November 25, 2014

Ms. Kirsten Walli
Board Secretary
Ontario Energy Board
P.O. Box 2319
2300 Yonge Street, 27th Floor
Toronto, ON M4P 1E4

Dear Ms. Walli:

Re: EB-2014-0012 – Union Gas Limited – Hagar Liquefaction Service Rate Correction to an Interrogatory

Please find attached Union's responses to interrogatories specific to the above-noted proceeding – including a correction to Exhibit B.BOMA.14 as referenced at the hearing on November 24, 2014 (TR pg 72). This has been re-filed in the RESS.

Please contact me at (519) 436-5473 if you have any questions or wish to discuss this submission in more detail.

Yours truly,

[Original signed by]

Karen Hockin
Manager, Regulatory Initiatives

c.c.: EB-2014-0012 Intervenors
Mark Kitchen, Union Gas
Charles Keizer, Torys

August 12, 2014

Ms. Kirsten Walli
Board Secretary
Ontario Energy Board
P.O. Box 2319
2300 Yonge Street, 27th Floor
Toronto, ON M4P 1E4

Dear Ms. Walli:

Re: EB-2014-0012 – Union Gas Limited – Hagar Liquefaction Service Rate

Please find attached Union's responses to interrogatories specific to the above-noted proceeding.

Please contact me at (519) 436-5473 if you have any questions or wish to discuss this submission in more detail.

Yours truly,

[Original signed by]

Karen Hockin
Manager, Regulatory Initiatives

c.c.: EB-2014-0012 Intervenors
Mark Kitchen, Union Gas
Charles Keizer, Torys

UNION GAS LIMITED

Answer to Interrogatory from
Board Staff

Reference: Exhibit A / Tab 1 / Page 1

Union on line 13 states, "However, as liquefaction services at Union's Hagar facility will be provided within a regulated regime the use of the LNG could be expanded beyond motor vehicle fuel without further regulatory approvals."

What other commercial uses of Liquefied Natural Gas ("LNG") does Union see in the future and how is this facilitated within a regulated regime?

Response:

As evident by the interruptible nature of Union's proposed L1 service, there is a limited supply of LNG available at Hagar. For example, based on 678,400 GJ per year (Union's 2018 liquefaction activity forecast) of LNG available from Hagar, Hagar will be able to provide enough fuel for:

200	**Class 8 Trucks**
	OR
30	**Mine Vehicles**
	OR
3	**Marine Ships**

This limited supply restricts Union's ability to expand the use of LNG to meet other commercial applications such as fuel mining vehicles, remote power applications, marine and/or rail engines. Union assumes using LNG to serve other commercial activities would fall outside the regulated business.

UNION GAS LIMITED

Answer to Interrogatory from
Board Staff

Reference: Exhibit A / Tab 1 / Page 4

In its evidence, Union has indicated that it offered a Natural Gas for Vehicles ("NGV") service from 1984 to 2001. NGV was a regulated service offered to automobile refuelling stations and fleet operators.

Did Union request a separate rate from the Board for providing the NGV service? If yes, please provide details including the Board's Decision.

Response:

No. Union did not request a separate rate from the Board for providing the NGV service.

UNION GAS LIMITED

Answer to Interrogatory from
Board Staff

Reference: Exhibit A / Tab 1 / Page 8

On page 8 of its evidence (Exhibit A), Union indicates that the CNG and LNG fuel market is being actively pursued in a number of other regulatory jurisdictions in both the United States and Canada.

a) Please list the jurisdictions in United States and Canada where a regulatory body has determined a rate for a new LNG service through an application or a proceeding.

b) Does Union consider the market for LNG as a competitive market in Ontario? Please substantiate your response.

Response:

a) The research conducted by Union was related to rates for Compressed Natural Gas (CNG) and LNG services.

Regarding Canadian jurisdictions:

- In a decision released November 4, 2010 (D-2010-144), the Régie de l'énergie in Quebec approved a methodology to calculate the cost billed to an affiliate of Gaz Métro for the use of its LNG facility (LSR facility) as part of the activity concerning the sale of LNG.

- In a decision released March 17, 2011 (D-2011-030), the Régie de l'énergie in Quebec determined costs that must be allocated to LNG sales (or to the LNG customer) since these costs will be deducted from the revenue requirement of the regulated sales activity in Québec.

- In its Order No. G-128-11 dated July 19, 2011, the British Columbia Utilities Commission rendered its Decision regarding FortisBC Energy Inc's application for approval of a Service Agreement for Compressed Natural Gas Service and for approval of General Terms and Conditions for Compressed Natural Gas ("CNG") and Liquefied Natural Gas ("LNG") Service.

- On April 2, 2012, Heritage Gas (Nova Scotia) announced that they had reached agreement with Minas Basin Pulp and Power and CKF Inc. of Hantsport to supply trucked CNG to their operations in 2013, pending all necessary approvals.

Regarding US jurisdictions, based on research conducted in 2012, Union gathered the following information:

- In a November 2010 report, the American Gas Association reported that:
  - 17 jurisdictions had a NGV/CNG Rate
  - 10 jurisdictions had Compressor / Filling Facilities included in rate base

  http://www.aga.org/our-issues/RatesRegulatoryIssues/ratesregpolicy/ratedesign/Pages/NaturalGasVehicleCompressedNaturalGasRates(November2010).aspx

- Atlanta Gas Light received approval from the Georgia Public Service Commission in November 2011 for a plan to support the development of a network of privately owned compressed natural gas (CNG) fuelling stations in Georgia and issued a Request for Proposals (RFP) for interested parties to participate.

- Questar Gas, which delivers natural gas in Utah, Wyoming and Idaho, owned and operated 29 public CNG stations with more planned for 2012.

- Citizens Gas received approval from the Indiana Utility Regulatory Commission on June 16, 2010 to establish Gas Rate No. 40 – Liquefied Natural Gas Service to facilitate the sales of LNG as a vehicle fuel to Flatiron Power Systems under a pilot program to end on September 12, 2012.

- Chesapeake Utilities (Delaware) offers a Natural Gas Vehicle Service (Rate NGV) for its New Castle, Kent & Sussex counties.

- Columbia Gas of Pennsylvania offers a NGV Rate where customers may elect Firm Sales Service, Interruptible Sales Service or Distribution Service.

- Integrys Peoples Gas of Illinois provides a compressed natural gas service (Service Classification No.8).

- Laclede Gas of Missouri offers a Vehicular Fuel Rate to customers.

- CenterPoint Energy of Texas offers a Small Commercial Firm Service (SCS-1-I) schedule to any natural gas vehicle fuelling facility, open for use by the general public.

- Connecticut Natural Gas offers a Natural Gas Vehicle Interruptible Rate where the rate is established monthly by the company.

- Consolidated Edison Company of New York offers a Natural Gas Vehicle Service rate (Schedule 14)

- Narragansett Electric Company d/b/a National Grid (Rhode Island) had a Natural Gas Vehicle Service Rate (Rate 70) which was eliminated as of May 7, 2012.

- Southwest Gas of Arizona offers a Gas Service for Compression on Customer's Premises rate schedule (No. G-55).

- Florida City Gas offers a Natural Gas Vehicle Service.

- In 2013, Intermountain Gas Company (Idaho) received approval from the Idaho Public Utilities Commission to sell excess LNG capacity from its Nampa LNG facility for non-utility use.

- Kansas Gas Service of Kentucky offers a Compressed Natural Gas General Transportation Service.

- National Fuel Gas (New York) offers a Natural Gas Vehicle Rate (Service Classification No. 7) to customers using either company-supplied or customer-supplied filling facilities.

- National Fuel Gas (Pennsylvania) offers a Natural Gas Vehicle Service.

- New Jersey Natural Gas offers a Natural Gas Vehicle Service under Non-firm Gas Services.

- New Mexico Natural Gas offers an Alternative Vehicle Fuel (Rate 39).

