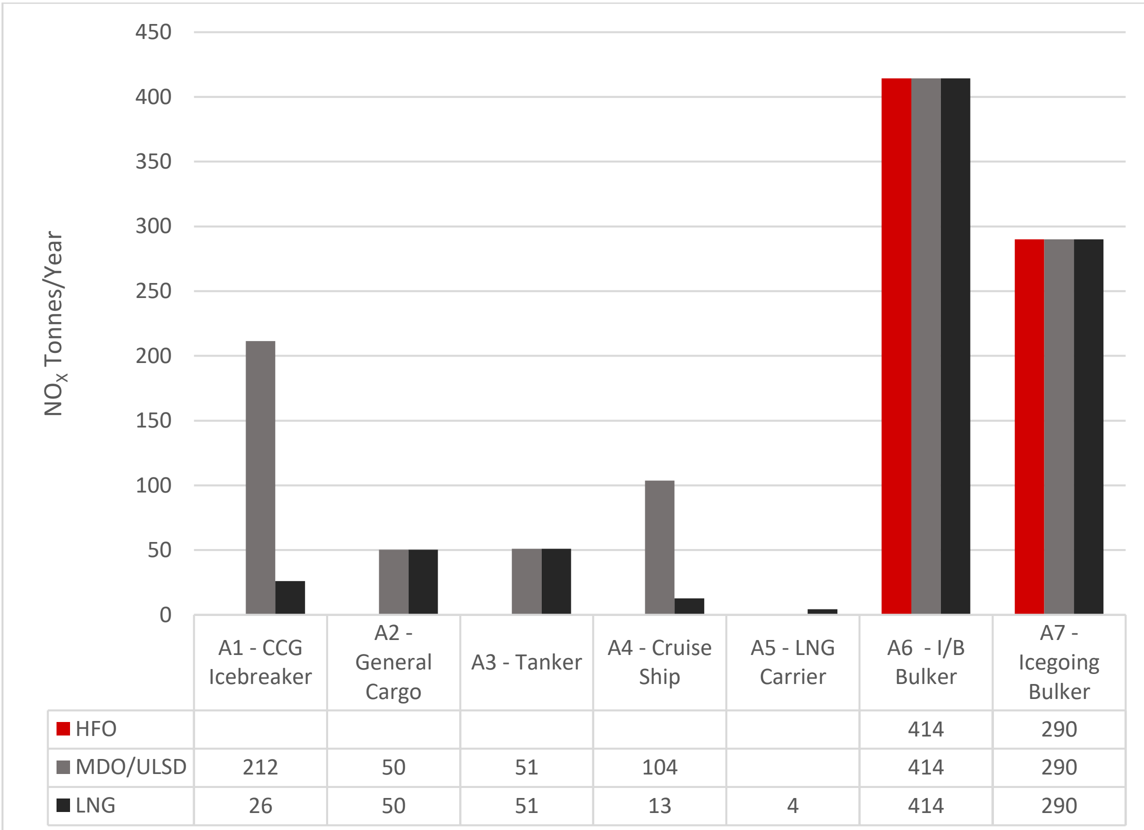


Figure 79: NO_X emissions

9.1.4 SHIP LEVEL SO_X EMISSIONS

The amount of SO_X produced is directly related to the amount of sulphur present in the fuel being burnt. The results shown in Table 42 and Figure 80 indicate that vessels such as the CCG Ice Breaker primarily consuming ULSD already produce very low levels of SO_X emissions. The reduction in SO_X production for vessels operating on HFO is approximately 99% when using LNG as shown in Figure 80 and Table 42.

Table 42: SO_X emissions (Baseline fuel is 100%)

	Fuel Option	Case A1	Case A2	Case A3	Case A4	Case A5	Case A6	Case A7
		CCG Icebreaker	General Cargo	Tanker	Cruise Ship	LNG Carrier	I/B Bulker	Icegoing Bulker
SOX	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%

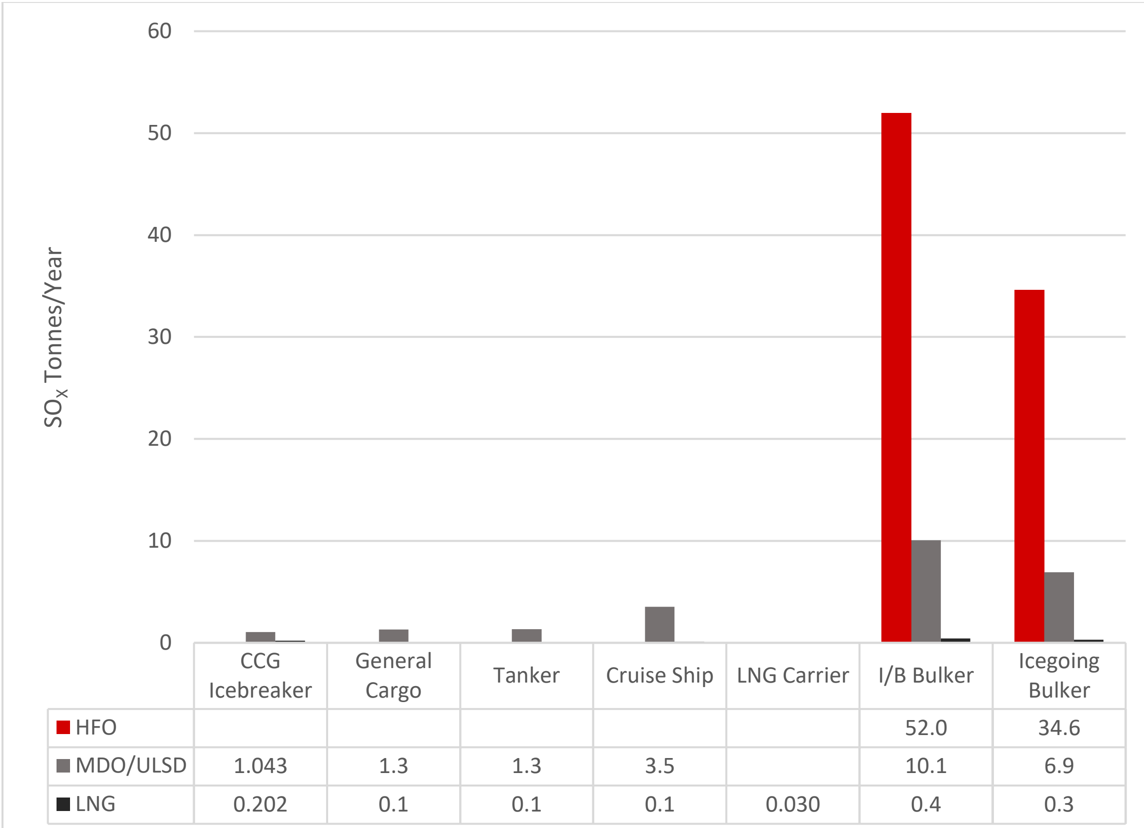


Figure 80: SO_X emissions

9.1.5 PM EMISSIONS

As discussed in Section 3.4, using LNG results in significant PM reductions. Table 43 and Figure 81 shows that PM emissions are reduced by approximately 88-99% when comparing HFO/ULSD to LNG. This is primarily due to the lower sulphur in LNG fuel.

Table 43: PM emissions (Baseline fuel is 100%)

	Fuel Option	Case A1	Case A2	Case A3	Case A4	Case A5	Case A6	Case A7
		CCG Icebreaker	General Cargo	Tanker	Cruise Ship	LNG Carrier	I/B Bulker	Icegoing Bulker
PM	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%

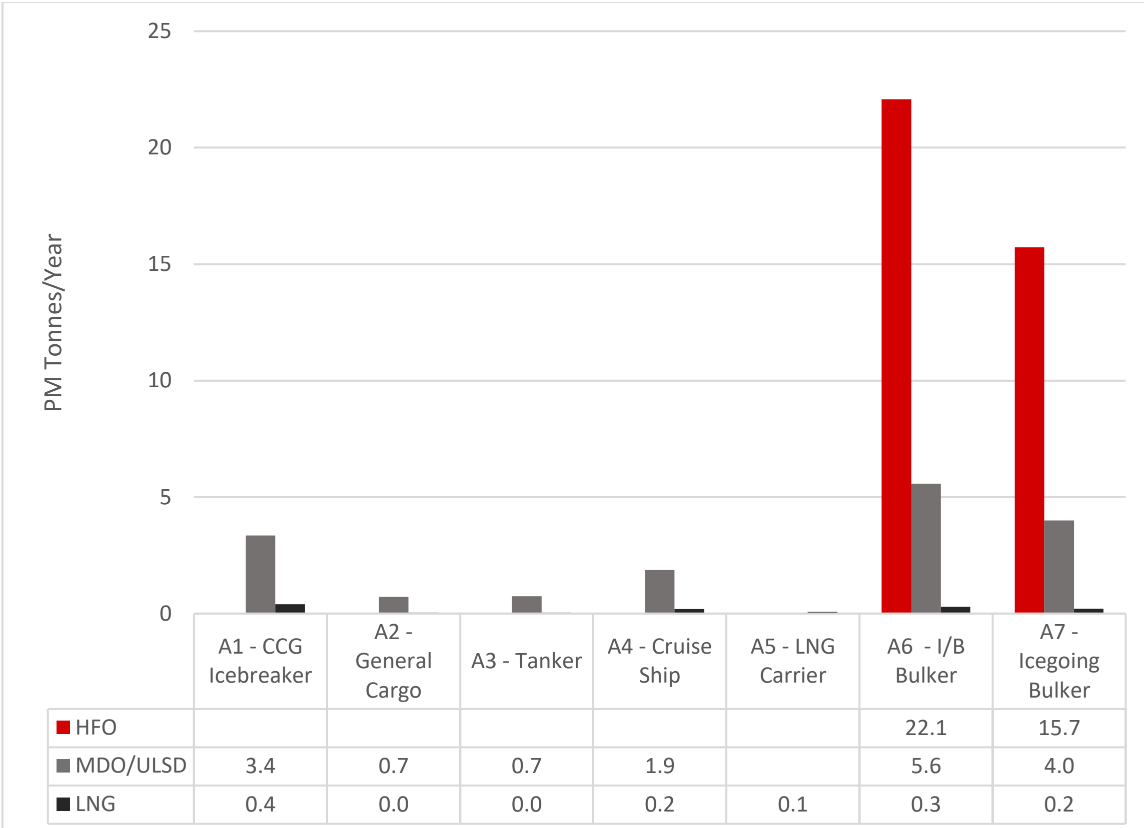


Figure 81: PM emissions

9.1.6 BC EMISSIONS

As discussed in Section 3.5, black carbon varies as a function of engine type and fuel. The use of LNG fuelled engines significantly reduces the emitted black carbon as shown in Table 44 and Figure 82 below. By switching to LNG fuelled engines, black carbon can be reduced by approximately 85-95% when compared to HFO/MDO fuelled engines.

Table 44: BC emissions (Baseline fuel is 100%)

	Fuel Option	Case A1	Case A2	Case A3	Case A4	Case A5	Case A6	Case A7
		CCG Icebreaker	General Cargo	Tanker	Cruise Ship	LNG Carrier	I/B Bulker	Icegoing Bulker
BC	HFO	-	-	-	-	-	100.0%	100.0%
	MDO/ULSD	100.0%	100.0%	100.0%	100.0%	-	22.4%	26.0%
	LNG	9.0%	14.5%	12.9%	4.8%	100.0%	5.2%	6.0%

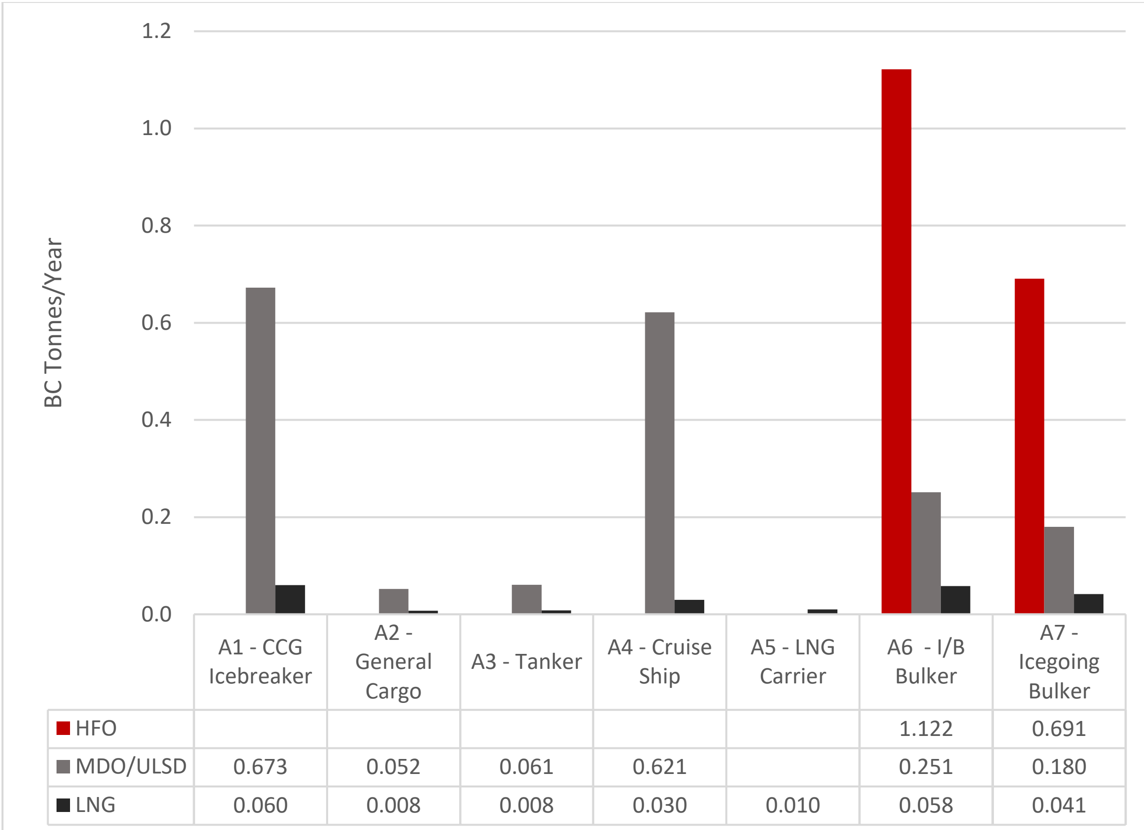


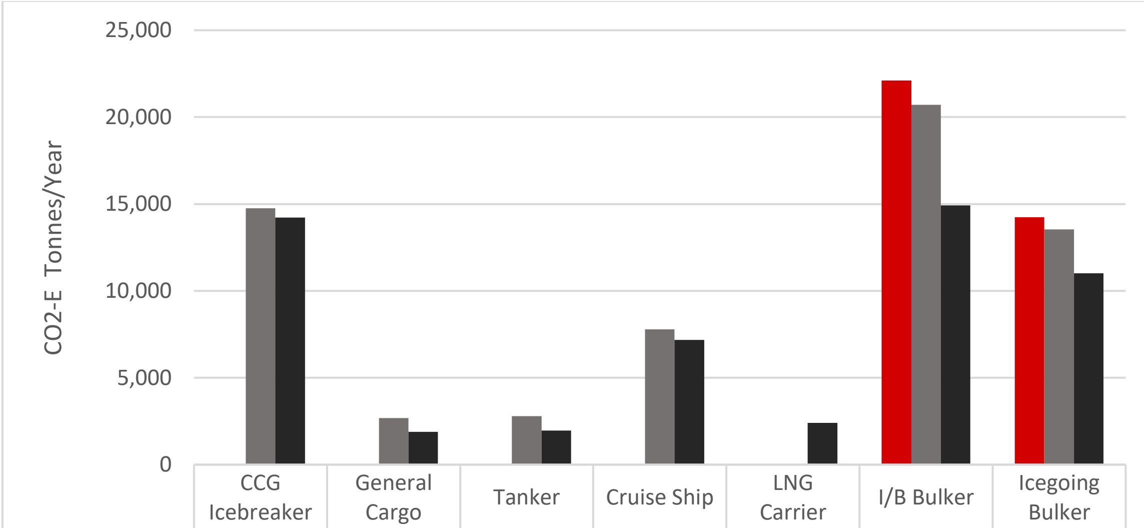
Figure 82: BC emissions

9.1.7 COMBINED UPSTREAM AND DOWNSTREAM GHG PRODUCTION

Using the fuel production supply chain GHG emissions data in Section 6 coupled with calculated emissions from ship engines based on IMO data and manufacturer's data, the amount of total GHG or CO_2-E produced was calculated for each of the cases and the results are shown in Table 45 and Figure 83. The results provide an overall indication of the impacts of using LNG when compared to petroleum fuels, not just at the ship level but encompassing the complete fuel supply chain and end use. The results show a 4-32% reduction in GHGs depending on case study specifics.

Table 45: CO2-E emissions - full lifecycle basis (Baseline fuel is 100%)

	Fuel Option	Case A1	Case A2	Case A3	Case A4	Case A5	Case A6	Case A7
		CCG Icebreaker	General Cargo	Tanker	Cruise Ship	LNG Carrier	I/B Bulker	Icegoing Bulker
CO2-E w/ Upstream	HFO	-	-	-	-	-	100.0%	100.0%
	MDO/ULSD	100.0%	100.0%	100.0%	100.0%	-	93.6%	95.1%
	LNG	96.4%	70.6%	70.1%	92.3%	100.0%	67.5%	77.4%



	CCG Icebreaker	General Cargo	Tanker	Cruise Ship	LNG Carrier	I/B Bulker	Icegoing Bulker
HFO						22,114	14,235
MDO/ULSD	14,754	2,677	2,787	7,779		20,708	13,537
LNG	14,215	1,888	1,953	7,180	2,397	14,927	11,016

Figure 83: CO_2-E emissions - full lifecycle basis

10 CONCLUSIONS

LNG is the cleanest burning fossil fuel. It offers a means of reducing emissions to meet current and pending environmental regulations and this is potentially a major factor which could drive the growth of natural gas as a marine fuel. The environmental benefits can include a reduction in CO_2, CO_2-E, SO_X, PM, BC, and NO_X emissions with the amount emissions reduced depending on the engine technology selected and the source of the LNG.

The degree of emission reduction also depends on the baseline oil-based fuel used for comparison. For CCG vessels such as ice breakers which already operate on ULSD fuels, the most significant improvements are in a reduction in CO_2, NO_X and BC Other bulker/tanker vessels which operate primarily on higher Sulphur content fuels oils show a significant reduction in SO_X emissions in addition to decreases in CO_2 emissions. The degree in reduction of NO_X emissions will depend on the type of LNG engine technology used for comparison. In the case of the medium speed LNG-fuelled engines operating on the Otto cycle, the NO_X reduction is significant and already meets IMO Tier III requirements with no additional after-treatment required. The slow speed LNG engines on the market operate on the diesel cycle and the reduction in NO_X is non-existent.

LNG spills and other accidental releases of LNG are highly undesirable and do represent a safety risk, however from an environmental standpoint they are far more benign than either HFO or diesel oil spills. Due to LNG's extremely low boiling point, any spill to the environment would quickly dissipate to the atmosphere leaving minimal impact on the local environment.

Until LNG availability, relative cost and emission requirements lead to widespread adoption by the Arctic fleet, the use of LNG will have modest though positive effects on total emissions given that the majority of Arctic marine fuel is HFO/MDO.

CHAPTER 5 INFRASTRUCTURE

1 INTRODUCTION

This chapter presents the outcome of the Infrastructure Options study (Task 4) of the Marine Natural Gas (NG) Supply Chain project, covering the Canadian Arctic.

This chapter is intended to provide information on infrastructure availability and requirements for the supply and distribution of LNG to marine applications. Supplementary information on energy consumption on land that is currently supplied by ship is also provided.

The scenarios analyzed in the Chapters 3 and 4 were based on the assumptions of ships refueling in Quebec or in Europe. No in-region refueling was considered as part of these analyses. This report, now attempts to supplement this analysis with how an Arctic supply of LNG could be created by considering two scenarios, the first importing LNG into the region, and the second scenario involving LNG produced in the Arctic, discussed further in Section 5. In order to understand the opportunities to supply LNG in the Arctic, this report also consolidates, and updates work completed for the Marine Natural Gas (NG) Supply Chain project, covering the East Coast and Great Lakes/St. Lawrence regions of Canada. Because natural gas consumption in the region is so limited, Arctic energy demands currently served by diesel fuel that could potentially be satisfied with natural gas are also summarised.

The chapter addresses:

- Drivers for the adoption of Natural Gas fuel in the Arctic;
- Overview of the Canadian Natural Gas supply and demand situation and Arctic energy use;
- Review of relevant existing and planned natural gas and LNG infrastructure in Canada and the Arctic;
- Development of a marine LNG supply infrastructure for the Arctic including estimated costs.

The task team has drawn on materials provided by a number of the project participants and including NG suppliers, distributors, energy utilities, port representatives, and regulatory agencies.

2 DRIVERS FOR THE ADOPTION OF NATURAL GAS FUEL IN THE ARCTIC

Natural gas is being considered as a candidate to replace some or all of the current diesel and heavy fuel oil (HFO) used in the Canadian Arctic. The drivers for this adoption are economic, environmental, and socio-political.

The economic driver comes from the fact that natural gas in the form of liquefied natural gas (LNG) provides a potential cost saving when compared to diesel fuel. The Task 2 report developed the business case for natural gas fuel for certain types of vessels in use in the Canadian Arctic.

Environmental drivers for the adoption of natural gas fuel in the arctic are:

- Reducing or eliminating the risk of oil spills in the Arctic – unlike conventional petroleum-based fuels, LNG evaporates when spilled.

- Reducing black carbon emissions from shipping and industry in the Arctic – burning LNG creates minimal particulate matter emissions and therefore less black carbon
- Eliminating Sulphur emissions and the wash water emissions from scrubbers – LNG contains little or no Sulphur.
- Reducing greenhouse gas emissions from shipping – LNG emits less CO2 but is still a fossil fuel and emits methane, a potent GHG when released unburned.

In addition, natural gas has the potential for reducing the health and pollution risk to Arctic communities, their food supplies and their livelihoods from shipping and industrial and local power generation by reducing reliance on diesel and its associated harmful pollution and replacing it with cleaner alternatives.

Further socio-political drivers to consider natural gas include mechanisms for meeting the 2050 net zero greening of government target. Opportunities for government vessels operating in the Arctic to contribute to achieving these targets by using alternative fuels including LNG (from both fossil and renewable sources) are being considered.

3 CANADIAN NATURAL GAS SUPPLY AND DEMAND

Canada is the world's fourth largest producer of natural gas according to the 2020-2021 Natural Resources Canada Energy Fact Book. In 2019, Alberta supplied 71% of Canada's domestic gas production, British Columbia provided 27% and Saskatchewan 2%.

Canada's natural gas pipeline network does not extend into the Arctic. The only gas production in the Canadian Arctic is in Northwest Territories. According to Canada Energy Regulator data, gas production in Northwest Territories in 2018 was 1.4 million cubic feet per day (MMcf/d). This represented less than 0.1% of total Canadian natural gas production. Gas is produced near the town of Norman Wells as a by-product of oil production at the Imperial Oil facility. The gas is used to generate electricity for the town of Norman Wells.

The town of Inuvik in Northwest Territories is supplied with natural gas in the form of LNG delivered by tanker truck from B.C. The local Ikhil field currently only provides back-up natural gas supply for Inuvik, but the Inuvialuit Regional Corporation (IRC) is planning to expand natural gas production and is exploring the possibility of establishing a small Liquefied Natural Gas (LNG) plant locally. The project is described in more detail in Section 4 below.

3.1 ENERGY USE IN THE CANADIAN ARCTIC

Arctic communities are heavily reliant on petroleum products for heating and electricity generation. According to the Government of Nunavut (Nunavut Petroleum Product Division, 2018), the territory consumed more than 200 million litres of petroleum fuel in 2017, 47.7 million litres for electricity generation and 71.5 million litres for heating. The Northwest Territories does have some hydro electric generating capacity; however 30 communities are still fully reliant on diesel generators for their electricity. The result is that electricity prices in Nunavut and Northwest Territories are more than double the national average, as shown in Figure 84.

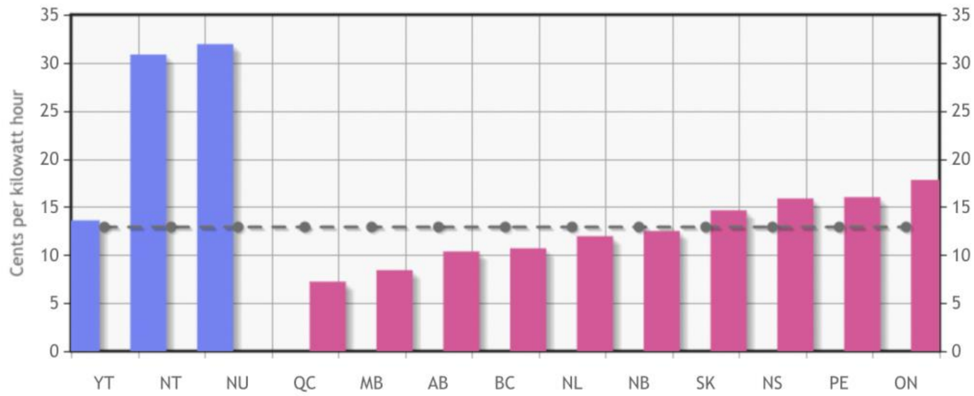


Figure 84: Representative Territorial and Provincial electricity prices in 2016 (Canada Energy Regulator, 2017)

Using data from the Natural Resources Canada Remote Communities Energy Database (RCED), a more comprehensive picture of diesel fuel consumption used for electricity generation in the Canadian Arctic can be constructed. Electricity generation for communities and industrial sites data is downloadable for 2017. The database provides annual electricity generated in MWh per year for communities and industrial sites. By filtering the data for locations north of 60 degrees latitude or only accessible through Arctic waters (for example on the shore of Hudson's Bay), a data set of Arctic remote communities and their energy consumption can be created. Using the following fuel consumption factor, the energy can be converted info fuel demand:

Generator fuel consumption: 0.2685 L/kWh (Generator Source, 2022)

Diesel fuel consumption figures were validated by comparing Nunavut diesel imports for electricity generation (see above) to the total calculated diesel consumption for settlements in Nunavut and were found to be within 5%. Where annual energy use for industrial users is not provided by the Natural Resources Canada database (Government of Canada, n.d.), data from company reports can be substituted to complete the picture. Data from the following mine sites was included:

QC

Raglan Mine

Nunavik Nickel Mine

NU

Mary River Iron Ore Project

Meadowbank Gold Mine

Hope Bay Gold Mine

NT

Diavik Diamond Mine

Gahcho Kué Mine

Ekati Diamond Mine

Prairie Creek Mine

NL

Voisey's Bay Mine

The data is further categorised by communities with coastal access so that fuel can be delivered directly by ship and those that are further inland. Total calculated Arctic diesel consumption in liters is summarised in Table 46

Table 46: Arctic diesel consumption for energy generation 2017 in liters

	Inland	Coastal Access	Grand Total
Mining	**49,291,940**	**174,164,426**	**223,456,366**
QC		75,126,072	75,126,072
NU		71,790,837	71,790,837
NT	49,291,940		49,291,940
NL		27,247,517	27,247,517
Settlements	**12,924,042**	**97,392,682**	**110,316,724**
NU		50,235,873	50,235,873
QC		24,890,722	24,890,722
NL		14,761,417	14,761,417
NT	7,332,311	4,335,069	11,667,380
YT	5,591,731		5,591,731
MB		2,346,271	2,346,271
ON		823,330	823,330
Grand Total	**62,215,982**	**271,557,108**	**333,773,090**

Using the following conversion factors, greenhouse gas emissions and black carbon emissions from Arctic mines and settlements with coastal access can be calculated.

Carbon Dioxide Emissions

CO_2 intensity of diesel: 2.788 kg CO_2/L

Black Carbon Emissions

Emissions standard: US EPA Tier II

PM2.5 emissions: 0.2 g/kWh (Tier II limits)

Generator efficiency: 90% (assumption)

Black Carbon to PM2.5 ratio: 0.77124 kg/kg (US EPA)

Black Carbon Emissions Factor: 0.1714 g/kWh electricity (calculated)

The results are summarized in Table 47:

Table 47: Arctic diesel electricity generation Carbon Dioxide (CO_2) and Black Carbon (BC) emissions from locations with coastal access

	CO2 emissions [tonnes]	BC emissions [tonnes]
Mining	**485,527**	**93**
QC	209,433	38
NU	200,135	38
NL	75,959	17
Settlements	**271,506**	**62**
NU	140,045	32
QC	69,389	16
NL	41,151	9
NT	12,085	3
MB	6,541	1
ON	2,295	1
Grand Total	**757,033**	**156**

4 EXISTING AND PLANNED LNG INFRASTRUCTURE

This section of the report provides a summary of current East Coast, Great Lakes and St. Lawrence Seaway natural gas and LNG infrastructure that could potentially provide marine fuel for Canadian Arctic shipping as described in Task 2 and 3. Existing and proposed Arctic LNG infrastructure is also summarized.

