Economic and GHG Emissions Benefits of LNG for Remote Markets in Canada

May 2016

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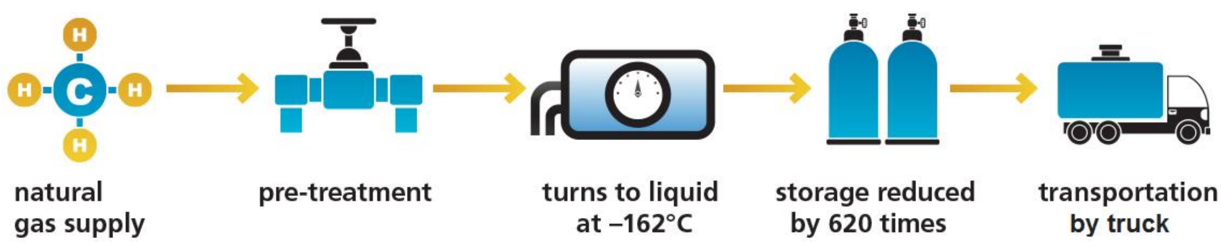
Executive Summary

The Role of LNG as a Fuel in Canada's North

Approximately 200,000 people live in nearly 300 remote communities spread across Canada that are disconnected from central energy supplies.[1] These remote energy markets are 'off-grid' regions of Canada that are not connected to the North American electrical grid or to natural gas distribution pipelines. This includes both remote communities and remote industrial energy users, such as mines. In these remote regions, reliable and cost-effective energy supply are a challenge for communities and industry, and serve as a barrier to economic development. Remote communities and industry typically rely on diesel, propane, or other fuel oils for heating and to generate their own power, all of which have to be shipped in by truck, rail, or marine vessel.

In many remote regions of Canada, liquefied natural gas (LNG) is increasingly being considered as an option to meet energy requirements. Advances in the technology used to liquefy, transport, and re-vaporize natural gas, have made LNG a viable option for remote customers. Natural gas is liquefied to reduce its volume, making it easier to transport in large quantities with truck tanks, as highlighted in Exhibit ES 1. The delivered gas is stored by customers on-site as a liquid and vaporized when needed.

Exhibit ES 1 Remote LNG Supply Chain[2]



Although LNG has many advantages, including environmental and safety benefits, cost savings are the primary driver of its adoption. In recent years, due to low natural gas prices, LNG has emerged as an affordable alternative to diesel or fuel oil in remote communities and mining sites.[3]

One major challenge to remote LNG adoption in Canada has been the lack of new LNG liquefaction infrastructure.[4] The lack of nearby plants to liquefy natural gas means that LNG must be shipped by truck over longer distances, adding to the cost for remote users and reducing LNG's competitiveness compared to other fuels. However, small-scale liquefaction plants can be strategically built in regions that are closer to the remote energy demand, but are still served by natural gas pipelines.

This issue of LNG supply is starting to be addressed by the market, with two new LNG plants built in Alberta since 2012, and two LNG plant expansions (BC and Quebec) commencing in 2015. Further, one new LNG plant is set to come online in 2016, in northern BC.

Project Background and Approach

To properly consider the merits of LNG for remote customers, regulators, governments, and other decision makers need a clear understanding of the costs and benefits for new LNG customers, as well

[1] MaRS Advanced Energy Centre, Enabling a Clean Energy Future for Canada's Remote Communities, 2015. http://www.marsdd.com/wp-content/uploads/2014/11/Clean-Energy-Future-for-Canada%E2%80%99s-Remote-Communities-.pdf
[2] Yukon Energy Corporation, Liquid Natural Gas, 2016. http://www.yukonenergy.ca/energy-in-yukon/our-projects-facilities/back-up-electricity/liquid-natural-gas/
[3] Braemar Engineering, LNG for the Mining Sector: A new Energy Option for Yukon, 2012.
[4] National Energy Board, Canada's Energy Future 2016: Energy Supply and Demand Projections to 2040, 2016. https://www.neb-one.gc.ca/nrg/ntgrtd/ftr/2016/2016nrgftr-eng.pdf

as the impacts on the broader Canadian economy and environment. This study assesses these costs and benefits, and presents key metrics that demonstrate the net impacts.

ICF worked with the CGA and Canadian natural gas distribution utilities to define the scope of expansions and type of customers that would be reached. This study assesses projects representing an investment of $1.4 billion in liquefaction plants, and the conversion of 58 industrial customers and 23 remote community power generating stations. These projects are just the beginning of the potential for LNG adoption, not the maximum potential, and will be used here to highlight the possible benefits. Exhibit ES 2 presents the annual consumption expected for the new customers considered in the study, the bulk of which is for industrial and mining customers.

Exhibit ES 2 Annual Natural Gas Consumption for New LNG Customers Considered in this Study (GJ/year)

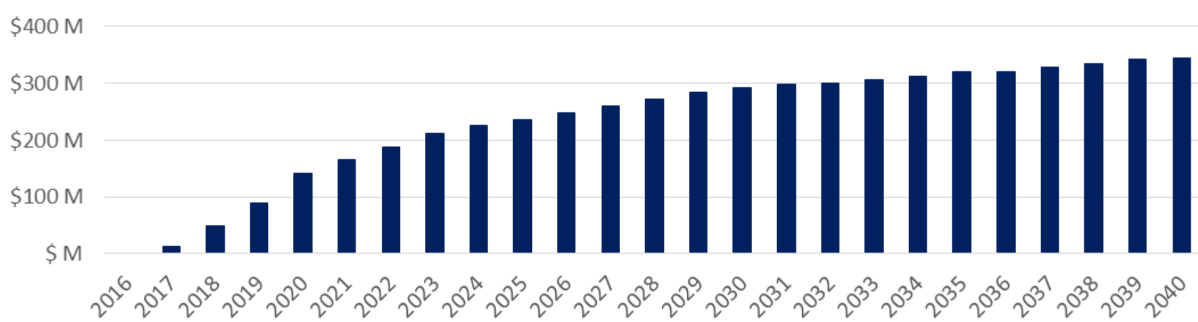
Communities (Power Generation)	Industrial & Mining	Total
2,766,583	**25,034,275**	**27,800,858**

Key parameters such as fuel cost savings and infrastructure costs were analysed to assess the viability of such projects from the customer's perspective and to serve as inputs to the economic model. The economic modeling assessed the effects on Canadian GDP, jobs, and government revenues from such projects. Additional analysis was carried out to assess the customer impacts of $30 and $100 per tonne CO2 prices. Finally, the impacts to customers from changes to fuel price projections were assessed, as there is considerable uncertainty in long term commodity price forecasts.

Study Results

Exhibit ES 3 presents the annual customer fuel cost savings[5] over the study period, but does not capture added customer costs for on-site LNG storage, handling, and utilization equipment. The fuel cost savings ramp up between 2017 and 2024, as the sites considered in this study adopt LNG. Annual fuel cost savings are $236 million in 2025, and continue to rise in later years as a result of differences in the price forecasts for fuels.

Exhibit ES 3 Annual Fuel Cost Savings of New LNG Customers (2015$ Million) [5]



Overall, these conversions represent a decrease in annual emissions of more than 500,000 tonnes of CO2 per year, equivalent to removing more than 100,000 passenger vehicles from the road.[6] Over the 25 year study period, this represents a cumulative reduction in CO2 of 11.1 million tonnes, equivalent to the annual CO2 production of over 2.3 million passenger vehicles.

[5] These values represent the annual net fuel cost savings, in real 2015 Canadian dollars, for all new remote LNG customers. This compares delivered fuel costs, so the LNG prices include costs for natural gas, liquefaction, and delivery. However, these savings do not account for customer costs for on-site LNG storage, LNG vaporizers, new gas burning equipment, or for the value of reduced CO2 emissions.
[6] United States Environmental Protection Agency, Greenhouse Gas Equivalencies Calculator, 2014.

The business case for replacing diesel and heavy fuel oil with LNG is improved by CO2 emission prices, as these fuels are more carbon-intensive than natural gas.

In addition to the annual fuel cost savings, this study calculates all of the incremental customer costs to convert to LNG, including expenses for on-site LNG storage, LNG vaporizers, and new gas burning equipment.

Accounting for these additional customer costs, Exhibit ES 4 shows that the new LNG customers gain over $2.3 billion in total customer benefits on a present value basis from the conversion. The savings for mines and industrial customers represent 90% of this total, as these customers make up 90% of the consumption considered to convert to LNG.

Exhibit ES 4 Net Present Value of Total Net Savings for New LNG Customers (2015$ Million)[7]

Communities (Power Generation)	Industrial & Mining	Total
230	2,147	2,377

The benefits of LNG adoption in remote markets extend beyond just the new customers (lower energy costs) and emission levels (lower CO2 production). There are also significant impacts for Canada's GDP, employment, and government taxes and revenues.

Exhibit ES 5 summarizes the broader macro-economic implications of LNG expansion. The primary drivers of economic impacts are the re-spending of customer fuel cost savings and infrastructure spending.

It is expected that over a 25 year period, these expansion projects would add $12.5 billion to Canada's GDP, contribute support of over 115,000 net job-years, increase government revenues by $4.4 billion, and reduce annual CO2 emissions by more than 500,000 tonnes.

Exhibit ES 5 Summary of Economic Impacts from LNG Expansion over Study Period

Type of Economic Benefit	Direct & Indirect Impacts	Induced Impacts	Total Impacts (2016-2040)
GDP ($Million)	8,923	3,591	12,514
Employment (Job-years)	85,269	32,343	117,612
Government Taxes and Revenues ($Million)	3,194	1,285	4,480

[7] Values in this table represent the Net Present Value of the conversions, in real 2015 Canadian dollars, for new LNG customers. This takes into account delivered fuel costs, LNG infrastructure costs, and incremental gas burning equipment costs. This NPV does not include benefits/costs for decreased CO2 emissions.

Table of Contents

List of Exhibits

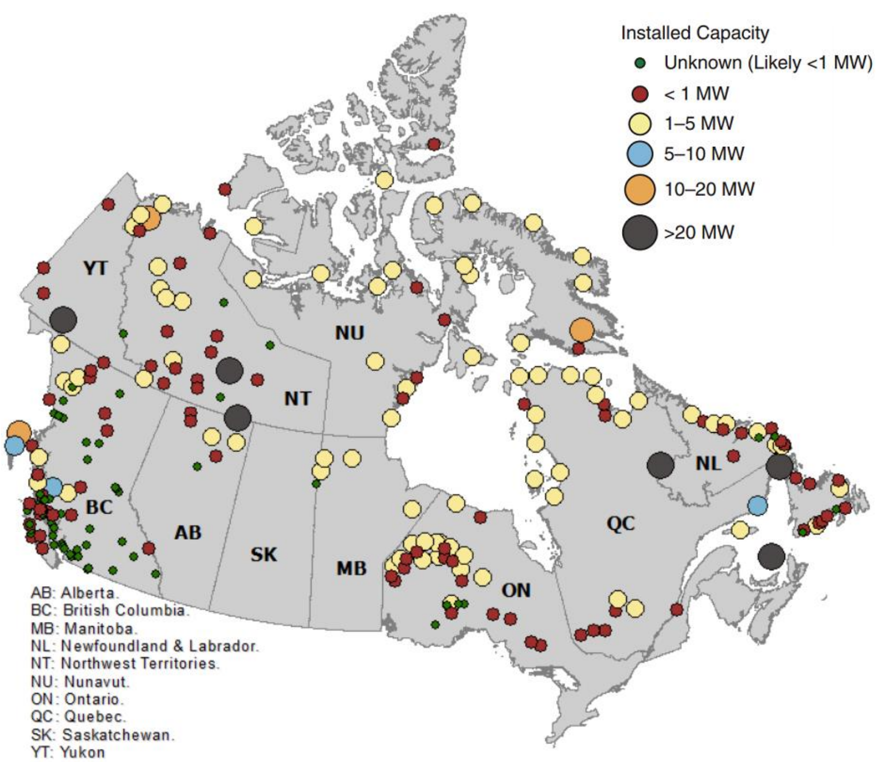
1 Overview of Remote Energy Markets in Canada

The remote energy markets considered in this study are 'off-grid' regions of Canada that are not connected to the North American electrical grid or to natural gas distribution pipelines.[8] This includes both remote communities and remote industrial energy users such as mines. In Canada, approximately 200,000 people live in nearly 300 remote communities across the country that are disconnected from these central energy networks.[9] In these remote regions, reliable and cost-effective energy supply are a challenge for communities and industry. These challenges also serve as a barrier to economic development in remote regions. Canada's mining sector is also a significant user of energy, consuming a total of roughly 1.1 billion litres of diesel fuel in 2013.[10]

Energy use in remote markets is very different from the rest of the country, where most customers can count on a reliable supply of natural gas for heating needs and electricity distributed from a central network of generating stations. Remote communities and industry typically rely on diesel, propane, or other fuel oils for heating and to generate their own power, nearly all of which have to be shipped in by truck, rail, or marine vessel.