- The Northern Indiana Public Service Company (NIPSCO) offers a LNG service rate that was designed primarily to develop a market for use of LNG in its liquefied form as vehicle fuel.

- PECO Energy (Pennsylvania) offers both a Motor Vehicle Firm (Rate MV-F) and Interruptible (MV-I) rate.

- Pacific Gas and Electric offers a Natural Gas Service Core (NGV1) for customers providing fuel on their premises and Non-core service (NGV2).

- Philadelphia Gas Works offers a Liquefied Natural Gas Service Rate (Rate LNG) which is associated with transportation of LNG via truck from PGW's LNG facilities.

- Piedmont Natural Gas (North Carolina) offers a Natural Gas Vehicle Fuel Rate (Schedule 142).

- San Diego Gas and Electric offers natural gas for motor vehicle fuel service (G-NGV) and a natural gas service for home refuelling of motor vehicles (G-NGVR).

- The Southern California Gas Company (SoCalGas) Compression Services Tariff (GO-CMPR) is a non-residential, optional tariff service for customers that allows SoCalGas to plan, design, procure, construct, own, operate, and maintain compression equipment on customer premises to meet pressure requirements as requested by the customer and agreed to by SoCalGas.

- South Jersey Gas (New Jersey) offers a Natural Gas Vehicle Service to commercial and industrial customers who utilize natural gas for the purpose of providing vehicle fuel at Company-operated fuelling stations or at separately metered customer-operated fuelling stations.

- Peoples Gas (Tampa) offers a Natural Gas Vehicle Service (Rate NGVS) for gas delivered to any Customer through a separate meter for compression and delivery (through the use of equipment furnished by Customer) into motor vehicle fuel tanks or other transportation containers.

- Texas Gas Service Company offers a Compressed Natural Gas Service (Rate Schedule CNG-1) which is available to any customer for usage where customer purchases natural gas which will be compressed and used as a motor fuel.

- Indiana Gas Company's (Vectren North) Natural Gas Vehicle Service (Rate 229) schedule applies to both company-owned and customer-owned NGV facilities.

- Southern Indiana Gas and Electric's (Vectren South) Natural Gas Vehicle Service (Rate 129) applies to the provision of (1) gas sales service to a customer-owned and operated CNG facility for the express purpose of converting such natural gas to CNG to fuel natural gas vehicles, or (2) the sale of CNG to any customer from company-owned and operated CNG facilities to fuel natural gas vehicles.

- Washington Gas Light Company (District of Columbia) offers a Developmental Natural Gas Service rate (Schedule No. 4) where service is available to a limited number of applicants in the District of Columbia service area for the sale of compressed gas and for the sale or delivery of gas to be used as Compressed Natural Gas (CNG) to fuel a vehicle or vehicles, to any customer who shall by contract agree to the terms for service at refuelling facilities operated at either Company or customer locations.

- Wisconsin Gas offers a Natural Gas Vehicle Service Rate (Schedule X-130) for provision of natural gas to customers who have natural gas compression facilities for fuelling natural gas vehicles.

- Yankee Gas (Connecticut) offers an Interruptible Natural Gas Vehicle Service (Rate NGV) to any customer requiring natural gas as a motor fuel for vehicles employed in fleet, car pool, public and private transportation, or other motor vehicle operations.

b) Yes. Union does consider the market for LNG as a transportation fuel competitive. At the same time, the LNG for vehicle transportation market is an emerging market, one that is expected to develop gradually over the next several years. There are currently two LNG wholesalers operating in Ontario, Gaz Metro Transport Solutions (GMTS) and ENN Canada. Both will source LNG from the most economical supply available looking at the total delivered cost including the natural gas price, liquefaction charges, and transportation costs. Union is also aware of two other parties looking at locating LNG refuelling facilities or transportation assets to serve the Ontario market.

UNION GAS LIMITED

Answer to Interrogatory from
Board Staff

Reference: Exhibit A / Tab 1 / Page 10

In its evidence, Union has indicated that it has had discussions with several parties looking to enter Ontario's LNG distribution market.

a) Please provide a list of all LNG wholesalers in Ontario.

b) Does Union expect to provide LNG service to wholesalers that are located outside Ontario?

Response:

a) Please see the response to Exhibit B.Staff.3 b).

b) Although Union is not currently pursuing opportunities outside Ontario, there is nothing that would prevent Union from providing LNG service to parties located outside Ontario.

UNION GAS LIMITED

Answer to Interrogatory from
Board Staff

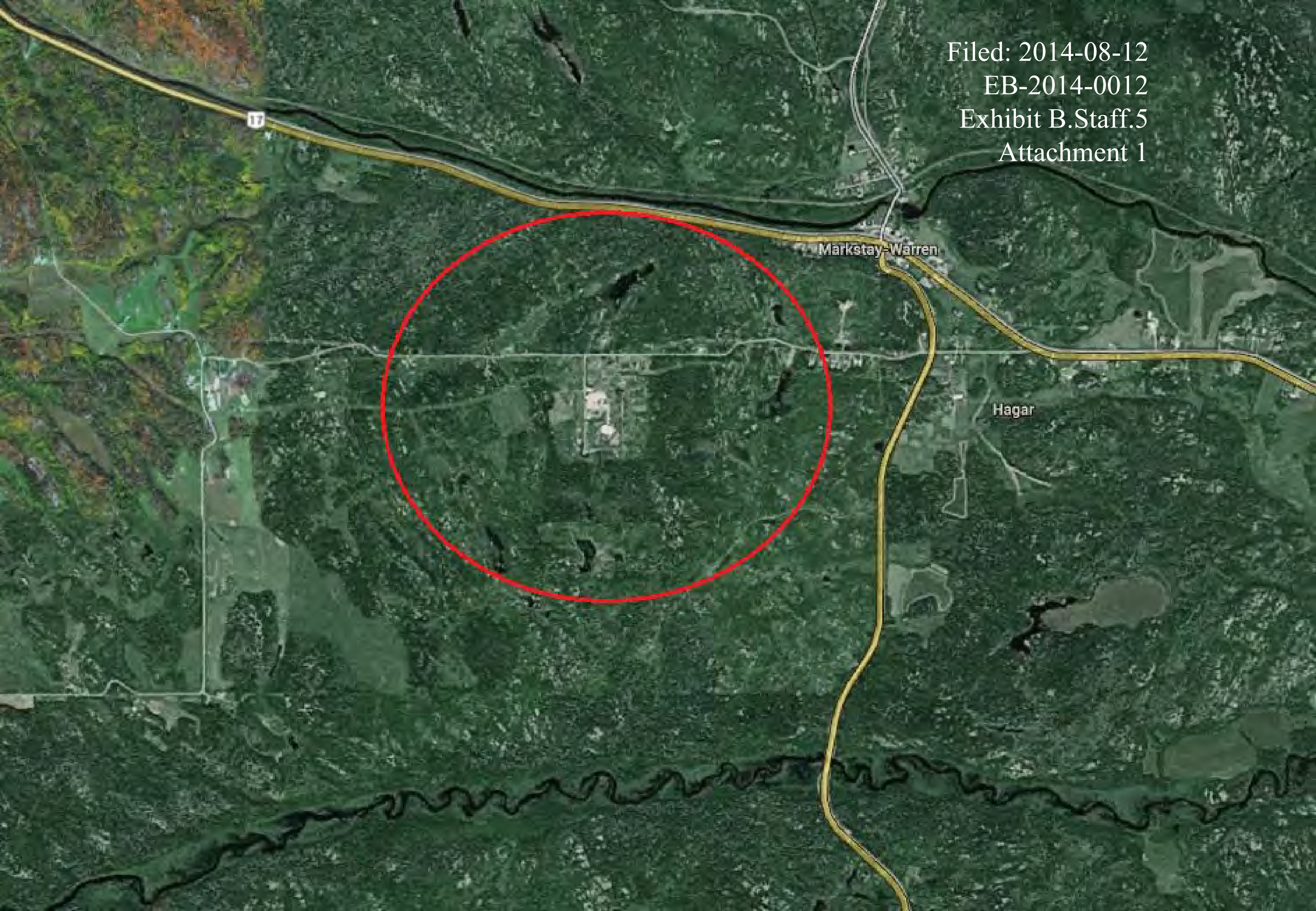
Reference: Exhibit A / Tab 1 / Page 11

Union has provided a map showing the Sudbury Lateral Pipeline System. Please provide a map of the Hagar facility that shows all housing and other commercial entities within a square km. of the facility. Also, please provide the number of people living or working within one square km.