4.1 GREAT LAKES, EAST COAST AND ST. LAWRENCE SEAWAY INFRASTRUCTURE

The Great Lakes, East Coast and St. Lawrence Seaway region has some existing LNG production capacity which was developed with the primary purpose of acting as peak shaving plants for the local natural gas distribution companies. Additional LNG/CNG infrastructure is being planned to support local demand for natural gas as a transportation fuel. Several export facilities have also been proposed.

This section of the report describes both the existing and planned natural gas and LNG infrastructure throughout the Great Lakes, East Coast and St. Lawrence Seaway.

4.1.1 GAS PIPELINES

The two main types of pipelines in the Great Lakes, East Coast and St. Lawrence are Transmission Pipelines, which are the main lines, and Distribution Pipelines that deliver gas from local distribution companies to homes, business and various industries. The main transmission pipeline is TransCanada's Mainline, shown in Figure 85 which is a pipeline that reaches from The Alberta/Saskatchewan border to the Quebec/Vermont border and is responsible for transporting natural gas from Western Canada east. There are a number of pipelines that connect with the Mainline including the Trans-Quebec and Maritime pipeline, 572 km, which connects the Montreal to Quebec City corridor and continues to the Quebec/New Hampshire border. The Great Lakes Gas Transmission pipeline connects the Canadian Mainline at the Manitoba-North Dakota border and continues to Michigan and the Dawn Hub.

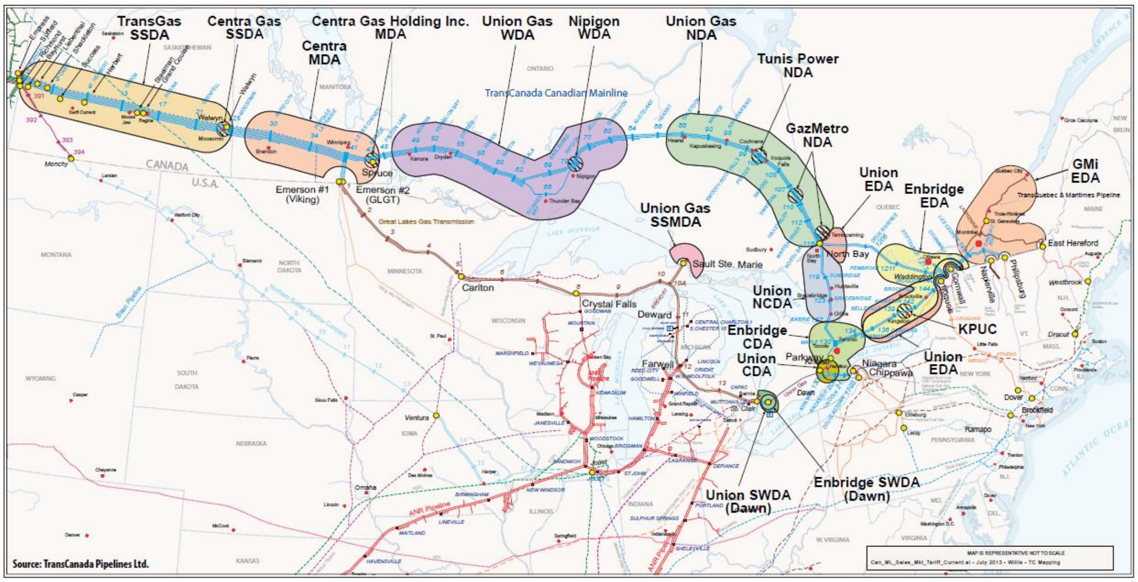


Figure 85: TransCanada Mainline Map

The Dawn Hub is a natural gas storage facility in southern Ontario that can store as much as 4.4 billion m^3 of gas. The Dawn hub's pipeline network gives it the ability to receive gas from Western Canada and the U.S. and deliver to markets in Eastern Canada and the Northeast U.S., as seen in Figure 86. With this much connectivity Dawn Hub is a major trading point for gas in the East Coast, Great Lakes and St. Lawrence region. The rise of U.S. gas production means that more gas is now coming from the U.S. into Dawn Hub than from Western Canada.

Figure 86: Dawn Hub Supply and Demand

The Maritimes and Northeast Pipeline (M&NE), majority owned by Enbridge, was originally built to transport gas produced offshore in Nova Scotia throughout Atlantic Canada and into the Northeast U.S. This pipeline, shown in Figure 87 is 1,400 km in length and travels from Goldboro, NS to Dracut, Massachusetts. The overall throughput declined throughout the lifetime of the pipeline (Figure 88Figure 88). The flow of gas in the pipeline has been reversed and is now proposed to provide the gas for the Goldboro LNG export project (See Section 4.2.3).

Figure 87: Maritimes and Northeast Pipeline

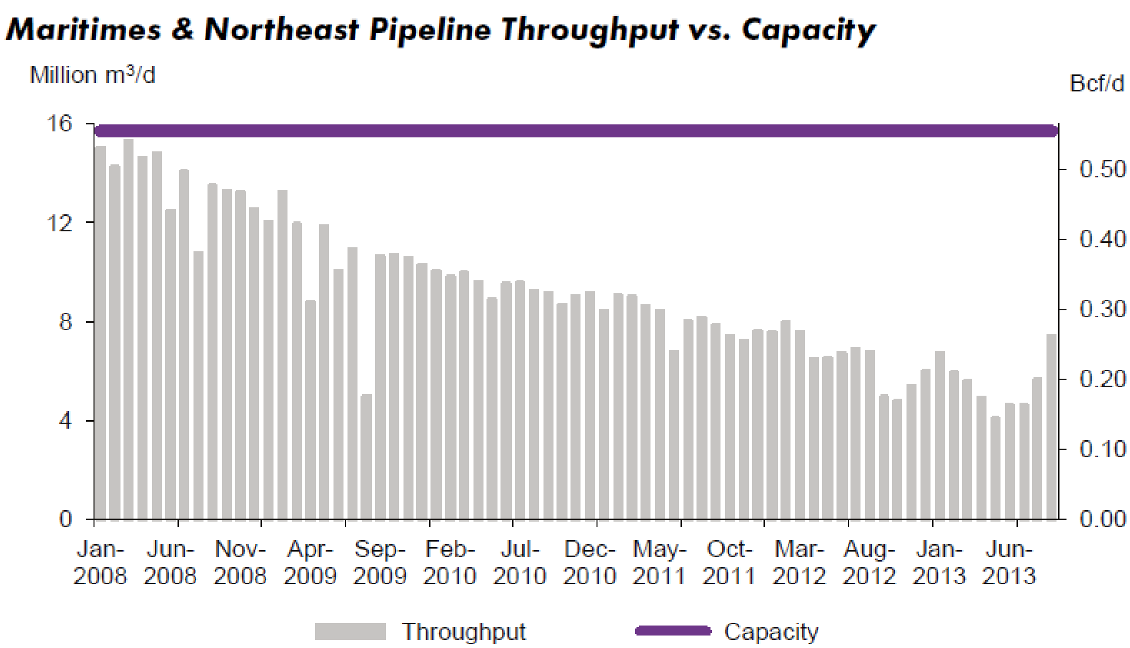


Figure 88: Maritimes & Northeast Pipeline Throughput vs. Capacity

Emera, a part owner of M&NE Pipeline, connects this pipeline with the Canaport LNG facility (See Section 4.2.3) via the Brunswick pipeline as shown in Figure 89. The Emera Brunswick pipeline is 145 km in length and runs from Saint John, NB to St. Stephen, NB. The Deep Panuke and Sable Offshore gas production wells have now been shut down.

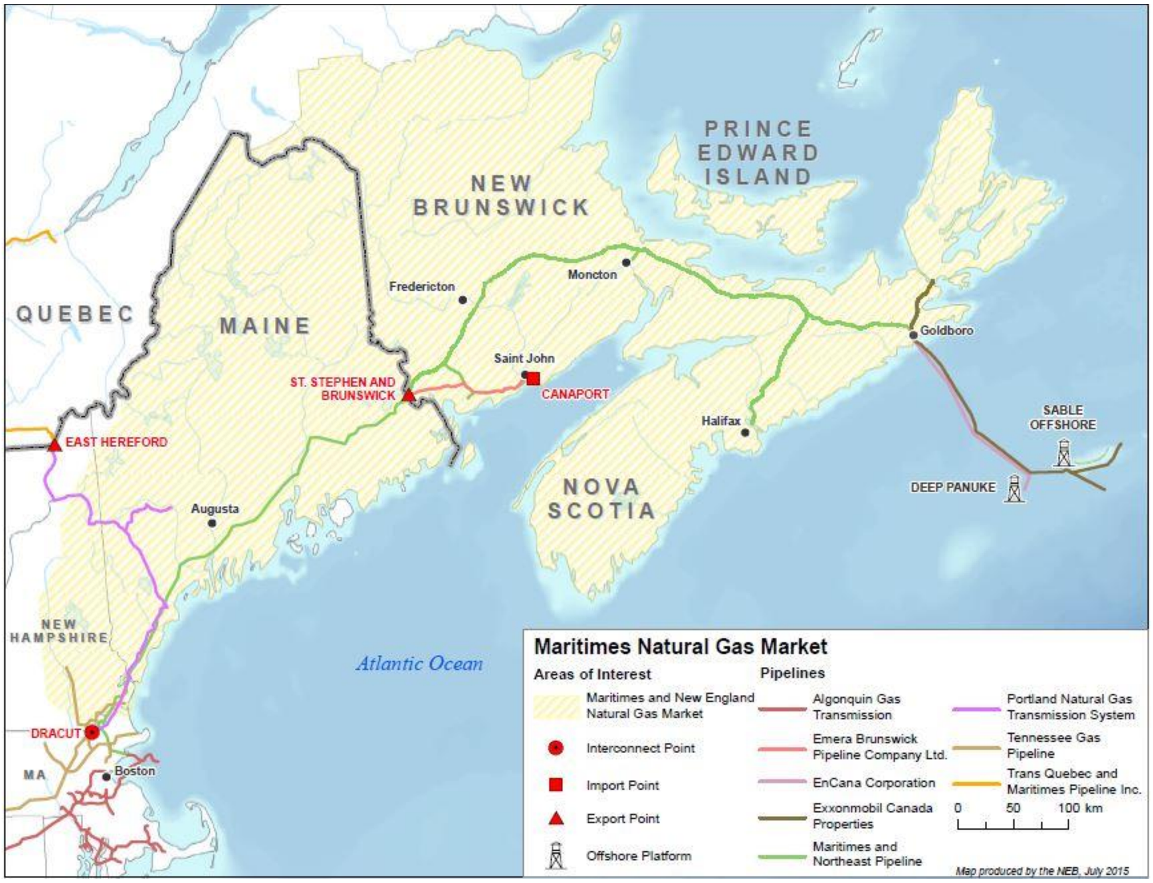


Figure 89: Pipeline Infrastructure in Maritimes, and New England Gas Market

4.2 LIQUEFACTION CAPACITY

There are a number of potential sources of LNG for marine and other transportation demands, including existing domestic facilities, new predominantly export-oriented projects, and supplies from adjacent areas of the U.S.

4.2.1 DOMESTIC

Currently there are two LNG production facilities in eastern Canada, Enbridge's Hagar facility in Ontario and Énergir's Montreal LNG facility in Quebec. These facilities are traditionally used to supplement the gas supply during periods of peak demands, also known as peak-shaving. The major infrastructure components of these LNG facilities include the liquefaction plant, storage tanks, and vaporization system. The vaporization system is used for regasifying LNG, which is then supplied to the gas distribution piping system for normal (non-LNG) consumers when needed to meet periods of peak demand. As these peak-shaving facilities are considered part of the overall gas supply infrastructure, investments in them and the costs of both the gas feedstock and the LNG that is produced by them are subject to regulatory control by the provincial utilities commission.

Enbridge's Hagar facility, built in 1968 by Union Gas, is a combination liquefaction, storage and vaporization facility located near the TransCanada Highway 17 between North Bay and Sudbury.

Hagar has a current liquefaction rate of 84,103 m^3/day (3,165 gigajoules (GJ)/day), storage capacity of 17,000,103 m^3 (640,000 GJ), and a maximum vaporization rate of 2,550,103 m^3/day (95,600 GJ/day). The plant was designed to liquefy for 200 days to fill the tank, then remain idle and prepared to vaporize for the remainder of the year. Year-round operation would provide an additional 165 days of LNG production or approximately 13,900,103 m^3 (522,000 GJ) of spare, interruptible capacity for other markets. The plant does not have truck loading facilities to supply LNG for the transportation market and currently operates purely for peak shaving.

Énergir's liquefaction, storage and regasification (LSR) plant in Montréal East has been in operation for 45 years. With three loading docks, the plant can produce more than 10 billion cubic feet of LNG per year (775,804 m^3/day) and store up to 2 Bcf (90,000 m^3) in its two cryogenic tanks, after the natural gas liquefaction. The loading docks fill tanker trucks, which supply refuelling stations or service customers directly. LNG can then be distributed to customers within a radius of over 150 km from the LSR plant. The truck loading facility is shown in Figure 90 below.

Figure 90: Énergir LNG loading facility in Montréal East, Que.

Quebec-based start-up Distributed Gas Solutions Canada (DGSC) has proposed to construct a micro-liquefaction site in Saguenay, Que. Northeast Midstream's previously proposed LNG facility near Nipigon, Ont. is no longer going ahead. Stolt LNGaz in Becancour, Que. also faces an uncertain future.

4.2.2 U.S. DOMESTIC

Pivotal LNG's Towanda LNG plant is situated in Northeastern Pennsylvania and has a 50,000 gallons per day capacity. U.S. renewable natural gas supplier REV is a minority owner of the plant. REV has provided truck to ship bunkering of LNG in the Great Lakes region.

In December 2020, REV provided Groupe Desgagnés with the first ever Truck-to-Ship Marine LNG Bunkering operation on the Great Lakes. REV's Fleet delivered 400 M3 of LNG to the Damia Desgagnés in the Port of Hamilton; Ontario as shown in Figure 91.

Figure 91: REV LNG truck to ship bunkering in Hamilton, Ont.

4.2.3 LNG EXPORT & IMPORT

Current and future planned LNG export or import facilities may provide a source of LNG fuel for Arctic use.

Canaport LNG has been operating as an LNG import facility since 2008. It has recently been renamed Saint John LNG following Spanish energy company Repsol's acquisition of a 100% ownership of the facility. It has three storage tanks with each having a capacity of 3.3 billion cubic feet.

Bear Head LNG is a proposed, 12 million tonne per annum LNG export facility situated in Point Tupper, Nova Scotia. The project was originally planned to come onstream in 2019. Bear Head LNG received a three-year extension to its construction permit which will now expire in Dec. 31, 2022. Construction on the facility has been halted and the project is for sale. In early 2022, the project proponent, Pieridae Energy, announced that it was evaluating deploying a smaller, 2.5

million tonne per annum floating LNG facility as a more financially attractive alternative for the project at the same site shown in Figure 92 below.

Figure 92: Bear Head LNG Facility Site

GNL Quebec has proposed to build Énergie Saguenay, an LNG export project located at the Port of Saguenay in Quebec, Canada. The 11 million tonnes per annum facility would be fully powered by hydroelectricity. In February 2022, the Impact Assessment Agency of Canada denied the project approval to move ahead. The Quebec provincial government also rejected the proposal in 2021.

The Goldboro LNG project had proposed to build a 10 mtpa export facility at the end of the Maritimes and Northeast Pipeline (see Figure 87) which would have allowed it to import gas from the U.S. to use for exporting overseas. The project had a contracted buyer in place with German E.ON. In June 2021, the $10 billion project to build the land-based LNG terminal was officially cancelled due to an inability to meet final investment decision criteria, but project proponents Pieridae Energy continue to evaluate options to use a floating LNG terminal instead. The floating LNG project would be smaller (2.5 mtpa) but considerably lower in cost (approximately $2 billion)

4.3 ARCTIC LNG PROJECTS

Inuvialuit Petroleum Corporation's (IPC) proposed Inuvialuit Energy Security Project (IESP) involves the construction of a small-scale LNG plant connected to a gas supply near Tuktoyaktuk as shown on the map in Figure 93 below.

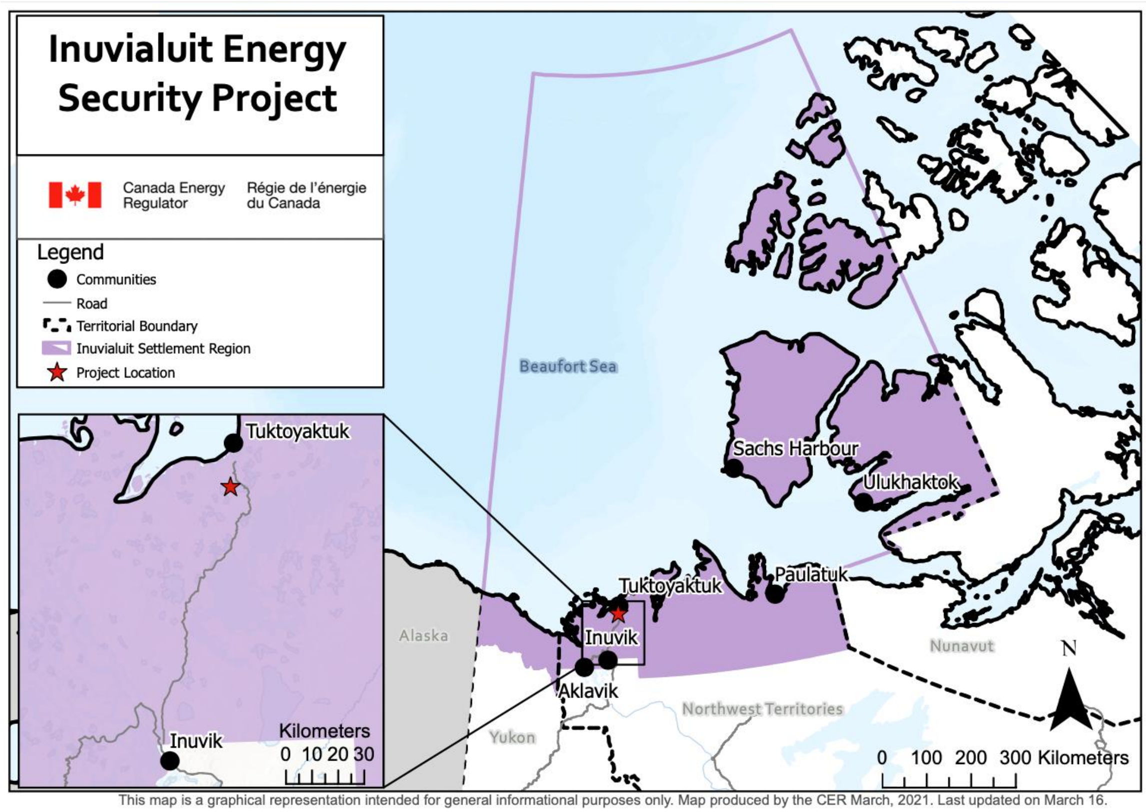


Figure 93: Location of the IESP project

The project is currently seeking approval through the Canada Energy Regulator. Gas would be supplied from an existing gas well called TUK M-18 that will be remediated as part of the project. First gas production is proposed for Q4 2023. This proposed facility is the basis for Case Study 2 in Section 5 below.

Cryopeak LNG Solutions has constructed an LNG production facility in Fort Nelson, British Columbia. Phase one of the production capacity of 27,000 gallons per day of LNG became operational in June 2021 (Briggs, 2021). LNG from this facility is supplied to customers in Canada and the U.S., including Inuvik in the Canadian Arctic. The Fort Nelson LNG Facility is shown in Figure 94 below.

Figure 94: Cryopeak Fort Nelson LNG Facility

The government of Northwest Territories is undertaking a prefeasibility study of a project to construct an export-scale LNG facility near Tuktoyaktuk (Thomson, 2020). The gas for the LNG facility would come from the offshore Mackenzie Delta gas fields originally proposed to be connected to Canada's natural gas grid via a pipeline through the McKenzie Gas Project that was cancelled in 2017. The export-scale project is inspired by the Russian Yamal LNG project that exports LNG to global markets from an LNG terminal in the Russian Arctic.

5 DEVELOPMENT OF A MARINE LNG SUPPLY INFRASTRUCTURE

Currently the Canadian Arctic has a small and localized LNG supply chain in the West, and no supply chain in the East. This existing supply chain does not currently have the capacity to supply LNG as a marine fuel. As demand increases there will be a need to add new capacity to one or more elements of the chain, potentially including gas supply, liquefaction, distribution and storage.

The LNG price charged to a marine customer will be a function of:

- Feed gas costs
- Liquefaction costs
- Fuel delivery costs
- Fuel Taxes and/or Subsidies (not analyzed in this study)

Each stage in adding capacity must make economic sense for all parties involved, including the end user. Therefore, the project has created a model detailing infrastructure costs, using data available from public sources and in some cases more specific costs provided by project participants and other organizations. These costs are intended to capture all aspects of the challenges when building and operating a supply chain in the Arctic. While all costs are considered to be realistic, it should be understood that they are indicative only, as there are very few examples of LNG use in the Arctic. Fuel taxes and subsidies are not included in this study as there are many different and complicated tax regimes over the Arctic region considered and they are not well defined for LNG. Project proponents will need to conduct their own due diligence and address their own parameter for required rates of return, risk contingencies, and other factors such as for example, consideration of environmental impact and benefits.

The cost modelling task for LNG has considered all elements of the supply chain as shown in Figure 95. The model has consolidated sections of the supply chain where possible. For example, "Gas Well -> Liquefaction Plant -> LNG Storage Tank" could be presented as the cost to purchase LNG from an existing supplier at a certain location, as the $/GJ of LNG would be an all-encompassing cost of the entire upstream supply chain from that point.

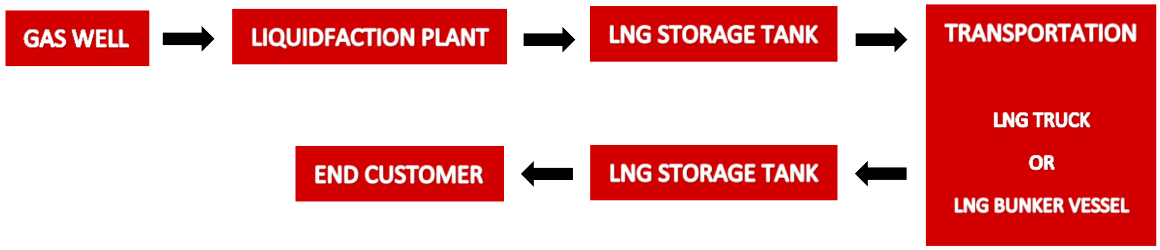


Figure 95: Hypothetical Arctic marine LNG supply chain

This report models two hypothetical Arctic LNG supply chain case studies. The purpose of these case studies is two-fold, one is to present a potential Arctic LNG supply chain, and the other is to present the costs ($/GJ) associated with Arctic LNG based upon the potential supply chain. Capacity, capital and operating costs of the case studies' supply chain sections are all considered in each model. Each section of the supply chain will be presented as it pertains to Arctic LNG in section 5.1 to 5.3. A summary of each case study supply chain will be presented to tie each section of the supply chain together and present the associated costs for both case studies in section 6.

All costs presented are quoted in Canadian dollars.

5.1 LIQUEFACTION

Liquefaction of natural gas is likely to involve the largest capital investment if Arctic liquefaction is required, depending on scale. Arctic LNG could be supplied from a local purpose-built liquefaction plant however the challenges with that would be significant, and to date there are no Canadian Arctic liquefaction plants operating.

5.1.1 SMALL SCALE LIQUEFACTION PLANTS

It can be assumed that producing Arctic LNG for transportation and for other non-traditional uses will involve the use of smaller-scale liquefaction plants rather than those for LNG export plants at locations relatively close to the end users (or to suitable distribution infrastructure). The economics of constructing a small-scale liquefaction plant depends on the size of the facility, location, utilization and energy requirements. The economics of smaller scale liquefaction has been investigated using data provided by industry experts (Jenmar Concepts, IPC, and Cryopeak) to cover most components of capital and operating costs, as described in more detail below. The characteristics of two differently sized systems are summarized in Table 48. It should be noted that these are not the only small-scale liquefaction technologies and options available, but they are representative of what capacity and technology could reasonably see implementation in the Canadian Arctic.

Table 48: Small scale LNG plants

	A – 30,000 m3/year	B – 50,000 m3/year
LNG production	30,000 m3/year methane loop	50,000 m3/year methane loop
Energy Use	0.42 kW.hr/litre	0.39 kW.hr/litre
Capital Cost	$46 million	$51 million
Lifespan	20 years	20 years
Land cost and site improvements	Negligible	Negligible

Costs

The capital cost components are the cost of the liquefaction system and all associated equipment and infrastructure, this cost does not include a storage tank, which has been accounted for separately. These costs have been amortized assuming, conservatively a lifespan of 20 years. These costs are inclusive of all challenges faced when building and operating in the Arctic, including but not limited to permafrost, shipping logistics and seasonal schedules.

The cost per GJ of LNG produced is then calculated by dividing the annual costs over the total GJ of LNG produced per year. This cost includes the cost of the liquification only. As the utilization of plant increases, the annual costs would be spread over a greater volume of LNG, the values referenced in Table 48 are calculated at 100% utilization. As shown Figure 96, there is a non-linear relationship between plant utilization and liquefaction cost, this relationship is independent of plant size.

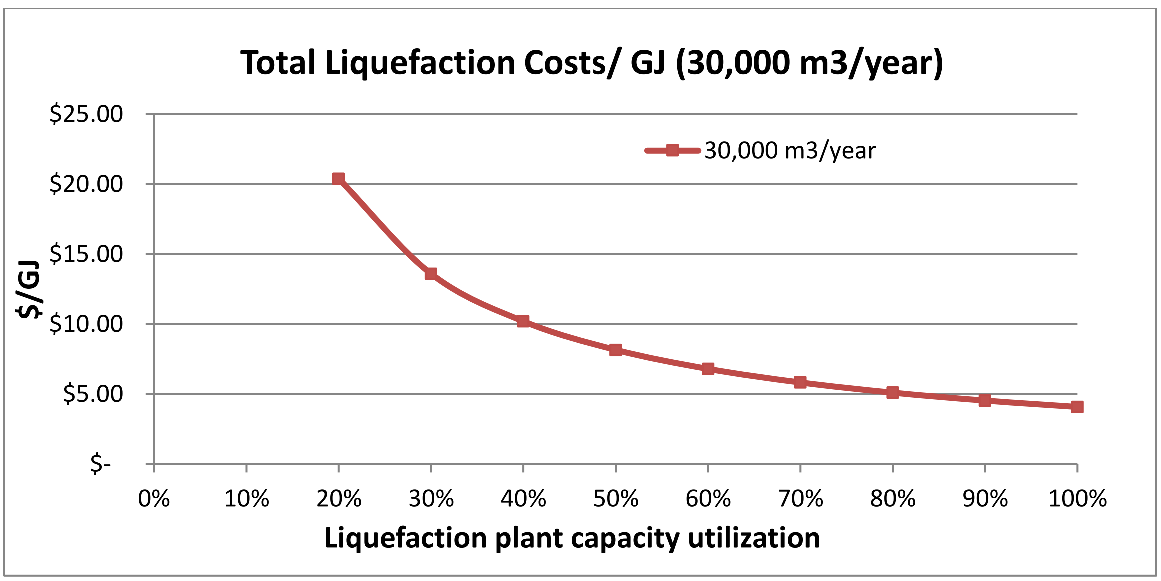


Figure 96: 30,000 m^3/year LNG Plant Costs/GJ

The operating costs include direct labor and materials for operations and maintenance, and energy consumption costs. It should be noted that both sizes of liquefaction plants referenced in Table 48 are powered by gas which is more cost effective than using the Arctic electrical grid. The cost for the power generation equipment is included in the capital cost.

Using information from industry experts; annual labour, maintenance, material and other operating costs are estimated at 3% of the Capex of the system per year. These costs are assumed for simplicity to be fixed; in reality there will be some dependency on utilization rate. The yearly cost for insurance is estimated to be 0.75% of Capex.

This analysis shows that liquefaction cost will always be a significant component of the cost of LNG fuel, and that the cost is highly sensitive to plant size and utilization. There are significant economies of scale in moving from the 30,000 m^3/year to the 50,000 m^3/year size. Accurately forecasting the overall level of demand for LNG will therefore be crucial for project economics. This is discussed further in Chapter 8.

5.1.2 LARGE SCALE LIQUEFACTION

Large-scale liquefaction for gas export can be more costly on a per unit basis than small scale liquefaction for transportation and other local markets, due to various market forces which currently influence the cost of large-scale projects. It can be noted that this also applies to other energy mega-projects in the oil sands, pipeline and related sectors.