To give context to the locations of remote communities, Exhibit 1 highlights the communities in Canada that rely on off-grid power generation, categorized according to electrical capacity.

Exhibit 1 Northern and Remote Communities Categorized by Installed Electrical Capacity[11]



[8] Natural Resources Canada, Status of Remote/Off-Grid Communities in Canada, 2011. http://www.nrcan.gc.ca/sites/www.nrcan.gc.ca/files/canmetenergy/files/pubs/2013-118_en.pdf
[9] MaRS Advanced Energy Centre, Enabling a Clean Energy Future for Canada's Remote Communities, 2015. http://www.marsdd.com/wp-content/uploads/2014/11/Clean-Energy-Future-for-Canada%E2%80%99s-Remote-Communities-.pdf
[10] Personal communications, Mining Association of Canada.
[11] Mariano Arriaga et Al., Northern Lights, IEEE Power & Energy Magazine, March 2014. With several ICF additions. http://normandmousseau.com/documents/Canizares-1.pdf

To give context to the locations of remote industry, Exhibit 2 highlights some of the mining regions in Canada that rely on off-grid power generation.

Exhibit 2 Remote Mining Regions of Canada[12]

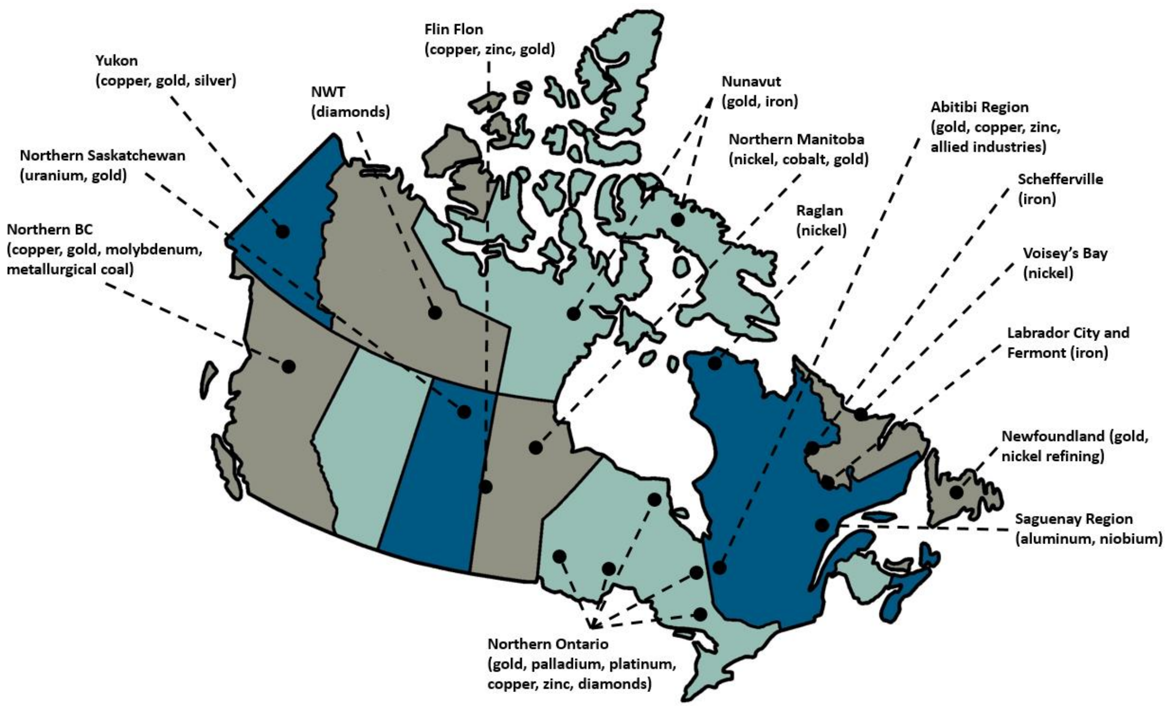
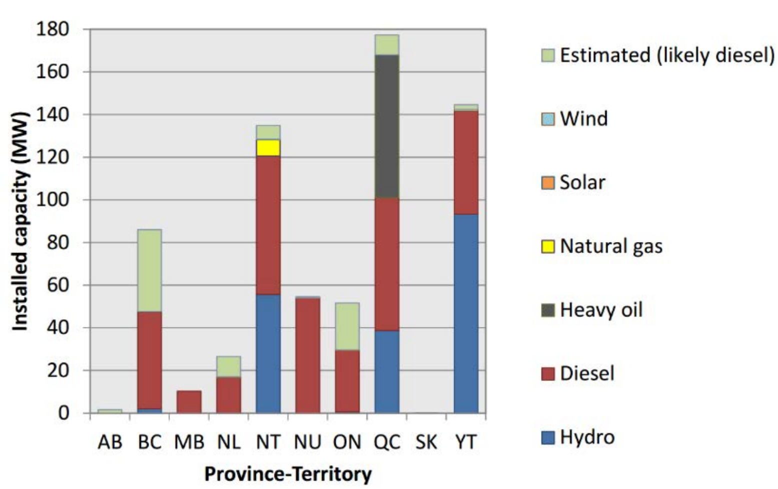


Exhibit 3 provides more details on the energy sources used to generate electricity in remote communities, with diesel-powered generators being the most common option, particularly where hydropower is not available. Remote mining projects also typically rely on diesel fuel,[13] with heavy fuel oil also used for industry in some regions.

Exhibit 3 Energy Sources for Remote Electricity Generation[14]



[12] Personal communication, Mining Association of Canada.
[13] Standing Senate Committee on Energy, the Environment & Natural Resources, Power Canada's Territories, 2014. http://www.parl.gc.ca/Content/SEN/Committee/412/enev/rep/rep14jun15-e.pdf
[14] Mariano Arriaga et Al., Northern Lights, IEEE Power & Energy Magazine, March 2014.

Remote communities and industry face many energy-related challenges, including a variety of economic, technical, social, and environmental issues that need to be considered when comparing energy supply options. Concerns surrounding existing remote energy infrastructure include:

- High operating costs due to high volumes of fuel consumption, and to diesel fuel being subject to significant price volatility. [15]
- High cost of energy, energy supply issues, and capacity constraints in off-grid communities can deter new businesses, thus limiting future economic opportunities in off-grid communities. [16]
- Fuel being trucked, marine shipped, and sometimes flown over long distances in challenging climates.
- Environmental disadvantages due to diesel generation emitting substantial volumes of greenhouse gases (GHGs), causing local air and noise pollution, and the risks of fuel spills/leaks.
- Significant numbers of aging generating plants operating past their designed service life, increasing issues with reliability and safety, particularly in cold remote locations.[15]

Diesel generation is prevalent in remote regions because in many cases historically, it was the only viable option for reliable power in remote communities and isolated mining sites. However, diesel generation has advantages as well. It is relatively easy to install and maintain, is flexible and reliable, and can respond rapidly to changing demand loads.

In a statement that summarizes the shift underway in all remote energy markets, the Standing Senate Committee on Energy, the Environment and Natural Resources outlined some ‘national priorities for the territories’ in a March 2014 report: [15]

> *“After over a year of examining territorial energy issues, it is clear that existing energy systems require change. In many communities energy costs are high and rising. There is heavy reliance on imported diesel and much of the territories’ energy assets are at capacity, aging and underperforming, threatening the reliable supply of energy to northerners. These factors strain public resources and limit economic growth and prosperity. That being said, the committee also observed that territorial governments are advancing plans to diversify their energy mix through renewable generation, biomass and LNG and have placed a focus on promoting and funding energy efficiency and conservation programs.”*

[15] Standing Senate Committee on Energy, the Environment & Natural Resources, Power Canada’s Territories, 2014.
[16] Natural Resources Canada, Status of Remote/Off-Grid Communities in Canada, August 2011.

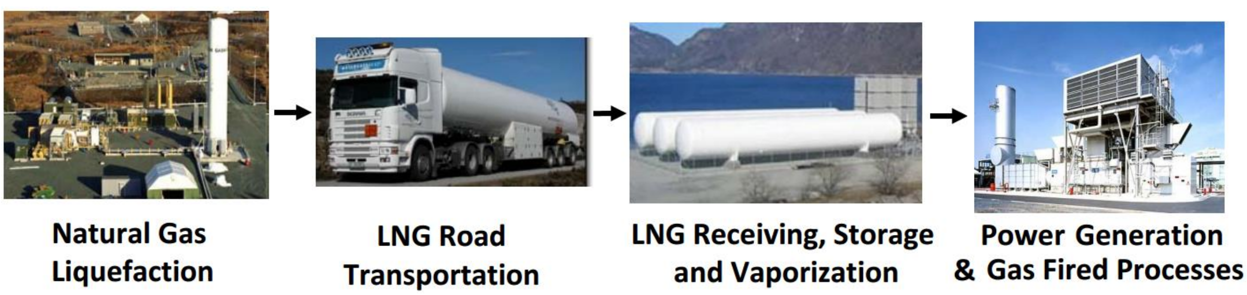
2 The Role of LNG as a Fuel in Canada's North

In many remote regions of Canada, liquefied natural gas (LNG) is increasingly being considered as an option to meet energy requirements. In Canada, natural gas costs less than diesel for an equivalent amount of energy. Historically, a lack of pipeline access meant that remote communities and mining sites could not use or have access to natural gas, and instead depended on more expensive fuels such as diesel, propane, and heavy fuel oil. However, advances in the technology used to liquefy, transport, and re-vaporize natural gas, as well as low natural gas prices, have made LNG a viable option for off-pipe customers. LNG for remote markets is produced by domestic liquefaction facilities that are often considerably smaller than facilities built to liquefy natural gas for export.

Natural gas is liquefied to reduce its volume, making it easier to transport in large quantities with ship or truck tanks. The density of natural gas is increased by a factor of more than 600 when it is liquefied, resulting in an energy density that is more comparable to other liquid fuels. For example, the energy in 1.68 gallons of LNG is equal to about 1 gallon of diesel.[17] LNG is a versatile fuel that can supply energy for a variety of end-uses, including for power generation, boilers, process heating, drilling rigs, mine haul trucks, and road trucks.