Response:

The attached map (Attachment 1) details an approximate 1 km radius centered around the Hagar facility. Attachment 2 shows the residents located along Northern Central Road within this same general radius area. Union estimates there are 40 people living in the area shown in Attachment 2.

Filed: 2014-08-12
EB-2014-0012
Exhibit B.Staff.5
Attachment 1




Filed: 2014-08-12
EB-2014-0012
Exhibit B.Staff.5
Attachment 2

UNION GAS LIMITED

Answer to Interrogatory from
Board Staff

Reference: Exhibit A / Tab 1 / Page 15

Union has indicated that it will provide liquefaction service under a new Rate L1 rate schedule. How does Union intend to proceed if it does not received approval from the Board to charge a regulated rate but does receive approval to provide the new service? In other words, Union would be free to charge a market or unregulated rate for the new LNG service.

Response:

The primary purpose of the Hagar facility is for system integrity needed to support regulated operations. There is no change to this purpose or operations as a result of this application. The proposal to provide a small amount of interruptible LNG service is a form of asset optimization which will ultimately benefit ratepayers upon rebasing. During the IRM term, the interruptible service and revenue will contribute to regulated earnings, and may affect earnings sharing. For LNG that is used exclusively as a transportation fuel and is therefore subject to regulatory exemption, a new stand-alone plant investment and related services would not be regulated. This is not the case with the Hagar facility. For LNG that is used for purposes other than transportation (i.e. non-exempt), a new stand-alone plant investment and related services should be subject to competitive market and regulatory forbearance determinations.

UNION GAS LIMITED

Answer to Interrogatory from
Board Staff

Reference: Exhibit A / Tab 1 / Page 20

Union has indicated that it will invest an estimated $8.7 million in capital costs to increase storage capacity and facilitate the dispensing of LNG into tanker trucks.

a) Please confirm whether Union intends to add the capital costs to rate base at Union's next cost of service proceeding.

b) Please provide the estimate capital costs that will be added to rate base in 2019.

c) Please provide the return on rate base that Union will be able to include in the revenue requirement in 2019 as a result of this addition. Please use the current Board approved ROE to estimate the return.

d) What will be the estimated net revenue in 2019 from the additional services proposed by Union in this application?

Response:

a) Confirmed. Union will add the capital costs to rate base when the proposed facilities are deemed to be in-service. These facilities will be included in Union's forecasted rate base at its next cost of service proceeding.

b) Union estimates that approximately $7.5 million will be added to rate base in 2019 as a result of Union's proposed capital investment of $8.7 million at Hagar.

c) Using the 2013 Board-approved return of 7.32%, the return on rate base in 2019 is estimated to be $0.550 million ($7.5 million net plant x 7.32%).

d) Union does not have a forecast of the 2019 net revenue associated with the proposed liquefaction service.

   Based on Union's proposed liquefaction rate of $5.096/GJ and forecasted 2018 liquefaction activity of 678,400 GJ, Union is forecasting approximately $3.5 million in liquefaction revenue in 2018. This figure represents the best available forecast of liquefaction revenue beyond 2018.

Union will forecast 2019 liquefaction revenue as part of its next cost of service proceeding.

UNION GAS LIMITED

Answer to Interrogatory from
Board Staff

Reference: Exhibit A / Tab 1 / Page 22

Union has forecasted an expenditure of $500,000 in 2015 for a one-time upgrade to the municipal road entering the Hagar LNG facility.

a) How does Union propose to recover the $500,000 expenditure to upgrade the road? Will this expenditure be added to the incremental capital cost?

b) How many LNG trucks are estimated to use the Hagar facility for each of the years - 2016, 2017 and 2018?

c) Please indicate whether there would be a significant increase in traffic as a result of the additional truck movements in the area around the Hagar facility.

Response:

a) Union will recover the $500,000 expenditure for a one-time upgrade to the municipal road entering the Hagar LNG facility in the proposed liquefaction rate.

No. This expenditure will not be added to the incremental capital costs. The $500,000 expense is included in the forecast of 2015 incremental O&M costs of $621,000. Please also see Exhibit A, Tab 1, page 21, Table 4, line 4.

b) The table below shows the number of trucks per year and per day as well as how these totals correlate to forecast liquefaction sales activity.

	2015	2016	2017	2018
Forecast (GJ)	67,840	339,200	576,640	678,400
# trucks/year	68	340	577	679
# trucks/day	0.6	1.0	2.0	3.0

assumes 1,000 GJ/truck
assumes 5 day/week loading

c) In Union's view, this will not result in a significant increase to traffic in the area. As shown in response to part b) above, the maximum number of trucks at peak liquefaction sales is three per day by 2018. Large trucks are currently making deliveries approximately two to three times a month in and out of a commercial sheet metal business which operates on the same road as the Hagar facility. There is also a horse farm on Northern Central Road which uses large trailers to move hay up and down the road. Two garbage trucks per week travel up and down the road and on occasion there are logging trucks and dump trucks that also use Northern Central Road.

UNION GAS LIMITED

Answer to Interrogatory from
Board Staff

Reference: Exhibit A / Tab 2 / pages 17-19

Union is forecasting an average of 416,000 GJ per year of interruptible liquefaction activity from September 2015 to December 2018.

In its new Rate L1 rate schedule, Union has proposed two rates: an interruptible rate of $5.096/GJ and a short-term rate (one year or less) of a maximum $15/GJ.

Please provide the annual breakdown in volumes that Union has forecasted to sell under the interruptible rate of $5.096/GJ and the short-term rate of $15/GJ.

Response:

Union has forecast to sell all volumes at the proposed interruptible rate of $5.096/GJ.

UNION GAS LIMITED

Answer to Interrogatory from
Board Staff

Reference: Attachment A, KPMG Report, "Identification of Liquefaction Service Costs", page 2

The report indicates that once the storage tank has been filled, almost all of the liquefaction capacity will be available for other purposes until the next refill cycle has started.

Please provide the liquefaction activity (volumes) for the Hagar LNG facility for each of the years 2009-2013 inclusive.

Response:

The following volumes have been liquefied to either replace LNG vapourized for a system integrity event or LNG lost due to boil-off.

Year	Annual Liquefaction Volume, GJ
2009	104,823
2010	115,958
2011	133,812
2012	104,055
2013	90,616
2014 (YTD)	0

UNION GAS LIMITED

Answer to Interrogatory from
Board Staff

Reference: Attachment A, KPMG Report, “Identification of Liquefaction Service Costs”, page 2

The report in Section C, “General Approach” recommends that LNG wholesalers should absorb any of the incremental costs associated with providing the new liquefaction service. These include any variable costs associated with additional LNG production.

Please confirm that the new rate class “L” will be allocated all costs for incremental production of LNG including all variable costs.

Response:

Confirmed. All incremental capital and O&M costs (including variable costs) associated with the provision of Union’s liquefaction service have been allocated to Rate L1 and will be recovered in the proposed liquefaction rate.