Figure 97 (Canadian Energy Research Institute, 2018) shows how the cost of large-scale liquefaction projects worldwide has increased in recent years, due to factors such as availability and cost of skilled workers at remote sites, bottlenecks in the supply of components, inexperience of project managers, etc. Based on research completed by the Canadian Energy Research Institute (CERI) the average capital costs of various Canadian LNG projects is \$1006 - \$1237 (Canadian Energy Research Institute, 2018) per tonne of capacity annually.

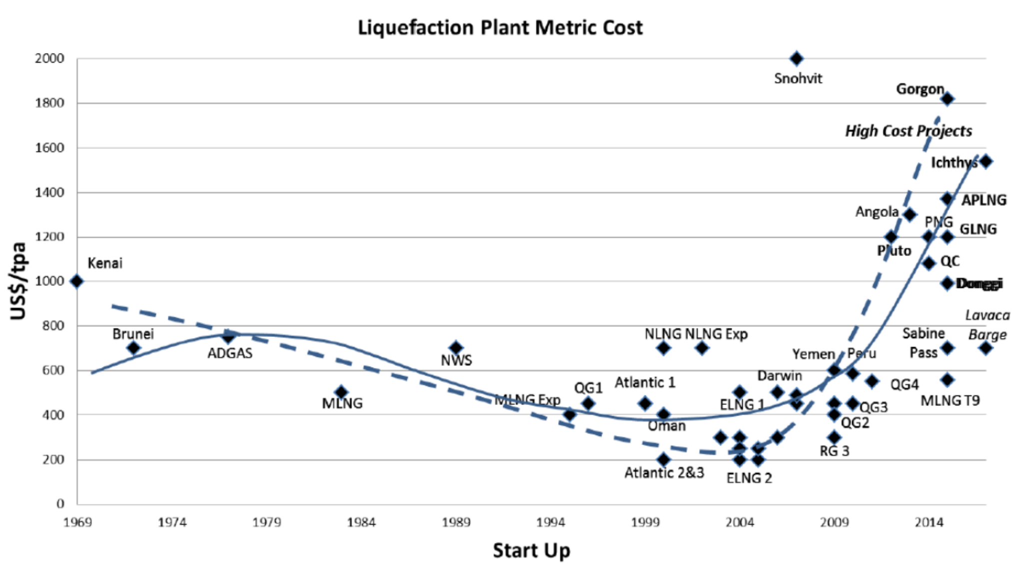


Figure 97: Cost of LNG Facilities, 1969-2014

The opportunity for a large-scale LNG liquefaction plant in the Canadian Arctic is generally regarded as non-existent. The Canadian Energy Research Institute's 2018 paper titled

“Competitive Analysis of Canadian LNG” highlighted some of the key challenges that Canada faces when developing LNG infrastructure. While the paper focus’ on Canadian LNG development in non-Arctic environments, two of the uniquely Canadian challenges described are;

- Lack of domestic experience in delivering LNG projects (Canadian Energy Research Institute, 2018)
    - Canada has no history in delivering large scale LNG projects
    - Lack of experience would cause delays and higher costs
- The need for Indigenous People’s support (Canadian Energy Research Institute, 2018)
    - Any LNG liquefaction plant and associated infrastructure would likely cross First Nations land or have an impact on the way the Indigenous Peoples use Crown or unceded land
    - From an investor’s perspective, having to gain Indigenous People’s support in Canada is an additional risk that is not found in other jurisdictions

There are no major Canadian Arctic LNG plants under construction or completed in the Arctic, therefore a complete understanding of all unique Arctic challenges is currently unknown. In this study, no large-scale Arctic LNG plants have been modeled.

5.2 DISTRIBUTION

A liquefaction facility may be able to supply LNG directly to a marine bunkering location, but in most cases, it is more probable that some form of distribution system will be required. As discussed earlier, options for fuel delivery to a marine customer include tanker trucks, rail cars, intermodal containers, and bunker barge or bunker vessel options. In the case of the Arctic LNG supply chain the most likely form of distribution will be by bunker barge or bunker vessel, with local land-based distribution by tanker truck.

5.2.1 TANKER TRUCK

A tanker truck can be used to transport fuel to distribution centres, shore-side storage tanks or directly to bunkering location. A tanker truck is a combination of a bulk trailer and the hauling tractor. Truck capacities vary from 35 – 56 m^3 of LNG in one trip.

For the economic analysis of tanker delivery the modelling assumes a delivered volume per trip of 50 m^3 using a standard cryogenic LNG tanker, hauled by a standard tractor. Both the trailer and tractor are assumed to have an economic useful life of 10 years. These are deliberately conservative assumptions.

<u>Costs</u>

Capital costs include purchase/lease cost of the trailer and the tractor. A cryogenic semi-trailer as shown in Figure 98 with 50 m^3 (13,000 gallons) capacity costs about $270,000 (Chart Industries, n.d.) and takes approximately four months to build. While a standard tractor unit costs about $110,000 (Kenworth, 2013). Tractors are readily available. A tractor unit with NG- fuelled engines cost approximately $175,000 (Minimax Express Transportation, 2014) . The combined cost has to be spread over the volume of fuel delivered over the life of the asset. The cost per unit of LNG delivered increases with distance from the liquefaction facility to point of delivery, both because of increased operating cost (see below) and because of the lower delivery capacity of the “system”.

Figure 98: Cryogenic tractor-trailer unit

Operating costs will include direct labour, fuel, maintenance, and other associated costs such as permitting and insurance.

The cost of delivery by a dedicated tanker truck system varies depending on two main factors, the effective utilization rate for the system and the distance from the liquefaction plant to the bunkering facility. In Figure 99, 50% utilization of available capacity is assumed to be utilized at different trip distances. In both cases, cost is shown as $/GJ of LNG delivered.

In this study, no LNG tanker trucks have been modeled. However, the cost of truck delivery has been provided for context when reviewing the costs of other modes of transportation such as bunker vessels as described in Section 5.2.2.

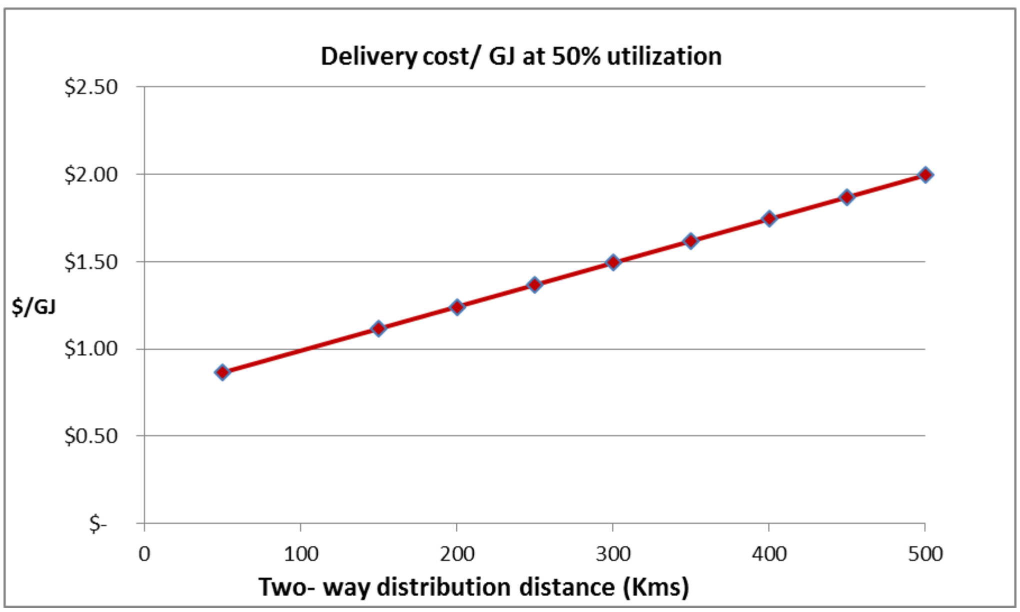


Figure 99: Truck delivery cost as function of round-trip distance

5.2.2 BUNKER VESSELS

Dedicated bunker barges or bunker vessels for LNG distribution require significantly higher capital and operating expenditure than trucks but are capable of delivering much larger volumes of LNG to much more remote coastal areas of the Canadian Arctic. As well there are additional infrastructure investments in berths and jetties that are likely to be required for filling the bunker barge or bunker vessel, if that infrastructure is not already in place.

Unlike the situation with other sections of the LNG supply chain, such as liquefaction plants and tanker trucks, there are no “standard” units for bunker barges or vessels. Two alternatives have been modelled: a 5,000 m^3 capacity bunker barge and a 10,000 m^3 capacity bunker vessel. It should be recognized that these are illustrative examples only, and a project will need to undertake its own analysis of capacity/throughput requirements, capital and operating costs. Some principal particulars for the two options are shown in Table 49. These represent syntheses of materials generated in-house by Vard Marine for other projects, materials publicized by potential suppliers or by information provided by this studies' participants. The crew numbers account for the use of two full crews and supplementary personnel.

Table 49: LNG supply vessel illustrations

	A – 5,000 m3 Bunker Barge	B – 10,000 m3 Bunker Vessel
LNG storage (m3)	5,000 m3	10,000 m3
Cost ($ CAD)	$60 million	$100 million
Propulsion power (kW)	Tug (2200 kW)	4000 kW
Transit speed (kts)	8	13
Crew number (total)	10	24

In both cases the LNG transfer operations at each end of a voyage are assumed to take 48 hours to conservatively allow for any delays during the bunkering process. The analyses have considered round trip distances and their impact on system capacity and trip cost.

Costs

The smaller ATB bunker barge (not including tug) is assumed to cost $60 million to construct, and the large bunker vessel $100 million. These values are from Vard Marine in-house estimates and from information provided by this study's participants.

The life expectancy of the vessels is taken as 20 years, and as with other components of the supply chain, capital costs are assumed to be spread over the volumes of LNG delivered. The significant components of operating cost that have been taken into account are crew, fuel, maintenance, insurance, and a component of overhead costs to deal with office administration, etc. Note that crew costs are for Canadian personnel.

Figure 100 and Figure 101 show some aspects of the sensitivity of delivery cost to voyage distance by bunker vessel or bunker barge respectively. It is important to note that these charts are based upon the case studies discussed in section 6, the details of these case studies have a direct impact on the cost ($/GJ) for each option. The bunker vessel benefits from;

- Higher utilization
- Greater capacity
- Higher speed
- No daily tug rate ($25,000 per day for the bunker barge)

This results in lower overall costs for the bunker vessel when compared to the bunker barge. Note that bunker barges can be just as, or more competitive than bunker vessels in the right application.

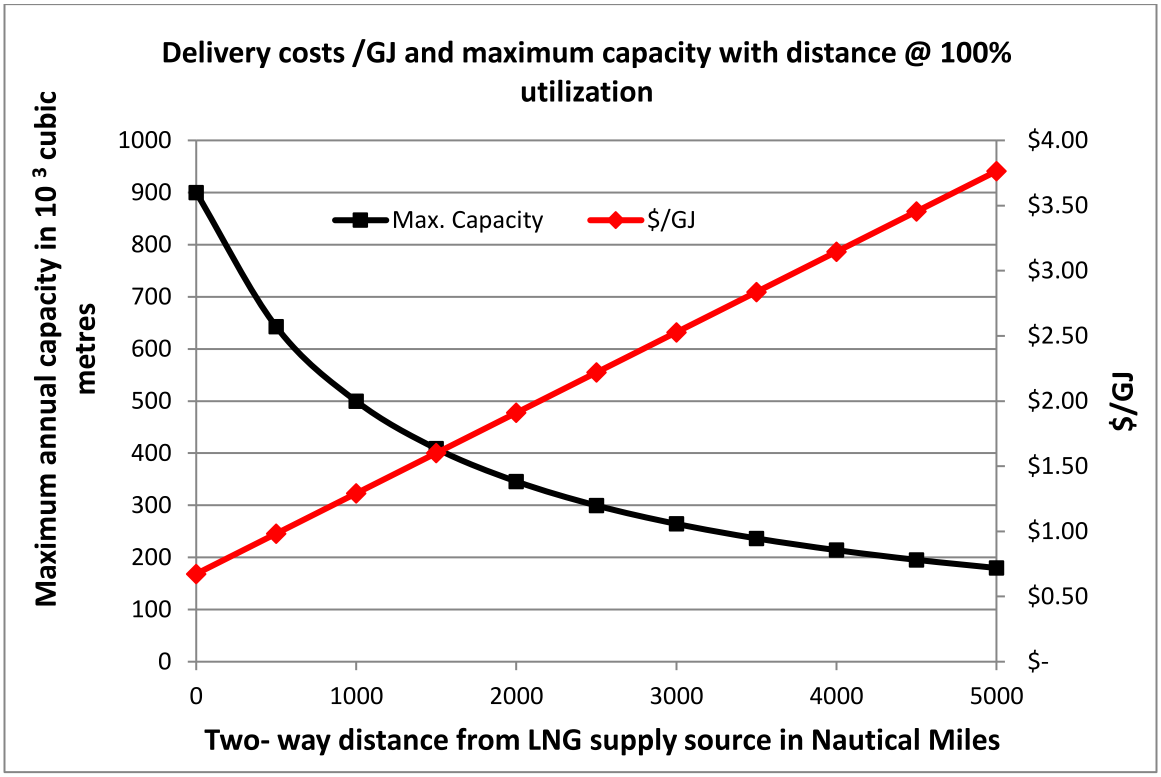


Figure 100: Bunker vessel delivery capacity as function of distance

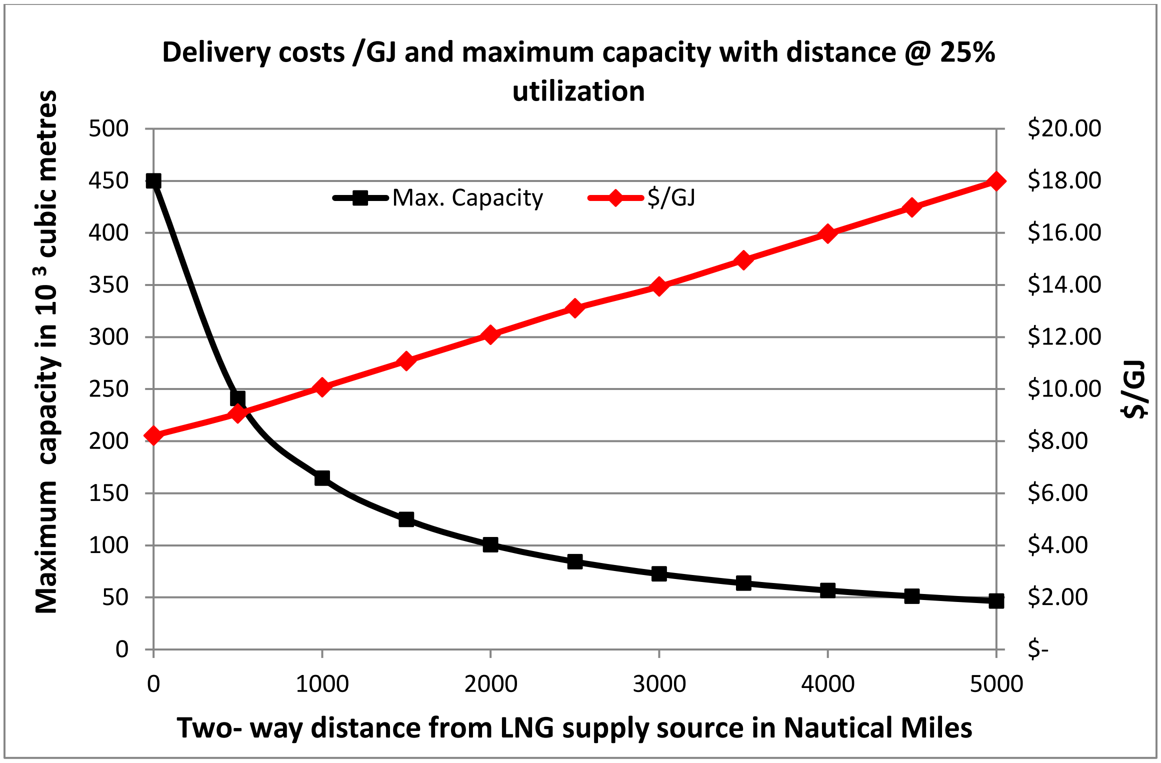


Figure 101: Bunker barge delivery capacity as function of distance

These numbers indicate that the bunker barge or bunker vessel delivery options can be economically competitive with trucks, even on shorter routes if their capacity is sufficiently well used. Given the lack of road access to many Arctic towns, bunker barge or bunker vessel use is likely necessary.

5.3 STORAGE AND BUNKERING FACILITIES

As discussed above, options such as tanker trucks and bunker barges or bunker vessels may supply an LNG-fuelled ship directly, or a shore-based bunkering facility may be used. The bunkering facility can act as a storage buffer and can incorporate systems allowing high fuel transfer rates, line purging, vapour return, emergency response and other features depending on the nature of the vessels and services it is intended to supply. These features could also be provided on a bunker barge or bunker vessel. In many applications it will be necessary to analyze several options to identify which of these offers the lowest overall costs. In cases where the liquefaction facility is sufficiently close to the bunkering location, it may provide many of the necessary features directly.

Costs have been estimated for a 10,000 m^3 and 30,000 m^3 storage facility as shown in Figure 102. The impact on delivered cost is quite small with high throughput (>10 tank turnovers per year), in the order of $0.50/GJ. However, due to the low annual LNG throughput for Arctic LNG storage applications the costs can be quite significant as shown in Figure 102.

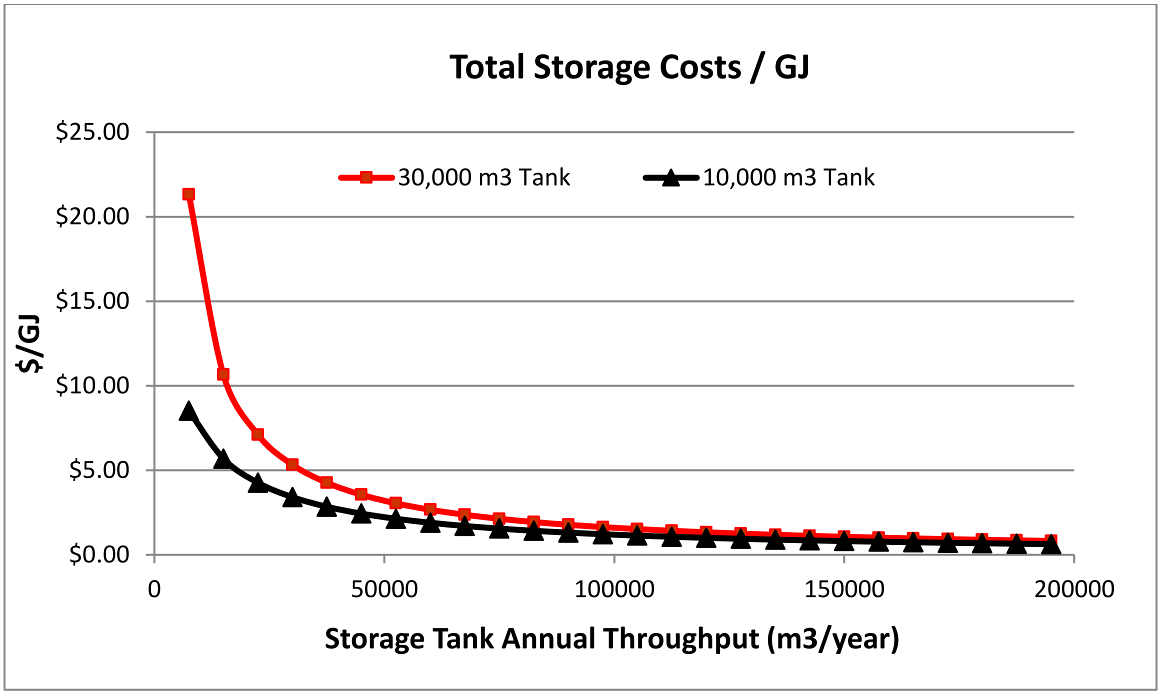


Figure 102 - Storage Tank Costs/GJ

Existing diesel tank farms in the Arctic see very little throughput each year, roughly 1 turnover per year. That would likely be the case with many Arctic LNG storage applications as well, as there is only a short window each year to fill them up which results in large storage volumes and low turnover rates. As shown above in Figure 102, the cost for a 30,000 m^3 tank, with 1 turnover per year is roughly $5/GJ.

5.4 COSTING UNCERTAINTIES

Equipment, operating and maintenance costs can be estimated with reasonable accuracy from industry experts, original equipment manufacturer data and other sources. However, inflated costs associated with Arctic construction and operation have had to be estimated. Some of the costs that may be incurred that are much more variable depending on the location and nature of the project are;

- Cost of facility construction;
- Cost of approval and permitting processes;
- Taxes and licensing fees.

Chapter 8 provides some additional discussion of the process and schedule for the creation of new infrastructure, but project-specific costings are generally commercially confidential and it is unlikely that more accurate costs will be made available within the timeframe of this study.

6 CASE STUDIES

This report models two hypothetical Arctic LNG supply chain case studies. The cases studies sum the various costs associated with each section of the supply chain to present the total cost of delivered energy, in $/GJ of LNG, to the end user.

As noted, the total cost of supply for LNG includes the feed gas, liquefaction, distribution and delivery. The analyses presented aims to give approximate ranges for each of these costs, and to indicate their sensitivity to various assumptions, one of the most significant of which is the level of utilization of each of the capital-intensive components of the overall system. This will be evidently shown in Case Study 2.

Profit, and required rate of return on investment (or some similar metric) have been included in the model, as this model needs to be reflective of a real project. They could be expected to add in the order of 20% to the total delivered cost of the fuel.

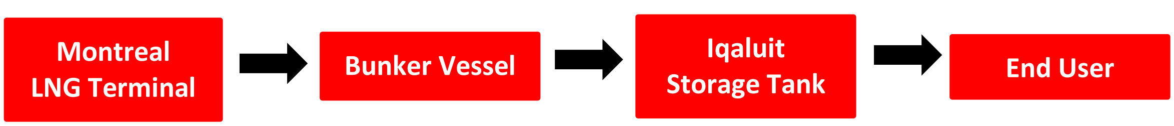
6.1.1 CASE STUDY – MODELING PROCEDURE

Fundamentally the modeling procedure for calculating the total cost of LNG to the end user is a summation of the costs at each step along the supply chain. The supply chain can be broken down into discrete sections which are each analyzed individually to determine the costs associated with the transportation, processing, or storage of LNG within that section of the supply chain. Each of these supply chain sections will typically have a key piece of infrastructure such as a tank, bunker vessel, bunker barge, or liquefaction plant that drives the supply chain and associated costs. The method for analyzing each section varies slightly but can be simplified down to Equation (13), where the annual asset costs (including O&M, profits and other business costs) divided by the amount of LNG processed (or delivered) equates to the cost of that section of the supply chain.

Simplified LNG Cost

$$\frac{\left(\frac{Capital\ Cost - Salvage\ Value}{Amortization\ Period\ (years)} + (Annual\ O\&M\ Cost)\right)}{GJ\ of\ LNG\ Delivered\ Annually} = LNG\ Cost\ \left(\frac{\$}{GJ}\right) \tag{13}$$

A breakdown for how the costs are summed for Case Study 1 (See Section 6.1.2) is shown in Figure 103 for each section of the supply chain. A similar procedure is done for Case Study 2 (See Section 6.1.3) but will not be reproduced here.



$$(LNG\ Cost) + (Transport\ Cost) + (Storage\ Tank\ Cost) = End\ User\ LNG\ Cost\ \left(\frac{\$}{GJ}\right)$$

Figure 103: Case study 1 Supply Chain Cost Summation

6.1.2 CASE STUDY 1 – MONTREAL TO IQALUIT

6.1.2.1 CASE STUDY 1 - DESCRIPTION

Iqaluit installs an LNG storage facility to offset the amount of diesel used by the town. Iqaluit currently has a conventional hydrocarbon tank farm with an estimated diesel capacity of 60,000 m^3. To potentially offset up to ~30% of their annual energy needs an LNG storage facility with a volume of 30,000 m^3 needs to be installed. This storage facility can both supply ships with LNG via shore to ship bunkering during the summer months and provide natural gas to local residents. A 10,000 m^3 ice class LNG bunkering vessel is built to deliver LNG to Iqaluit during the summer months (3) with 100% utilization. In the winter months (9) the vessel is assumed to have 100 % utilization in the Great Lakes and St. Lawrence regions. The winter profile of the vessel has not been modeled, but is assumed to involve bunkering of LNG-fuelled vessels using the major ports, and potentially supplying other consumers in the region.

6.1.2.2 CASE STUDY 1 - SUPPLY CHAIN AND GEOGRAPHY

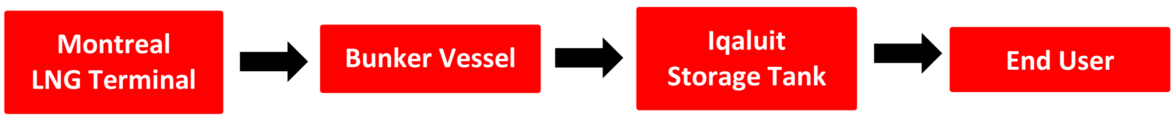


Figure 104: Case Study 1 Supply Chain

For this case study, the supply chain route analyzed is from a Montreal LNG Terminal to an Iqaluit LNG storage facility via a bunker vessel, as shown in Figure 104. In this case study, the end user could either be the town of Iqaluit via a regasification unit, or Marine customers via shore to ship bunkering. The geographic route that this supply chain follows is shown in Figure 105.

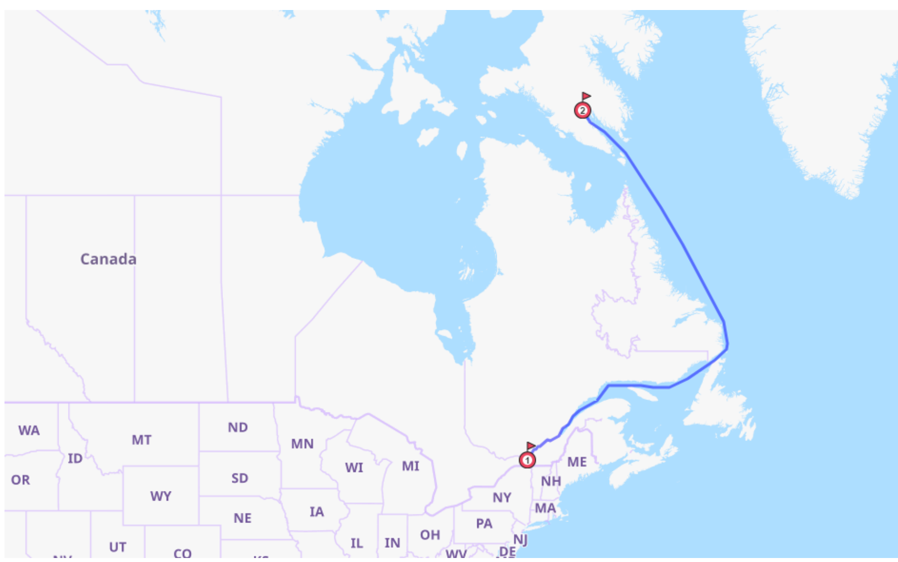


Figure 105: Case Study 1 Geographic Route

6.1.2.3 CASE STUDY 1 - BUNKER VESSEL

A 10,000 m^3 ice class LNG bunker vessel will be used to transport LNG from Montreal to Iqaluit, see Table 50. This vessel will only deliver LNG to Iqaluit during the Arctic summer season (July – October), during the remainder of the year the vessel will operate in the Great Lakes and St. Lawrence region.

Table 50: LNG Carrier Vessel Particulars

Type	LNG Carrier
Overall Length (m)	115
Beam (m)	20
Draft (m)	5.5
Gross Tonnage	5,000
Deadweight (t)	4,000
Speed (kts)	13
Power (kW)	4,000

6.1.2.4 CASE STUDY 1 - STORAGE TANK DESCRIPTION

A 30,000 m^3 LNG storage tank will be built in Iqaluit to receive LNG deliveries from the LNG bunker vessel. The storage tank will not have a boil off gas management system for simplicity. In this scenario it is assumed that the town of Iqaluit could use at minimum, the maximum boil off gas rate (1%/day), which for the 30,000 m^3 tank equates to 6,500 GJ of gas per day as a maximum. A higher rate of gas can be used, however, usage less than 1% of the remaining tanks volume will require the excess boil off gas to be vented or flared, as there is no boil-off gas management system. The boil off profile of the tank is shown below in Figure 106.