Exhibit 4 highlights that liquefaction plants are just the first stage of the remote LNG supply chain. Tanker trucks are required to supply the remote customer with LNG, and the customer will need to install infrastructure to unload tankers, store LNG, and vaporize the LNG. Finally, the customer will also require natural gas burning equipment, although diesel generators can often be converted to operate on both natural gas and diesel fuels.[18]

Exhibit 4 Remote LNG Supply Chain[19]



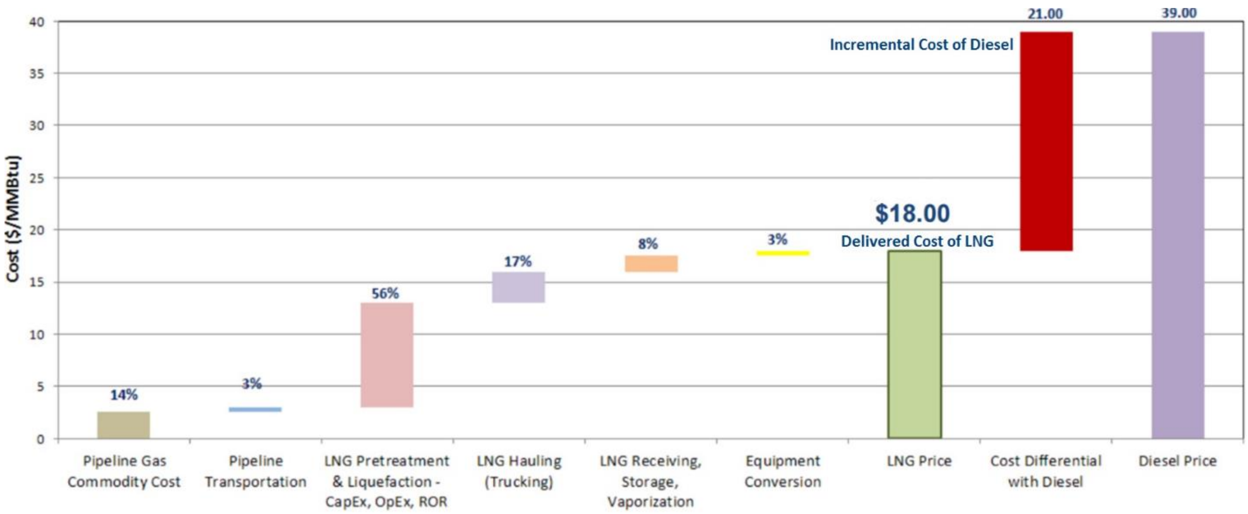
Although LNG has many advantages, including environmental and safety benefits, the primary driver for remote customers to commit to the additional supply chain steps is the opportunity for cost savings through LNG. In recent years, due to low natural gas prices, LNG has emerged as an affordable alternative to diesel or fuel oil power/heat generation in remote communities and mining sites.

A cost breakdown showing the various components of the LNG supply chain is presented in Exhibit 5. This exhibit compares the LNG supply option for a remote customer to delivered diesel prices. The first thing to note is the significant price differential between the gas commodity cost (far left column) and the diesel price (far right). While the costs included in this diagram are not reflective of the current fuel price environment, the breakdown highlights that the largest portion of LNG costs will actually be for liquefaction. This includes cost recovery to cover the liquefaction plant capital costs, as well as the large amount of energy required for the plant to liquefy natural gas. However, even after including all

17 Plum Energy, Liquefied Natural Gas FAQ, 2016. http://www.plumenergy.com/liquefied-natural-gas-faq/
18 Standing Senate Committee on Energy, the Environment & Natural Resources, Power Canada's Territories, 2014.
19 Braemar Engineering, LNG for the Mining Sector: A new Energy Option for Yukon, 2012. http://www.economicdevelopment.gov.yk.ca/pdf/Braemar.pdf

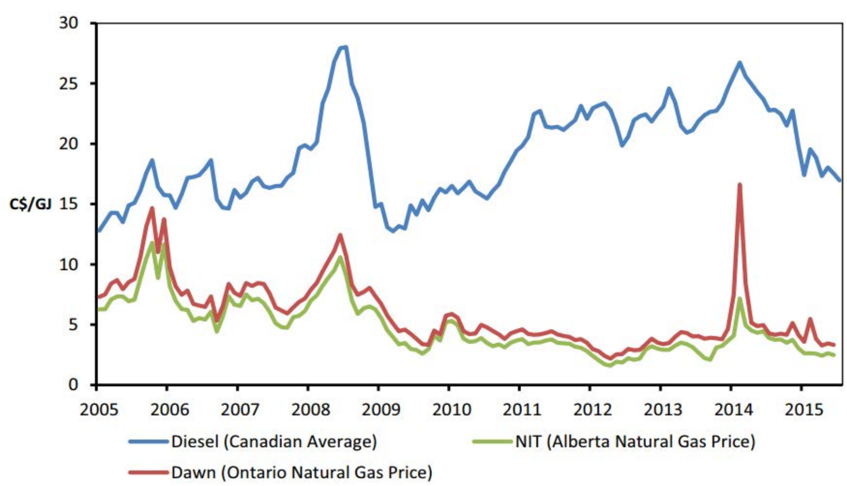
of the LNG cost components, the delivered LNG price in Exhibit 5 is estimated to be significantly lower than diesel prices.

Exhibit 5 Comparison of Hypothetical Costs of LNG Supply Chain vs Diesel[20]



The rate of remote LNG adoption is related to the difference in prices between natural gas and refined petroleum products. Exhibit 6 compares the wholesale prices for diesel and natural gas, and shows that despite recent reductions in diesel prices, a significant margin remains. It is important to keep in mind that the diagram below compares commodity prices, and does not account for LNG costs such as liquefaction. For example, FortisBC advertises a liquefaction charge of $4.35/GJ.[21] In general, LNG-specific costs are expected to reduce, but not eliminate, the price-advantage shown below.

Exhibit 6 Wholesale Diesel and Natural Gas Prices[22]



While the delivered-price advantage for LNG is expected to be smaller than what is shown above, in its 2016 Energy Futures report, the National Energy Board indicated that its oil and natural gas price projections suggest the differential could be sufficient to encourage growth in remote LNG

[20] Braemar Engineering, LNG for the Mining Sector: A new Energy Option for Yukon, 2012.
[21] FortisBC, Buying liquefied natural gas (LNG): What charges can I expect for LNG service. Accessed March 2016. https://www.fortisbc.com/About/ProjectsPlanning/GasUtility/NewOngoingProjects/BuyingLiquefiedNaturalGas/Pages/default.aspx

consumption.[22] Additionally, improvements are also still being made to the economics of the LNG value chain, such as the commercialization of larger LNG tanker trucks to mitigate shipping cost differences, and the development of more efficient small-scale liquefaction units.

Natural gas is the cleanest burning fossil fuel, and the adoption of LNG in remote communities brings several environmental advantages. LNG generation emits fewer GHGs than diesel generation, and nearly eliminates other forms of air pollution (SO2, NOX, CO, PM).[23] The transportation of LNG is also very safe. As a liquid, LNG is not at risk of combustion and is held at a low pressure. In the event of a LNG spill, the LNG vaporizes, and there is no contamination or residual waste to clean up.[24]

There are however also limitations and barriers to the adoption of LNG for remote markets, including:

- LNG still needing to be shipped onto site, and there are limitations on how far is feasible for some end users (depending on their current energy prices).
- Year-long road access generally being required since long term LNG storage is costly.[25]
- LNG requiring new infrastructure, including receiving terminals, storage, and vaporizers, all of which must be maintained to ensure a reliable energy supply.
- LNG supply chain is still developing, which can make procurement more difficult.

One major challenge to remote LNG adoption in Canada has been the lack of new LNG liquefaction infrastructure.[22] The lack of nearby plants to liquefy natural gas means that LNG must be shipped by truck over longer distances, adding to the cost for remote users and reducing LNG's competitiveness compared to other fuels. However, small-scale liquefaction plants can be strategically built in regions that are closer to the remote energy demand, but are still served by natural gas pipelines.

Several recent and proposed small-scale liquefaction facilities in Canada will decrease trucking distances for many prospective LNG users,[22] including remote communities (discussed later in Exhibit 8). Two new LNG plants have been built in Alberta since 2012, and two LNG plant expansions (BC and Quebec) commenced in 2015. Further, one new LNG plant is set to come online in 2016, in northern BC. Details on these LNG production facilities are provided below in Exhibit 4.

Exhibit 7 Small-Scale LNG Facilities in Canada [26]

Company	Facility Location	Date Commissioned / Expected	Expansion Date	Capacity (MMcf/d)	
				Current/Proposed	Expansion/Potential
AltaGas	Dawson Creek, BC	2015	By 2020	1.65	TBD
Ferus	Strathmore, AB	2013	-	0.41	-
FerusNGF	Elmworth, AB	2014	-	4.13	--
FortisBC	Tilbury Island, BC	1971	2016	4.24	36.74
FortisBC	Mt. Hayes, BC	2011	-	7.50	-
Gaz Métro	Montreal, QC	1969	2016	10.04	29.22
Northeast Midstream	Thorold, ON	2017	-	29.74	-
Union Gas	Hagar, ON	1968	2015/16	N/A	3.00

[22] National Energy Board, Canada's Energy Future 2016: Energy Supply and Demand Projections to 2040, 2016. https://www.neb-one.gc.ca/nrg/ntgrtd/ftr/2016/2016nrgftr-eng.pdf
[23] Braemar Engineering, LNG for the Mining Sector: A new Energy Option for Yukon, 2012.
[24] Plum Energy, Liquefied Natural Gas FAQ, 2016.
[25] Standing Senate Committee on Energy, the Environment & Natural Resources, Power Canada's Territories, 2014.
[26] National Energy Board, 2015. https://www.neb-one.gc.ca/nrg/ntgrtd/mrkt/dnmc/2014/index-eng.html#s9

Having weighed these considerations, LNG has already been adopted as a fuel source in several remote Canadian markets. Exhibit 8 showcases four projects where LNG has been selected to meet remote energy requirements.

Exhibit 8 Examples of Remote LNG Projects in Canada

Remote Community: Inuvik [27]	Remote Mine: Stornoway [28]
Located at the northern edge of the North West Territories, Inuvik started using LNG to generate electricity in 2013. Inuvik already had a power plant designed to run on natural gas, which had been supplied by a local well until 2012, when gas stopped flowing. Inuvik then became reliant on standby diesel generators to supply power to the community, driving the adoption of LNG. While early results showed cost savings of 10% to 20% over diesel, and Inuvik burns LNG whenever they can, they continue to rely on diesel generation. LNG storage was built in 2014, but a limited number of tanker trucks, coupled with extreme distances to existing liquefaction plants (up to 7500 km return trip), have so far limited LNG from supplying the majority of community power.	The Renard Diamond Mine currently under construction in Quebec selected LNG because of its lower operating cost and reduced emissions. Annual operating cost savings are expected to be between \$8 and \$10 million. The cost of building an LNG power plant was only \$2.6 million more than a diesel plant, giving a net payback of only 4 months. The LNG plant will have 43% fewer greenhouse gas emissions. The power plant will hold seven 2.1 MW LNG gen-sets, normally producing 9.5 MW. Onsite gas storage will be sufficient for 10 days operation, with LNG delivered daily by tanker truck from the existing Gaz Metro liquefaction plant in Montreal. LNG will also be used for heating buildings and the underground mine.
Remote Community: Whitehorse [29] [30]	**Remote Mine: Casino [31]**
Yukon Energy is able to meet almost all of their generation requirements through hydroelectricity. Historically, they have relied on diesel generators during power outages, very cold weather, and droughts. In 2015, two aging diesel electric generators in Whitehorse were replaced with new modular natural gas engines to be supplied through LNG. Before the LNG plant was built, the back-up diesel capacity in Whitehorse was 20 megawatts. The two new natural gas engines offer 8.8 megawatts of capacity, and there is the possibility to add a third engine. Through these LNG generators, Yukon Energy expects to achieve \$2.2 million in annual savings.	The Casino mine is a \$2.46 billion project under consideration in the Yukon, about 400 kilometres northwest of Whitehorse. The gold and copper project is planning to rely on LNG, and expects this to provide power at about 9.5 cents per KWh. To provide power to the camp and for construction activities, the proposed plan includes three dual fuel driven generators (capable of using both LNG and diesel) with a combined capacity of 20.1 MW. In addition, to power the mine operations and the concentrator complex, the plan calls for LNG to supply two gas turbine driven generators and a steam generator (combined cycle) to nominally produce 125 MW. Two additional LNG powered back-up generators are also planned (18.6 MW).