UNION GAS LIMITED

Answer to Interrogatory from
Board Staff

Reference: Attachment A, KPMG Report, "Identification of Liquefaction Service Costs", page 6

The report indicates that in recent years, the plant has not been fully cycled and the LNG storage tank has remained full, or nearly full, throughout the course of the year. It is assumed that once Union introduces the new service, liquefaction activity would increase significantly at the Hagar location. Considering that historically, liquefaction activity for system integrity would be minimal or non-existent until the next refill cycle, how does Union propose to deal with costs related to liquefaction activity increasing significantly as a result of the new service?

How will Union ensure that the allocation of indirect OM&A costs takes into account the fact that liquefaction, maintenance costs and general traffic at the facility will increase disproportionally as a result of offering the new service; a service that operates throughout the year as compared to the current state of providing system integrity service on certain occasions?

Response:

As described in Union's response to Exhibit B.Staff.11, all forecasted incremental capital and O&M costs (including variable costs) will be recovered in the proposed liquefaction rate. In addition, the proposed liquefaction rate is intended to make a contribution towards the recovery of 2013 Board-approved Hagar liquefaction and storage costs and Union North distribution costs, which include indirect OM&A costs.

As part of its next cost of service proceeding, Union will include the new Rate L1 rate class in its cost allocation study consistent with the cost allocation methodologies proposed in this application. This approach will ensure that the Rate L1 rate class is allocated the costs associated with the provision of the liquefaction service, based on the forecasted level of activity, including indirect OM&A costs.

UNION GAS LIMITED

Answer to Interrogatory from
Building Owners and Managers Association ("BOMA")

Reference: A-1-1

Page 1 - What are the other uses of the LNG proposed to be provided to wholesale distributors at Hagar?

Response:

Parties who expressed interest in the proposed service indicated the LNG would be used mainly for vehicle fuel as well as some power production. For additional detail, please see the response to Exhibit B.Staff.1.

UNION GAS LIMITED

Answer to Interrogatory from
Building Owners and Managers Association ("BOMA")

Reference: A-1-1

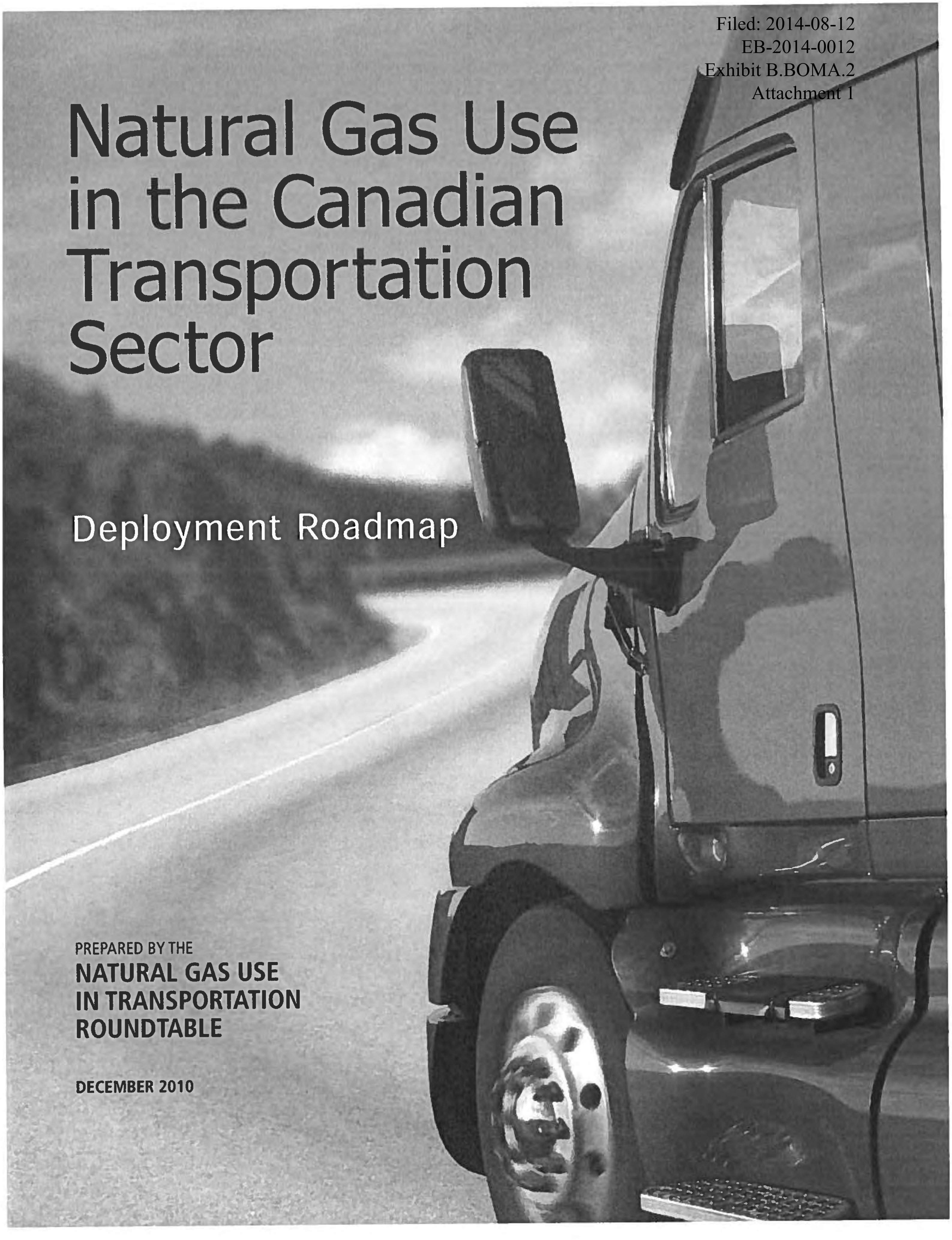
Page 5 – Please provide a copy of the document, The Natural Gas Use in the Canadian Transportation Sector Deployment Roadmap.

Response:

Please see Attachment 1 for a copy of the Natural Gas Use in the Canadian Transportation Sector Deployment Roadmap. This document is found at the following link:

http://www.nrcan.gc.ca/sites/www.nrcan.gc.ca/files/oee/pdf/transportation/alternative-fuels/resources/pdf/roadmap.pdf

Filed: 2014-08-12
EB-2014-0012
Exhibit B.BOMA.2
Attachment 1



Natural Gas Use in the Canadian Transportation Sector

Deployment Roadmap

PREPARED BY THE
NATURAL GAS USE IN TRANSPORTATION ROUNDTABLE

DECEMBER 2010

Disclaimer

This Roadmap provides the perspective of numerous stakeholders and was prepared under the direction of the Roundtable members. The contents, conclusions, and recommendations are not necessarily endorsed by all participating organizations and their employees or by the Government of Canada.

For more information or to receive additional copies of this publication, write to:

Canadian Natural Gas Vehicle Alliance
350 Sparks Street, Suite 809
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Foreword by the Deputy Minister

The *Natural Gas Use in the Canadian Transportation Sector Deployment Roadmap* initiative, launched in March 2010, brought together stakeholders from governments, industry — including gas producers, transporters, distributors, vehicle and equipment manufacturers, and end-users — as well as representatives from environmental non-governmental organizations and academia. Facilitated by Natural Resources Canada, this process provided a platform for this broad array of stakeholders to discuss the potential for natural gas use across the medium- and heavy-duty transportation sector, explore strategies for overcoming barriers associated with its use, and develop recommendations for deployment.

As this work was conducted, key stakeholders worked together in an unprecedented manner and pace. Consensus-building played an essential role during the development of the Roadmap's analyses and in the formulation of its recommendations.

This Roadmap focused on expanding the use of natural gas across the transportation sector and represents an important contribution to deliberations toward a broader strategy to reducing greenhouse gas (GHG) emissions. Other efforts in the transportation sector include, for example, a suite of regulations to address GHG emissions from vehicles and minimum requirements for renewable content in fuels. Continued dialogue among governments and market participants will be important to ensure that all opportunities are properly assessed to inform decision-making.