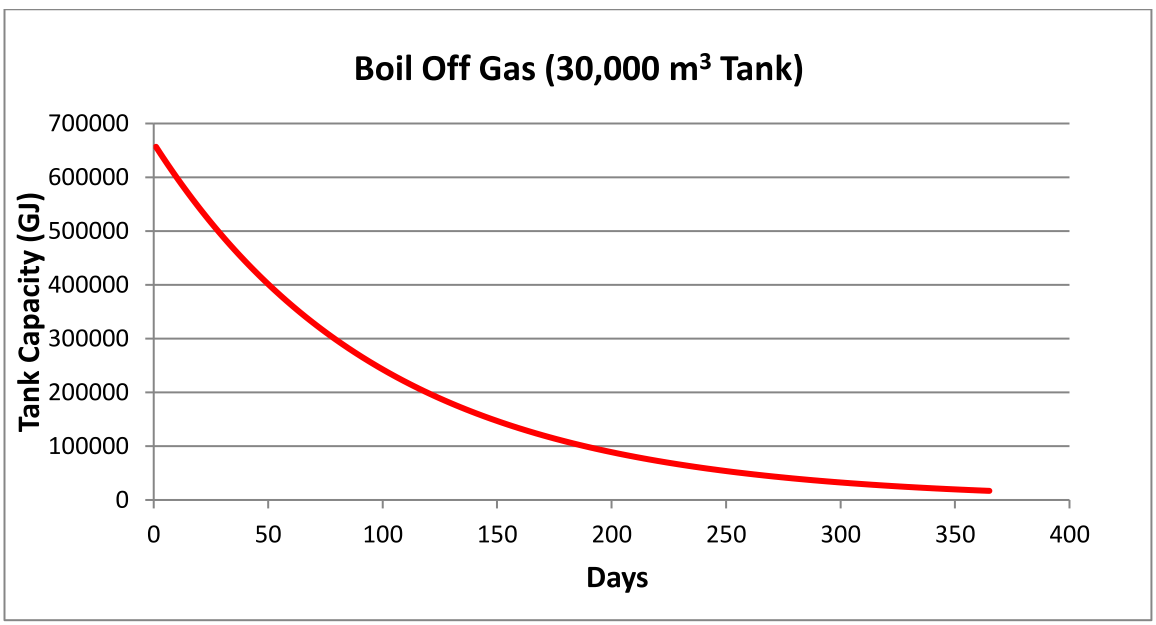


Figure 106: 30,000 m^3 Boil Off Gas Profile (@ 1%/day)

6.1.2.5 CASE STUDY 1 - MODEL INPUTS

The case study inputs shown in Table 51 is a non-exhaustive list of the inputs used to run the model.

Table 51: Case Study 1 Inputs

Category	Value	Units
LNG Storage Tank		
Capex	$50,000,000	$
Labor, Material and Other	2%	%CAPEX/year
Amortization Period	20	years
Bunker Vessel		
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	#
Feedstock LNG Price	$10.35	$/GJ

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

6.1.2.6 CASE STUDY 1 - RESULTS

The output for Case Study 1 is the cost ($/GJ) to the end user, which in the case of this study could either be the town of Iqaluit via a regasification unit, or marine customers via shore to ship bunkering. The end user cost is 18.83 $/GJ of LNG in Iqaluit, as detailed in Figure 107 below. The figure shows that the transportation and storage of the LNG to the Arctic roughly doubles the cost of the feedstock LNG to the end user, not considering any potential Arctic LNG energy subsidies. To compare the LNG price to diesel prices in terms of delivered energy per dollar, the cost of LNG in this case study is $0.69 Diesel Liter Equivalent (DLE). The DLE is calculated by determining the cost per GJ ($/GJ) of energy delivered and then converting that to cost per liter ($/L) as if based on the energy density of diesel.

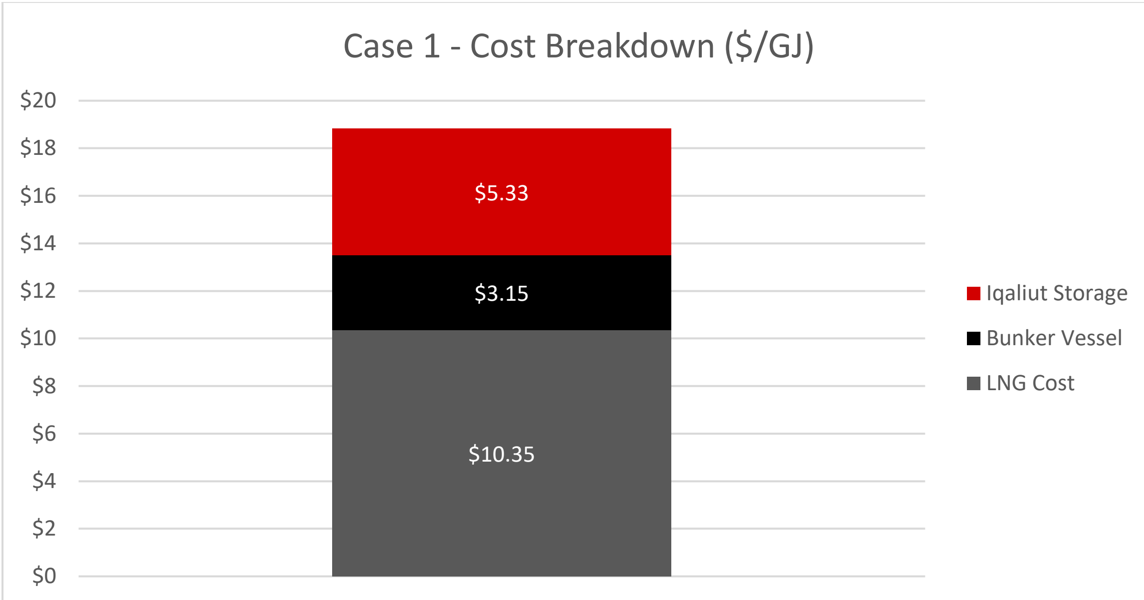


Figure 107: Case Study 1 Results

With respect to the required CAPEX for Case Study 1, it is estimated at approximately $150,000,000, as shown in Figure 108. While these costs are considered to be realistic, it should be understood that they are indicative only, as there are very few examples of LNG use in the Arctic.

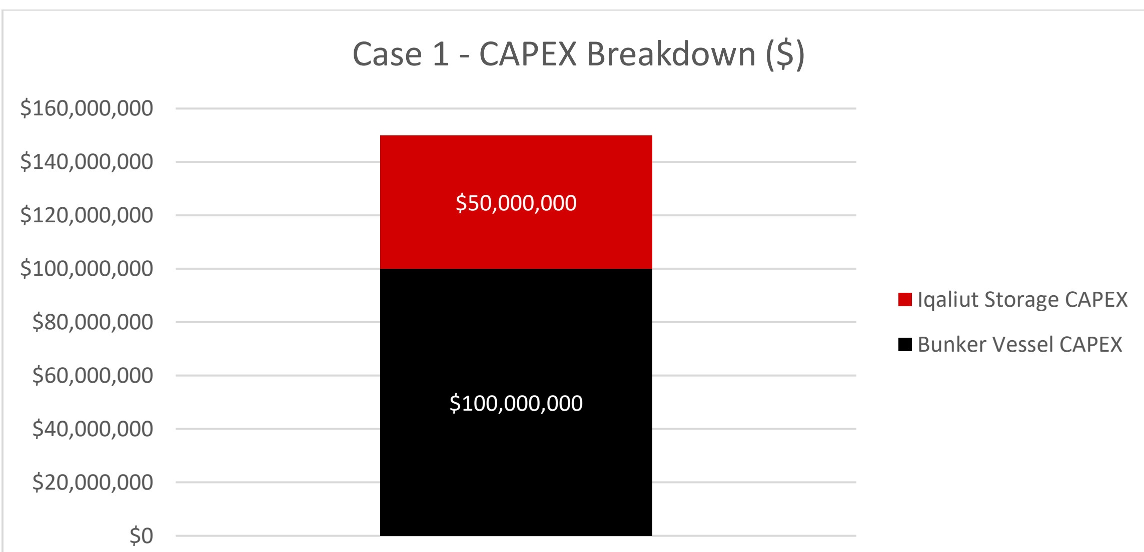


Figure 108: Case Study 1 CAPEX

6.1.3 CASE STUDY 2 – TUKTOYAKTUK TO CAMBRIDGE BAY

6.1.3.1 CASE STUDY 2 - DESCRIPTION

Tuktoyaktuk has installed an LNG liquefaction plant and storage tank for the M-18 natural gas well just South of the town by a few kilometers. The plant exports LNG overseas via shore to ship bunkering, as well as shipping the LNG South to Inuvik and others by truck. A 5,000 m^3 LNG Articulated Tug Barge (ATB) is built to supply Cambridge Bay with LNG from Tuktoyaktuk. Located at Cambridge Bay is a 10,000 m^3 LNG storage tank used to either supply ships with LNG via shore to ship bunkering during the summer months or provide natural gas to local residents throughout the year. The ATB has 100% utilization in the summer months (3) delivering LNG to Arctic customers, and 0% utilization in the winter months (9).

6.1.3.2 CASE STUDY 2 - SUPPLY CHAIN AND GEOGRAPHY

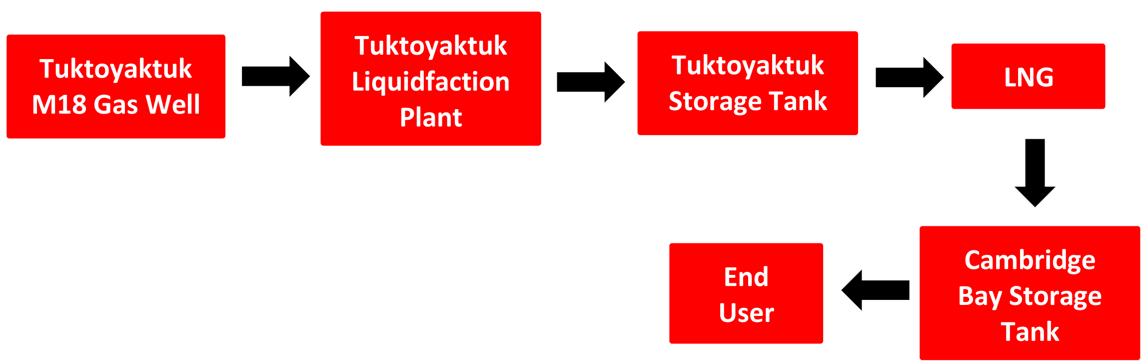


Figure 109: Case Study 2 Supply Chain

For this case study, the supply chain route analyzed is from the Tuktoyaktuk M18 Well to the Cambridge Bay LNG storage facility, as shown in Figure 109. In this case study, the end user could either be the town of Cambridge Bay via a regasification unit, or marine customers via shore to ship bunkering. The geographic route that this supply chain follows is shown in Figure 110, note that Tuktoyaktuk is location 1 and Cambridge Bay is location 2.

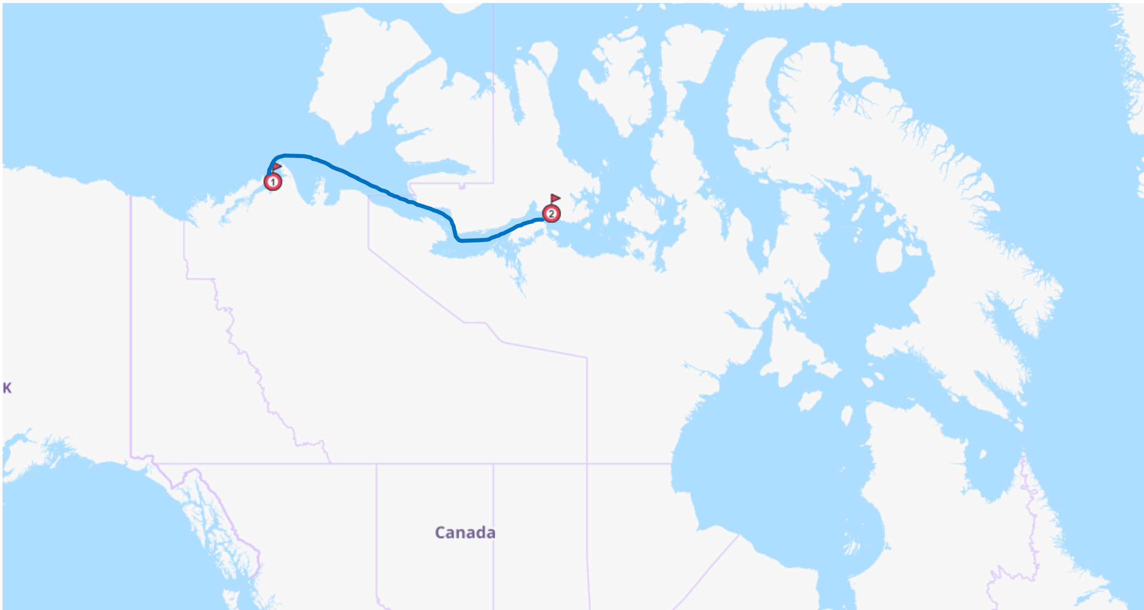


Figure 110: Case Study 2 Geographic Route

6.1.3.3 CASE STUDY 2 - LIQUEDFACTION PLANT DESCRIPTION

A 30,000 m^3/year liquefaction plant will be built near Tuktoyaktuk to feed off the nearby M18 natural gas well. The liquefaction plant will dedicate about 1/3rd of its annual production to supplying Cambridge Bay with 10,000 m3 of LNG per year through the above mentioned supply chain. The remainder to the liquefaction plants annual production will either be exported via the port or be sent South to other customers via truck tankers.

While many parts of these case studies are hypothetical, the LNG liquefaction plant in Tuktoyaktuk does have some real merit to it. As discussed earlier in the report, there is currently a proposal by IPC to install a liquefaction plant to send LNG South to Inuvik. At the time of this report, the proposed plan is going through an environmental assessment and some site preparation work has started.

A 5,000 m^3 LNG storage tank will also be built in Tuktoyaktuk to receive LNG from the LNG liquefaction plant. The storage tank will not have a boil off gas management system for simplicity, but will be able to send surplus boil off gas back to the liquefaction plant for re-liquefaction. Depending on the exact details of this facility, the 5,000 m^3 LNG storage tank could be used for both shore to ship bunkering and truck tanker bunkering.

6.1.3.4 CASE STUDY 2 - ATB

A 5,000 m^3 ice class LNG ATB will be used to transport LNG from Tuktoyaktuk to Cambridge Bay, see Table 52. This vessel will deliver LNG to Cambridge Bay during the Arctic summer season (July – October), during the remainder of the year the ATB is docked in Tuktoyaktuk. In this case study the ATB will not see a utilization rate of 100%, instead it will be much lower, closer to 25%. This low utilization will have a large impact on the final $/GJ of LNG to the end user in Cambridge Bay.

It is assumed that during the summer months the bunker barge could be making other LNG deliveries when not on the Tuktoyaktuk to Cambridge Bay route.

Table 52: LNG Carrier Vessel Particulars

Type	LNG ATB
Overall Length (m)	95
Beam (m)	19
Draft (m)	4
Gross Tonnage	2,500
Deadweight (t)	2,000
Speed (kts)	6
Power (kW)	Tug

6.1.3.5 CASE STUDY 2 - CAMBRIDGE BAY STORAGE TANK DESCRIPTION

A 10,000 m^3 LNG storage tank will be built in Cambridge to receive LNG deliveries from the LNG bunker barge. The storage tank will not have a boil off gas management system for simplicity. In this scenario it is assumed that the town of Cambridge Bay could use at minimum, the maximum boil off gas rate (1%/day), which for the 10,000 m^3 tank equates to 2200 GJ of gas per day as a maximum. The boil off profile of the tank is shown below in Figure 111.

The number of Arctic vessels could be bunkered with a 10,000 m^3/year liquefaction plant varies depending on the size of each vessels onboard LNG tank. However, as an example, current Northern Canadian LNG cargo vessels like the Mia Desgagnés have onboard LNG tanks of ~600 m^3, that would equate to roughly 16 bunkering's if 100% of the plants LNG went to ship bunkering.

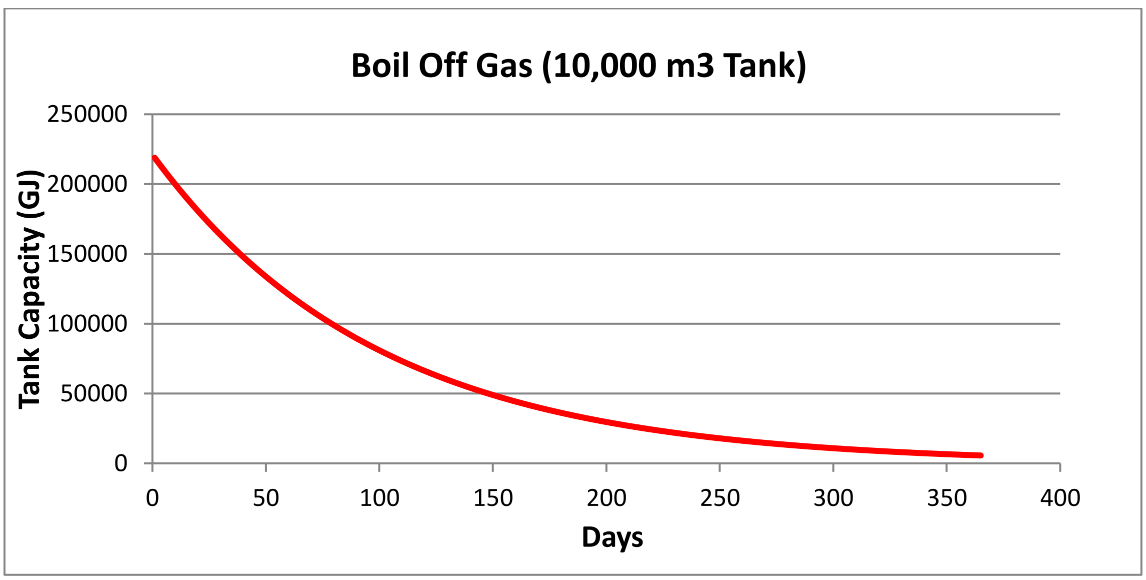


Figure 111: 10,000 m^3 Boil Off Gas Profile (@ 1%/day)

6.1.3.6 CASE STUDY 2 - MODEL INPUTS

The case study inputs shown in Table 53 is a non-exhaustive list of the inputs used to run the model.

Table 53: Case Study 2 Inputs

Category	Value	Units
Small Scale LNG Plant		
Capex	$46,000,000	$
Labor, Maintenance and Other	3%	%CAPEX/year
Amortization Period	20	Years
LNG Storage Tank - Tuktoyaktuk		
Capex	$26,000,000	$
Labor, Material and Other	2%	%CAPEX/year
Amortization Period	20	years
Bunker Barge		
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	$
Labor, Material and Other	2%	%CAPEX/year
Amortization Period	20	years

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

6.1.3.7 CASE STUDY 2 - RESULTS

The output for Case Study 2 is the cost ($/GJ) to the end user, which in the case of this study could either be the town of Cambridge Bay via a regasification unit, or marine customers via shore to ship bunkering. The end user cost is 37.95 $/GJ of LNG in Cambridge Bay, as detailed in Figure 112 below. The figure shows that the production, transportation and storage of LNG in the Arctic is roughly triple the cost of LNG in the South, not considering any Arctic LNG energy subsidies. To compare the LNG price to diesel prices in terms of delivered energy per dollar, the cost of LNG in this case study is $1.39 Diesel Liter Equivalent (DLE). The DLE is calculated by determining the cost per GJ ($/GJ) of energy delivered and then converting that to cost per liter ($/L) as if based on the energy density of diesel.

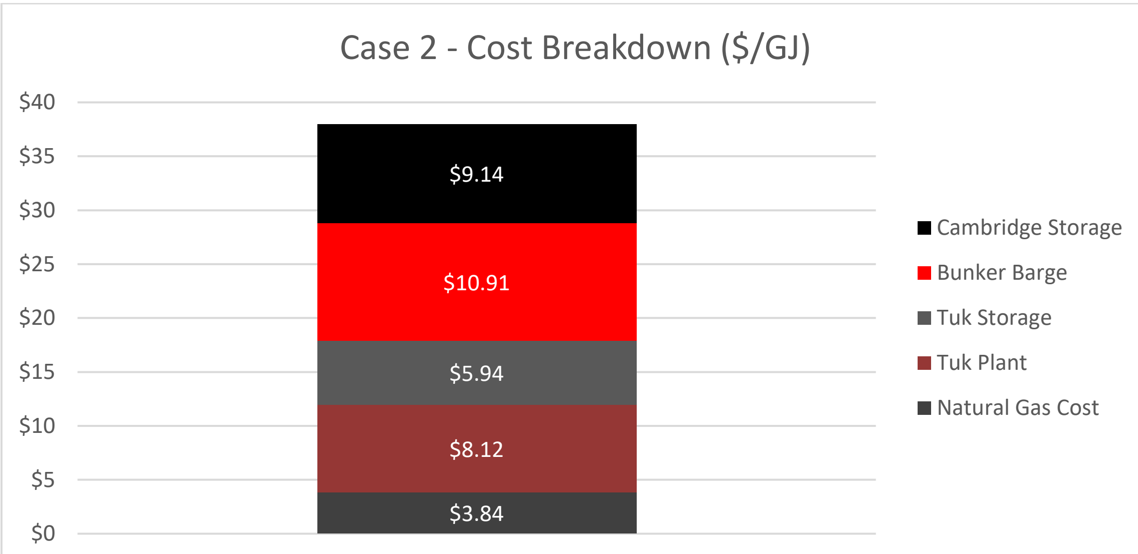


Figure 112: Case Study 2 Results

With respect to the required CAPEX for Case Study 2, it is estimated at approximately $170,000,000, as shown in Figure 113. While these costs are considered to be realistic, it should be understood that they are indicative only, as there are very few examples of LNG use in the Arctic.

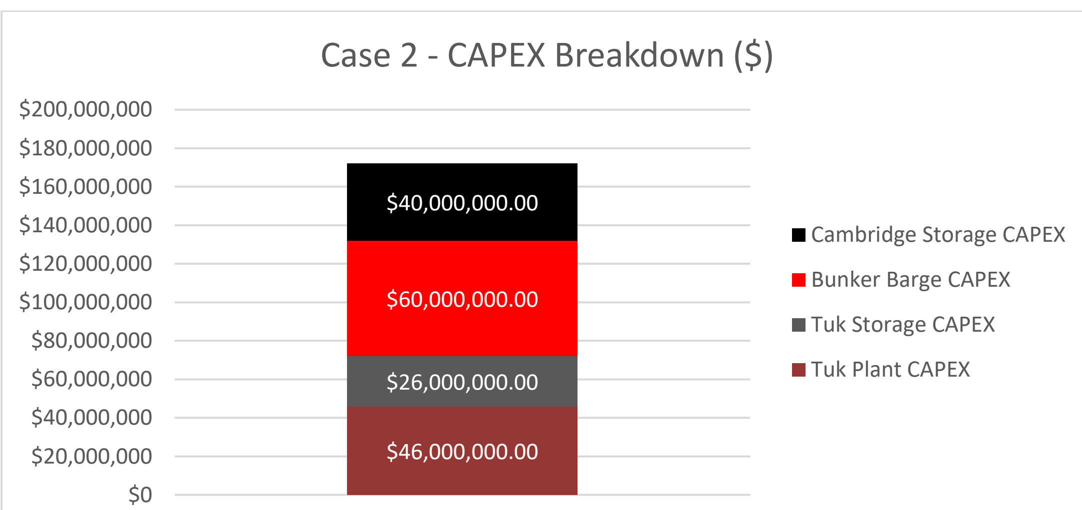


Figure 113: Case Study 2 CAPEX

7 CONCLUSIONS

This project task has explored the infrastructure aspects of adopting LNG as a marine fuel. This task is intended to provide information on infrastructure availability and requirements for the supply and distribution of LNG to marine applications. Supplementary information on energy consumption on land that is currently supplied by ship is also provided, as shown in Table 46.

While natural gas (NG) itself is plentiful throughout Canada and the United States, there is currently very little LNG production or distribution capacity in the Arctic, which currently does not have the capacity to support a fleet of LNG fuelled marine vessels. There are expansion plans for domestic LNG production and when various export-oriented projects are brought online, potentially in the near future, production of LNG is expected to rise dramatically. It is less clear whether any of the export orientated plant capacity will be made available to marine fuel projects, whether purely domestic or oriented towards deep sea operators.

LNG for marine use may be drawn from large export-oriented facilities, or from smaller-scale facilities that target transportation fuel and other sectors. Any option must make economic sense to all of the entities involved in the supply chain.

The estimated price per GJ and DLE of LNG is listed in Table 54. This clearly shows how critical the economics are when considering how to implement an Arctic LNG supply chain, especially how important energy independence is when considering the local production of LNG.

Table 54: Case Study LNG Cost

	Location	LNG Cost ($/GJ)	DLE
Case Study 1	Iqaluit	$18.83	$0.69
Case Study 2	Cambridge Bay	$37.95	$1.39

The overall conclusion is that it should be possible to develop an Artic LNG supply chain at attractive prices ($/GJ) in comparison with fuel oil alternatives, as shown by the conversion of LNG prices to a DLE. However, LNG pricing is sensitive to many factors and assumptions, including the level of utilization of a number of capital-intensive assets, and also the distances between the LNG production facility and the bunkering locations for the end users.

The results of this task feed into the review of implementation strategies under Chapter 9.

CHAPTER 6 HUMAN RESOURCES

1 INTRODUCTION

Chapter 6 of the report focuses on identifying the competency and training requirements associated with the introduction of LNG in the Arctic. An overview of competency requirements is provided for personnel required at all stages in the vessel lifecycle: vessel designers, shipyard personnel, original equipment manufacturers, certification and inspection authorities, seafarers, facility and bunkering personnel and emergency responders.

2 COMPENTENCY OVERVIEW

2.1 VESSEL DESIGNERS

Since the previous studies, the number of LNG and LNG-ready vessels has increased substantially, as shown in Figure 114. A portion of these have been designed in North America, enhancing the experience of vessel designers in LNG. There are several training options for vessel designers which provide an overview of design and operations considerations, although there are no formal training requirements.

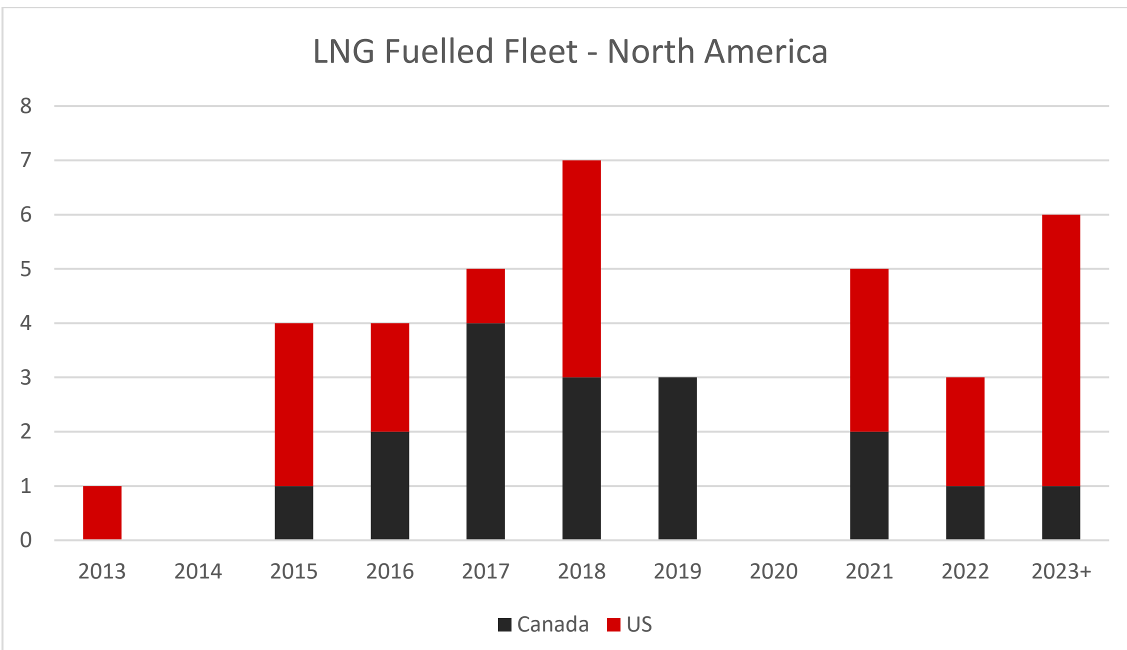


Figure 114: New LNG Vessels Entering Service

2.2 SEAFARERS

For seafarers there are established competency requirements for different levels; basic and advanced. These requirements are detailed in Standards of Training, Certification and Watchkeeping for Seafarers (95) (STCW 95) Convention and Part A of the STCW Code. Those required to have advanced training include masters, engineer officers and all personnel with immediate responsibility for the fuel and fuel system on IGF Code vessels. Basic training shall be completed for seafarers who have safety duties related to the care, use or emergency response to the fuel on board IGF Code vessels.

An amendment to the STCW Code in 2015 (IMO-RESOLUTION, 2015) introduced training requirements for personnel work on board vessels subject to the IGF Code. These are summarized in Table 55.