[27] NT Energy, LNG Potential in the NWT: Inuvik Case Study, 2014.
[28] Stornoway, Press Release: Stornoway to Proceed With LNG Power Plant for Renard Diamond Project, 2013.
[29] Yukon Energy Corporation, Liquid Natural Gas, 2016. http://www.yukonenergy.ca/energy-in-yukon/our-projects-facilities/back-up-electricity/liquid-natural-gas/why-are-we-looking-at-it/
[30] Yukon Energy Corporation, Whitehorse Diesel – Natural Gas Conversion Project, 2013. http://yukonenergy.ca/media/site_documents/LNG_Part_III_Application.pdf
[31] Western Copper and Gold, Casino Mine Feasibility Study, 2013. http://www.westerncopperandgold.com/_resources/reports/CasinoNI43-101-Jan2013.pdf

3 Project Background

In many remote regions of Canada, liquefied natural gas is increasingly being considered as an option to meet energy requirements.

To properly consider the merits of LNG for remote customers, regulators, governments, and other decision makers need a clear understanding of the costs and benefits for customers, as well as the costs and benefits for the broader Canadian economy. This study assesses these costs and benefits, and presents key metrics that demonstrate the net benefit of supplying LNG to remote markets.

More specifically, this study provides an understanding of the macro-economic implications and benefits (GDP, jobs, government revenues) of providing LNG access to remote communities and industry in Canada. Some of the key areas into which this study provides insight include:

- The economic impacts of LNG infrastructure investments to supply remote market energy demand.[32]
- Energy cost savings achieved by switching to LNG from the alternative energy sources.
- The total (direct, indirect, and induced) economic benefits to the Canadian economy in terms of contribution to GDP, support of jobs, and provincial and federal tax revenues.
- GHG emission benefits for Canada from transitioning from diesel or fuel oil to LNG as a fuel source for remote regions of the country.
- The sensitivity of remote LNG project economics to CO2 emission prices and fuel cost increases for LNG and alternative fuels.

The primary driver of overall economic benefits is the re-spending of customer fuel cost savings, which is calculated by comparing fuel price forecasts. However, it is important to consider all macro-economic implications, as LNG conversions will lower domestic consumption of some other fuels, and hence have negative economic impacts in some areas.

This study focuses on LNG displacing other fuels at remote industrial facilities (including mines), as well as being used for power generation in remote communities. This study does not consider distributing natural gas within remote communities (isolated gas distribution networks) or expanding pipelines to remote communities.

A separate ICF report assessing the benefits from expanding natural gas distribution pipelines to Canadian consumers is also available through the CGA. That study examined the consumer and economic impacts from utility investments connecting more customers to affordable natural gas supplies.

[32] All dollar amounts in this report are expressed in Canadian dollars unless otherwise stated.

4 Project Approach

This section provides an overview of ICF's approach to assessing the benefits to consumers, and the economic impacts on the Canadian economy of the expansion of LNG infrastructure for remote markets. A detailed discussion of the project's methodology and key assumptions is provided later, in Appendix A. The three main stages of this project are outlined in Exhibit 9, and are summarized below.

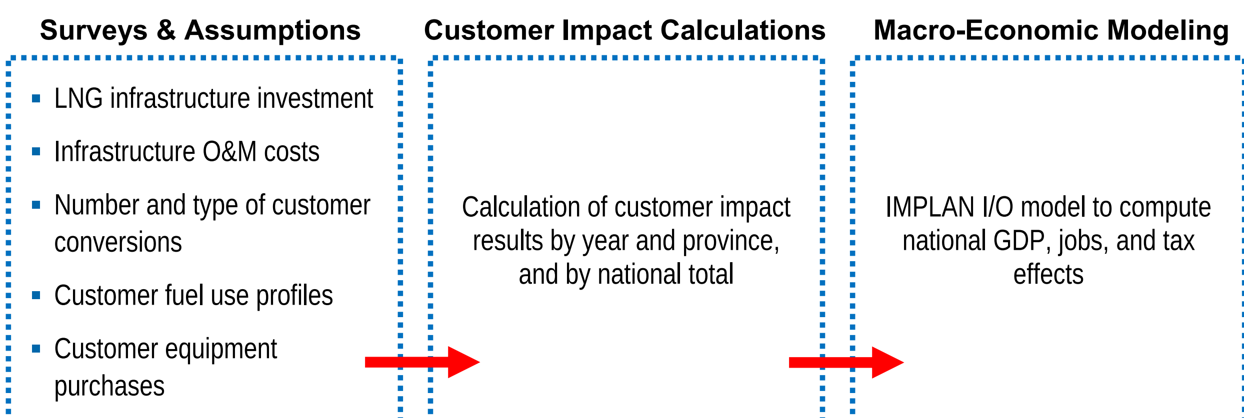
The first stage of the work involved data collection, which included surveys and discussions with Canadian natural gas distributors, independent research, and the collection of institutional knowledge from experts at both ICF and the CGA member company utilities.

The second stage of the project, customer impact calculations, involved an analysis of key parameters that could be used to judge the favourability of remote LNG expansion projects. The outputs of this stage provide important metrics on the viability of such projects from the customer's perspective and serve as inputs to the economic model. This stage also assessed the sensitivity of new customer benefits to hypothetical low and high CO2 emission price scenarios, as well as the sensitivity of results to different fuel-price scenarios.

The third stage of the project focused on economic modeling, and provides additional metrics to assess the impact of distribution pipeline projects on the broader Canadian economy. This stage assesses the effects on GDP, jobs, and government revenues from such projects. This modeling is based on IMPLAN input/output matrices. IMPLAN tracks different types of Canadian economic impacts from expenditures in 103 sectors of the economy. By determining how the expenditures associated with natural gas distribution pipeline expansion align with the categories in IMPLAN, it was possible to establish their impacts.

The IMPLAN model differentiates between spending impacts for the Canadian economy and impacts 'leaked' to imports. All of the results in this study present impacts to the Canadian economy, and have been adjusted to remove the effect on imports.

Exhibit 9 Project Approach and Stages



Appendix A discusses the study process steps in more detail, provides information on some key assumptions driving the analysis, and describes the IMPLAN model.

5 Study Results

In this section, the results of the customer impact calculations are presented first, followed by the economic modeling results, and then a look at the sensitivity of customer impacts to both CO2 emission prices and different fuel price scenarios.

The customer impact calculation results showcase the benefits from the remote LNG consumer's perspective, and include Net Present Value (NPV) calculations demonstrating that the fuel cost savings will outweigh the requirement for customers to invest in LNG equipment, over the 25 year study period. This first set of results also highlights the capital expenditures for LNG infrastructure that would be required to supply LNG to remote customers. The economic modeling results then quantify the benefits these projects would bring to the broader Canadian economy. These results focus on value added (GDP), increased employment, and increased government revenues.

The CO2 emission price sensitivity results first show the expected net changes to GHG emissions from the customers targeted in these remote LNG projects. Low and high price scenarios then demonstrate how customer fuel cost savings and NPV could be affected by existing or future CO2 emission prices. Finally, two alternative fuel price scenarios are presented to showcase how the customer impact results could fluctuate with the changes to the cost of natural gas and diesel.

Customer Impacts: The Role of LNG as an Affordable Fuel

The customer impact calculations were conducted at a provincial/territorial level, and these results are presented separately for each of the regions where the study team identified feasible opportunities for LNG to supply remote markets. Together, the overall results are intended to broadly represent the potential for such projects and the benefit to Canada.

Exhibit 10 presents the number of remote customers that are considered to convert to LNG in this study, as well as the expected annual natural gas consumption for these customers by 2025. The results are split between two customer types: power generation facilities that will provide electricity to remote communities, and industrial customers (including mines) that will use the natural gas for both thermal loads and on-site electricity generation.

Exhibit 10 Number of New Remote LNG Customers and New Gas Consumption (2025)

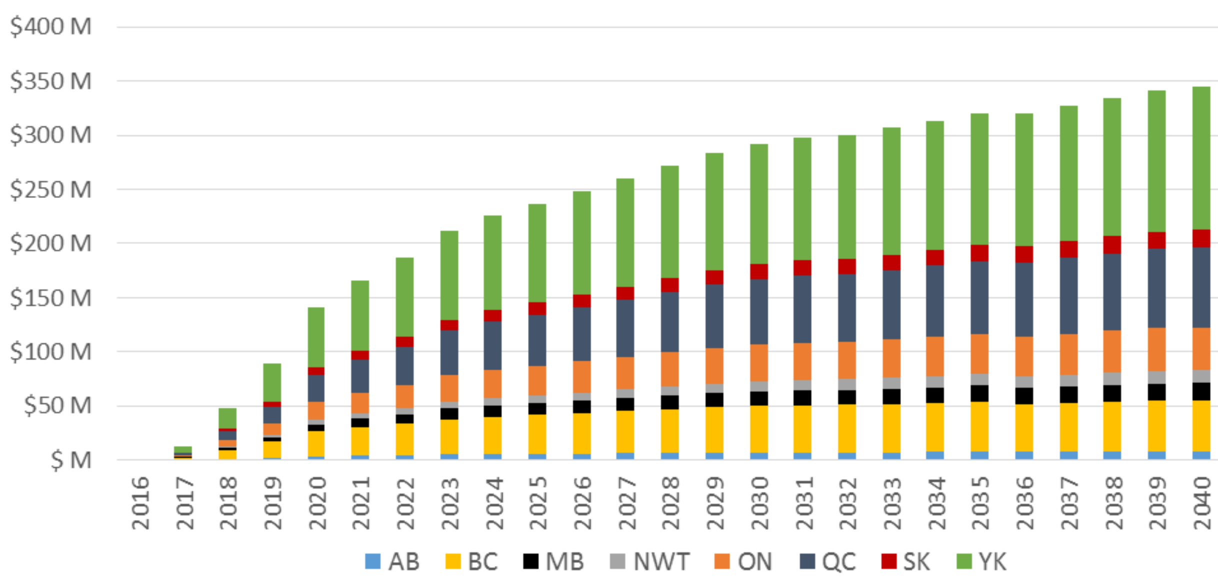
Province / Territory	Number of New Customers			Annual Gas Consumption (GJ/year)		
	Power Gen.	Industrial	Total	Power Gen.	Industrial	Total
Alberta	-	10	**10**	-	571,913	**571,913**
British Columbia	5	12	**17**	351,969	3,057,332	**3,409,301**
Manitoba	1	6	**7**	140,788	1,060,000	**1,200,787**
North West Territories	2	-	**2**	1,039,841	-	**1,039,841**
Ontario	12	8	**20**	469,292	2,495,620	**2,964,912**
Quebec	1	10	**11**	140,788	7,619,524	**7,760,312**
Saskatchewan	-	10	**10**	-	1,130,877	**1,130,877**
Yukon	2	2	**4**	623,905	9,099,009	**9,722,914**
Canada	**23**	**58**	**81**	**2,766,583**	**25,034,275**	**27,800,858**

When considering the LNG projects shown in Exhibit 10 it is important to keep in mind several aspects of this study:

- These customers are not intended to represent the maximum potential for remote LNG. These numbers are intended to represent likely LNG customers.[33] For example, 12 industrial facilities are considered here for B.C., but it might be possible to reach 100 customers with LNG in B.C.
- This study only considers customers adopting LNG between 2016 and 2025, while the impacts are tracked until 2040.
- The majority of the remote LNG is considered to displace diesel,[34] which generally remains the most viable opportunity in the current low fuel price environment.
- New LNG customers include both newly constructed facilities, which would otherwise have defaulted to other fuel types, as well as conversions to LNG at existing facilities.

Fuel cost savings are one of the key drivers for remote LNG adoption. Exhibit 11 presents the annual customer fuel cost savings[35] over time, broken down by region. For example, the Yukon is represented by the green section of each bar, highlighting that this is the region with the largest portion of savings, which is in line with the relative size of new gas consumption presented in Exhibit 10. The cost savings in the exhibit below do not account for added customer costs for on-site LNG equipment.