I would like to take this opportunity to thank all of those involved in this process for their dedication in contributing to the delivery of the Roadmap.

Serge P. Dupont, Deputy Minister

Roadmap Participants

Alberta Ministry of Energy

Auto21

British Columbia Ministry of Energy, Mines and Petroleum Resources

Canadian Association of Petroleum Producers

Canadian Gas Association

Canadian Natural Gas Vehicle Alliance

Canadian Trucking Alliance

Canadian Urban Transit Association

Climate Change Central

Daimler

Dynetek Industries

Encana Corporation

Gaz Métro

IMW Industries

Ministère des Ressources naturelles et de la Faune du Québec

Natural Resources Canada

Pembina Institute

Pollution Probe

Terasen Gas

TransCanada Pipelines

Westport Innovations Inc.

Glossary

Biogas: Methane produced from the decomposition of biomass in landfills, digesters, and wastewater plants.

Biomethane: Biogas that is upgraded to pipeline quality-standard and can be used interchangeably with fossil natural gas.

Compressed natural gas (CNG): One possible form in which natural gas can be used in vehicles. CNG is formed by compressing gas to high pressures in the range of 3,000 to 3,600 pounds per square inch (psi). Compression reduces the volume by a factor of 300 (or more) compared with gas at normal temperature and pressure. It is stored in steel or fibre-wound cylinders at high pressures (3,000 to 3,600 psi). Onboard a natural gas vehicle, the gas travels through a pressure regulator and into a spark-ignited or compression ignition engine.

End-user: The person or organization that is the actual user of a product.

Fuel Value Index (FVI): A measure that allows all costs associated with natural gas use to be consolidated and reflected as a cost-per-diesel-litre equivalent, as used in the business modelling. For those vehicle applications with FVI values greater than 1, the value proposition for natural gas is equivalent to or better than that for a comparable diesel fleet.

Heavy-duty vehicle: Class 7–8 vehicles with a gross vehicle weight of 15 tonnes or greater.

Internal Rate of Return (IRR): The rate of return used to measure and compare the profitability of investments — in other words, the level of payback that an investor can expect to receive over the life of the asset.

Lifecycle greenhouse gas (GHG) emissions: The total amount of GHG emissions created throughout the full fuel lifecycle, including stages of fuel and feedstock production, distribution, delivery, and use.

Light-duty vehicle: Class 1–2 vehicles with a gross vehicle weight of up to 4.5 tonnes.

Liquefied natural gas (LNG): One possible form in which natural gas can be used in vehicles. LNG is made by cooling the gas temperature to -162°C. The liquefaction process reduces the volume by a factor of 600 compared with gas at normal temperature and pressure. The LNG is stored on vehicles in a double-walled stainless steel tank and vaporized before injection into the engine.

Medium-duty vehicle: Class 3–6 vehicles with a gross vehicle weight between 4.5 and 14.9 tonnes.

Natural gas vehicle (NGV): An alternative fuel vehicle that uses CNG or LNG as a clean alternative to conventional liquid fuels.

Original Equipment Manufacturer (OEM): The company that originally manufactures the products.

Shale gas: Natural gas that is trapped in fine-grained sedimentary rock that can be accessed through advanced drilling techniques including horizontal drilling and multi-stage fracturing.

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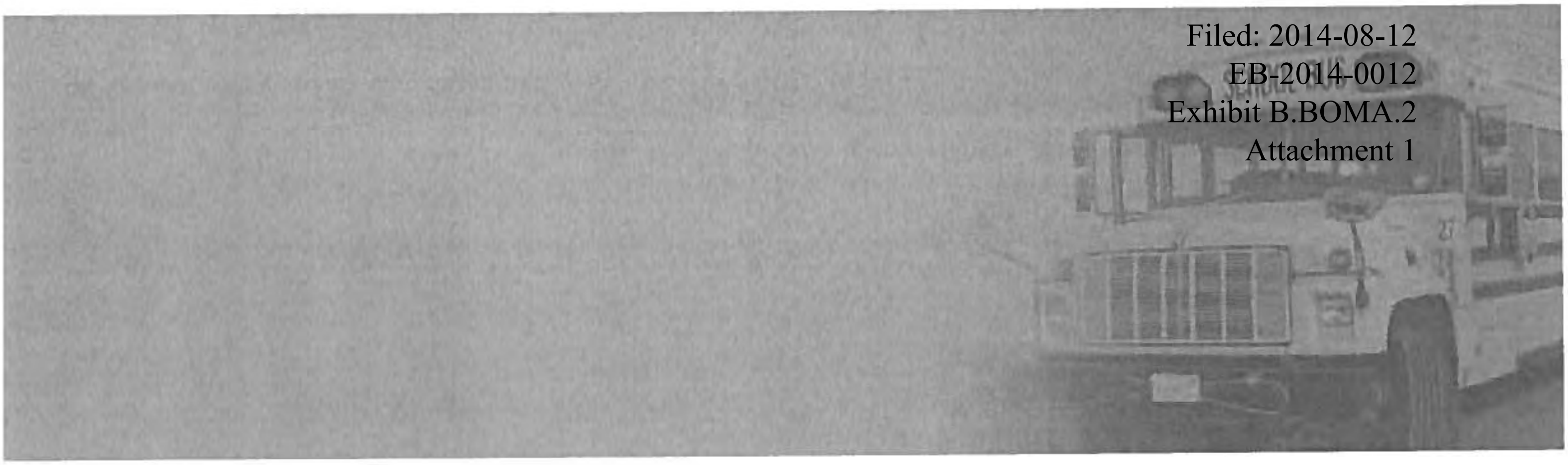


Executive Summary

The Context

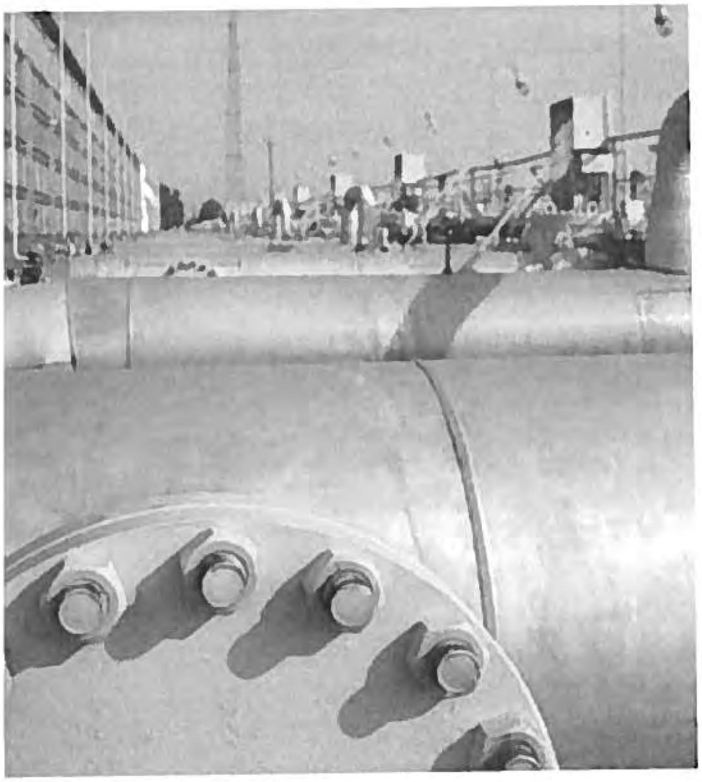
Canada's transportation sector is characterized by high energy use and significant greenhouse gas (GHG) emissions. In 2007, transportation accounted for 29 percent of secondary energy use, making it Canada's second-largest sector in terms of energy consumption.[1] Unlike most other sectors of the Canadian economy, though, transportation relies on a single energy source (crude oil-based fuels) to meet the vast majority of its energy needs. Energy demand for transportation is increasing, and vehicle energy use is projected to increase by 31 percent between 2004 and 2020.[2] GHG emissions from transportation sources are also rising. More than one-third of the increase in Canada's GHG emissions between 1990 and 2008 was attributable to transportation sources.[3] To address the transportation sector's increasing energy demand and GHG emissions, a comprehensive strategy is needed to improve vehicle efficiency, increase the use of lower-carbon fuels, and enhance system efficiencies. The increased use of natural gas in the transportation sector is one component of the overall solution.