Table 55: STCW Code – IGF Competency Requirements

Competency	Basic	Advanced
Contribute to the safe operation of a ship subject to the IGF Code	✓	✗
Take precautions to prevent hazards on a ship subject to the IGF Code	✓	✗
Apply occupational health and safety precautions and measures	✓	✓
Carry out firefighting operations on a ship subject to the IGF Code (Advanced includes prevention, control, firefighting and extinguishing)	✓	✓
Respond to emergencies	✓	✗
Take precautions to prevent pollution of the environment from the release of fuels found on ships subject to the IGF Code	✓	✓
Familiarity with physical and chemical properties of fuels aboard ships subject to the IGF Code	✗	✓
Operate controls of fuel related to propulsion plant and engineering systems and services and safety devices on ships subject to the IGF Code	✗	✓
Ability to safely perform and monitor all operations related to the fuels used on board ships subject to the IGF Code	✗	✓
Plan and monitor safe bunkering, stowage and securing of the fuel on board ships subject to the IGF Code	✗	✓
Monitor and control compliance with legislative requirements	✗	✓
Take precautions to prevent hazards	✗	✓

Further to the competency requirements detailed in the Code, a notable requirement in the STCW International Convention (Annex Regulation V/3) is for advanced training candidates to have:

- “8.2 completed at least one month of approved seagoing service that includes a minimum of three bunkering operations on board ships subject to the IGF Code. Two of the three bunkering operations may be replaced by approved simulator training on bunkering operations as part of the training” and,
- “9.3 have completed sea going service of three months in the previous five years on board: .1 ships subject to the IGF Code; 2. tankers carrying as cargo, fuels covered by the IGF Code; or .3 ships using gases or low flashpoint fuel as fuel.”

The seagoing service requirements were a significant challenge for some of the earliest adopters of LNG, and a number of Canadian (and other) ship operators sent personnel aboard (LNG) gas carriers to comply under 9.3 above. This has become less necessary as more candidate vessels become available in gas-fuelled fleets. Simulator training has also become more widely available.

Transport Canada does not have specific requirements with regards to training on personnel on board LNG fuelled vessels. In terms of Canada specific regulations, there are the Marine Personnel Regulations. As discussed in Task 6, efforts are ongoing to bring these Regulations in line with the STCW requirements for vessels subject to the IGF Code. Thus, it can be presumed that Canada will not implement more onerous requirements.

2.3 CERTIFICATION AND INSPECTION AUTHORITIES

All of the Recognized Organizations (ROs) have experience with LNG vessels, although not all have experience in America as shown in Table 56 (data for 2021). LR, BV and ABS are so far the only ROs who have undertaken projects within Canada. The majority of classification societies have in-house training programs for their surveyors, and in some cases make these available to 3rd parties including representatives from flag states.

Although most approval and certification aspects of an LNG project are normally delegated to an RO by Transport Canada, they will still have involvement due to the role of the Marine Technical Review Board (MTRB) – see also Chapter 7 for regulatory requirements. Transport Canada has provided a number of its staff with training on LNG and participates in many of the risk assessments required under TC policies for IGF vessels.

Table 56: Classification Societies and LNG

Name of Class	Acronym	LNG Vessels (America)	LNG Vessels (Rest of World)
American Bureau of Shipping	ABS	15	67
Bureau Veritas	BV	8	91
Class NK	NK	0	13
Det Norske Veritas	DNV	3	211
Korean Register	KR	0	1
Lloyd's Register	LR	7	46
RINA Services	RINA	0	16

2.4 SHIPYARD PERSONNEL

Whether constructing or maintaining LNG-fuelled vessels, shipyard personnel must be familiar with the safety precautions and procedures required when working with natural gas. In addition to its low flashpoint, LNG is also a cryogenic liquid which poses a hazard to humans related to cold vapours as well as a risk of material embrittlement in the event of a spill.

Training is required to ensure shipyard workers and technical staff are aware of the hazards of LNG and the specific requirements when constructing or repairing a gas fuelled vessel.

While a large portion of the construction of an LNG-fuelled ship is similar to that of a diesel driven ship, there are a number of LNG-specific technologies and systems which are generally not found on a diesel-powered ship. OEMs normally play a role in providing the technical expertise and detailed installation specifications to deal with any knowledge or skill gaps.

In the case of repairs or servicing of these systems, OEMs also play a large role in providing the technical and practical expertise required, and normally act as subcontractors for these repairs contracted to the owner or the yard. Overhauls of gas systems have now been undertaken without incident on a range of vessels on Canada's East and West Coasts.

2.5 BUNKERING PERSONNEL

The safe bunkering of a gas-fuelled vessel requires additional safety awareness and competencies which are not addressed in the typical training provided to personnel involved in bunkering fuel oils for ships. For vessel operators to consider LNG, they will require confidence that LNG can be bunkered safely and efficiently. This is also an essential consideration for port authorities and other stakeholders. Specific training is required for bunkering personnel to ensure that the operation is undertaken in a safe manner. Two standards which provide details on recommended training include CSA Z276-18 LNG Production, Storage and Handling and the NFPA-59A: Standard for the Production, Storage, and Handling of Liquefied Natural Gas (CSA, 2021), (NFPA, 2021).

The delivery method selected for bunkering a vessel is dependent on the facilities available and the amount of fuel being bunkered. For LNG-fuelled vessels, the following bunkering methods may be considered by ship operators and fuel suppliers:

- Tanker truck to ship;
    - truck shore-side
    - trucks onboard the vessel;
- Shore facilities to ship;
- Ship to ship (STS);
    - LNG bunker ship to ship
    - LNG supply barge to ship

Tanker truck to ship is only method of LNG bunkering currently used in Canada and is available in both the West and East Coasts of Canada. The truck operators have to be trained in LNG bunkering and in Quebec there is a requirement for the operator to complete 6 bunkerings under supervision by a certified trainer.

Ship to ship LNG bunkering is not available in Canada, although several projects are known to be progressing targeting the Greater Vancouver area. Both bunker vessel and bunker barge options for refueling are under development. The proponents are planning to utilize the extensive guidance available from organizations such as the Society for Gas as a Marine Fuel (SGMF) to set up the procedures for training and operations that will be used.

Shore side bunkering facilities have many similarities to LNG export terminals. Existing standards and industry best practices have been developed which address the training requirements for bunkering facilities, by the SGMF and others. While the scale of bunkering and export facilities is quite different, aspects of the safety management training provide a model for LNG fueling. There are no fixed shore facilities for LNG bunkering in Canada at present, but this approach is expected to be used for the LNG escort tug fleet that will be employed at the LNG Canada export terminal in Kitimat.

2.6 SHORESIDE FACILITIES

Ship bunkering is one of the functions that could be provided by a shoreside installation. Others may include local distribution to power or heating plants, fueling of road vehicles, etc. Provincial and territorial standards for training requirements exist to cover aspects such as the management pressure vessels, electrical power, etc. Companies such as Cryopeak and Energir provide additional in-house training to personnel with the necessary education and experience to meet applicable standards. Energir for example runs its Ecole de Technologies Gaziere which offers a full range of practical and theoretical courses to its own staff and external contractors.

2.7 EMERGENCY RESPONDERS

Fire fighters and other emergency responders who confront fires and emergencies involving marine vessels typically need to be provided with training in order to ensure that they can respond safely and effectively to emergencies involving LNG vessels. Hazards include the low flashpoint of the natural gas as vapour, the cryogenic temperature of LNG, and rapid phase transition. While land-based fire fighters are already trained to respond to fires involving various fuels and hazards such as gasoline or chemicals, specialized training focused on the properties of LNG and its combustion characteristics should be considered for emergency responders. A model for this is the program used by FortisBC working with first responders in the B.C. lower mainland.

The Arctic provides a particular challenge due to the expansive area coupled with low and widely distributed population. Therefore, vessel operators should assume that they need to be largely self-sufficient in dealing with emergencies. Those who have completed the Basic Training for IGF Vessels will already have competency with emergency response. Should vessel operators wish to strengthen their capabilities in emergency response LNG firefighting and spill response training facilities do exist throughout the world. US institutions which offer specific LNG emergency response training include Marine Firefighting Inc., Texas A&M Engineering Extension Service, Fire Academy of the South. In Canada, the Justice Institute of British Columbia promote an LNG Facilities Emergency Response Training.

Although vessel operators should ensure they are well prepared, training of emergency responders however should not be ruled out. Ferus NGF who provide LNG to Yukon and Northwest Territories via. truck, delivered virtual LNG safety training to 17 organizations, primarily fire departments. The training provided an awareness of LNG characteristics and hazards to equip emergency responders with essential knowledge for decision making in emergency events. This type of initiative should be considered should LNG vessels become more prevalent in the Arctic, or when new facilities are built.

2.8 ORIGINAL EQUIPMENT MANFACUTURERS

Original equipment manufacturers (OEMs) must provide employees with training in accordance with occupational health and safety requirements mandated by the applicable regulatory authorities. LNG-fuelled vessels require specific engines, tanks, and gas distribution systems which differ from the systems typically found onboard vessels fuelled by diesel or fuel oil. OEMs have training programs that are in place 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.

3 TRAINING

3.1 SEAFARERS

Whilst the STCW Convention provides details of the training required, IMO does not approve training course or institutions. It is the responsibility of governments to determine these for their country.

There are many colleges and institutions in Canada offering training for mariners, and Transport Canada provides a comprehensive list of recognized institutions and their approved training courses. Although they recognize the training courses of "IGFA - Advanced Training for service on vessels subject to the IGF code" and "IGFB - Basic Training for service on vessels subject to the IGF code", TC does not list institutions offering these as approved courses. The Institut Maritime du Québec is providing basic and advanced training to mariners for Groupe Desgagnés and the Societé des traversiers du Québec. The Justice Institute of British Columbia also offers a "Gas Fuelled Vessel – Basic Training" course. It is unclear whether these and other Canadian courses and training programs have formal approval from TC. Cryopeak has provided supplementary training courses to many mariners and shore staff from BC Ferries and Seaspan Ferries.

A wider range of options is available outside Canada, and a number of Canadian operators have made use of courses provided by such providers. In the US, training providers offering Basic and Advanced IGF Code Operations training approved by the United States Coast Guard include the STAR Center, State University New York Maritime College, United States Maritime Resource Center (USMRC) and United States Merchant Marine Academy. In the UK, Maritime & Coastguard Agency approved training is offered by Clyde Training Solutions, Stream Marine Training and Tyne Coast College.

Training options include seafarers travelling to a training location, an approved trainer travelling to Canada or exploring remote training options. Generally, the second option has been used, with challenges during pandemic restrictions.

Larger companies with significant numbers of LNG vessels and staff involved in their operations have set up in-house programs for training. As an example, in Canada, BC Ferries is currently aiming to recruit/select an LNG Advanced/Person in Charge Trainer for their LNG fleet and shoreside operations.

3.2 FACILITY & SHORE-SIDE BUNKERING PERSONNEL

Training for facility and shore-side bunkering personnel will comprise of different elements including formal external training courses and internal training where more practical skills would be developed. Guidance on internal training programs could be sought from companies within Canada who already have LNG facilities, such as Fortis BC and Cryopeak.

An external training program which could be considered is the Liquefied Natural Gas Process Operations program offered by Southern Alberta Institute of Technology (SAIT). This comprises of the following four courses:

- Level A: Introduction to Liquefied Natural Gas Plant Operations
- Level B: Liquefied Natural Gas Plant Process and Operation
- Level C: Liquefied Natural Gas Plant Equipment
- Level D: Liquefied Natural Gas Auxiliary Equipment/Instrumentation.

3.3 ARCTIC TRAINING NEEDS AND CAPABILITIES

Whilst the preceding sections have focused more generally on competency and LNG, an important consideration is how the training could be conducted specifically for the Arctic application. This mainly concerns personnel in the vessel lifecycle who would be stationed in the Arctic, bunkering personnel and potentially emergency responders.

As described above, a number of institutions and organizations across Canada have now established training and certification programs for ship- and shore-side LNG operations. It is probable that in the early stages of implementing LNG operations in the Arctic, ship personnel will be trained by these organizations and obtain practical experience with an existing LNG-capable fleet in Canada or elsewhere (see Section 2.2). An increase in the number of LNG-fuelled vessels in the Arctic will expand the opportunities for gaining experience directly on these vessels.

For shore-side personnel, it is likely to be more cost-effective for the facility suppliers to arrange for on-site training using the actual equipment installed. Different level of training could be provided to the facility staff and to local emergency responders; and potentially familiarization programs could be offered to other local stakeholders to increase understanding and comfort. As an example of a broad-based approach, B.C. Ferries has provided familiarization training to almost its entire staff, to enable all personnel to respond to customer questions on issues of potential concern with new technology insertion. This is considered to have contributed to high levels of public acceptance of the introduction of LNG-fuelled vessels.

4 CONCLUSIONS

Operating a supply chain for LNG-fuelled operations in the Canadian Arctic will require personnel with competencies in design, operation, maintenance, and safety management. Training is available within Canada for the majority of these, with organizations in the US and elsewhere available to supplement Canadian resources.

Canadian shipowners, fuel distribution companies, and LNG facility operators have established effective programs for training their staff, using a mix of in-house and external resources. There are a large and increasing number of best practices documents that can assist with this.

There will be some unique challenges in the Canadian Arctic due to the general lack of human and other resources. However, there are no major barriers to building the necessary competencies for an Arctic LNG supply chain.

CHAPTER 7 REGULATIONS

1 INTRODUCTION

In overall terms, Task 6 of the project is intended to describe the framework for the regulatory approach to the use of NG as a marine fuel from the supply of the gas plant to the operations of the ship. An effective regulatory framework is considered essential to the success of any future project involving the use of LNG. It is needed to assure all stakeholders of safety, reduce project risk for the proponents, and inform and guide the work of designers, suppliers, operators and others throughout the project's life.

The framework has been developed by reviewing present and planned regulations, rules, standards and guidelines, and highlighting absences of such documents, that relate to:

- Vessel design and construction;
- Operations in coastal waters and waterways;
- Bunkering and terminal facilities; and
- Personnel (see also Chapter 6).

Security issues were addressed in the previous phases of the work, which concluded that the existing regulatory approach provided adequate coverage for these. There have been no subsequent developments sufficient to change this conclusion.

A large number of Acts, Regulations, Rules and Standards are referenced throughout the report, and the summary descriptions provided are believed to be accurate as of the date of the report. It should be understood that all of this documentation is amended regularly, and so interested parties should check the most current versions in all cases.

2 REGULATORY FRAMEWORK

This report summarizes previous regulatory findings as well as providing a summary of new or updated regulations. These are be split into regulations which apply at an International, Canadian (National) and Canadian (Provincial) level.

2.1 INTERNATIONAL

At the international level there are several bodies which provide regulations or guidance related to LNG. The bodies are summarized in Figure 115 with further explanation of their applicable content detailed in the proceeding sections.

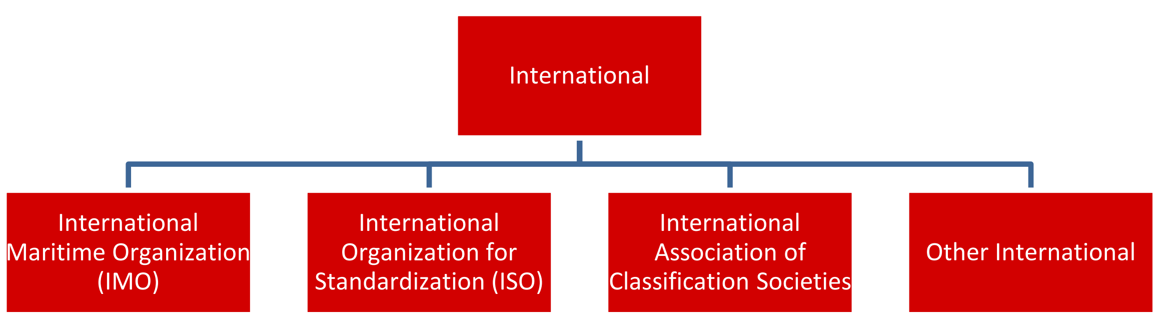


Figure 115: International Regulatory Framework

2.1.1 INTERNATIONAL MARITIME ORGANIZATION

The IMO is the United Nations specialized agency with responsibility for the safety and security of shipping and the prevention of marine pollution by ships. IMO does this through three major conventions, and a range of Codes, Guidelines and other instruments which address more specialized aspects of shipping. The conventions names are self-explanatory:

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

A notable recent update to the MARPOL convention is the HFO use and carriage ban in the Arctic. This will take effect in 2024 but waivers will be possible until 2029. This will drive many vessel operators to consider alternative fuels, including LNG.

Overviews on Conventions and Codes particularly relevant to LNG vessels are detailed as follows:

<u>International Code of Safety for Ships Using Gases or Other Low Flashpoint Fuels (IGF Code):</u>

IMO's development of a Code covering NG and other low flashpoint (<60^0 C) fuels culminated in the adoption of the Code at the 95^{th} session of the Maritime Security Committee (MSC) in June 2015. The Code took effect on January 1, 2017, under amendments to various chapters of the SOLAS Convention. No updates have been made to the Code since its original publication date.

It is a quite lengthy document, with 124 pages covering various aspects of design and operation. While some of its provisions are highly prescriptive, others set goals and performance requirements that can be satisfied in a number of different ways. In consequence, the Code requires a risk assessment of some aspects to demonstrate compliance.

Achieving a satisfactory level of risk will often involve following additional rules, standards and guidelines such as those of standardization organizations and classification societies, as outlined further below.

<u>International Code for the Construction and Equipment of Ships Carrying Liquefied Gases in Bulk (IGC Code)</u>

The volume of liquefied gases transported by ship increased rapidly in the 1980s, and IMO introduced the International Code for the Construction and Equipment of Ships Carrying Liquefied Gases in Bulk (IGC Code) to regulate such gas carriers. The purpose of the Code is to minimize additional risks to the ship and the environment owing to the products being transported under cryogenic (refrigerated) or pressure conditions. Under amendments to SOLAS, the IGC code is mandatory for all gas carriers. The new IGF Code has drawn extensively on the IGC code in many areas, but IGF has been developed within a new "goal based" framework and some aspects differ considerably from IGC as a result.

The IGC Code is applicable to vessels carrying fuel with which to bunker IGF Code ships. However, a number of administrations adjust aspects of its application to deal with the specific features of bunkering operations (see below).

IMO considers that a ship will either be subject to IGF or to IGC, so that a gas carrier using its cargo as a fuel is IGC, while other ships using NG fuel will be IGF. There may, however, be some situations in which some or all of the tankage on an NG-fuelled vessel can be used to transport NG as a cargo for other users. This is envisaged in a number of projects but has not yet reached realization in any.

International Safety Management Code (ISM Code)

Human error is recognized as being a contributor to the majority of marine (and other) accidents. The ISM Code, mandatory for SOLAS ships, establishes safety-management objectives and requires a safety management system (SMS) to be established by "the Company", which is defined as the shipowner or any person, such as the manager or bareboat charterer, who has assumed responsibility for operating the ship. The Company is then required to establish and implement a policy for achieving these objectives. This includes providing the necessary resources and shore-based support.

The Company's SMS is externally assessed for adequacy before a Safety Management Certificate is awarded, and is subject to ongoing internal and external audits.

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

The IMO's International Convention on Standards of Training, Certification and Watchkeeping for Seafarers (STCW), 1978 was the first internationally agreed Convention to address the issue of minimum standards of competence for seafarers. In 1995 the STCW Convention was completely revised and updated to clarify the standards of competence required and provide effective mechanisms for enforcement of its provisions. Since then, another seven amendments have been adopted.

Those of interest with regards to LNG include the 2010 amendments which added new requirements for personnel serving on liquefied gas tankers. All officers serving aboard LNG carriers must have completed the basic training and the advanced competency must be met by masters, first officers, chief/1st/2nd engineers, and any person with immediate responsibility for loading, discharging, care in transit, handling of cargo, tank cleaning or other cargo-related operations on liquefied gas tankers. Prerequisites for both levels of training include sea time onboard an LNG carrier.

More recently the 2015 amendments included Resolution MSC.397(95) which introduced training requirements for personnel on ships subject to the IGF code. As noted above, this code relates to all vessels using gases or other low flashpoint fuels. Minimum competency requirements are detailed for basic and advanced training.

Code for Recognized Organizations (RO Code)

This Code, introduced in 2015 under Resolutions MSC/Res.349(49) and MEPC/Res.237(65) provides for flag states such as Canada to delegate inspection and certification responsibilities to suitable "recognized" external organizations, mainly (but not limited to) classification societies. This and other roles of classification societies are discussed at Section 2.1.3.

2.1.2 INTERNATIONAL ORGANIZATION FOR STANDARDIZATION

The International Organization for Standardization (ISO) is an international standard-setting body composed of representatives from various national standards organizations. The organization promotes worldwide proprietary, industrial and commercial standards. It is headquartered in Geneva, Switzerland.

ISO is a voluntary organization whose members are recognized authorities on standards, each one representing one country. The bulk of the work of ISO is done by the 2,700 technical committees, subcommittees, and working groups. Each committee and subcommittee is headed by a Secretariat from one of the member organizations

Many ISO standards and guidelines are used in the marine industry. Some significant ISO documents relevant to gas-fuelled shipping include:

ISO/TS 18683: Guidelines for Systems and Installations for Supply of LNG as Fuel to Ships

ISO/TS 18683:2015 gives guidance on the minimum requirements for the design and operation of the LNG bunkering facility, including the interface between the LNG supply facilities and receiving ship. It provides requirements and recommendations for operator and crew competency training, for the roles and responsibilities of the ship crew and bunkering personnel during LNG bunkering operations, and the functional requirements for equipment necessary to ensure safe LNG bunkering operations of LNG-fuelled ships. The standard is applicable to bunkering of both seagoing and inland trading vessels, and addresses all operations required such as inerting, gassing up, cooling down, and loading.

ISO/TS 16901: Guidance on performing risk assessment in the design of onshore LNG installations including the ship/shore interface

ISO/TS 16901:2015 provides a common approach and guidance to those undertaking assessment of the major safety hazards as part of the planning, design, and operation of LNG facilities onshore and at shoreline using risk-based methods and standards, to enable a safe design and operation of LNG facilities. The environmental risks associated with an LNG release are not addressed in the specification.

ISO 20519: Specification for bunkering of liquefied natural gas fuelled vessels

ISO 20519:2017 sets the requirements for LNG bunkering systems used to bunker LNG vessels, it aims to standardize the bunkering operations to ensure that vessel operators can select fuel provides which meet safety and quality standards.

Other ISO standards

ISO also has a number of technical standards relevant to equipment and materials relating to LNG. Many of these standards are prescriptive and can be directly applied to systems on board LNG-fuelled ships and in the systems supplying LNG to such ships. They can be found through the ISO website at www.iso.org.

2.1.3 INTERNATIONAL ASSOCIATION OF CLASSIFICATION SOCIETIES

Classification societies traditionally set and maintain technical standards for the design, construction, and operation of ships. These non-government organizations work around the world, often on behalf of governments for surveys on their registered vessels. Classification societies develop their own rules, adopt, adapt, and apply international standards, most significantly all IMO ship requirements.

The International Association of Classification Societies (IACS) is the membership organization for classification societies, providing the societies a forum to discuss, research and ensures they meet minimum technical standards. IACS is also the primary technical advisor to IMO, and contributed to the development of the IGF Code. IACS aims to standardize classification society rules through the publication of Unified Requirements, Guidelines and Interpretations of IMO instruments.

Classification societies work on behalf of national administrations such as Canada as “Recognized Organizations” (ROs). Currently, Canada authorizes seven societies, all of which have rules to address gas-fuelled ships, as listed in Table 57. It should be noted that since the last study many documents have been superseded, and there is now significantly more guidance and rule documentation available. IACS published Rec 142 LNG Bunkering Guidelines in 2016 which provide minimum recommendations for bunkering risk assessments, equipment and operations. This has fed into individual classification society rules and guidance on bunkering.

Table 57: Classification societies' rules and guidance for gas-fuelled ships (Canadian ROs)

Name of Class	Acronym	Title
American Bureau of Shipping	ABS	Guide for Vessels Intended to Carry Compressed Natural Gases In Bulk 2020 Guide for Gas and Other Low-Flashpoint Fuel Ready Vessels 2021 Guide for LNG Bunkering 2018 Guide for LNG Cargo Ready Vessels 2019
Bureau Veritas	BV	NR529 Gas-fuelled ships NR645 Rules for the classification of floating storage regasification units and floating storage units NI618 Guidelines on LNG bunkering NI654 Guidelines on conversion to LNG as fuel NR620 LNG bunkering ship NI655 LNG carrier conversion to FSRU or FSU
Class NK	NK	Guidelines for Gas-Fuelled Ships
Det Norske Veritas	DNV	Rules for classification of ships, Part 6, Chapter 13 Gas Fuelled Ship Installations DNV-RP-G105 Development and operation of liquefied natural gas bunkering facilities
Korean Register	KR	Guidance for Gas-Fuelled Ships 2016 Guidance for floating liquefied gas units 2017 Guidance for LNG fuel ready ships 2017
Lloyd's Register	LR	Rules for LNG ships and barges equipped with regasification systems Rules and regulations for the construction and classification of ships for the carriage of liquefied gases in bulk Rules and regulations for the classification of ships using gases or other low-flashpoint fuels
RINA Services	RINA	Rules for the classification of ships

2.1.4 OTHER INTERNATIONAL

2.1.4.1 INTERNATIONAL SOCIETY OF GAS TANKER AND TERMINAL OPERATORS

The International Society of Gas Tanker and Terminal Operator (SIGTTO) and International Oil Companies Marine Forum (OCIMF) have developed many guidelines for the handling of LNG as a cargo. Some which may be more applicable for Arctic operations include:

- Ship to Ship Transfer Guide for Petroleum, Chemicals and Liquefied Gases
- LNG and LPG Experience Matrix Guidelines for Use
- LNG Shipping Suggested Competency Standards
- LNG Operations in Port Areas
- Crew Safety Standards and Training for Large LNG Carriers.

2.1.4.2 SOCIETY FOR GAS AS A MARINE FUEL

In 2013 SIGTTO announced that it would take the lead in establishing an organization targeted at gas-fuelled vessels; the Society for Gas as a Marine Fuel (SGMF). A major purpose for SGMF is to develop advice and guidance for best industrial practice among its members and to develop best practice for the use of LNG as marine fuel. It also has Consultative Status with the IMO and is the key resource for information in the industry.

Since its establishment SGMF has issued 16 publications, including an introductory guide, LNG Bunkering Safety Guidelines, and LNG Bunkering Competency Guidelines. Many Canadian organizations involved with marine LNG including BCFS, Seaspan, VFPA and FortisBC are SGMF members, and follow SGMF publications in many aspects of their operations.

2.1.4.3 INTERNATIONAL ELECTROTECHNICAL COMMISSION

The International Electrotechnical Commission (IEC) is a non-profit, non-governmental international standards organization that prepares and publishes International Standards for electrical, electronic and related technologies – collectively known as "electrotechnology". IEC standards cover technologies from power generation, transmission and distribution to home appliances and office equipment, and many others. The IEC also manages three global conformity assessment systems that certify whether equipment, system or components conform to its International Standards. The IEC cooperates closely with the ISO and several major standards development organizations such as the European Union (EU) and the U.S.-based Institute of Electrical and Electronics Engineers (IEEE) in order to align standards internationally.

Of particular relevance to LNG-fuelled ships is IEC 60079, Part 10 Electrical apparatus for explosive gas atmospheres: Classification of hazardous areas.

2.1.5 UNITED STATES COAST GUARD

The USCG has been active in developing policies, guidance, and regulatory proposals related to NG as a fuel. Some notable policies include:

<u>USCG Policy Letter CG-MMC No. 01-21, (2021) “Guidance for Obtaining Endorsements for Basic and Advanced Endorsement for Low Flashpoint Fuels (IGF Code)”</u> provides guidance on how mariners can get Merchant Marine Credential (MMC) endorsements in accordance with STCW for service on vessels subject to the IGF Code. Whilst USCG does not require mariners to hold these endorsements, it may be required for US vessels in foreign ports or mariners serving on foreign vessels.

USCG Policy Letter CG-521 No. 01-12 "Equivalency Determination – Design Criteria for Natural Gas Fuel Systems" establishes criteria determined to achieve a level of safety at least equivalent to traditional fuel systems. An update was issued to this letter in 2017

USCG Policy Letter CG-OES No. 01-15 "Guidance for Liquefied Natural Gas Fuel Transfer Operations and Training of Personnel on Vessels Using Natural Gas as Fuel" provides a comprehensive cross-referencing to existing USCG (CFR) regulations applicable to NG-fuelled vessels and personnel qualifications. It also presents detailed recommendations for the content of operations, maintenance and emergency manuals that should be available, and guidance for the conduct of bunkering operations.