Exhibit 11 Annual Fuel Cost Savings of New LNG Customers (2015 $Million)[35]



In the above exhibit, fuel cost savings ramp up between 2017 and 2024, as the new customers considered in this study become connected to LNG supplies. From 2025 onwards, savings continue to rise, mainly as a result of differences in the price forecasts for fuels. Price forecasts show

[33] Further adoption of LNG, beyond the number of customers included here, would represent additional economic benefits above and beyond what is presented in this study.
[34] All LNG is considered to displace diesel, except in Quebec and British Columbia. Conversions in Quebec include both diesel and heavy fuel oil, while those in B.C. include diesel and some propane.
[35] These values represent the annual net fuel cost savings, in real 2015 Canadian dollars, for all new remote LNG customers. This compares delivered fuel costs, so the LNG prices include costs for natural gas, liquefaction, and delivery. However, these savings do not account for customer costs for on-site LNG storage, LNG vaporizers, new gas burning equipment, or for CO2 emissions.

expectations for a larger rise in diesel prices than in natural gas prices. Additionally, the natural gas commodity costs make up a smaller portion of the delivered LNG costs (since liquefaction and delivery represent the majority of the delivered total LNG prices), as compared to the commodity portion of delivered diesel prices. This again contributes to the increasing savings from LNG as commodity prices rise.

Exhibit 12 presents the total expenditures for LNG infrastructure and new customer equipment considered in this study. Costs for the first two categories, liquefaction plants and transport trucks, are factored into the delivered LNG price, and are hence factored into the annual costs savings above. The other three cost categories (storage, vaporizers, gas equipment) require capital expenditures by the new LNG customers, and these costs will be compared to the savings in the Net Present Value calculations that follow. These expenditures represent approximately 1.1 million gallons per day[36] of liquefaction capacity, 6.1 million gallons of storage, 114 transport trucks, and 81 vaporizers.

Exhibit 12 Expenditures for LNG Infrastructure and New Customer Equipment

Province / Territory	Expenditures for LNG Expansion ($)					
	Liquefaction Plants	LNG Transport Trucks	LNG Storage Facilities	LNG Vaporizers	Natural Gas Equipment	Total
Alberta	195,000,000	550,000	2,800,000	10,000,000	42,719,000	**251,069,000**
British Columbia	195,000,000	3,850,000	16,400,000	23,666,667	79,996,000	**318,912,667**
Manitoba	65,000,000	1,925,000	5,800,000	7,000,000	18,003,000	**97,728,000**
North West Territories	-	3,300,000	5,000,000	8,000,000	32,363,000	**48,663,000**
Ontario	260,000,000	3,300,000	14,400,000	20,000,000	47,927,000	**345,627,000**
Quebec	520,000,000	8,525,000	37,600,000	27,666,667	82,728,000	**676,519,667**
Saskatchewan	130,000,000	1,100,000	5,400,000	10,000,000	34,304,000	**180,804,000**
Yukon	65,000,000	13,475,000	47,000,000	16,000,000	200,648,000	**342,123,000**
Canada	**1,430,000,000**	**36,025,000**	**134,400,000**	**122,333,333**	**538,686,000**	**2,261,446,333**

To properly consider the merits of LNG for remote customers, a Net Present Value calculation is used to compare all of the increased customer costs to the savings, and to show what the net benefit would be for new customers today (2015 dollars).

Exhibit 13 presents the NPV of the total net savings for LNG from the customer's perspective. This combines the present value (in constant 2015 dollars) of fuel cost savings (2016-2040) with customer costs for the installation of LNG infrastructure (vaporizers and on-site storage), as well as the incremental cost of new natural gas equipment (boilers, burners, and generators).[37]

The Canada-wide present value of benefits for new remote LNG customers is shown here to be over $2.3 billion.

[36] Liquefaction capacity included here is intended to supplement existing LNG supply, and does not match the LNG demand added in this study.
[37] Incremental natural gas equipment costs are used to reflect that the majority of applications where LNG is being proposed are either new construction, facilities where diesel equipment can be converted to run on natural gas, or facilities where equipment is past its rated end of life. As such, costs are compared to the alternative of installing new diesel equipment, not the full gas equipment costs shown in Exhibit 12.

Exhibit 13 Net Present Value of Total Net Savings for New Customers

Province / Territory	Net Present Value from New Customer Perspective ($2015)		
	Power Gen.	Industrial	Total
Alberta	-	49,362,316	**49,362,316**
British Columbia	36,316,717	315,075,313	**351,392,031**
Manitoba	12,551,083	97,510,451	**110,061,535**
North West Territories	68,053,321	-	**68,053,321**
Ontario	42,219,403	231,537,615	**273,757,018**
Quebec	13,024,916	458,489,786	**471,514,702**
Saskatchewan	-	109,617,074	**109,617,074**
Yukon	57,407,846	885,723,315	**943,131,162**
Canada	**229,573,288**	**2,147,315,871**	**2,376,889,159**

Macro-Economic Impacts: LNG as an Economic Driver for Canada

This section starts with a summary of the economic benefits from the expansion of LNG for remote markets, followed by a closer look at each of the economic indicators considered here. The economic modeling was conducted at a national level, so these results are presented for Canada as a whole. It is important to keep in mind that all of the results represent impacts specific to the Canadian economy, and have already been adjusted to remove any changes in spending on imports.

Exhibit 14 summarizes the results of the economic modelling, presenting the three primary economic indicators targeted in this project. It is expected that over a 25-year period these remote LNG projects would add more than $12 billion to Canada's GDP, contribute support of 117,000 net job-years, and increase government revenues by over $4 billion. The results are also provided separately for direct/indirect benefits and induced benefits, and are also presented both as the national total impacts over the study period and the average annual impacts.

Exhibit 14 Summary of Economic Impacts from LNG for Remote Markets in Canada

Type of Economic Impact	Total Impacts over Study Period (2016-2040)			Average Annual Impacts		
	Direct & Indirect Impacts	Induced Impacts	Total Impacts (2016-2040)	Direct & Indirect Impacts	Induced Impacts	Average Annual Impacts
GDP ($Million)	8,923	3,591	**12,514**	357	144	**501**
Employment (Job-years)	85,269	32,343	**117,612**	3,411	1,294	**4,704**
Government Taxes and Revenues ($Million)	3,194	1,285	**4,480**	128	51	**179**

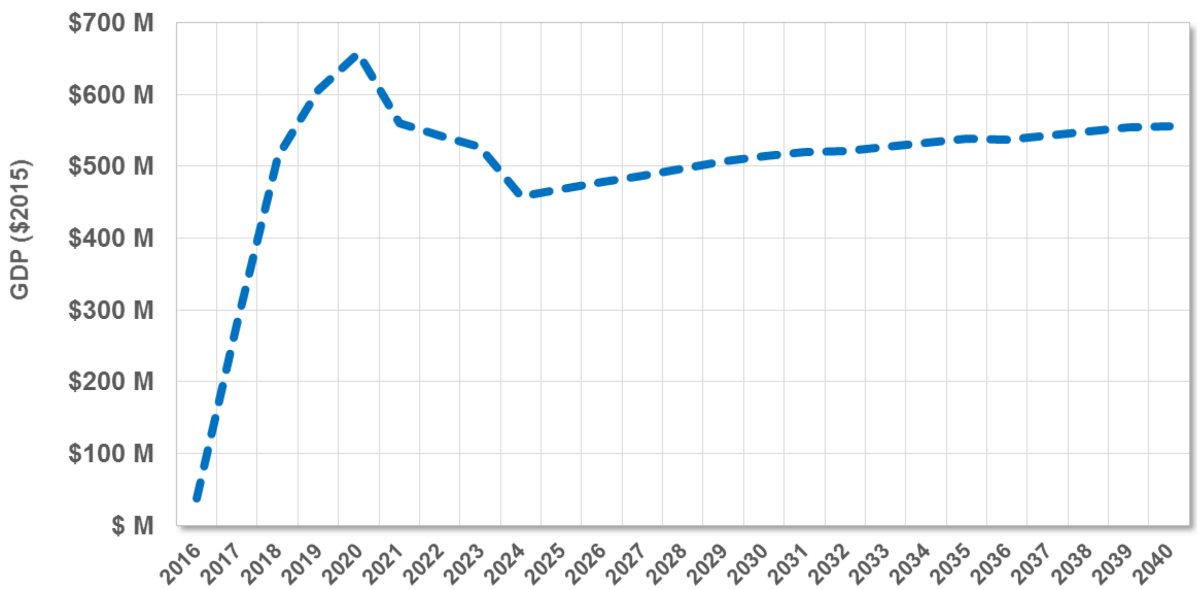
Although there are significant economic benefits for stakeholders throughout the natural gas production and LNG value chains, the largest group of impacts are for the new remote LNG customers, who achieve significant fuel cost savings.

It is also important to keep in mind that although we have limited the study period to 25 years, a certain level of economic impact can reasonably be expected to continue within the Canadian economy after 2040. Additionally, it is noteworthy that government revenue increases over this 25 year period would likely be larger than the overall investment requirement.

Annual benefits for each of the three types of economic impact are shown separately in the following three exhibits.

Exhibit 15 shows how the national total value added (GDP) changes over the study period. Annual GDP impacts are highest a few years into the study, peaking around $650 million, with all of the capital expenditures for LNG infrastructure occurring before 2025. During that same period remote customers gain access to LNG supplies and start to achieve fuel cost savings, which in turn drives customer re-spending GDP impacts. Annual GDP impacts rise gradually from 2024 onwards, as forecasted fuel prices increase, further increasing customer savings and re-spending impacts. The LNG fuel volumes also drive a steady baseline of economic benefits from operating costs in the LNG supply chain, as well as from increased natural gas production levels.

Exhibit 15 Annual Increase in Canadian Gross Domestic Product



It is important to note that these GDP results, as well as the other economic modeling results, represent impacts for Canada and already factor out leakages (economic effects in other countries attributed to imported goods or services).

Exhibit 16 presents the annual Canadian job impacts of the expansion projects for remote LNG markets. As with the previous GDP exhibit, LNG infrastructure investments create an early peak in employment impacts. However, a larger portion of the overall job impacts are created by the customer re-spending of fuel cost savings, operating costs in the LNG supply chain, and increased natural gas production levels. Employment impacts also increase gradually overtime as forecasted fuel prices increase.