Canada's natural gas supplies have grown substantially in recent years due to the advent of new drilling technology. Canada's transportation sector could benefit from expanding the use of lower-emission technologies and fuels such as natural gas. For medium- and heavy-duty vehicles that operate in return-to-base and corridor fleets, natural gas offers some important potential benefits, such as the ability to:

- Diversify energy use in the transportation sector and meet increasing energy demand;
- Reduce carbon emissions from the transportation sector;
- Introduce into a new market a cost-effective fuel that has historically traded at a discount to crude oil-based fuels on an energy equivalent basis; and
- Provide an alternative compliance option as carbon-related regulations enter the transportation sector.

Despite these potential benefits, market adoption for medium- and heavy-duty natural gas vehicles (NGVs) in Canada has been very limited to date. There are significant challenges associated with NGV deployment in Canada, including operating risks associated with costs and technology performance, high upfront vehicle costs, a lack of widespread infrastructure, and non-economic issues, including scarce recent experience with NGVs, insufficient information about current technology, and a lack of comfort with NGVs based on past history.

[1] Natural Resources Canada, *Energy Efficiency Trends in Canada 1990 to 2007*, April 2010.
[2] Natural Resources Canada (2006), *Canada's Energy Outlook: Reference Case 2006*.
[3] Natural Resources Canada, *Energy Efficiency Trends in Canada 1990 to 2007*, April 2010.



Natural Gas Use in Transportation Roundtable

To respond to these challenges, the Natural Gas Use in Transportation Roundtable — led by the Deputy Minister of Natural Resources Canada — was formed in March 2010 to identify the optimal use of natural gas in Canada's transportation sector. The Roundtable consisted of federal and provincial officials; industry representatives, such as natural gas producers, transporters, distributors, vehicle makers, equipment manufacturers, and end-users; and representatives from environmental non-governmental organizations and academia.

The *Natural Gas Use in the Canadian Transportation Sector Deployment Roadmap* is the result of the Roundtable's work. This Deployment Roadmap is innovative in nature and distinguishes itself from technology roadmaps in three fundamental ways: 1) the detailed business modelling work that was performed to assess, analyze, and rank potential end-use applications in the medium- and heavy-duty portion of the transportation sector, 2) the consultations that were undertaken with various end-users that might adopt this technology, and 3) the significant contributions made by the Roundtable member organizations, which were fully engaged in the Roadmap development from the outset. The Roadmap's framework for assessing the true potential of NGV adoption could also be used by those considering other fuel or technology pathways.

Roadmap Process

As an initial step in developing the Roadmap, working groups assessed opportunities for new natural gas markets in the on-road transportation sector (including light-, medium-, and heavy-duty vehicles), as well as marine and rail applications. In the near term, medium- and heavy-duty vehicles were found to offer the greatest opportunities for increased natural gas use. The prospects for natural gas use in other applications, including light-duty vehicles, marine vessels, and locomotives, were also found to be promising. However, due to more substantial barriers, which may include supply chain, technological, and market issues, these vehicle applications will likely require a longer time frame to achieve widespread natural gas use. Because of this finding, the working groups' subsequent work — which included conducting business case modelling, developing an education and outreach strategy, and examining research and development (R&D) requirements — focused primarily on medium- and heavy-duty applications.

The resulting Roadmap aims to:

- Address fundamental knowledge gaps regarding stakeholder interest, capacity, and economic and environmental impacts;
- Inform public and private sector decision-makers;
- Assist stakeholders in determining long-term investment requirements; and
- Outline key steps for implementation by defining future government programming needs and industry's role.

Recommendations

The following set of recommendations was developed in consultation with stakeholders representing all Roadmap working groups as well as Roundtable members. These recommendations reflect findings related to business modelling work; capacity-building needs; and research, development, and demonstration (RD&D) requirements. Recommendations have been proposed in four key areas: 1) De-risking Investment and Early Adoption, 2) Addressing Information Gaps, 3) Increasing Capacity to Sustain Markets, and 4) Ensuring Ongoing Competitiveness.

De-risking Investment and Early Adoption

1. Analysis has demonstrated that investment in medium- and heavy-duty NGVs can provide environmental and over-vehicle-life economic benefits, but the upfront capital cost vehicle premium and the risks associated with operation costs and achieving ongoing fuel savings are barriers to adoption. Fiscal measures implemented on a temporary basis could address these barriers and de-risk decision-making for early fleet adopters.
2. To introduce natural gas into the new market of over-the-road trucking, coordinated investments are needed to ensure that the development of key corridor infrastructure is consistent with projected demand, strategically located to support end-users, and installed in a timely manner across jurisdictions.
3. Existing industry players could provide access to private onsite refuelling stations. Fleets could further improve the business case for natural gas adoption by allowing other fleets to use these stations via cardlock and other arrangements. However, there are implementation details (e.g. liability issues) that would need to be addressed by the parties involved.
4. Demonstration of the use of natural gas is needed to address technical barriers, develop standards, and conduct feasibility studies and business cases.

Rationale

Temporary fiscal measures would help de-risk adoption and lower economic barriers to market entry. End-users perceive early adoption as risky and, in particular, they attach uncertainty and risk to 1) the residual value of an NGV after the initial ownership period (e.g. four to five years for highway tractors), 2) the potential for ongoing fuel savings, and 3) the lack of refuelling infrastructure relative to diesel fuel infrastructure. Temporary fiscal measures would encourage early adoption of NGVs in larger quantities, which in turn would help the NGV industry achieve the economies of scale required to reduce the cost of vehicle systems. While there is a positive internal rate of return for several end-use applications, temporary fiscal measures would also be necessary to overcome the barriers to adoption if they are determined to be the result of market failure within the medium- and heavy-duty portion of Canada's transportation sector. While there are many precedents for market intervention by governments to assist in developing scale and removing barriers to entry, over the longer term it will be important for natural gas as a transportation fuel to be able to compete on a level playing field with other fuels — based on its own merits. This principle should be considered by policy-makers in terms of the design and duration of any policies moving forward.

Addressing Information Gaps

5. An education and outreach strategy would be needed to target end-users as well as market influencers and other key stakeholders. This strategy should consist of both a "top-down" and a "bottom-up" approach. A top-down approach would include a central website for all target audiences with local content tailored to specific jurisdictions. A bottom-up approach would feature a local support network for end-users and provide access to resources including workshops and case studies of local fleets.

Rationale

End-users identified gaps in their knowledge and awareness of NGVs as an option that could serve their needs. In addition, end-users with past experience using natural gas had additional information requirements related to recent NGV developments, particularly technological innovations. It would provide momentum if governments and other players were to provide essential information to enable markets to function efficiently, especially since there is no single private sector actor that operates across the entire spectrum of the NGV value chain. Governments are regarded as unbiased providers of information in the vehicle and fuel market arenas, and this neutrality is important to end-users. Benefits of this measure include the development of a broader understanding and increased awareness of the applicability of NGVs, which would facilitate adoption of these vehicles in greater numbers.