USCG Policy Letter CG-OES No. 02-15 "Guidance Related to Vessels and Waterfront Facilities Conducting Liquefied Natural Gas (LNG) Marine Fuel Transfer (Bunkering) Operations" identifies minimum safety and security requirements and provides guidance for assessing situations where regulations are not applicable or appropriate.

USCG Policy Letter CG-ENG No 01-15 "Design Standards for U.S. Barges Intending to Carry Liquefied Natural Gas in Bulk" provides guidance intended to bridge the gap between LNG carriers and bunkering vessels, though its applicability is limited to non-self-propelled vessels (barges) which are not covered under the IGC Code.

USCG Memorandum LGC NCOE Field Notice 01-2015 "LNG Bunkering Recommendations" provides recommendations drawn from field observations of best practices and of errors during recent LNG bunkering operations in the US. An update to this memorandum (01-2016) clarifies differences in requirements for U.S. and non-U.S. vessels.

2.2 CANADIAN (NATIONAL)

Almost all aspects of marine transportation in Canada are federally regulated, and the lead department for most aspects of regulations regarding design and maintenance is Transport Canada. Other departments and agencies have roles in operational safety and emergency response, most notably the Coast Guard (under the Department of Fisheries and Oceans).

The situation regarding terminal infrastructure is somewhat more complex, and a number of federal government bodies are involved in project reviews and approvals and in ongoing inspection and certification. As infrastructure moves away from the water's edge, the provincial and territorial ministries and agencies take on the leading role in most cases.

Federal and provincial regulations often incorporate by reference or allow for the use of 3rd party standards, such as those of the CSA Group (formerly Canadian Standards Association) and ISO/IEC and other internationally recognized standards bodies.

Figure 116 presents the broad framework of the Canadian regulatory system, with the more important aspects discussed in more detail in the following sections.

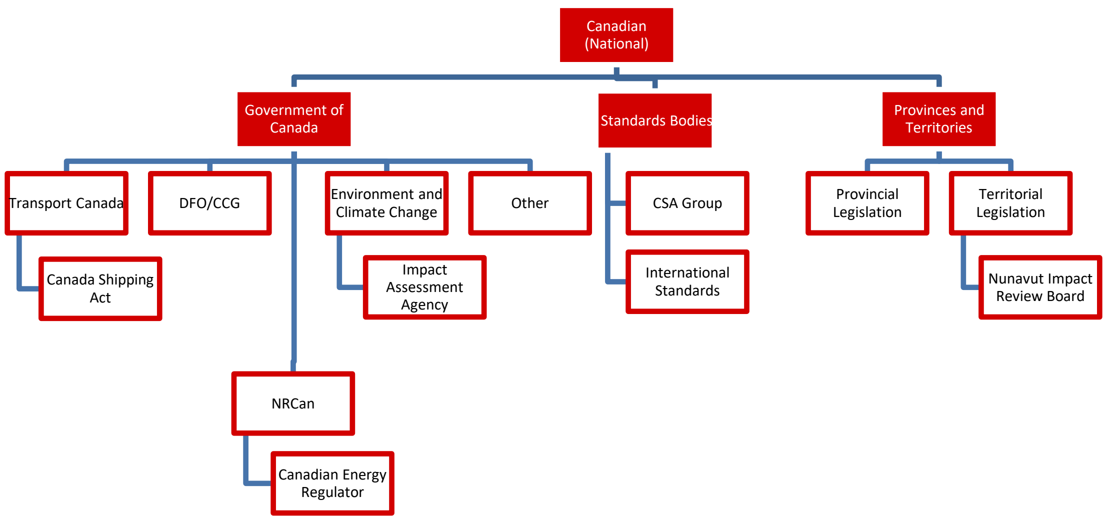


Figure 116: Canadian National Regulatory Framework

2.2.1 TRANSPORT CANADA

Legislation for which TC is the responsible department includes:

- Canada Shipping Act
- Arctic Waters Pollution Prevention Act (joint with DFO, NRCan and Crown-Indigenous Relations and Northern Affairs)
- Navigation Protection Act
- Transportation of Dangerous Goods Act
- Ports Act
- Pilotage Act

Under each of these acts various regulations govern design and/or operations of ships and other form of transportation, including the transport of LNG by trucks and containers. TC also has responsibilities for pipelines, but the long distance transport of bulk gas by pipeline is outside the scope of this project.

2.2.1.1 CANADIAN SHIPPING ACT

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.

Many Canadian regulations are not fully aligned with IMO Conventions and Codes, including those applicable to the use of natural gas as a fuel or the carriage of LNG as a cargo. An alternative set of policies and procedures are available to allow for this, including:

- TP 13585 – 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

Jointly, these allow for the use of the IMO Convention framework together with some specific Canadian supplementary requirements to be used to demonstrate an equivalent level of safety to the Canada Shipping Act system. The Policy regarding natural gas as a fuel is very closely aligned with the IGF Code.

Any use of this approach requires review by the Marine Technical Review Board, which is authorized to grant Canadian certifications on this basis. MTRB submissions frequently – and in the case of LNG vessels always – require that a risk assessment be undertaken. This is discussed further at Section 3.

2.2.1.2 ARCTIC WATERS POLLUTION PREVENTION ACT (AWPPA)

Under the AWPPA, the Arctic Shipping Safety and Pollution Prevention Regulations (ASSPPR) are closely aligned with the IMO Polar Code, whose provisions are themselves incorporated into the IMO SOLAS and MARPOL Conventions. Canada applies more stringent standards for some issues, including the control of operations in ice-infested waters. The level of ice strengthening of a ship determines where and when it is allowed to go, depending on the prevailing ice conditions. Control is exercised through a reporting regime which is coordinated by the Coast Guard through the NORDREG (Northern Canada Vessel Traffic Services Zone) organization.

There are no specific LNG-related provisions under the ASSPPR, but it is an important element of the overall Arctic marine safety system.

2.2.1.3 NAVIGATION PROTECTION ACT (NPA)

The most relevant aspects of the NPA for LNG use and transportation are contained under the TERMPOL (Technical Review Process of Marine Terminal Systems and Transhipment Sites) Code (TP 743 E). This is a notionally voluntary review process. When a marine terminal is built regional shipping changes as vessels route to the new location, TERMPOL aims to review the changes to determine potential threats to safety. The code applies to terminals for bulk shipments of oil, chemicals, liquefied gas and other cargo which Transport Canada deems as posing a safety risk.

A TERMPOL assessment is in practice a necessary component of any approvals for any marine terminal above a given size, though this size is not explicitly defined.

2.2.1.4 TRANSPORTATION OF DANGEROUS GOODS ACT (TDG)

TC designates NG/LNG as a dangerous good, and therefore the Transportation of Dangerous Goods Act and its regulations are applicable to truck and rail transportation of NG from liquefaction plant (or compressor) to the vessel or bunkering station. These set design and procedural requirements for vehicles and their operation.

For ships the regulations under the Canada Shipping Act take the place of TDG.

2.2.1.5 MARINE ACT

The Marine Act designates Port Authorities (major ports) and other ports throughout Canada, and provides them with various level of authority depending on status. The Act currently has limited relevance in the Arctic, as there are no large ports anywhere in the region. Elsewhere, it provides ports with the ability to control and set standards for bunkering operations (LNG and conventional fuels).

2.2.1.6 PILOTAGE ACT

The Pilotage Act (1985), as amended, and associated regulations establish: standards for pilots; the geographic areas where pilots must be carried; the processes for obtaining pilot services; and the provisions for cost recovery for pilot services. The Act establishes four Pilotage Authorities (Atlantic, Laurentian, Great Lakes and Pacific).

The Arctic does not have a Pilotage Authority. The role of the pilot is assumed to be provided by ice navigators who currently assist in providing navigation services, as defined under the ASSPPR.

2.2.2 DEPARTMENT OF FISHERIES AND OCEANS/COAST GUARD (DFO/CCG)

DFO shares with TC and ECCC responsibility for the Oceans Protection Plan (OPP). It (CCG) is the lead agency for marine emergency response, sharing search and rescue responsibilities with National Defence. In the Arctic it has a range of roles and responsibilities including the provision of icebreaking services to support commercial shipping. Under OPP the department provides navigational aids, hydrography and other forms of support to maintain shipping corridors.

CCG is responsible for the development of emergency response plans. To date, none of these either in or outside the Arctic devote attention specifically to vessels carrying or fuelled by LNG, though this is under discussion with several major port authorities.

2.2.3 NATURAL RESOURCES CANADA (NRCAN)

Responsibility for natural resources belongs to the provinces rather than the federal government. However, the federal government has jurisdiction over off-shore resources, trade and commerce in natural resources, statistics, international relations, and boundaries. Under the Oil and Gas Operations Act NRCan has jurisdiction over oil and gas in the territories, to various degrees depending on location. This covers production, processing and transportation of oil and gas. Further discussion is included at Section 2.6.

The Canadian Energy Regulator (CER) is an agency under NRCan. CER has responsibilities for interprovincial/territorial projects and may have involvement in aspects of any LNG transportation as part of the Arctic supply chain.

2.2.4 ENVIRONMENT AND CLIMATE CHANGE CANADA (ECCC)

ECCC is responsible for federal aspects of environmental policies and programs, environment being a shared jurisdiction with the provinces and territories.

In 2019 the Canadian Environmental Assessment Act, 2012 was replaced by the Impact Assessment Act (IAA). At the same time the Canadian Environmental Assessment Agency was replaced by the Impact Assessment Agency of Canada, which operates under ECCC. . The purpose of the Act remains the same, to ensure that projects carried out on federal lands do not have significant environmental effects. The main differences with the IAA are increased engagement of Indigenous peoples, early planning and engagement phases and expansion of the assessments to cover positive and negative environmental, economic, social and health impacts.

2.2.5 OTHER FEDERAL - GREENHOUSE GAS POLLUTION PRICING ACT

Unlike all the other regulatory measures described above, this Act does not relate to either safety or pollution prevention. However, it has the potential to alter the economics of using LNG as opposed to conventional fuels in the future.

The Act, which falls under the Ministry of Finance, was passed in 2018. It implemented a federal carbon pollution pricing scheme in two parts: a fuel charge and an output-based pricing system (OPBS). Beginning in 2019 the fuel charge was at \$20/ton CO_2 with the price being increased \$10 per year until a maximum of \$50/ton CO_2 in 2022.

OPBS applies to facilities which emit over 50,000 tons of CO_2 per year, an emissions limit is set and they must compensate if the limit is exceeded. Provinces/territories have several options for implementation of the Act, they can apply:

- their own system, which is at least equivalent to the federal system
- the federal system in full
- a hybrid approach, using the federal system for one part and a provincial system for the other.

The way in which the provinces and territories have chosen to implement is summarized in Figure 117.

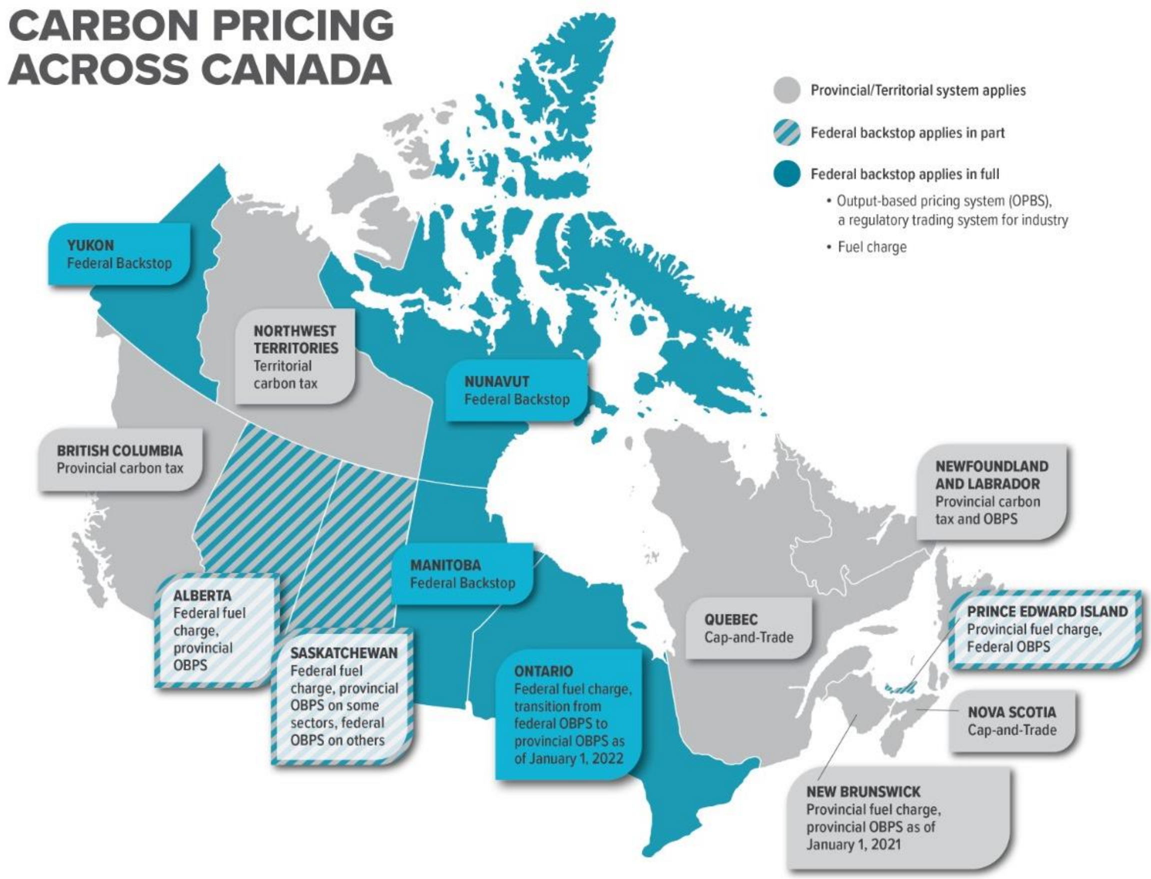


Figure 117: Carbon Pricing Across Canada

Marine fuel for international trade is exempted from this tax. For internal voyages, the system is somewhat complex and depends on the jurisdiction(s) involved. For example, in B.C. marine fuels are subject to the provincial tax based on carbon content. For most interprovincial shipping no taxes are currently paid.

2.3 CANADIAN (PROVINCIAL/TERRITORIAL)

As noted above (Section 2.2.4 and elsewhere), oil and gas and environmental issues are areas of joint jurisdiction. Generally, for projects entirely within a single province, the local agency will take the lead role. For territories the situation is somewhat more complex.

For oil and gas project and operations, provinces have their own regulators such as the BC Oil & Gas Commission, Alberta Energy Regulator and Régie de l'énergie (Quebec). These provinces all have LNG facilities, and correspondingly have regulations which include LNG. For example, BC has the Liquefied Natural Gas Facility Regulation.

The CER has varying regulatory responsibilities across Canada. In relation to Arctic regions, they regulate gas exploration and development in Nunavut and part of the Northwest Territories. In these areas the regulations are the Canada Oil and Gas Operations Act (COGOA) and the Oil and

Gas Operations Act (OGOA). An overview of areas regulated by CER and the regulations which apply are presented in Figure 118.

The existing OGOA and COGOA Acts which apply in Nunavut and the shoreside areas of the Northwest Territories are not well suited for the LNG facilities and are rather more suited to traditional oil and gas facilities. There has not been a need to update them to date due to a lack of LNG development in Arctic regions of Canada. The Acts include natural gas but without reference to liquefied natural gas or gas in liquid form. Despite this, facilities have still progressed due to acceptance of deviation requests which have proposed alternative and more appropriate regulations and standards to apply. An example of this is the Inuvialuit Petroleum Corporation who have submitted several deviation requests for the Inuvialuit Energy Security Project.

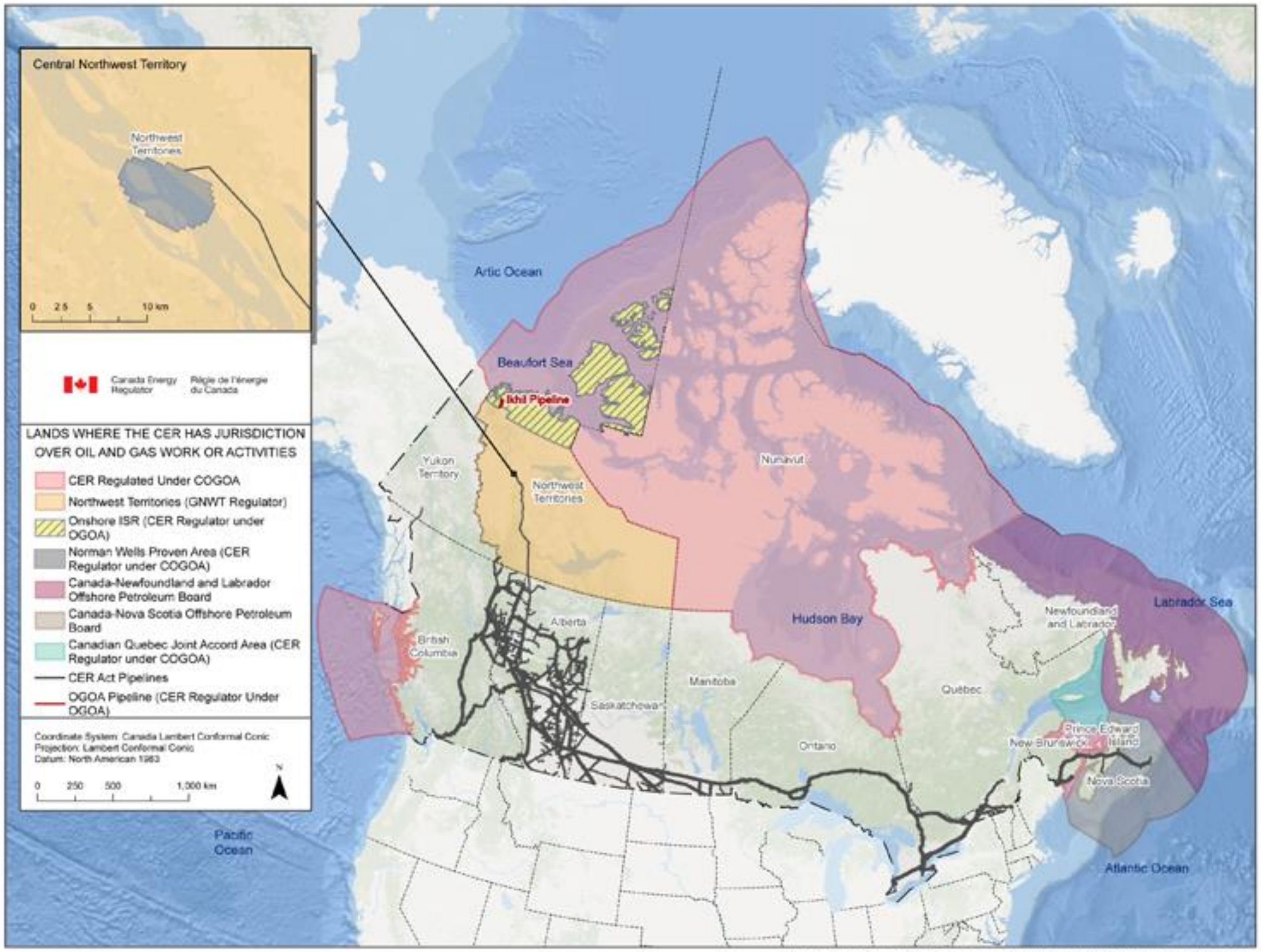


Figure 118: CER Regulatory Areas

Developments in the Arctic would also need to be approved through the local environmental assessment process. The Nunavut Impact Review Board (NIRB) aims to protect communities and ecosystems and their assessment reviews the potential biophysical and socio-economic impacts of any development proposals. Similarly, there is the Mackenzie Valley Environmental Impact Review Board (MVEIRB) conducting assessments governed by the Mackenzie Valley Resource Management Act (MVRMA). Finally for the Inuvialuit Settlement Region the Environmental Impact Screening Committee (EISC) and Environmental Impact Review Board (EIRB) conduct assessments governed by the Inuvialuit Final Agreement (IFA) and the Impact Assessment Act (IAA).

2.4 CSA GROUP

The CSA Group (formerly the Canadian Standards Association) is an independent standards body, and member of ISO. Much of its standards development work is closely aligned with ISO, though its other activities are broader in nature. Standards are developed by teams of domain experts drawn from industry, academia and government, who are normally volunteers supported by CSA staff.

CSA has several standards related to LNG, notably “CSA Z276 – Liquefied natural gas – Production, storage and handling”. Aspects of this have recently been updated in “CSA SPE-276.1:20 Design requirements for marine structures associated with LNG facilities”. A companion document which in 2020 replaced “CSA EXP276.1. – Additional updates” are in “EXP276.2.19 Design requirements for near-shoreline floating liquefied natural gas (FLNG) facilities” which covers floating LNG (FLNG) facilities. Neither of the updates are standards, rather they provide guidance and recommendations for compliance with local and national regulations and industry best practice.

3 RISK ASSESSMENT AND MITIGATION

The previous phases of this set of projects predated the effective implementation of the IGF Code, and the growth of bunkering operations from the initial truck-to-ship model to larger scale operations. Planning for larger scale waterside LNG operations (export-oriented and other) was also in its early stages in Canada. The requirements and expectations for risk assessments and as a part of the approvals process for all of these aspects of LNG project implementation and operation are now better defined, in most areas. This section of the report presents the current state-of-the-practice for projects in Canada, and notes some remaining areas of uncertainty. It should be recognized that while the focus of this work has been on LNG, the findings will generally be equally applicable to other “unconventional” fuels such as hydrogen, methanol or ammonia.

3.1 VESSEL REQUIREMENTS

3.1.1 GAS-FUELLED VESSELS

Agreement on the IMO IGF Code and its incorporation into the latest Class rules mean that the ship design and operational elements of risk assessment can be reduced considerably in scope in comparison with early gas-fuelled vessel designs.

The relevant IGF Code wording is:

> *“4.2.1 A risk assessment shall be conducted to ensure that risks arising from the use of low-flashpoint fuels affecting persons on board, the environment, the structural strength or the integrity of the ship are addressed. Consideration shall be given to the hazards*

associated with physical layout, operation and maintenance, following any reasonably foreseeable failure.

4.2.2 … the risk assessment required by 4.2.1 need only be conducted where explicitly required by paragraphs 5.10.5, 5.12.3, 6.4.1.1, 6.4.15.4.7.2, 8.3.1.1, 13.4.1, 13.7, and 15.8.1.10 as well as by paragraphs 4.4 and 6.8 of the annex."

The paragraphs cited here are listed in full below for ease of reference.

5.10.5 Each (drip) tray shall have a sufficient capacity to ensure that the maximum amount of spill according to the risk assessment can be handled.

5.12.3 The airlock shall be designed in a way that no gas can be released to safe spaces in case of the most critical event in the gas dangerous space separated by the airlock. The events shall be evaluated in the risk analysis according to 4.2.

6.4.1.1 The risk assessment required in 4.2 shall include evaluation of the ship's liquefied gas fuel containment system, and may lead to additional safety measures for integration into the overall vessel design.

6.4.15.4.7.2 Additional relevant accidental scenarios shall be determined based on a risk analysis. Particular attention shall be paid to securing devices inside of tanks.

8.3.1.1 The bunkering station shall be located on open deck so that sufficient natural ventilation is provided. Closed or semi-enclosed bunkering stations shall be subject to special consideration within the risk assessment.

13.4.1 The tank connection space shall be provided with an effective mechanical forced ventilation system of extraction type. A ventilation capacity of at least 30 air changes per hour shall be provided. The rate of air changes may be reduced if other adequate means of explosion protection are installed. The equivalence of alternative installations shall be demonstrated by a risk assessment.

13.7 Bunkering stations that are not located on open deck shall be suitably ventilated to ensure that any vapour being released during bunkering operations will be removed outside. If the natural ventilation is not sufficient, mechanical ventilation shall be provided in accordance with the risk assessment required by 8.3.1.1.

15.8.1.10 Permanently installed gas detectors shall be fitted.. ..at ventilation inlets to accommodation and machinery based on the risk assessment required in 4.2.

In addition to the risk assessment requirements of the IGF Code, Transport Canada Tier I Policy Requirements for Vessels Using Natural Gas as Fuel (RDIMS 11153519) include the following provisions:

2.2.3 In addition to the elements stated in paragraph 4.2.2 of the IGF Code, the risk assessment must take into consideration the risk criterion described in paragraph 3.2.1 of the IGF Code to address the risk created by:

a) The LNG or CNG tank when located adjacent to accommodation spaces;

b) The LNG or CNG tank if located in an open deck that may be subject to damage resulting for cargo handling or similar operation;

c) The use of the ESD-Protected machinery spaces concept;

d) Operation in low temperature environment, ice accretion and snow accumulation; and

e) The bunkering arrangement and operation.

Bunkering is discussed further below. Of the other TC-specific requirements, the low temperature considerations are also covered by the IMO Polar Code and its implementation through the Canadian ASSPPR. The tank location concerns reflect the fact that most early Canadian LNG vessels were ferries, for which both actual and perceived safety risks for passengers were of paramount importance.

For recent Canadian projects, the design development has included special consideration of all factors for which risk assessment is required, involving the owner, designer and RO. The formal risk assessment process then comprises a Hazard Identification (HAZID) process and the documentation of the overall risk assessment for submission to TC under the MTRB process. Much of the work is still based on qualitative assessments of likelihood for different types of events, but these can be increasingly grounded in-service experience for similar vessel types in Canada and elsewhere. The safety record of IGF-compliant vessels worldwide is currently excellent, with incidents that have occurred being minor in nature with limited impacts on ships or personnel.

3.1.2 GAS CARRIERS

Gas carriers, whether carrying cargoes to/in the Arctic for offloading to shore facilities or operating as bunkering vessels fall under the IGC Code and associated class rules. These do not have any requirements for risk assessments of any aspect of design.

Canada does not currently have any gas carriers under its flag, and so does not have any specific requirements for them within the Canada Shipping Act or any policy documents. Several designs for self-propelled and barge gas carriers have now been developed for potential Canadian services. In addition to compliance with IGC, these have often also adopted compliance with the USCG regulatory requirements as a supplementary safety measure, and also to allow for potential operations within US waters.

Risk assessments of the design of these vessels will be part of the processes required for bunkering and terminal operations. Normally, for larger LNGCs that are fully compliant with IGC, supplementary safety measures would be applied only to their operations rather than to their design, but in developing a complete system for Arctic operations it may be desirable to incorporate some features into the ship design itself, if this allows the overall system to be more cost-effective.

3.2 SHIP-TO-SHIP BUNKERING OPERATIONS

As bunkering involves (at least) two vessels that are normally operated by different organizations which have different operating procedures, there will typically be some form of risk assessment undertaken prior to transfer operations involving the two parties, even where this is not prescribed by regulation or policy. Most bunkering occurs in port, and port authorities generally mandate that the parties follow one of the sets of guidelines developed by the SGMF or other bodies (see above). Compatibility issues are of great importance, and pre-bunkering preparations need to address items such as:

- Port standard operating procedures, where applicable;
- Environmental limitations for bunkering operation (wind, wave, current etc.);
- Safety, Security and Hazardous Zones for receiving and bunkering ships;

- Fendering and mooring for receiving and bunkering ships, considering individual and combined ship loads;
- Physical connections (hoses, mechanical and electrical e.g. emergency shutdown);
- Deluge systems on receiving and bunkering ships;
- Lighting on receiving and bunkering ships;
- Personnel qualifications and experience;
- Assignment of roles and responsibilities for all aspects of the operation;
- Access from bunkering ship to receiving ship;
- Communications procedures;
- Emergency response and disconnect;
- Anticipated draft changes during bunkering;
- Quantity, composition, pressure/temperature and flow rate of bunkering;
- Pressure management (e.g. top fill vs bottom fill in receiving ship);
- Pressure of receiving ship's tank(s);
- Lifting appliances management of bunkering hose (inc. consideration for hose bending radius);
- Etc.

Some of these may be incorporated into one or both vessel's overall safety management systems while others can be captured in more specific documents shared by the two parties.

Unlike design, which is formally certified by flag state (such as Canada) operating procedures may or may not be reviewed and are generally not "approved" by Flag or class. Compliance is also not often verified or audited. Local authorities such as ports may therefore take on more of a leading role in ensuring that risk-based measures are actually implemented.

3.3 SHORE FACILITIES

The impact assessment for any shore-based facility is likely to require some form of risk assessment under the various regulations and policies that are applicable, with the scope and depth dependent on the size and location of the facility in question. Any suitable location will have a significant level of marine traffic now or as part of other future plans, and so navigational risk can probably be taken as acceptable, subject to satisfactory design of the LNG carriers that will be used. As noted at Chapter 4 and elsewhere, spill risks from LNG are much smaller than those from any liquid hydrocarbon fuel oil, and accident consequence modelling such as gas dispersion analysis is less likely to show potentially severe impacts in the Arctic than in southern locations.