Exhibit 16 Annual Increase in Canadian Employment

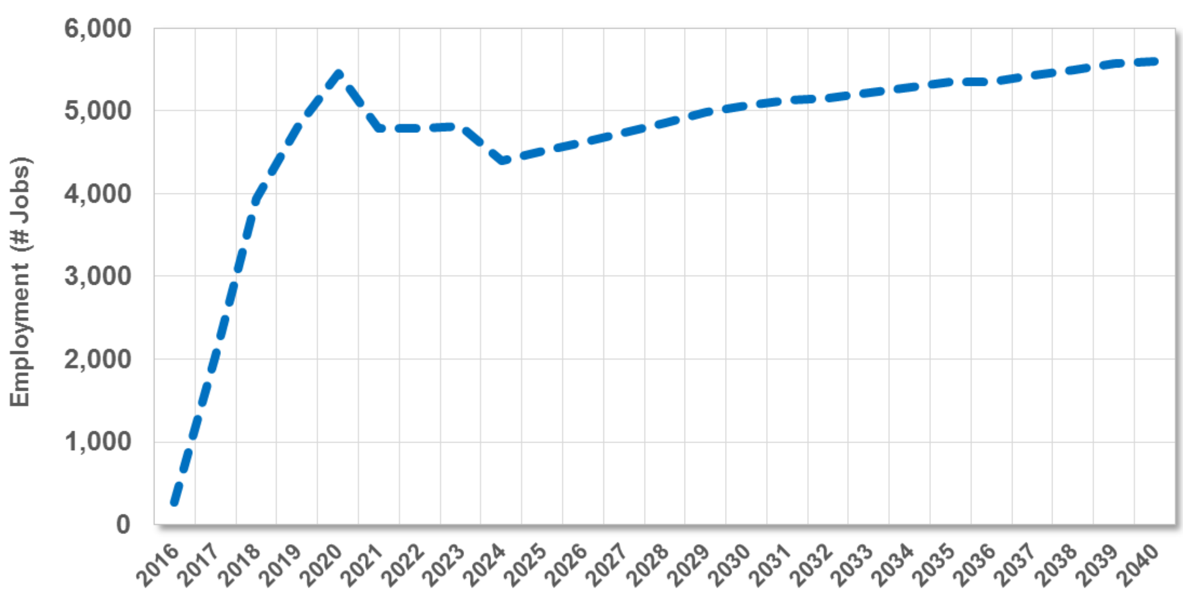
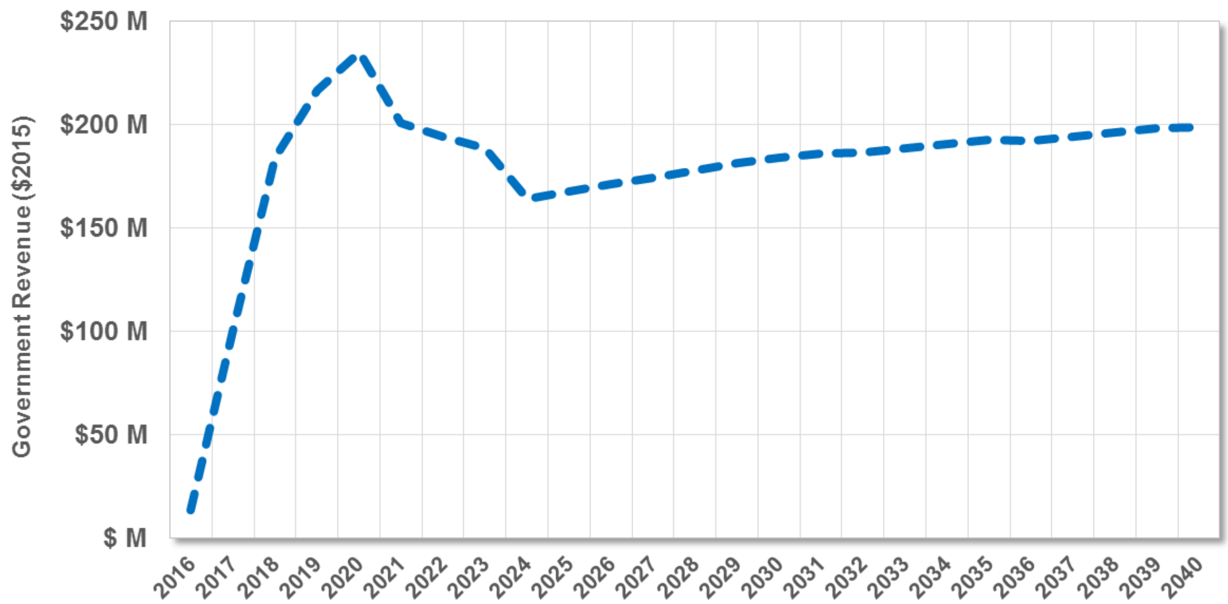


Exhibit 17 estimates the annual impacts on Canadian government taxes and revenues from the pipeline expansion projects. This is presented as a combined total for federal, provincial, and municipal governments, and follows the same profile as GDP impacts.

Exhibit 17 Annual Increase in Government Taxes and Revenues



CO2 Emission Price Sensitivity

It is important to understand how the customer impacts calculated in this study would be affected by existing or future CO2 emission prices. The NEB commodity price forecasts used in this study do not include any CO2 emission prices,[38] and results before this section have not accounted for any CO2 emission prices. To establish the sensitivity of results to GHG prices, emission factors were used to calculate the net changes to GHG emissions from remote LNG adoption, and two CO2 emission price scenarios were considered:

- The low CO2 emission price scenario, which generally reflects existing or anticipated CO2 emission prices in various provinces.
- The high price scenario, which highlights potential impacts from CO2 emission prices that are significantly higher than what is currently planned.

Along with the net changes to annual (2025) GHG emissions, presented below in Exhibit 18, subsequent exhibits in this section highlight the impact of CO2 emission prices on the new LNG customers considered in this study.

Overall, the conversions considered in this study would result in a decrease in annual GHG emissions equivalent to more than 500,000 tonnes of CO2 per year.

The business case for replacing diesel, propane, and heavy fuel oil with natural gas is improved by CO2 emission prices, as these fuels are more carbon-intensive than natural gas. After accounting for additional emissions from the LNG conversion processes (liquefaction and re-gasification), LNG represents around a 22% improvement over diesel.[39]

Exhibit 18 Net Annual GHG Emission Reductions (2025)

Province / Territory	Annual GHG Emission Reductions (tCO2e), 2025		
	Power Gen.	Industrial	Total
Alberta	-	9,698	**9,698**
British Columbia	5,989	39,148	**45,137**
Manitoba	2,559	19,267	**21,826**
North West Territories	8,604	-	**8,604**
Ontario	8,502	45,213	**53,715**
Quebec	2,555	174,135	**176,690**
Saskatchewan	-	22,474	**22,474**
Yukon	11,080	161,597	**172,678**
Canada	**39,290**	**471,532**	**510,822**

[38] The NEB Energy Futures study accounts for CO2 emission prices when estimating impacts on consumption growth, but no CO2 emission prices are included in the commodity price forecasts referenced here.
[39] The GHG emission factors are based on combustion of natural gas and alternative fuels and do not account for all "life-cycle" GHG emission related to production, processing, and transport of the fuels. In the case on LNG, the GHG factor is measured from the point at which the natural gas enters the liquefaction plant and, thus, does account for the GHG emissions from the portion of the natural gas used in the liquefaction and regasification processes.

The low CO2 emission price scenario considers a price frozen at $30 per tonne of CO2 equivalent emissions throughout the entire study period (2016-2040) for all provinces.[40] The high price scenario considers a price of $100 / tCO2e for all provinces, throughout the entire study period.

Exhibit 19 demonstrates how the inclusion of low and high CO2 emission prices would impact the annual fuel cost savings of new LNG customers. Along with the annual cost savings under each scenario, the percent increase from the inclusion of CO2 emission prices is included. This exhibit shows that, on average, remote LNG customers would see their annual fuel cost savings increase by 6% and 22% under the low and high CO2 emission price scenarios respectively, compared to not accounting for any GHG price. It is important to keep in mind that CO2 emission prices will cause LNG costs to rise substantially in absolute terms, and customers will be paying larger fuel cost bills under these scenarios. However, the increased annual fuel cost savings under these scenarios highlights that remote LNG customer costs would increase even more, if they were instead using diesel, the default option for most remote customers.

Exhibit 19 CO2 Emission Price Impacts on Annual Fuel Cost Savings (2025)

Province / Territory	Annual Customer Fuel Cost Savings ($), 2025				
	No CO2 Emission Price	Low CO2 Emission Price		High CO2 Emission Price	
	($/year)	($/year)	CO2 Change (%) [41]	($/year)	CO2 Change (%) [41]
Alberta	**5,822,274**	**6,113,202**	5%	**6,792,033**	17%
British Columbia	**35,809,813**	**37,163,913**	4%	**40,323,479**	13%
Manitoba	**10,953,668**	**11,608,453**	6%	**13,136,282**	20%
North West Territories	**7,239,611**	**7,497,735**	4%	**8,100,025**	12%
Ontario	**27,486,474**	**29,097,933**	6%	**32,858,006**	20%
Quebec	**47,055,672**	**52,356,376**	11%	**64,724,685**	38%
Saskatchewan	**11,330,763**	**12,004,973**	6%	**13,578,129**	20%
Yukon	**91,160,305**	**96,340,644**	6%	**108,428,103**	19%
Canada	**236,858,581**	**252,183,230**	**6%**	**287,940,743**	**22%**

The exhibit above shows minor differences between regions, driven by the minor regional differences in emission factors and the fuel-mixes expected to be converted to LNG.

Exhibit 20 presents the NPV of remote LNG from the new customer's perspective, for the low and high CO2 emission price scenarios. The NPV impacts from CO2 emission prices mirror the above annual savings impacts. The overall customer NPV in the high price scenario is 23% higher. Again, CO2 emission prices will cause LNG costs to rise substantially; however, the increased NPV highlights that the average customer would see a smaller cost increase than if they were reliant on diesel.

[40] The study authors are not aware of specific plans for CO2 emission prices in all regions, but all are included here to highlight potential impacts.
[41] Percent change from case with no CO2 emission price.

Exhibit 20 CO2 Emission Price Impacts on Customer NPV

Province / Territory	Net Present Value of Remote LNG for New Customer ($2015)				
	No CO2 Emission Price	Low CO2 Emission Price		High CO2 Emission Price	
	NPV ($2015)	NPV ($2015)	CO2 Change (%) [42]	NPV ($2015)	CO2 Change (%) [42]
Alberta	**49,362,316**	**52,434,325**	6%	**59,602,347**	21%
British Columbia	**351,392,031**	**365,690,456**	4%	**399,053,446**	14%
Manitoba	**110,061,535**	**116,975,634**	6%	**133,108,531**	21%
North West Territories	**68,053,321**	**70,778,946**	4%	**77,138,736**	13%
Ontario	**273,757,018**	**290,772,994**	6%	**330,476,937**	21%
Quebec	**471,514,702**	**527,486,720**	12%	**658,088,096**	40%
Saskatchewan	**109,617,074**	**116,736,295**	6%	**133,347,811**	22%
Yukon	**943,131,162**	**997,832,209**	6%	**1,125,467,987**	19%
Canada	**2,376,889,159**	**2,538,707,579**	**7%**	**2,916,283,892**	**23%**

[42] Percent change from case with no CO2 emission price.

Fuel Price Sensitivity

Accurately forecasting fuel prices over the next 25 years is not possible, so it is important to understand how different fuel price scenarios would impact the findings of this study. Since cost savings are the primary driver for remote LNG adoption, it is important for potential customers to understand the risks involved with all options.

The fuel prices used in this study are based on commodity price forecasts from the 'Low Price' scenario of a 2016 National Energy Board study.[43] The low price scenario is used because it is more in line with current commodity prices, and because it results in a more conservative estimate of LNG benefits. The same NEB study's 'Reference Case' scenario would increase benefits because oil prices increase more than natural gas prices. This uncertainty highlights that the benefits of LNG could both be higher or lower than what is presented in this study.

To establish a better understanding of the sensitivity of results to fuel prices, remote customer impacts were calculated for the following two alternative scenarios:

- The 'High LNG Cost' scenario is reflective of LNG prices that are 25% higher than the reference case, with the alternative fuel prices unchanged from the reference case.
- The 'High Alternative Fuel Cost' scenario captures the impacts of the alternative fuel prices being 25% higher (diesel, propane, heavy fuel oil), while LNG remains at reference case levels.

Exhibit 21 compares the annual customer fuel cost savings in each region to the equivalent savings in the two alternative scenarios. In addition to the annual savings in each scenario, the exhibit shows the percent change from the reference case savings. Note, these results combine savings for power generation and industrial customers.

Exhibit 21 Fuel Price Sensitivity of Annual Fuel Cost Savings (2025)

Province / Territory	Annual Customer Fuel Cost Savings ($), 2025				
	Reference Case	LNG Price +25%		Alternative Fuel Price +25%	
	($/year)	($/year)	Change (%)[44]	($/year)	Change (%)[44]
Alberta	**5,822,274**	**4,099,187**	-30%	**9,000,930**	55%
British Columbia	**35,809,813**	**25,275,280**	-29%	**55,296,798**	54%
Manitoba	**10,953,668**	**6,620,925**	-40%	**18,024,829**	65%
North West Territories	**7,239,611**	**1,894,086**	-74%	**14,395,039**	99%
Ontario	**27,486,474**	**17,388,853**	-37%	**44,455,713**	62%
Quebec	**47,055,672**	**20,626,324**	-56%	**85,248,938**	81%
Saskatchewan	**11,330,763**	**7,803,284**	-31%	**17,690,934**	56%
Yukon	**91,160,305**	**56,694,377**	-38%	**148,416,309**	63%
Canada	**236,858,581**	**140,402,317**	**-41%**	**392,529,491**	**66%**

[43] National Energy Board, Canada's Energy Future 2016: Energy Supply and Demand Projections to 2040, 2016.
[44] Percent change from reference case fuel prices.