Increasing Capacity to Sustain Markets

6. A "safety codes and standards" working group should be established to collaborate with existing Canadian Standards Association technical committees to address gaps and issues in existing codes and standards identified during the Roadmap process. Separate committees for liquefied natural gas (LNG) and compressed natural gas (CNG) may need to be formed to review existing codes and revise or develop new codes and standards. An umbrella committee is needed to ensure that codes and standards for CNG, LNG, liquefied compressed natural gas, and biomethane are coordinated and comprehensive.
7. Appropriate training materials for stations, vehicle repairs, and NGV fleet operations, as well as for cylinder inspection, need to be developed and delivered.
8. An NGV implementation body — consisting of Roundtable members and other key stakeholders — should be established to:
   - Support the implementation of the Roadmap's recommendations and assess progress against key milestones;
   - Provide recommendations to stakeholders regarding how the natural gas community could respond to future developments, such as changes in market conditions and technological innovations;
   - Act as an umbrella organization for the local support network for end-users; and
   - Serve as a forum for stakeholders to discuss issues pertinent to the natural gas community.

Rationale

To encourage NGV adoption, end-users need to be supported during their purchasing decisions, and adequate codes and standards need to be in place to ensure a successful technology rollout. Over the past decade, very little work has been done in Canada to update CNG codes and standards, while LNG codes and standards require even more fundamental development. As NGV technology becomes increasingly available, fleets will require support, since this technology features specific maintenance and safety requirements that will necessitate training of operators and mechanics. An NGV implementation body is recommended as a way to coordinate the work of governments and stakeholders along the NGV value chain to ensure the successful deployment of this technology and mitigate the risks borne by end-users or by any individual player.

Ensuring Ongoing Competitiveness

9. The NGV industry funds R&D activities at present. Further investment by others, including governments, has the potential to enhance the competitive position of the industry through targeted R&D investment. Priorities for future R&D include reducing or eliminating the cost differential between natural gas and diesel vehicles over the long term and maximizing NGVs' operational and environmental benefits.
10. Potential for natural gas use in other transportation applications should continue to be explored.

Rationale

While NGV technology is already mainstream and commercially proven, support for NGV R&D is needed to further reduce the incremental cost of NGV-related technologies. In addition, assistance is needed to sustain market development through the expansion of the number of NGV offerings for end-users. NGV technologies would also benefit from R&D investments to reduce the incremental cost of these vehicles, which

TABLE 1 Natural Gas Use in Transportation: Roles and Responsibilities

		GOVERNMENTS	NG PRODUCERS, TRANSPORTERS, AND DISTRIBUTORS	INFRASTRUCTURE AND VEHICLE SUPPLY STREAM	END-USERS
De-risking Investment and Early Adoption	Vehicle Premium	■	■		■
	Corridor Infrastructure	■	■	■	
	Return-to-Base Infrastructure		■	■	■
	Demonstrations	■		■	■
Addressing Information Gaps	Education and Outreach	■	■	■	
Increasing Capacity to Sustain Markets	Codes and Standards	■	■	■	
	Training	■	■	■	
	Implementation Committee	■	■	■	■
Ensuring Ongoing Competitiveness	R&D	■		■	
	Use of NG in Other Applications	■	■	■	■

would ensure ongoing competitiveness for innovative low-emission Canadian technologies. By continuing to explore the potential for natural gas use in other transportation applications, the natural gas community will help expand the benefits of natural gas as a fuel and potentially leverage infrastructure and R&D investments made for the medium- and heavy-duty vehicle market.

Roles and Responsibilities

The stakeholders in Table 1 were identified as parties who could take on roles and responsibilities as they relate to moving the recommendations of this Roadmap forward. For many of these activities, numerous stakeholders could play a role; however, the table aims to provide a general overview of the roles that key stakeholders could play during the early stages of NGV market development.

Moving Forward

For governments and industry alike, the changing supply story for natural gas, projected high oil prices, and the need to reduce GHG emissions and criteria air contaminants have all contributed to renewed interest in natural gas as a transportation fuel. Now that market conditions are more favourable, Canada's natural gas community is well positioned to take a significant leap forward in deploying these vehicles in greater numbers. While natural gas is not the only solution for reducing GHG emissions produced by medium- and heavy-duty vehicles, it provides a particularly good set of benefits for return-to-base and corridor fleets. As a result of past research assistance from governments, several Canadian companies are now technology leaders in the areas of natural gas vehicles and fuelling infrastructure. There is also a sound base of codes and standards that the natural gas community can build upon. But perhaps the most important advantage for Canada's natural gas community is the new collaborative environment that has developed as a result of the Roadmap process. Such collaboration, which was essential during the Roadmap's development, will again be critical as Canada's natural gas community turns its focus to implementing the recommendations set out in this report.

BACKGROUND

BACKGROUND

Chapter 1

Introduction

Natural Gas: An Energy "Game Changer"

Not long ago, energy analysts projected that natural gas production in North America would decline steadily for the foreseeable future. However, recent advances in drilling technology have enabled cost-effective extraction of natural gas from unconventional reservoirs, such as shale formations, which are in abundant supply. In response to this development, North American energy market analysts now describe natural gas as a potential energy game changer, and governments and industry are exploring new and expanded opportunities for this resource.

Roadmap Approach

In response to this opportunity, a Roundtable — led by the Deputy Minister of Natural Resources Canada — was formed in March 2010. It consisted of senior officials in federal and provincial governments, end-users, executives from industry (including gas producers, transporters, distributors, and vehicle and equipment manufacturers) and representatives from environmental non-governmental organizations and academia. During the Roundtable's inaugural meeting, working groups were formed to focus on the following issues:

- Natural gas fundamentals;
- Vehicle readiness and R&D;
- Infrastructure readiness and R&D;
- End-user needs;
- Codes and standards; and
- Market transformation and policy analysis.

Co-leaders from Natural Resources Canada and private sector organizations were assigned to each working group, which consisted of staff from the Roundtable member organizations. These working groups conducted research and analysis in their respective subject areas, and met periodically by teleconference to assess progress and determine next steps.

As an initial step in developing the Roadmap, working groups assessed opportunities for new natural gas markets in the on-road transportation sector (including light-, medium-, and heavy-duty vehicles), as well as marine and rail applications. During its second meeting, which took place in June 2010, the Roundtable determined that medium- and heavy-duty vehicles offered the greatest opportunities for increased natural gas use in this sector in the near term. The prospects for natural gas use in other applications, including light-duty vehicles, marine vessels, and locomotives, were also found to be promising. However, due to more substantial supply chain and technological barriers, these vehicle applications were identified as likely requiring a longer time frame to achieve widespread natural gas use in Canada.

The Roadmap's purpose is to identify the optimal use of natural gas in Canada's transportation sector.

As a result of this decision, the working groups' subsequent analytical work primarily dealt with medium- and heavy-duty applications. During the analytical stage of the Roadmap's development, work focused on three key areas:

- Conducting business case modelling to determine the optimal use of natural gas in specific medium- and heavy-duty vehicle applications;
- Developing an education and outreach strategy to ensure that end-users and other key stakeholders have the information they need to facilitate NGV deployment; and
- Identifying R&D requirements to ensure that the NGV industry becomes self-sustaining over the long term.

During its final meeting in September 2010, the Roundtable reviewed drafts of the Roadmap report and recommendations and provided a final set of revisions. Once these revisions were complete, Roundtable members provided their final concurrence to the report.

The Final Product

The *Natural Gas Use in the Canadian Transportation Sector Deployment Roadmap* is the culmination of the work led by Roundtable members and the working groups from March to October 2010. The Roadmap's purpose is to identify the optimal use of natural gas in Canada's transportation sector. It also aims to:

- Address fundamental knowledge gaps regarding stakeholder interest, capacity, and economic and environmental impacts;
- Inform public and private sector decision-makers;
- Assist in determining long-term investment requirements by stakeholders; and
- Outline key steps for implementation and define future government programming needs and industry's role.

This report is unique in nature and distinguishes itself from technology roadmaps in three fundamental ways: 1) the detailed business modelling work that was performed to assess, analyze, and rank potential end-use vehicle applications, 2) the consultations that were undertaken to identify opportunities and challenges within the end-user community, and 3) the significant contributions made by the Roundtable member organizations, which were fully engaged in the Roadmap's development from the outset. Because of its emphasis in these areas, the Roadmap's framework could potentially be used by others who are assessing other fuel and technology pathways.