Offloading (or onloading) involving the shore facility and the LNGC will involve many similar risk factors to bunkering, though there may be additional issues depending on how the transfer ashore is to be accomplished, e.g. by the use of floating hose technology. This will depend on the nature of the port infrastructure.

4 REGULATORY GAPS AND UNCERTAINTIES

The project Phase 1 and 2 reports identified a number of gaps in how Canada was then addressing NG-fuelled ships and operations. Since then, there have been many developments on both the international, and to a lesser extent the domestic front. Many more vessels are now operating successfully on NG, including the first in Canada.

The recommended approach to a Canadian regulatory system from previous phases was to utilize existing international documents as a basis wherever possible. This approach avoids the need for new research and drafting efforts and also ensures a high level of commonality between Canadian requirements and those adopted elsewhere. As described in Section 3, the policies currently being followed by Transport Canada are largely in line with this recommendation. However, there are still a number of gaps and uncertainties some of which derive from the nature of the international rules system – for example where other guidelines and standards are performance based rather than prescriptive, there can remain a need to provide better definition of methodologies that will be used to demonstrate compliance.

The report sub-sections below outline a number of perceived high-level gaps in the current and planned Canadian regulatory regime for NG-fuelled vessels, LNG carriers, and the shore facilities that will be needed for an Arctic supply chain. These lead into a number of recommendations for future actions provided in Section 6.

4.1 DESIGN AND CONSTRUCTION

Transport Canada regulations for most NG-fuelled vessels follow international (IGF Code) requirements and there are no major issues of concern with respect to design and construction. As noted above, it would be highly desirable for TC to provide more information on its expectations for the conduct of risk assessments, and for contribution to the development of the quantitative data that should inform such work.

There are some concerns as to how TC intends to regulate bunkering vessels, including both self-propelled and tug-barge options. These are becoming increasingly popular in Europe (self-propelled), the U.S. (tug-barge) and other jurisdictions, as the volumes of LNG required by larger ships start to exceed those which can be practicably supplied by tanker truck operations. In principle, the IGC Code can be applied to any such vessel, and most European vessels are believed to be IGC-compliant. However, the nature of the operations to be undertaken by such vessels are quite different from those of “normal” IGC vessels, which are normally widely segregated from other ships and terminal, rather than operating alongside them in (frequently) congested ports and harbours. In some respects, IGC is less stringent than IGF, for example in the side protection of tanks. There is also no requirement for risk assessment of the design, though LNG tanker operations have normally been subjected to extensive and stringent assessments.

In the U.S., where tug-barge operations have traditionally been very popular for other operational and regulatory reasons, USCG has determined as noted above that LNG (bunker) barges will be governed by separate requirements that aim to bridge the gaps between IGF and IGC (as reflected in the U.S. CFR approach to regulations). There are also requirements for the conduct of Barge Situational Awareness (BSA) assessments, which are essentially risk assessments of operations in any locations where the barge is intended to be operated (see also 4.3 below).

There is a need for TC to give consideration to how it will regulate small gas carrying self-propelled vessels and barges (both composite and towed units) of the types that have been considered under other project tasks. Possible ways forward are outlined in Section 5.

4.2 OPERATION IN CANADIAN WATERWAYS AND PORTS

LNG-fuelled vessels are now operating in most Canadian waterways and in many ports. While a majority of the vessels involved are ferries on fixed routes, the LNG dual-fuel vessels of Groupe Desgagnes have operated throughout the East Coast, Great Lakes and St. Lawrence Seaway, and much of the Canadian Arctic. No special provisions or restrictions have been considered necessary for any of these operations. Furthermore, while no large ocean-going vessels with LNG/dual fuel machinery have been operated to date in Canadian ports and waterways, several port authorities have considered this and concluded (preliminarily) that the only aspects requiring special consideration will be bunkering and any simultaneous operations (SIMOPS), as discussed in the next section.

The situation regarding LNG carriers, and particularly smaller bunkering vessels and local supply carriers is less clear. Large LNG carriers are only likely to be employed for transportation of cargoes from (or to) major terminals, for which navigation studies will be part of overall project approvals. Typically, when these types of vessel are operating in confined waters they will be accompanied by escort tugs and subject to pilotage requirements and other types of constraint.

Similar restrictions may not be necessary for small LNG carriers, for several reasons. The smaller volumes of cargo will incur reduced levels of risk. The smaller vessels involved will typically have better maneuverability, shorter stopping distances, etc., and this may be particularly the case for vessels designed as bunkering vessels, which will be required to undertake frequent operations in close proximity to other ships. The crews of such bunkering vessels will also tend to have more familiarity with the waterways than the crews of large LNG carriers, as they will undertake more and shorter voyages, generally to the same locations. It will be necessary to set up some form of risk-based process to establish appropriate operational limits for operations of small-scale LNG carriers. As there is overlapping jurisdiction between federal agencies, port authorities and other stakeholders, it will be highly desirable to establish a process that can be used consistently across Canada to simplify compliance. How this could be done is discussed further at Section 5.

4.3 BUNKERING OF LNG-FUELLED SHIPS

As outlined in Section 5.2 many Canadian LNG operations involve ferries on set routes with well-defined bunkering locations and procedures, and all currently utilize truck-to-ship transfer using a variety of techniques such as truck onboard, truck on dock, and manifolded transfer.

The basic regulatory approval of the intended bunkering operations has been rolled into the approvals and certification of the vessels themselves. This is a pragmatic approach that has also helped to build TC's understanding of bunkering technologies and risks. For vessels that bunker in many locations, such as the Group Desgagnes tankers, approvals for bunkering in additional ports have been provided by the port authorities following risk assessments. As with other aspects on LNG operations, the new scope required by such assessments decreases as familiarity increases, and additional quantitative information is generated on the number of fuel transfers and the (non-) occurrence of incidents. Transportation of the LNG to the bunkering location is subject to federal, provincial and local authorities and has not led to any (known) issues.

Future bunkering of larger vessels and/or with larger quantities of LNG using bunker vessels and barges requires additional consideration. Such operations are increasingly common worldwide, and there is a body of experience and best practices developed by organizations such as SGMF, Class and others to guide their development and approvals.

Within Canada, the Vancouver Fraser Port Authority (VFPA) has undertaken a series of assessments of potential bunkering operations at different terminals within the Port, and with different ship types ranging from cruise ships to vehicle carriers on the demand side, and from self-propelled bunker vessels (BVs) to tug-barge combinations on the supply side. This work has considered all phases of operations, from the transits of the BVs to the terminal through connection, transfer, and departure. Simultaneous operations such a container handling, passenger embarkation and oil tanker loading have been taken into account. At this stage, vessels have been considered generically, though in most cases the LNG-fuelled vessels have been based on ships that are already in service or under construction, and the BVs represent reasonably mature designs.

The work has assumed that any vessels involved will be fully compliant with IGF and IGC requirements. It has also been assumed that LNG supply contracts will involve long-term relationships, rather than individual operations. This will allow for compatibility assessments of the vessels involved well in advance of an actual fuel transfer, which can be used to ensure that systems and equipment are able to work together, and that responsibilities are clearly defined.

In general, this work has concluded that there are no major barriers to LNG bunkering within the VFPA context. Depending on the vessel and location, supplementary safety measures have been recommended for consideration by the parties involved. These range from providing additional training and information to first responders to establishing exclusion zones in which SIMOPS will not be allowed and access will be strictly controlled. VFPA is currently in the process of consolidating its requirements and expectations for LNG bunkering, and will incorporate information in its Port Information Guide and supporting materials.

It has been notable that in the VFPA and other work federal agencies have not been active participants in the work, although they have often attended workshops and been circulated relevant materials. The “de facto” policy of TC and DFO/CCG has been one of delegation to port authorities, which may be less appropriate for smaller ports and for future Arctic operations.

5 RECOMMENDED ADDITIONS TO THE REGULATORY FRAMEWORK

The recommendations below are presented in three categories: vessel and facility design, operations, and personnel. In each category they are based on the materials presented in the preceding sections.

It should be understood that this study does not consider that the current framework prevents projects related to the Arctic marine LNG supply chain from being undertaken. However, uncertainties in some areas represent barriers to those contemplating such projects, and have the potential to cause costs and delays.

It is not always necessary to formulate regulations to address issues. Many of these can be addressed by policies and guidelines, particularly where the regulations themselves are couched in performance terms, rather than setting prescriptive requirements.

5.1 DESIGN AND CONSTRUCTION

Current TC regulations and policies provide an adequate basis for the design and construction of LNG-fuelled ships, as proven by the number and variety of these that are now in service in Canada or under construction. Aspects in which the situation could be improved include clarification of the expectations for risk assessments of various aspects of the design to support MTRB applications. TC could also facilitate that exchange of information on best practices and of safety concerns. Shipowners and other stakeholders cannot currently access such information through TC, or easily develop a picture of LNG operations in Canada. TC (and its ROs) could collate and anonymize such information in ways that would allow for a more consistent evaluation of risks.

The situation is less satisfactory for LNG Carriers of the sort that would be required to establish infrastructure in the Arctic, or efficient bunkering options for larger vessels operating in Arctic waters. Canada does not have any regulations or policies for such vessels. Owners and designers (those we are aware of) have been using the default assumptions that SOLAS compliance will be acceptable, that TC will delegate design approvals to an RO, and that TC will provide the RO with instructions regarding the required contents for any MTRB application. To date this approach has not been tested and it is known to have become an issue in price negotiations with shipbuilders. It is therefore strongly recommended that TC develop a policy in this area analogous to that for the IGF Code; preferably in dialogue with those ROs who have their own supplementary rules and service experience in this area.

For shore-side facilities on the waterfront there is also very little guidance on how to address smaller scale plants of any type. The TERMPOL process for large scale facilities is not appropriate for (as an example) a storage facility with small-scale liquefaction or regasification. It requires a huge investment of resources and does not provide an actual approval route; merely a necessary step. TC and the other federal departments and agencies with involvement in this issue should consider how this can be handled going forward. In some cases it may be appropriate to delegate the lead to a port authority, but in many cases the facility may not be on port lands. Provincial/territorial administrations could also take the lead role, provided that the various federal bodies provide appropriate guidance on the treatment of any marine concerns regarding pollution and safety. This in turn will require policy formulation.

5.2 OPERATIONS

There is a similar situation on the operational side. There are no significant restrictions for dual-fuel ships for any type of operation (or maintenance), other than for bunkering. Bunkering operations are generally subject to restrictions ranging from weather conditions to the establishment of safety zones around potential sources of gas release.

For gas carriers, restrictions on coastal navigation and loading and offloading of cargoes need further consideration. The types of approach used around the existing LNG Canaport Terminal in New Brunswick or the proposed LNG Canada terminal in B.C. are not appropriate to the types of smaller LNG carrier envisaged for the Arctic supply chain. Whether any form of additional operational control is required may be a matter of perception as much as reality. The types of hazards represented by an LNG carrier are quite different to those for a product tanker of similar size, or those for another type of cargo vessel; and there are still many misperceptions of what these are.

As discussed in other study reports, a major incident with an LNG carrier will not create a pollution incident similar to that for a tanker if the cargo containment is breached. It will probably be less severe than that for a general cargo ship, as the use of LNG as the ship's own fuel will reduce the amounts of fuel oil carried. Higher risk items are associated with the potential release of a gas cloud, and its ignition to generate fire or explosion. There is no experience of this ever having happened to an LNG carrier or LNG-fuelled ship, either due to failures of the loading system or due to high energy collisions. However, it is not appropriate to consider these as zero probability events. It would be very valuable for regulatory bodies to work to define realistic worst case scenarios that should be considered in any risk assessments to ensure that these are handled consistently and logically when selecting locations for shore facilities and bunkering locations.

5.3 PERSONNEL

Human resources issues are discussed in more detail in Chapter 6, but recommendations are consolidated here for convenience.

As noted, several locations in Canada now offer LNG training for mariners, but to date none is formally included in TC's lists of approved courses. It is recommended that TC takes action to provide approvals for basic and advanced training programs, including any expectations for personnel who will operate bunkering vessels and LNG carriers.

LNG training for shore-side personnel is handled adequately by existing service providers, generally by providing specific in-house training to supplement general education and certification standards. There does not appear to be any need to set up any additional standards or courses in this area.

Bunkering operations, whether smaller or larger scale will continue to require some level of particularization to deal with the equipment and responsibilities that will be used. For larger scale cargo or fuel transfers it is advisable to plan for emergency response exercises, which can be desktop or broader simulations. These should include all groups who are likely to be involved.

6 CONCLUSIONS

Task 6 of the project provides a description of the regulatory framework for the design, build and operation of the vessels and shore facilities that will be needed to establish 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 framework includes both prescriptive and performance based elements, and many of the latter lead to a need for risk-based assessments of the combinations of hardware, procedures and training used to ensure safety. Risk assessment methodologies are outlined in the report.

There are a number of gaps and uncertainties in the current Canadian regulatory framework, particularly in relation to vessels subject to the IGC Code including 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. Regulatory uncertainty is a major barrier for project implementation, and recommendations are provided for measures that could improve this situation.

CHAPTER 8 IMPLEMENTATION SCENARIOS

1 INTRODUCTION

This section presents the results of the Implementation Scenarios component of the Marine Natural Gas Supply Chain Project for the Arctic region of Canada. It is intended to first generate a picture of 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 component draws on the case study results discussed in earlier chapters to make an assessment of the fuel demand and emissions impact these scenarios would have.

2 COMPETENCY OVERVIEW

2.1 OVERVIEW

While earlier chapters on Economics (Chapter 3) and Environment (Chapter 4) 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.

Chapter 2 on Technological Readiness established technical feasibility and status of LNG vessel deployment globally, as well as highlighting key projects in Canada. Chapter 5 (Infrastructure) supplemented this information with an update on the status of key initiatives in Canada that could provide a source of LNG fuel for ships and other operations in the Canadian Arctic region. The present discussion on implementation scenarios relies on the technical feasibility and fuel supply options from these earlier studies.

Chapter 5 (Infrastructure) in this report provides the supply chain options for Arctic LNG infrastructure. Case Study 2 – Tuktoyaktuk to Cambridge Bay – in Chapter 5 considers the implications of locally produced LNG for use in the Arctic. As the total LNG demand assessed as part of the implementation scenarios is relatively small compared to global LNG ship fuel demand, no significant new infrastructure beyond Case Study 2 is required. The best practices for design, development and regulatory approvals of any new infrastructure are well documented in Chapter 2 (Technological Readiness) and Chapter 7 (Regulations); therefore, no additional information on locally produced LNG is provided in this section.

This section considers the fleet of ships that currently use Canada's Arctic waters and attempts 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:
    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?

2.1 REPORT STRUCTURE

This chapter is structured to provide answers to the above questions in the following sections:

- Shipping in Canada's Arctic fuel use and emissions

- Vessel implementation scenarios
- Emissions impacts, and
- Supply chain options

In some places, this chapter summarizes and/or cross-references materials presented in earlier chapters, while in other areas the material is wholly new.

2.2 SHIPPING IN CANADA'S ARCTIC FUEL USE AND EMISSIONS

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. This section of the report will draw on publicly available data sources to characterize the fleet of ships travelling in these waters and to quantify the emissions from these ships.

The Government of Canada provides public data estimating the emissions from shipping activity in 22 regions across Canada. The data is published by Environment and Climate Change Canada through the online Marine Emissions Inventory Tool (MEIT), with data currently available from 2015 through 2019.

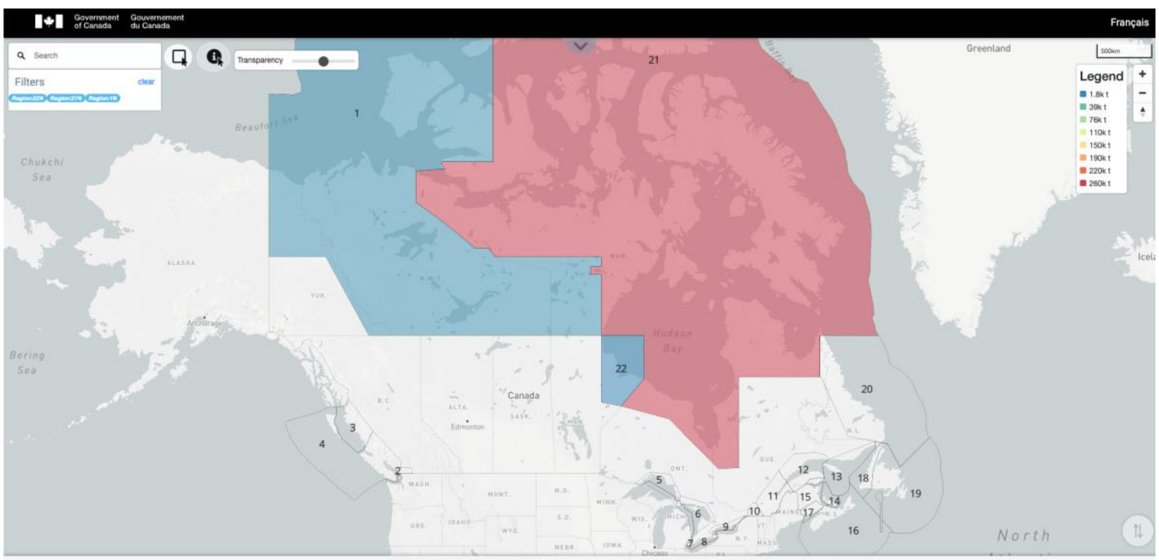


Figure 119: Marine Emissions Inventory Tool Region Map

Canada's Arctic region is equivalent to sub-regions 1, 22 and 23 in the MEIT as highlighted in Figure 119. Further regions were created for comparison by grouping the MEIT sub-regions 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 CO2-e, as shown in Table 58.

Table 58: Canadian Shipping Greenhouse Gas Emissions for 2019

Region	2019 GHG Emissions Mt CO_2e	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

Based on a review of this data, in can be determined that Canadian Arctic region shipping was responsible for 0.27 Mt of CO_2e emissions in 2019 and represents approximately 3% of total emissions from shipping in and around Canadian waters. Although this is significantly lower than 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. For comparison, Canada's domestic shipping accounts for 4.4 Mt of emissions annually according to Canada's 2019 National Inventory Report and the emissions from Nunavut Territory in the same report were reported as 0.7 Mt.

The 0.27 Megatonnes of Arctic shipping emissions in 2019 can be further broken down by ship type. To create summary emissions data aligned with the case studies considered in Chapters 3 (Economics) and 4 (Environment), the lowest level of ship type in the MEIT data was aligned with the ship types used in this project according to Table 59.

Table 59: Creation of Summary Ship Types

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	I/B 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 full data extract from the MEIT for 2019 is contained in Appendix B The summary by ship type of individual GHG emissions including carbon dioxide (CO2) and methane (CH4), nitrogen oxide (N2O), black carbon (BC) and CO2-equivalent emissions calculated according to the MEIT methodology10 is summarised in Table 60.

[10] 100-year global warming potential from IPCC AR4 excluding Black Carbon

Table 60: 2019 Canadian Arctic Greenhouse Gas Emissions by Ship type in MT

Ship Type	Case	BC	CO2	CH4	N2O	CO2e	% 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
I/B 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
Grand Total		**16.5**	**267,420**	**4.0**	**14.3**	**271,769**	**100**

Table 60 shows that the six case study vessels in this report 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_x), sulphur oxides (SO_x), and particulate matter (PM), is presented in Table 61.

Table 61: 2019 Canadian Arctic Greenhouse Gas Emissions by Ship type in MT

Vessel Type	NO_X	SO_X	PM
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
I/B 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	**5359.8**	**2601.6**	**284.9**

As the data from MEIT is from 2019, the assumption here is that Bulk Carrier, General Cargo, Tanker, I/B Bulk Carrier and Cruise vessel types use high-sulphur heavy fuel oil (HFO) in the emission factors, so the SO_x emissions are proportionally higher than for vessels, like CCG Icebreaker, assumed to be burning low-sulphur diesel. PM emissions are also higher in the MEIT because particulate emissions from combustion engines are known to increase with sulphur content and so corresponding emissions factors were chosen in the MEIT. Consistent with the assumptions in Chapters 3 and 4, as of 2020, all the ships burning HFO will be required to comply with the IMO 2020 sulphur limit of 0.5% by either operating an exhaust gas cleaning system or using lower-sulphur fuel.

The next part of the analysis provides details on the number of ships responsible for these emissions. Researchers from the University of Ottawa Environment, Society, and Policy Group analyzed Automatic Identification System data from ships in Canada's Arctic waters over a nine-year period (2010-2018). They found that, over this period, fewer than 180 unique ships travel through the study area each year. The methodology and summary data is published in an academic journal (van Luijk, 2019). The full data provided by the authors is shown in Table 62.

Table 62: Unique Vessels Visiting the Canadian Arctic Region 2010-2018

Vessel Type	2010	2011	2012	2013	2014	2015	2016	2017	2018
Bulk Carriers	23	19	18	24	21	20	21	27	36
Fishing Vessels	24	25	23	22	24	24	21	30	32
General Cargo	15	12	11	11	13	14	16	19	17
Government Vessels and Icebreakers	20	23	23	23	22	22	20	28	24
Oil/Gas/Exploration /Exploitation		1	1						
Passenger Ships	11	8	6	10	9	11	12	12	10
Pleasure Crafts	11	20	24	26	31	23	23	30	18
Tanker Ships	13	15	11	11	11	10	11	13	14
Tug/Barge	23	20	19	13	13	14	15	20	18
Grand Total	140	143	136	144	144	138	139	179	169

The vessel types used by the University of Ottawa research team closely align with the summary vessel types used in this study. The only adjustments required were:

- Separating Icebreakers from the Government Vessels and Icebreakers type based on data from Canadian Coast Guard seasonal reports to the Prairie and Northern Region Canadian Marine Advisory Council in 2019 and 2020.
- Separating Icebreaking Bulk Carriers from the Bulk Carriers type using publicly available data from Fednav.[11]

[11] Fednav. 2022. Vessels in Arctic Operations. Retrieved from: https://www.fednav.com/en/company/divisions/arctic-operations

- Consolidating the other ship types into another category.

Using 2018 as a representative year from Table 62, it is possible to create a unique count of vessels by ship type together with the fuel consumption from the latest (2019) MEIT data and the case numbers from Chapters 3 and 4. 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 as shown in Table 63.

Table 63: 2019 Canadian Arctic Region Shipping and Fuel Use

Vessel Type	Number of Vessels in 2018	Fuel Consumption in Arctic in 2019 (MT)	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
I/B 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 (refer to Table 62) based on University of Ottawa research (van Luijk, 2019).

2.3 VESSEL IMPLEMENTATION SCENARIOS

The implementation scenarios here call for all the ships whose type matches with a case study in Chapters 3 and 4 to switch to LNG fuel. Chapter 2 additionally confirmed the technical feasibility of LNG vessels of each type, as well as the market trends leading towards these scenarios. This Chapter therefore delivers a potential scenario for fuel switching to LNG based on the vessel type profiles. For each vessel type, the emissions impact, economic impact, and fuel demand are calculated. Where possible, the investment required is also calculated using the case study results in Chapter 3 applied to the fleet of vessels.

Emissions impact is calculated by applying the percentage change in emissions due to the adoption of LNG calculated in Chapter 4 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 Canadian Artic region.

Economic impact is calculated using the results described in Chapter 3 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.

Fuel demand for LNG is also calculated for the portion of the voyage that occurs within the Canadian Arctic region.

The detailed scenarios results are presented for each ship type grouped by International, Quebec, and Arctic. The emissions impact is consolidated in a summary in Section 2.4, while the fuel demand is consolidated in Section 2.5.

2.3.1 INTERNATIONAL

These vessels are internationally flagged ships that visit the Canadian Arctic from an international port. Fuel is provided at the international port of origin. LNG has a higher gravimetric energy density than MDO which means fewer tonnes of LNG are required when assessing total fuel demand in each of these scenarios.

2.3.1.1 ICEGOING BULK CARRIERS

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 (marine diesel oil distillate fuel) required by HFO ban.

Reference Case: A7

Number of vessels: 33

Emissions Impact Calculation: Canadian Arctic region emissions from MEIT x section 4 (Environmental) Factors as demonstrated by the tables in Section 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 3 (Economics) x # vessels

Incremental investment per ship	$22 million
Total incremental investment	$726 million

Fuel Demand Calculation: Fuel use in one season from Chapter 3 (Economics) 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 GHG reduction but reducing NO_x emissions.
- New build LNG-fuelled bulk carriers are available as an alternative to the conversion considered in this scenario.

2.3.2 QUEBEC

These vessels call on the Canadian Arctic region from ports in Quebec, typically Montreal, Valleyfield and Quebec City. They are Canadian flagged vessels and take on fuel in the south for the voyage.

2.3.2.1 GENERAL CARGO

Scenario: Arctic sealift ships replaced with best available technology LNG-powered ships instead of ships using MDO (distillate fuel).

Reference Case: A2

Number of vessels: 17

Emissions Impact Calculation: Canadian Arctic region emissions from MEIT x Chapter 4 (Environmental) Factors, as demonstrated by the tables in section 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 3 (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 3 (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 MS-LPDF engines are used instead, methane emission increase, limiting GHG reduction but reducing NO_x emissions.
- Vessels will take on fuel in Montreal for each voyage. Currently there is only truck to ship bunkering available.

2.3.2.2 TANKER

Scenario: Arctic fuel delivery ships replaced with best available LNG-powered ships instead of ships using MDO (distillate fuel)

Reference Case: A3

Number of Vessels: 14

Emissions Impact Calculation: Canadian Arctic region emissions from MEIT x Chapter 4 (Environmental) Factors, as demonstrated by the tables in section 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 3 (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 3 (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 MS-LPDF engines are used instead, methane emission increase, limiting GHG reduction but reducing NO_x emissions.
- Vessels will take on fuel in Quebec for each voyage. Currently there is only truck to ship bunkering available.

2.3.2.3 ICEBREAKING BULK CARRIERS

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

Reference Case: A6

Number of vessels: 3

Emissions Impact Calculation: Canadian Arctic region emissions from MEIT x Chapter 4 (Environmental) Factors, as demonstrated by the tables in section 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 3 (Economic) x # vessels

Incremental investment per ship	$22 million
Total incremental investment	$66 million

Fuel Demand Calculation: Fuel use in one season from Chapter 3 (Economic) x # vessels

Arctic fuel consumption	4013 MT LNG per vessel
Total fuel demand	12,039 MT per year

Notes:

- Reference case assumes the best available low-methane emissions engines. If MS-LPDF engines are used instead, methane emission increase, limiting GHG reduction but reducing NO_x emissions.
- Vessels will take on fuel in Quebec for each voyage. Currently there is only truck to ship bunkering available.

2.3.3 ARCTIC

These vessels operate completely within the Arctic region during each season. They therefore require fuel to be provided at a convenient location in the Arctic.

2.3.3.1 CCG ICEBREAKER

Scenario: New CCG icebreakers are built as LNG-fuelled ships instead of diesel.

Reference Case: A1

Number of vessels: 6

Emissions Impact Calculation: Canadian Arctic region emissions from MEIT x Chapter 4 (Environmental) Factors, as demonstrated by the tables in section 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 ultra-low sulphur diesel (ULSD) vs. in Arctic LNG Price from Chapter 5 (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 3 (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.

2.3.3.2 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 4 (Environmental) Factors, as demonstrated by the tables in section 4 - Summary of Emissions Impact.

Economic Impact Calculation: Value of fuel purchased in Arctic calculated as # vessels x annual fuel demand x Chapter 5 (Infrastructure) cost

Annual fuel demand	1,582 metric tonnes LNG per vessel
Price of LNG from Chapter 5	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 3 (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.

2.4 SUMMARY OF EMISSIONS IMPACT

This section summarises the impact on emissions in the Canadian Arctic of the six implementation scenarios. The change in emissions from baseline are calculated by applying the percentage change as calculated and presented in Chapter 3. The engine technologies deployed in each implementation scenario are defined in Chapter 4 (Environmental), Table 37. The engine technologies selected represent a non-exhaustive sample of possible engines that could be employed. 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 as part of the implementation scenario

2.4.1 GREENHOUSE GAS

The three emissions considered are carbon dioxide, black carbon, and methane. Changes are presented in absolute and percentage terms. It should be noted that for methane, the absolute volumes produced by burning fuel oils are very small, and so the change to LNG produces very large percentage increases. Table 67 combines all three components to present the overall impact.