It is notable from the exhibit above that in the scenario where LNG prices are higher, cost savings are reduced, but all regions are still expected to achieve cost savings through LNG adoption. This is however a snapshot in time, looking at 2025,[45] and is not necessarily the case for all customers, in all regions, in all years.

It is also notable that the regions with higher profit margins in the reference case, see smaller percent changes from the fuel price fluctuations. For example, the largest percentage swings are for the North West Territories, where the significantly longer trucking distances make the profit margin for LNG smaller. As a result of the smaller profit margin, the alternative fuel price scenarios cause larger positive and negative swings in project economics for the North West Territories.

Exhibit 22 presents the effects of the fuel price scenarios on the NPV of the total net savings for LNG, from the customer's perspective. This combines the present value of fuel cost savings (2016-2040) with customer costs for the installation of LNG infrastructure (vaporizers and on-site storage), as well as the incremental cost of new natural gas equipment. The NPV impacts from alternative fuel price scenarios are similar to the annual savings impacts in the previous exhibit.

Exhibit 22 Fuel Price Sensitivity of NPV for Remote LNG

Province / Territory	Net Present Value of Remote LNG for New Customer ($2015)				
	Reference Case	LNG Price +25%		Alternative Fuel Price +25%	
	NPV ($2015)	NPV ($2015)	Change (%)[46]	NPV ($2015)	Change (%)[46]
Alberta	**49,362,316**	**31,146,230**	-37%	**83,755,976**	70%
British Columbia	**351,392,031**	**240,026,600**	-32%	**561,006,335**	60%
Manitoba	**110,061,535**	**64,265,626**	-42%	**186,469,227**	69%
North West Territories	**68,053,321**	**11,569,117**	-83%	**145,117,492**	113%
Ontario	**273,757,018**	**167,021,723**	-39%	**457,239,499**	67%
Quebec	**471,514,702**	**192,147,473**	-59%	**884,277,330**	88%
Saskatchewan	**109,617,074**	**72,326,851**	-34%	**178,415,816**	63%
Yukon	**943,131,162**	**578,829,395**	-39%	**1,561,813,045**	66%
Canada	**2,376,889,159**	**1,357,333,014**	**-43%**	**4,058,094,721**	**71%**

45 Results are presented for this year because all LNG projects in this study are considered to be adopted by 2025.
46 Percent change from reference case fuel prices.

Appendix A Methodology and Assumptions

The next sections discuss key steps in the study process in more detail, provide information on some key assumptions driving the analysis, and describe the IMPLAN model in more detail.

Distributor Consultations

The original scope of LNG projects in each province/territory considered in this project was developed by the CGA, based on information related to potential projects. Canadian natural gas distribution utilities were surveyed and consulted to get their feedback on the number, size, and type of remote LNG projects they expected. Distributors were also able to provide feedback on their experience with costs for liquefaction, LNG infrastructure, and alternative fuels.

Customer Impact Calculations

The customer impact calculations took the results of the distributor consultations, and processed this information with several other key data sources to establish the metrics from which the merit of projects can be assessed, including the total costs and fuel cost savings. The two primary calculations are as follows:

- **Fuel Cost Savings:** The customer impact calculations computed the total natural gas consumption from new remote customers, and estimated the equivalent consumption from alternative fuels. The price forecasts for both LNG and the alternative fuels were then used to establish the net fuel cost savings.

- **Customer Net Present Value:** The NPV from the customer's perspective was calculated by computing the present values of fuel cost savings, installation cost for customer LNG infrastructure (vaporizers and on-site storage), and net natural gas equipment costs.

The sub-sections below describe the data sources and key assumptions in more detail.

Scope of LNG Projects

Through the distributor consultations, estimates were refined for the number, size, and type of remote LNG projects. This included the number of power generation LNG customers (supplying residential and commercial customers in remote communities with electricity), the number of remote industrial customers (including mines, drilling rigs, and other industrial facilities), as well as the alternative fuel types that would be displaced by LNG. The expected equipment capacities or the expected natural gas consumption for these new LNG customers was also estimated for each region, in consultation with the distributors. Finally, the expected number and capacity of liquefaction plant installations in each region was also discussed with distributors.

The final numbers of customers included in this study are not intended to represent the maximum potential for remote LNG. Instead, these numbers are intended to represent likely LNG customers, with the focus of this study being to highlight the magnitude of benefits from connecting LNG supplies to these customers. In the modeling, a distribution was used to spread the start dates for new LNG customers between 2017 and 2024.

Customer Fuel Use

In the cases where distributors did not provide estimates for the natural gas use of new customers, expectations for customer equipment capacities were used to calculate the expected natural gas use.

Based on the customer type, typical heating rates, load factors, efficiencies, and hours of operation were used to estimate LNG requirements. Additionally, it was assumed that the equivalent of 8% of LNG production would be used up to power the liquefaction process, with a further 1.5% loss at the re-gasification stage.

The customer alternative fuel consumption, or the baseline option where LNG is not being used, was calculated based on the assumed new remote customer natural gas use. For diesel and propane conversions, equipment efficiencies for the alternative fuels are assumed to be the same as for natural gas. Heavy fuel oil equipment is assumed to be 10% less efficient. These assumptions are considered to be conservative, given the potential efficiency improvements that could be achieved by replacing what is typically old and inefficient equipment in remote communities.

Infrastructure Investments
The expected project costs for LNG infrastructure expansion were estimated based on LNG case studies, vendor information, and previous work for CGA. In addition, it was assumed in the customer impact calculations that annual operations and maintenance (O&M) costs would be increased by the equivalent of 1.5% of the new project capital expenditures. The following cost assumptions were used for key LNG infrastructure components, to cover both capital and installation costs:

- $1,000,000 to $4,000,000 / vaporizer
- $275,000 / LNG transport truck (13000 gallon)
- $1,300 / gallon per day of liquefaction plant capacity
- $20 / gallon of LNG storage
- $1,500,000 / MW of gas generators

Delivered Fuel Prices
The delivered fuel prices for both LNG and alternative fuels were based on a commodity price forecast. Applicable distribution, transportation, and liquefaction costs were then added to the commodity price forecasts to produce the annual delivered fuel prices used in this study. The resulting delivered fuel costs are presented below for several milestone years, in Exhibit 23. The following components were included in these calculations:

- Natural gas commodity prices were taken from a National Energy Board (NEB) forecast, using their 'Low Price' scenario.[47] This forecast provides a Henry Hub gas price up to 2040.
- Diesel, propane and heavy oil prices have historically been correlated to crude oil prices. The same NEB forecast included the price expectations for crude oil up to 2040 that were considered in their assessment. Using monthly historical data from the U.S. Energy Information Administration (EIA), ICF established that the 10-year average ratio of crude oil[48] to heavy oil[49] prices (per GJ) was 85%, propane[50] was 143% of crude oil, and diesel was 140% of crude oil. These ratios were used to calculate the diesel, propane, and heavy oil wholesale prices used over the study period, based on the NEB crude oil price forecast.
- A natural gas pipeline distribution charge of $0.5/GJ was assumed for LNG sourced from western Canadian provinces, while LNG liquefied in Ontario and Quebec included a $1/GJ pipeline charge. For diesel fuel, a 9% distributor margin was added to wholesale prices.
- In terms of natural gas liquefaction, total costs ranging from $4.6/GJ to $6/GJ were used to cover plant capital cost recovery, energy requirements to power the liquefaction process, plant operating and maintenance, as well as other margins.
- LNG transportation costs for a truck were estimated based on a rolling rate of $3.4/km, which had been developed for the CGA by previous consultants, based on oversized 13000 gallon trucks. This includes all costs for vehicle leasing, drivers, and company

[47] National Energy Board, Canada's Energy Future 2016, 2016. https://apps.neb-one.gc.ca/ftrppndc/dflt.aspx
[48] EIA, Cushing OK WTI Spot Price FOB, http://www.eia.gov/dnav/pet/hist/LeafHandler.ashx?n=PET&s=RWTC&f=M
[49] EIA, Refiner Petroleum Product Prices by Sales Type, http://www.eia.gov/dnav/pet/pet_pri_refoth_dcu_nus_m.htm
[50] EIA, Propane (Consumer Grade) Prices by Sales Type, http://www.eia.gov/dnav/pet/pet_pri_prop_dcu_r10_a.htm

margins. For consistency, diesel transport costs were also based on this rolling rate, but reduced by a factor of 1.6 to approximate the lower shipping volume requirements for diesel through its increased energy density. Average distances for transportation were estimated based on expected customer locations, and refined based on feedback from the distributor consultations.

It is important to note that the economic impacts highlighted in this study would be higher if fuel prices were based on the NEB forecast's 'reference case' scenario or 'high price' scenario. Even though natural gas prices are higher in those forecasts than in the 'low price' scenario, the prices for alternative fuels to be displaced by natural gas are also higher, resulting in greater savings and making the 'low price' scenario used in this study the more conservative option.

Exhibit 23 presents the final delivered fuel costs[51] for several years to provide a sense of the relative costs being considered in this analysis. The 'Other Fuel' category in this table typically represents diesel fuel, with the exception of Quebec, where there is also heavy fuel oil, and British Columbia, where there is also some propane.

Exhibit 23 Base Case Delivered Fuel Costs for Several Milestone Years [51]

Province / Territory	Base Case Delivered Fuel Cost by Milestone Year ($/GJ)					
	2017		2020		2025	
	LNG	Other Fuel	LNG	Other Fuel	LNG	Other Fuel
Alberta	11	17	12	19	12	22
British Columbia	12	18	12	20	12	23
Manitoba	14	19	14	21	14	24
North West Territories	20	23	20	25	20	28
Ontario	13	18	13	20	13	23
Quebec	13	15	13	16	13	19
Saskatchewan	12	18	12	20	12	22
Yukon	14	19	14	21	14	24
Average	**13**	**18**	**14**	**20**	**14**	**23**

Net Customer Equipment Purchases
Incremental costs for natural gas burning equipment are used to reflect that the majority of applications where LNG is being proposed are either new construction, facilities where diesel equipment can be converted to run on natural gas, or facilities where equipment is past its rated end of life. As such, costs are compared to the alternative of installing new diesel equipment, not the full gas equipment costs. The incremental cost to new customers for natural gas burning equipment purchases is assumed to be 15% of the full gas equipment cost. The overall economic modeling decision about whether or not to include full costs has little impact. This is because reducing customer expenditures on new equipment lowers the equipment cost inputs for GDP impacts, but increases the customer spending inputs by the same amount. So this re-classification of costs balances out and has little overall impact.

[51] Delivered LNG fuel costs include costs for the natural gas commodity, distribution, liquefaction, and delivery. However, these prices do not account for customer costs for on-site LNG storage, LNG vaporizers, or new gas burning equipment.

Output to Economic Model
The final step of the customer impact calculations involved adding up all provincial results for use in the economic model at a national level. These customer impact calculations have already computed the expenditure (price x quantity) calculations which serve as the inputs for assessing economic impacts. The economic model was developed to pull in the appropriate expenditures by category, and applies the relevant factors to determine economic impacts.