Table 64: Impact on CO_2 Emissions of Implementation Scenarios (MT)

	HFO	→ Distillate (MDO/ULSD)			→ LNG	
Vessel Type	**Baseline**	**Change**	**Percent (%)**	**New Baseline**	**Change**	**Percent (%)**
Bulk Carrier	67,899.6	(1862.7)	-3	66,036.98	(17,654.5)	-27
General Cargo	61,901.6	(1508.5)	-2	60,393.06	(16,636.6)	-28
Tanker	31,393.5	(724.9)	-2	30,668.53	(8561.6)	-28
I/B Bulk Carrier	12,479.8	(354.1)	-2	12,125.70	(3209.9)	-26
CCG Icebreaker*	24,515.9	-	-	24,515.87	(5238.5)	-21
Cruise	16807.6	(433.9)	-3	16,373.7	(3499.8)	-21
Total	214,998.0	(4884.1)		210,113.9	(54,800.9)	

*using ULSD fuel, not HFO

Table 65: Impact on BC of Implementation Scenarios (MT)

	HFO	→ Distillate (MDO/ULSD)			→ LNG	
Vessel Type	**Baseline**	**Change**	**Percent (%)**	**New Baseline**	**Change**	**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
I/B 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 66: Impact on CH4 of Implementation Scenarios (MT)

	HFO	→ Distillate (MDO/ULSD)			→ LNG	
Vessel Type	**Baseline**	**Change**	**Percent (%)**	**New Baseline**	**Change**	**Percent (%)**
Bulk Carrier	1.0	-	0	1.0	19	1904
General Cargo	1.0	-	0	0.99	18.7	1887
Tanker	0.4	-	0	0.43	8.1	1903
I/B 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	-	0	3.19	392.2	

*using ULSD fuel, not HFO

Table 67: Impact of CO2e GWP 100 Emissions of Implementation Scenarios (MT)

	HFO	→ Distillate (MDO/ULSD)			→ LNG	
Vessel Type	**Baseline**	**Change**	**Percent (%)**	**New Baseline**	**Change**	**Percent (%)**
Bulk Carrier	64,459.8	(3732.4)	-6	60,727.40	(17,594.4)	-29
General Cargo	71,456.1	(3743.7)	-5	67,712.34	(17,167.9)	-25
Tanker	32,641.8	(1454.6)	-4	31,187.15	(8,757.5)	-28
I/B 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	(1476.4)	-8	16,860.16	(856.2)	-5
Total	227,125.5	(11,332.8)			(47,920.9)	-21

*using ULSD fuel, not HFO

2.4.2 OTHER AIR POLLUTANTS

Table 68: Impact on NOx Emissions of Implementation Scenarios

	HFO	→ Distillate (MDO/ULSD)			→ LNG	
Vessel Type	**Baseline**	**Change**	**Percent (%)**	**New Baseline**	**Change**	**Percent (%)**
Bulk Carrier	1,416.8		-	1,416.82	-	
General Cargo	1,369.7		-	1,369.7		
Tanker	659.4		-	659.4		
I/B Bulk Carrier	205.3		-	205.3		
CCG Icebreaker*	559.0		-	559.0	(490.5)	
Cruise	285.9		-	285.9	(250.2)	-
Total	4,496.1		-	4,496.1	(740.6)	-

*using ULSD fuel, not HFO

Table 69: Impact on SOx Emissions of Implementation Scenarios after IMO 2020 and HFO Ban

	HFO	→ Distillate (MDO/ULSD)			→ LNG	
Vessel Type	**Baseline**	**Change**	**Percent (%)**	**New Baseline**	**Change**	**Percent (%)**
Bulk Carrier	866.9	(694.0)	-80	172.88	(165.4)	-
General Cargo	967.6	(774.6)	-80	192.96	(178.0)	-
Tanker	436.2	(336.8)	-77	99.41	(92.0)	-
I/B Bulk Carrier	171.9	(138.5)	-81	33.39	(32.1)	-
CCG Icebreaker*	0.2	-	-	0.22	(0.2)	-
Cruise	158.3	(125.8)	-79	32.5	(30.6)	-
Total	2601.1	(2069.9)	-80	531.4	(498.2)	-

*using ULSD fuel, not HFO

Table 70: Impact on PM Emissions of Implementation Scenarios after IMO 2020 and HFO Ban

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

*using ULSD fuel, not HFO

2.5 SUPPLY CHAIN OPTIONS

2.5.1 INTERNATIONAL LNG DEMAND

The 33 icegoing bulk carriers from case A7 would require approximately 91,000 MT per annum of LNG. According to the Port of Rotterdam bunkering sales data, 213,250 m^3 of LNG were sold in Q3 of 2021. This amounts to approximately 426,500 metric tonnes per annum. The incremental demand from the icegoing bulk carrier implementation scenario could therefore likely be able to be absorbed by current LNG bunkering capacity in Rotterdam or other European ports.

2.5.2 QUEBEC LNG DEMAND

The potential demand for LNG in Quebec from the implementation scenario is as follows:

- Direct LNG bunkering of ships refuelling of up to 24,727 MT per year
  - General Cargo 7,480 metric tonnes per year
  - Tanker 5,208 metric tonnes per year
  - I/B 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 5). The total demand could be accommodated by a small-scale LNG plant, similar to the one operated by Energir. The capacity of the Energir plant is 436,000 m^3 of LNG, which 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.

2.5.3 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^2 storage tank considered in Case Study 1 of Chapter 5 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.

2.6 CONCLUSIONS

This section explored the impact of a set of implementation scenarios should six types of vessels common in the Canadian Arctic region adopt LNG as a fuel. The impact assessment assumes that the IMO 2020 sulphur cap and the HFO ban in the region are in force. As such, the economic and emissions impacts are assessed from a baseline of distillate fuels (MDO or ULSD).

Shipping in Canada's Arctic region is responsible for an estimated 0.27 Megatonnes of CO_2e emissions each year from 169 individual vessels. The change in emissions due to a fuel switch to LNG has been 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_x and PM reductions. CO_2 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 increased. The change in 100-year GWP CO_2e emissions in the Canadian Arctic region from the implementation scenarios is dependent on which engine technology is used, with limited 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 available capacity in Europe and Quebec should be sufficient to meet these demands. New infrastructure would be required to supply vessels that require refuelling in the Arctic.

CHAPTER 9 BENEFITS TO CANADA

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.

2 ENVIRONMENTAL

This section provides a consolidated view of the environmental 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 substituting diesel fuel delivered by tanker ship used primarily for power generation in the Canadian Arctic region. The conclusions are drawn from the work conducted for Chapters 4, 5, and 8 of the project.

2.1 SUMMARY RISK 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. Task 7 of this study has shown that 80% of the emissions come from just six ship types, all of which are capable of being switched to natural gas as a fuel in the form of LNG based on the analysis conducted in Tasks 1 through 3.

This study has 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 sulphur oxides (SOX) and particulate matter (PM) emissions. These pollution reduction opportunities identified are over and above the benefits derived from the implementation of the International Maritime Organization (IMO) global 0.5% sulphur emissions limit, the impending HFO ban 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 powerful effect in the Arctic were found to be reduced. Carbon dioxide (CO2) emissions from ship engine operations were also reduced. However, the study identifies increased methane emissions from ships using natural gas fuel. 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 dependent on the technology used to power the ships that switch to LNG fuel, and in some cases the negative effects of methane emissions could reduce the benefits from reducing CO2 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 delivered by ship in preference to diesel. Prudent methane management in power generation is essential in maximizing the positive emissions reductions that could come with greater use of natural gas.

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 or diesel.

2.2 AIR POLLUTION IMPACTS FROM SHIPPING

The impact of air pollution on human health and the environment is well understood and documented. Particulate matter (PM) 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_x and nitrogen oxides (NO_x) 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_x and PM emissions are reduced by ships burning natural gas fuel. These reductions are over and above the reduction achieved by the implementation of the 0.5% IMO sulphur emissions limit that came into effect in 2020. Implementation scenarios in found that 498 metric tonnes of SO_x 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 PM were eliminated (a reduction of 95%).

Implementation scenarios indicated that 76 metric tonnes of PM were eliminated (a reduction of 95%). This reduction may be even greater if shipowners use blended fuels that which still compliant with the HFO ban, but contain more impurities than the distillates assumed in the analyses.

In most cases, NO_x emissions remained similar even when ship engines are switched to natural gas fuel. Implementation scenarios did not find any NO_x 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_x 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 will reduce the GHG emissions reductions associated with switching to LNG fuel. More details on NO_x emissions are provided in the Chapter 4 (Environment) and Chapter 8 (Implementation Scenarios) of the report.

2.3 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_2 and black carbon emissions were found to be reduced in all cases but methane emissions increased. Combining these effects into a ship-level CO_2-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 limited reductions in CO_2-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 4 (Environmental) showed a similar result.

CO_2 emissions reductions of between 21% and 28% were found as part of Chapter 4 (Environmental) emissions modelling. Implementation scenarios in Chapter 8 identified 54 thousand metric tonnes of CO_2 emissions reduction potential. The variation in CO_2 emissions reduction benefit is due to the operating parameters of the vessels studied as part of Chapter 4 (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 as discussed in more detail in Chapter 8.

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 emission from these two scenarios alone.

Both methane and black carbon are 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 PM emissions if blended 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 as a result of a switch to LNG is heavily dependent on the engine technology selected with little 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.

2.4 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 5 (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 including 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.

Chapter 5 (Infrastructure) identified the combustion of diesel delivered by ship to Arctic settlements and industries for generating electricity creates CO_2 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 PM in the four-stroke high-speed diesel engines used in these applications. Chapter 5 (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 supplied in the Arctic from local gas reserves present. These scenarios were explored in more detail in Chapter 5. The environmental risks and benefits of replacing diesel generators with natural gas-fuelled generators are similar to those from shipping.

2.5 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, commentators have highlighted the risks presented by waivers and exemptions to these measures. 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 4 (Environment) of this project studied the impact of an LNG spill and found that 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.

3 ECONOMICS

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 as reported in Chapters 3, 5, 6, 7 and 8.

3.1 SUMMARY OF COSTS 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 3 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 with the lowest methane emissions is the high-pressure dual-fuel engine technology. This technology is currently only available for 2-stroke engines used in larger ships. Low pressure technology (Otto cycle) is available for low, medium and high speed engines. Manufacturers are working on methane slip reduction measures for these engines, which may lead to some increase in the cost of future models.

3.2 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" (IMO, 2022) 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 3 (Economics) 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. Chapter 3 (Economics) analysis also highlighted the incremental investment required and found that payback periods for the shipowners could range from 4 to 13 years depending on fuel prices. However, the large and ongoing economic benefits for communities should be taken into account in policy formulation.

3.3 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 3 also determined that the payback period for converting these vessel types was the longest of all those considered, between 16 and 25 years.

This study has not attempted to quantify the additional benefits that could accrue to the use of LNG to fuel shore transportation, mining equipment operation, and other infrastructure at mine sites, which could also be substantial. The types of small-scale LNG carrier discussed at Chapters 3, 5 and 8 could supply mine sites in addition to ports and vessels.

3.4 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 engine technology currently available for this application is the higher methane emissions engines, which if used for this application resulted in little change in CO_2-equivalent emissions.

3.5 OPPORTUNITIES FOR EXPLOITATION OF LOCAL NATURAL GAS RESERVES

Chapter 5 (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 8 – Implementation Scenarios), this proposed Inuvialuit Energy Security Project could contribute to local demand for gas in the Canadian Arctic Region.

3.6 OPPORTUNITIES FOR LNG FUEL SALES IN 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 Section 8.

3.7 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 Section 2 Technological Readiness would also be required.

If the two ship types that require refuelling in the Arctic (cruise ships and icebreakers) did convert to LNG fuel, then LNG storage and bunkering facilities would also be required at a convenient location in the Arctic. Section 5 Infrastructure provides further detail on the infrastructure required.

Using LNG for community and mining needs would present additional opportunities for infrastructure development.

4 CONCLUSION

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 cases where methane emissions may negate the environmental benefits.

Environmental benefits include improvements to human health and the environment from reduced SO_X and PM emissions.

Emissions of black carbon, a powerful short-lived climate forcer with particularly significant effect in the Arctic, were found to be reduced. CO2 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 limit the benefits from CO2 and black carbon emissions reduction. Suppliers claim significant success in measures to reduce methane slip, while regulators are considering how to factor this into future 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. Prudent methane management is essential in ensuring GHG reductions from the use of natural gas in 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 more 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 LNG-fuelled ships remains significantly higher than that of conventionally-powered vessels, and conversions are particularly costly. The payback periods for these investments depend on the ship’s type and its operating profile, including any need for additional Arctic infrastructure. However, for some ships and services the use of LNG fuel is attractive on both an economic and an environmental basis.

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APPENDIX A – PAYBACK PERIOD SENSITIVITY ANALYSIS

A1 - CCG Icebreaker

		LNG											
	$/MT	**$400**	**$500**	**$600**	**$700**	**$800**	**$900**	**$1,000**	**$1,100**	**$1,200**	**$1,300**	**$1,400**	**$1,500**
MDO	**$400**	47.847	-44.114	-15.097	-9.107	-6.520	-5.078	-4.158	-3.520	-3.052	-2.694	-2.411	-2.182
	$500	14.348	38.277	-57.327	-16.390	-9.562	-6.750	-5.216	-4.250	-3.586	-3.101	-2.732	-2.442
	$600	8.440	13.348	31.898	-81.842	-17.925	-10.065	-6.997	-5.362	-4.347	-3.655	-3.153	-2.772
	$700	5.978	8.083	12.478	27.341	-142.988	-19.778	-10.623	-7.262	-5.517	-4.448	-3.726	-3.205
	$800	4.628	5.797	7.756	11.714	23.923	-565.438	-22.057	-11.248	-7.549	-5.680	-4.553	-3.800
	$900	3.775	4.519	5.626	7.454	11.038	21.265	289.310	-24.930	-11.950	-7.859	-5.854	-4.664
	$1,000	3.188	3.702	4.415	5.466	7.174	10.436	19.139	115.187	-28.664	-12.746	-8.195	-6.039
	$1,100	2.759	3.136	3.632	4.315	5.314	6.915	9.897	17.399	71.908	-33.713	-13.655	-8.562
	$1,200	2.432	2.720	3.085	3.564	4.220	5.170	6.674	9.410	15.949	52.270	-40.921	-14.705
	$1,300	2.174	2.401	2.682	3.036	3.499	4.129	5.034	6.449	8.969	14.722	41.057	-52.050
	$1,400	1.965	2.149	2.371	2.645	2.989	3.436	4.042	4.905	6.239	8.568	13.670	33.805
	$1,500	1.793	1.945	2.125	2.342	2.609	2.943	3.376	3.958	4.783	6.042	8.200	12.759

A2 - General Cargo

		LNG											
	$/MT	**$400**	**$500**	**$600**	**$700**	**$800**	**$900**	**$1,000**	**$1,100**	**$1,200**	**$1,300**	**$1,400**	**$1,500**
MDO	**$400**	26.449	-45.426	-12.220	-7.059	-4.963	-3.827	-3.114	-2.625	-2.269	-1.998	-1.784	-1.612
	$500	9.338	21.159	-79.610	-13.815	-7.564	-5.208	-3.971	-3.208	-2.692	-2.318	-2.036	-1.815
	$600	5.670	8.581	17.632	-321.648	-15.890	-8.146	-5.477	-4.125	-3.309	-2.762	-2.370	-2.076
	$700	4.071	5.382	7.937	15.113	157.646	-18.699	-8.826	-5.776	-4.293	-3.416	-2.836	-2.425
	$800	3.176	3.920	5.121	7.383	13.224	63.309	-22.713	-9.629	-6.110	-4.474	-3.530	-2.914
	$900	2.603	3.083	3.780	4.885	6.902	11.755	39.607	-28.923	-10.593	-6.484	-4.672	-3.651
	$1,000	2.205	2.540	2.996	3.650	4.669	6.479	10.579	28.818	-39.805	-11.772	-6.908	-4.888
	$1,100	1.913	2.160	2.481	2.913	3.528	4.472	6.105	9.618	22.649	-63.815	-13.246	-7.390
	$1,200	1.689	1.879	2.117	2.424	2.835	3.414	4.290	5.772	8.816	18.655	-160.824	-15.142
	$1,300	1.512	1.663	1.846	2.075	2.370	2.761	3.307	4.123	5.473	8.138	15.859	309.184
	$1,400	1.369	1.491	1.637	1.815	2.036	2.318	2.691	3.207	3.969	5.204	7.557	13.791
	$1,500	1.250	1.351	1.470	1.612	1.784	1.997	2.268	2.624	3.113	3.825	4.960	7.053

A3 - Tanker
Payback Period Sensitivity Analysis

MDO \ LNG $/MT	$400	$500	$600	$700	$800	$900	$1,000	$1,100	$1,200	$1,300	$1,400	$1,500
$400	22.923	-71.427	-13.962	-7.737	-5.351	-4.090	-3.310	-2.780	-2.396	-2.105	-1.878	-1.694
$500	8.916	18.339	-323.171	-16.470	-8.450	-5.683	-4.281	-3.434	-2.867	-2.460	-2.155	-1.917
$600	5.535	8.126	15.282	128.015	-20.075	-9.308	-6.058	-4.491	-3.568	-2.959	-2.528	-2.207
$700	4.013	5.220	7.465	13.099	53.426	-25.703	-10.359	-6.487	-4.722	-3.712	-3.058	-2.600
$800	3.147	3.844	4.938	6.903	11.462	33.757	-35.714	-11.679	-6.981	-4.978	-3.869	-3.163
$900	2.589	3.043	3.690	4.686	6.419	10.188	24.674	-58.498	-13.384	-7.556	-5.264	-4.039
$1,000	2.199	2.518	2.945	3.547	4.458	5.999	9.169	19.442	-161.586	-15.671	-8.235	-5.585
$1,100	1.911	2.147	2.450	2.853	3.415	4.251	5.631	8.336	16.041	211.989	-18.901	-9.047
$1,200	1.690	1.872	2.098	2.387	2.767	3.292	4.063	5.305	7.641	13.652	64.008	-23.809
$1,300	1.514	1.659	1.834	2.051	2.326	2.686	3.178	3.891	5.015	7.053	11.883	37.695
$1,400	1.372	1.490	1.630	1.798	2.006	2.269	2.610	3.072	3.732	4.755	6.550	10.520
$1,500	1.254	1.352	1.466	1.601	1.764	1.963	2.214	2.538	2.972	3.586	4.521	6.113

A4 - Cruise
Payback Period Sensitivity Analysis

MDO \ LNG $/MT	$400	$500	$600	$700	$800	$900	$1,000	$1,100	$1,200	$1,300	$1,400	$1,500
$400	10.260	53.981	-16.552	-7.176	-4.581	-3.364	-2.658	-2.197	-1.872	-1.631	-1.445	-1.297
$500	4.981	8.208	23.314	-27.739	-8.696	-5.156	-3.665	-2.842	-2.321	-1.962	-1.699	-1.498
$600	3.289	4.442	6.840	14.868	-85.592	-11.034	-5.897	-4.024	-3.054	-2.461	-2.060	-1.772
$700	2.455	3.045	4.008	5.863	10.914	78.843	-15.092	-6.887	-4.461	-3.299	-2.618	-2.169
$800	1.958	2.316	2.834	3.651	5.130	8.621	26.990	-23.871	-8.276	-5.006	-3.588	-2.796
$900	1.629	1.869	2.192	2.651	3.353	4.560	7.125	16.282	-57.062	-10.366	-5.701	-3.932
$1,000	1.394	1.566	1.788	2.081	2.490	3.100	4.104	6.071	11.657	146.161	-13.870	-6.621
$1,100	1.219	1.348	1.509	1.713	1.981	2.348	2.882	3.731	5.288	9.079	32.043	-20.950
$1,200	1.082	1.183	1.305	1.455	1.644	1.890	2.221	2.693	3.420	4.685	7.434	17.994
$1,300	0.973	1.055	1.150	1.265	1.406	1.581	1.806	2.107	2.527	3.157	4.205	6.294
$1,400	0.885	0.951	1.028	1.119	1.227	1.359	1.522	1.730	2.004	2.381	2.931	3.814
$1,500	0.810	0.866	0.929	1.003	1.089	1.192	1.315	1.468	1.660	1.911	2.250	2.736

	A6 - I/B Bulker Payback Period Sensitivity Analysis												
		LNG											
	$/MT	$400	$500	$600	$700	$800	$900	$1,000	$1,100	$1,200	$1,300	$1,400	$1,500
MDO	$400	87.579	-93.926	-30.570	-18.256	-13.014	-10.111	-8.266	-6.991	-6.057	-5.343	-4.779	-4.323
	$500	27.519	70.063	-128.334	-33.493	-19.260	-13.516	-10.411	-8.466	-7.134	-6.163	-5.426	-4.845
	$600	16.325	25.515	58.386	-202.528	-37.033	-20.380	-14.058	-10.730	-8.676	-7.282	-6.274	-5.511
	$700	11.604	15.598	23.783	50.045	-480.076	-41.411	-21.639	-14.646	-11.069	-8.896	-7.436	-6.388
	$800	9.001	11.232	14.933	22.271	43.789	1296.050	-46.963	-23.064	-15.285	-11.430	-9.128	-7.598
	$900	7.352	8.776	10.883	14.322	20.940	38.924	275.774	-54.233	-24.689	-15.982	-11.816	-9.372
	$1,000	6.214	7.201	8.561	10.555	13.760	19.759	35.031	154.304	-64.167	-26.561	-16.746	-12.228
	$1,100	5.381	6.105	7.056	8.357	10.246	13.240	18.704	31.847	107.120	-78.556	-28.740	-17.587
	$1,200	4.744	5.299	6.001	6.917	8.162	9.955	12.758	17.756	29.193	82.035	-101.264	-31.309
	$1,300	4.243	4.681	5.220	5.900	6.783	7.976	9.680	12.309	16.899	26.947	66.470	-142.438
	$1,400	3.837	4.192	4.619	5.144	5.802	6.654	7.799	9.420	11.891	16.121	25.022	55.869
	$1,500	3.502	3.796	4.142	4.559	5.069	5.707	6.530	7.629	9.173	11.501	15.412	23.354

	A7 - Icegoing Bulker Payback Period Sensitivity Analysis												
		LNG											
	$/MT	$400	$500	$600	$700	$800	$900	$1,000	$1,100	$1,200	$1,300	$1,400	$1,500
MDO	$400	31.798	-62.344	-15.741	-9.008	-6.309	-4.855	-3.945	-3.323	-2.870	-2.526	-2.255	-2.037
	$500	11.521	25.439	-122.281	-17.964	-9.694	-6.638	-5.047	-4.071	-3.412	-2.936	-2.577	-2.296
	$600	7.035	10.564	21.199	-3166.338	-20.919	-10.494	-7.004	-5.256	-4.206	-3.506	-3.005	-2.630
	$700	5.063	6.666	9.754	18.170	132.516	-25.036	-11.438	-7.412	-5.482	-4.350	-3.605	-3.078
	$800	3.955	4.869	6.334	9.059	15.899	64.900	-31.172	-12.568	-7.871	-5.729	-4.504	-3.710
	$900	3.245	3.836	4.690	6.034	8.457	14.133	42.973	-41.292	-13.946	-8.390	-5.999	-4.669
	$1,000	2.751	3.164	3.723	4.523	5.760	7.930	12.719	32.121	-61.141	-15.663	-8.982	-6.296
	$1,100	2.387	2.692	3.087	3.617	4.368	5.511	7.464	11.563	25.645	-117.734	-17.863	-9.665
	$1,200	2.109	2.343	2.637	3.014	3.517	4.223	5.282	7.051	10.599	21.342	-1583.169	-20.781
	$1,300	1.888	2.074	2.301	2.583	2.944	3.423	4.087	5.071	6.680	9.784	18.275	138.305
	$1,400	1.710	1.861	2.041	2.260	2.532	2.878	3.333	3.960	4.877	6.347	9.085	15.979
	$1,500	1.562	1.687	1.834	2.009	2.221	2.482	2.814	3.248	3.840	4.697	6.045	8.480

APPENDIX B – MARINE EMISSIONS INVENTORY TOOL RAW DATA

Emissions By Vessel Type in Canadian Arctic for 2019 [MT]														
Type	**NO_x**	**SO_x**	**CO**	**HC**	**PM**	**PM_{10}**	**PM_{25}**	**BC**	**CO_2**	**CH_4**	**N_2O**	**CO_2e**	**fuel_cons**	**Arctic LNG Study**
Coast Guard Icebreaker	559	0.2	19	24	5.8	5.6	5.1	2.8	24,515.90	0.4	1.2	24,882.00	7,646	CCG Icebreaker
Coast Guard Rescue	1.5	0	0.1	0.1	0	0	0	0	89.2	0	0	90.6	27	Other
Coast Guard Supply	3.7	0	0.2	0.2	0	0	0	0	233.3	0	0	237.1	72	Other
Coast Guard Tender	17.9	0	1	0.9	0.2	0.2	0.2	0.1	1,066.10	0	0.1	1,084.40	332	Other
Cruise	285.9	158.3	10.5	9.9	18.8	18	16.6	1.7	16,807.60	0.2	0.8	17,048.50	5,397	Cruise
Factory Ship	105.4	0.1	4.9	4.1	0.3	0.3	0.3	0.1	5,581.60	0.1	0.3	5,681.10	1,740	Fishing Vessel
Fishing Vessel	293.2	0.2	10.7	9.3	1.5	1.4	1.3	0.7	20,172.30	0.2	1.1	20,492.30	6,292	Fishing Vessel
Merchant (Tanker)	274.1	160.6	9.3	9.6	15.7	15.1	13.9	0.4	12,131.00	0.2	0.6	12,328.50	3,895	Tanker
Merchant Bulk	1,416.80	866.9	53.1	59	107	103	94.5	2.8	61,901.60	1	3.4	62,936.90	19,878	Bulk Carrier
Merchant Chemical	66.9	45.4	2.2	2.1	3.2	3	2.8	0.1	3,263.40	0	0.2	3,314.20	1,047	Tanker
Merchant Chemical/Oil Products Tanker	318.5	230.3	12.1	12	21.5	20.6	19	0.8	15,999.10	0.2	0.9	16,259.20	5,137	Tanker
Merchant General	1,369.70	967.6	54.3	52	95.7	91.9	84.5	3.9	67,899.60	1	3.8	69,053.30	21,804	General Cargo
Merchant Ore/Bulk/Oil	205.3	171.9	8.3	7.1	9.5	9.1	8.4	0.8	12,479.80	0.2	0.6	12,671.50	4,007	I/B Bulk Carrier
Merchant Passenger	100.9	0.1	4	4.6	1.4	1.3	1.2	0.3	5,553.10	0.1	0.3	5,637.70	1,732	Other
Special Purpose Research VSL	4.9	0	0.3	0.3	0.1	0.1	0.1	0	297.3	0	0	302.3	92	Other
Special Purpose Supply VSL	52.6	0	3.2	3.3	0.9	0.9	0.8	0.3	3,404.40	0.1	0.2	3,462.00	1,061	Other
Trawler	112.8	0.1	5.4	5.1	0.9	0.8	0.8	0.3	5,839.20	0.1	0.3	5,942.70	1,821	Fishing Vessel
Tug	87.8	0.1	5.1	5.8	1.4	1.3	1.2	0.8	5,660.00	0.1	0.3	5,748.50	1,765	Tug
Tug Harbour	42.1	0	2.1	2.6	0.6	0.6	0.6	0.3	2,398.40	0	0.1	2,435.90	748	Tug
Tug Ocean	27.1	0	1.2	1.3	0.4	0.4	0.3	0.1	1,481.80	0	0.1	1,505.60	462	Tug
Tug Supply	5.3	0	0.2	0.2	0.1	0.1	0.1	0	260.8	0	0	264.3	81	Tug
Warship Surface	8.5	0	0.3	0.3	0.1	0.1	0.1	0	384.8	0	0	390.8	120	Other
Total	**5,359.80**	**2,601.60**	**207**	**213**	**285**	**274**	**252**	**16.5**	**267,420.20**	**4**	**14.3**	**271,769.40**	**85,167**	

Emissions By Vessel Type in Canadian Arctic for 2019 [MT]														
Type	NO_x	SO_x	CO	HC	PM	PM_{10}	PM_{25}	BC	CO_2	CH_4	N_2O	CO_2e	fuel_cons	Arctic LNG Study
Special Purpose Supply VSL	52.6	0.0	3.2	3.3	0.9	0.9	0.8	0.3	3,404.4	0.1	0.2	3,462.0	1,061	Other
Trawler	112.8	0.1	5.4	5.1	0.9	0.8	0.8	0.3	5,839.2	0.1	0.3	5,942.7	1,821	Fishing Vessel
Tug	87.8	0.1	5.1	5.8	1.4	1.3	1.2	0.8	5,660.0	0.1	0.3	5,748.5	1,765	Tug
Tug Harbour	42.1	0.0	2.1	2.6	0.6	0.6	0.6	0.3	2,398.4	0.0	0.1	2,435.9	748	Tug
Tug Ocean	27.1	0.0	1.2	1.3	0.4	0.4	0.3	0.1	1,481.8	0.0	0.0	1,505.6	462	Tug
Tug Supply	5.3	0.0	0.2	0.2	0.1	0.1	0.1	0.0	260.8	0.0	0.0	264.3	81	Tug
Warship Surface	8.5	0.0	0.3	0.3	0.1	0.1	0.1	0.0	384.8	0.0	0.0	390.8	120	Other
Total	5,359.8	2,601.6	207.3	213.0	284.9	273.5	251.6	16.5	267,420.2	4.0	14.3	271,769.4	85,167	