Net GHG Emissions
Emission factors were used to calculate the net changes to GHG emissions from the adoption of LNG. First, emissions from the new natural gas customers were calculated, based on their assumed consumption. Then additional emissions for the LNG customers were factored in, accounting for the incremental natural gas required to power the liquefaction and regasification processes, as well as the additional transportation emissions. Then emissions were calculated for those same customers, based on emission factors for their alternative fuel types. The new emissions were subtracted from the baseline emission levels to establish the net GHG savings. This means that while absolute impacts from CO2 emission prices on customer costs may be large, the net impact may remain small, if both the new and old fuel types result in similar levels of GHG emissions.

The emission factors used in this section to assess the CO2 emission price impacts are shown in Exhibit 24. These are established from Environment Canada's National Inventory Report, using Global Warming Potentials of 25 grams of CO2e per gram of CH4, and 298 grams of CO2e per gram of N2O.

Exhibit 24 GHG Emission Factors

Province / Territory	GHG Emission Factors			
	Natural Gas	Diesel	Heavy Fuel Oil	Propane
Alberta	1,928.8	74,353.8	-	-
British Columbia	1,890.4	74,353.8	-	1,539.9
Manitoba	1,888.4	74,353.8	-	-
North West Territories	2,464.8	74,353.8	-	-
Ontario	1,890.4	74,353.8	-	-
Quebec	1,889.4	74,353.8	3,146.1	-
Saskatchewan	1,830.8	74,353.8	-	-
Yukon	1,901.8	74,353.8	-	-
Units	**g CO2e/m³** [52]	**kg CO2e/TJ** [53]	**g CO2e/L** [54]	**g CO2e/L** [55]

[52] Environment Canada, National Inventory Report, 2014, Section A8 (marketable natural gas)
[53] Environment Canada, National Inventory Report, 2014, Section A8 (diesel fuel - industrial)
[54] Environment Canada, National Inventory Report, 2014, Section A8 (heavy fuel oil - industrial)
[55] Environment Canada, National Inventory Report, 2014, Section A8 (propane)

IMPLAN Scenarios

The core of the economic modeling, which is discussed in the following section, is driven by the IMPLAN model. ICF used the Canadian version of the IMPLAN model to estimate the macro-economic impacts of expanding LNG infrastructure for remote Canadian customers, focusing on the national-level impacts. IMPLAN is a commonly used model for such analyses and produces results that are regularly used to evaluate economic outcomes (jobs, economic output, labour income, tax revenues, etc.).

An IMPLAN scenario was developed for each type of expenditure that needed to be factored into the economic modeling, with a total of 21 unique scenarios being considered in this project. IMPLAN's Canadian model contains impacts for 103 different sectors. So each IMPLAN expenditure scenario that ICF developed allocated the spending among the model's 103 core sectors.

For each IMPLAN scenario, ICF modeled the economic impacts from a nominal $100 million expenditure, with this total value divided between sectors according to the breakdown developed for that expenditure scenario. This modeling established the Canada-specific economic impacts (GDP, jobs, labour income, and induced benefits) resulting from $100 million of investment in each type of expenditure relevant to the distribution pipeline expansion. These results were then brought into an economic model spreadsheet, where the impacts were scaled according to the ratio of the actual expenditures in each category in each year to the $100 million nominal input.

Macro-Economic Modeling

The economic model organized expenditures from the customer impact calculations to enable application of the appropriate economic impact factors from IMPLAN. The model first calculates direct and indirect effects on the Canadian economy, which exclude the impacts to imports (leakages). The model then assesses the induced economic impacts that will result from these direct and indirect changes, as people who earn income through the direct and indirect activity spend that income.

While most of the required expenditures came directly from the customer impact calculations, some other data sources were required to provide a comprehensive breakdown of the impacts from LNG deliveries. Assessing LNG-related impacts required sub-categories to more accurately distinguish between expenditures related to LNG infrastructure expansion, natural gas production, LNG transportation, and O&M costs. This more detailed breakdown of natural gas expenditures allowed the model to use more specific IMPLAN factors for each sub-category, and more realistically distributed the economic impacts over the study period (timeline reflects when major spending occurs, instead of when customers are charged for gas).

The three primary calculations in the economic model are as follows:

- **Gross Domestic Product:** The first step of calculations for value added or GDP impacts was reducing expenditures by factors from IMPLAN to remove leakages, as well as some other adjustments representing the sale of replaced fuel types into new markets. Each of the LNG expenditure sub-categories also had leakages removed, including an assessment of the percentage of natural gas sourced from outside of Canada. Finally, the induced and total impacts were calculated, again using factors from IMPLAN.
- **Employment:** Employment calculations followed a similar format to GDP, with expenditures brought in by category, and corresponding IMPLAN factors used to calculate direct and indirect job-year impacts, while removing any leakages. For some operating cost categories, employment impact data from distributors with LNG infrastructure

experience was used in place of the IMPLAN factors. Some other adjustments were again made to the alternative fuel types, assuming most fuels would be re-sold into new markets with no net job impacts, other than from reduced transportation. Finally the corresponding IMPLAN induced employment ratio was applied to each category, to determine the additional jobs from these knock-on effects.

- **Government Revenue:** Increased government taxes and revenues were estimated based on historical ratios of government revenue to GDP. These ratios were applied to the GDP impacts calculated above to determine the revenue impacts. Separate ratios were used for federal, provincial, and municipal revenue to GDP, the total of which is presented with this study's results.

The sub-sections below describe the data sources and key assumptions in more detail.

Source of Natural Gas

The production location of natural gas used in each province/territory is important in determining whether the commodity costs from increased gas consumption will contribute to increased Canadian economic activity. This study captures economic impacts from the portion of gas considered to be produced in Canada, but includes no commodity cost impacts from gas produced in the U.S. (other impacts such as from distribution are still included for this gas).

ICF's natural gas market forecast was used to estimate the source of gas used in Canadian provinces over the study period. Based on the regions where gas consumption is expected to increase, the resulting assumption used in the economic model is that 85% of the gas is expected to be produced in Canada, with the remaining 15% imported from the United States. [56]

Reduced Fuel Consumption

This study considers the adoption of LNG fuel to replace other fuels in remote markets. The displacement of those alternative fuels will have negative economic impacts. For the alternative fuels considered in this study, diesel, heavy fuel oil, and propane, it is assumed that the decreased consumption will not be significant enough to lower production of these fuels in Canada. All volume losses are expected to come from imported fuels. It is also expected that the fuels will instead be sold into new markets, minimizing economic impacts. GDP calculations for these fuels include a negative impact corresponding to 15% of the original delivered costs to reflect the loss of transportation costs of delivering alternative fuels to remote communities (increases from LNG transportation impacts accounted for separately). Aside from reduced transportation impacts, changes in the markets for these alternative fuels are also considered to have negligible job impacts.

LNG Infrastructure Investments

The expenditures for LNG infrastructure, LNG transport trucks, natural gas equipment, and operating costs were taken directly from the customer impact calculations.

Natural Gas Production Costs

The same NEB Henry Hub natural gas commodity cost forecast that is used as the base for LNG price expectations is used here in the assessment. To establish a commodity price for the portion of gas sourced from Canada, ICF multiplied this Henry Hub forecast by a typical ratio to AECO prices. A ratio of 87.4% was used between the two gas price benchmarks, based on the average of 5 years of historical data from ICF's Gas Market Model.

[56] Data is based on a "supply-source" analysis of results from ICF's Q3 (July) 2015 natural gas market forecast (GMM0715, run date 7/16/2015)

The above commodity prices were used to compute increases in expenditures for gas production, which were further split into three categories (capital spending on wells; O&M for wells; and production return on capital, royalties, and taxes). The portion of the total commodity costs directed towards capital spending and O&M were estimated by ICF, based on typical well installation and lifecycle costs. The remainder of the commodity costs were categorized as return on capital, royalties, and taxes.

Consumer Spending
The increase in consumer spending is taken from the customer impact calculations, where it is derived from the fuel cost savings, customer investments in LNG infrastructure, and net equipment purchase expenditures.

Government Revenues
Government tax and revenue impacts were estimated based on the GDP impacts from the economic model, using historical ratios of GDP to government revenue. Government revenue was estimated to increase by a total of 35.8% of GDP. This is based on contributions of 14.4% for the federal government[57], 17.7% for provincial governments[58], and 3.7% for municipal governments.[58] This analysis did not specifically look at impacts from the special taxes on different fuel types.

General Assumptions

Some other general assumptions that are important to the results of this study include:

- **Discount Rate:** A discount rate of 5.5% was used throughout this study, based on average values used in planning by the CGA's membership.
- **Study Period:** The study considers the 2016 to 2040 timeframe, and benefits are captured from equipment installation up until the end of the study period.
- **Exchange Rate:** In the select instances where currency conversions were required, which was in conjunction with benchmark prices used in the NEB fuel price forecast, the corresponding USD/CAD exchange rates from the NEB study's 'low price scenario' were used, to maintain consistency.[59]

57 Department of Finance, Annual Financial Report of the Government of Canada, Fiscal Year 2013–2014. http://www.fin.gc.ca/afr-rfa/2014/report-rapport-eng.asp
58 Calculated from Statistics Canada, CANSIM, tables 385-0024 and 385-0001
59 National Energy Board, Canada's Energy Future 2016, https://apps.neb-one.gc.ca/ftrppndc/dflt.aspx

IMPLAN Background

The following section provides a brief overview of the IMPLAN model. The economic modeling was conducted using IMPLAN v.3.1 model and 2012 data. IMPLAN is a static input-output model that is extensively used to analyze the economic impacts of any infrastructure development scenario, including various energy infrastructure improvement scenarios. The impacts produced by IMPLAN can be assessed annually and job impacts can be reported in annual job-years. The baseline data used (i.e., multipliers) are for a snapshot/historical year, in this case 2012, and hence projected results for future years are an approximation based on historical relationships.

The IMPLAN modeling framework used by ICF consists of two components – the descriptive model and the predictive model. The descriptive model defines the specified modeling region, and includes accounting tables that trace the "flow of dollars from purchasers to producers within the region". It also includes the trade flows that describe the movement of goods and services, both within, and outside of the modeling region. In addition, it includes the Social Accounting Matrices (SAM) that trace the flow of money between institutions, such as transfer payments from governments to businesses and households, and taxes paid by households and businesses to governments. The predictive model consists of a set of "local-level multipliers" that can then be used to analyze the changes in final demand and their ripple effects throughout the local economy. These multipliers are thus coefficients that "describe the response of the (local) economy to a stimulus (a change in demand or production)."

Three types of multipliers are used in IMPLAN:

- **Direct** – represents the impacts (e.g., employment or output changes) due to the direct changes being modeled, such as the higher demand for goods and services for the directly affected sectors, which benefit from the additional spending from the reduced energy costs.
- **Indirect** – represents the impacts due to the industry inter-linkages caused by the iteration of industries purchasing from industries, brought about by the changes in final demands. These are commonly referred to as the "upstream" impacts.
- **Induced** – represents the impacts on all local industries due to consumers' consumption expenditures arising from the new household incomes that are generated by the direct and indirect effects of the final demand changes.

One of the biggest advantages of IMPLAN is the finer level of sectoral detail than is available in other competing models. The latest version of the Canadian IMPLAN model provides data on 103 industry sectors, including several institutional sectors such as households by income categories and various government sectors (federal, provincial, and local). These industry sectors are based on the North American Industry Classification System (NAICS). The detailed breakdown of the impacts by sector allows the user to analyze impacts specific to individual sectors of interest.

There are two main types of impact results that are often reported from IMPLAN – changes in value added output and employment. IMPLAN can also model impacts in labour income.

- **Total Value Added** – represents the commonly used metric for measuring economic output for a given scenario. It represents a "catch-all" for payments made by individual industry sectors to workers, interests, profits, and indirect business taxes. These are commonly referred to as "Gross Domestic Product" (GDP) impacts.
- **Employment** – represents the jobs supported by industry, based on the output per worker and output impacts for each industry.
- **Labour Income** – is part of the value added, and consists of all forms of employment income. Consistent with I/O terminology, IMPLAN defines this as the sum of the employee compensation and proprietor's income.

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