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BACKGROUND

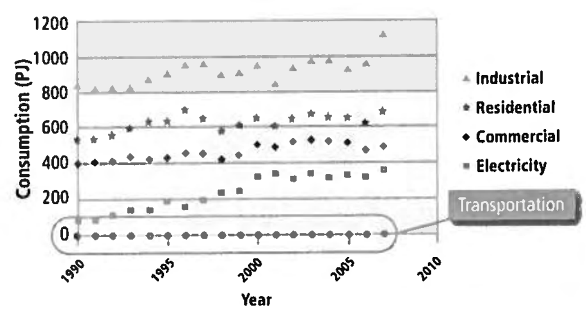
Chapter 2

Drivers of Interest and Market Opportunities

Participants involved in the Roadmap's development focused on addressing two fundamental questions pertaining to scope. The first question was, "Recognizing that natural gas use could be expanded in several key sectors, why should governments and industry consider natural gas in the transportation sector at this time?" In other words, what factors are driving interest among stakeholders to consider natural gas use specifically in the transportation sector? The second question was, "Within the transportation sector, which vehicle applications have the greatest potential for natural gas use?" This chapter provides the Roundtable's responses to these questions.

Why Should Governments and Industry Consider Natural Gas Use in the Transportation Sector?

Canada's abundant natural gas resources can be used in any of the nation's major economic sectors, including commercial, residential, industrial, electricity, and transportation. As Figure 1 indicates, natural gas use in the various sectors of the economy increased from 1990 to 2007. The transportation sector is unique in that it currently uses significantly less natural gas relative to the other sectors. Even if demand for natural gas use in the transportation sector increased significantly over the coming decade, the effect on natural gas prices would likely be minimal.



Source: Natural Resources Canada (2010), "Energy Use Data Handbook Tables (Canada)." Accessed February 2010.

FIGURE 1 Natural Gas Consumption in Canada by Sector (1990–2007)

There are a number of benefits that can be derived from expanded natural gas use in the transportation sector. First, it will diversify the sector's potential energy sources. Unlike all other sectors of the Canadian economy, transportation relies on a single energy source (crude oil-based fuels) to meet nearly all of its energy demands. In 2007, crude oil-based fuels supplied 99 percent of transportation energy demands, compared with propane (0.5 percent), electricity (0.1 percent), and natural gas (0.1 percent).[1] And while Canada is a net exporter of crude oil, more than half of the oil processed in Canadian refineries is imported from Europe, the Organization of Petroleum Exporting Countries (OPEC), and the northeastern United States.[2]

[1] Natural Resources Canada, "National Energy Use Database," http://www.oee.nrcan.gc.ca/corporate/statistics/neud/dpa/trends_tran_ca.cfm.
[2] EcoRessources Consultants, *Cost-Benefit Analysis of the Proposed Regulations to Require Renewable Fuels Content in Canadian Fuels – the 2% Requirement*. A report prepared for Environment Canada. Page 11.

TABLE 1 Drivers for Key Stakeholders

STAKEHOLDER	DRIVERS
Governments	▪ Enhance energy diversification ▪ Develop clean energy solutions ▪ Meet GHG reduction targets / build a low-carbon economy / encourage growth of green industries ▪ Foster strong markets for Canada's energy resources ▪ Support economic recovery and sustainable growth ▪ Support the economic competitiveness of Canadian industries and technology
Fuel Supply Stream (Natural Gas Producers)	▪ Take the opportunity to provide abundant, Canadian, low-cost natural gas resources ▪ Stimulate demand and expand markets ▪ Retain and attract investment in Canada ▪ Strategically invest in anticipation of climate change regulations
Fuel Supply Stream (Natural Gas Transmission and Distribution)	▪ Use the significant infrastructure already in place ▪ Increase throughput to reduce tolls and improve competitiveness ▪ Diversify markets ▪ Build demand beyond traditional end-use markets
Vehicle and Equipment Suppliers	▪ Supply consumers with lower-carbon fuel options ▪ Position Canadian companies to compete more effectively when heavy-duty vehicle carbon regulations are implemented ▪ Build on the competitiveness of Canada's world-leading industry: ▪ Develop a strong technology and manufacturing base nationally ▪ Encourage wider use of technologies to achieve economies of scale in production ▪ Provide local economic benefits through jobs and accessing local supplier networks

End-Users	▪ Invest strategically in expectation of heavy-duty GHG emissions regulations
	▪ Demonstrate commitment to customers/shareholders:
	  ▪ Significant GHG reduction benefits associated with renewable natural gas
	  ▪ Ability to measure and quantify GHG reductions
	  ▪ Opportunity to reduce noise in urban settings
	▪ Take advantage of expectations that natural gas will remain competitively priced:
	  ▪ Natural gas use may reduce fuel price volatility risks
	▪ Take into account the increasing cost and complexity of 2010 diesel engine emission control technology

Second, natural gas can provide important benefits as a low-carbon transportation fuel. In 2007, Canada's transportation sector accounted for approximately 29 percent of total energy demand, making it the second-largest energy consumer in the nation.[3] As a result of such significant energy demand, this sector also accounted for 36 percent of Canada's GHG emissions, making it the second-largest source of emissions in the country.[4] Moreover, total energy demand in the transportation sector is expected to grow by 31 percent between 2004 and 2020.[5] The major source of energy use and emissions is on-road vehicles.

Third, natural gas is a cost-effective fuel that has historically traded at a discount to crude oil-based fuels on an energy equivalent basis. Furthermore, recent growth in the Canadian natural gas supply lends confidence that this discount will continue for the foreseeable future. This benefit is potentially critical for operators of medium- and heavy-duty vehicle fleets, who may be able to use natural gas to substantially lower their fuel costs on a per kilometre basis. With the growing availability of factory-built natural gas medium- and heavy-duty vehicles, there is an opportunity to ensure that lower-emission NGVs are seen as a viable option for the normal replacement of vehicle fleets over time. In addition to these benefits, there are also numerous other factors driving interest in the use of natural gas in the transportation sector. These drivers — which can be unique to specific stakeholders — are provided in Table 1.

[3] Natural Resources Canada, *Energy Efficiency Trends in Canada 1990 to 2007*, April 2010.
[4] Natural Resources Canada (2010), *Canada's Secondary Energy Use by Sector, End-Use and Sub-Sector.*
[5] Natural Resources Canada (2006), *Canada's Energy Outlook: Reference Case 2006.*

Within the transportation sector, which vehicle applications have the greatest potential for natural gas use?

With interest in potentially increasing natural gas use in the transportation sector identified, the Roundtable turned its focus to determining the specific vehicle applications that have the greatest potential for increased natural gas use in the near term. To address this issue, the Roundtable assessed the potential for increased natural gas use in various vehicle segments, including light-, medium-, and heavy-duty vehicles, as well as marine vessels and locomotives. The following criteria were used to evaluate these segments: technology availability, market potential, environmental benefits, energy use, and economic impact. In the near term, medium and heavy-duty vehicles were found to have the greatest potential for widespread deployment as a result of the following factors:

- The availability of mature, certified vehicle engine and storage technologies;
- The growing energy demand for which these vehicles, particularly heavy-duty vehicles, account;
- The potential for significant fuel savings and a good rate of return for fleet owners; and
- Significant market potential given the focus on return-to-base and corridor fleets.

In addition, natural gas may have a role to play in the light-duty marketplace in the medium term, particularly for fleet applications used by taxi companies, municipalities, construction businesses, and utilities. For large fleets that already have a private onsite CNG station, there is an opportunity to further improve the economics of infrastructure investment for the fleet owners by extending natural gas use to their light-duty vehicles. Similar synergies may also exist for corridor as well as marine and rail applications. See Appendix A for additional details regarding the results of the scoping analysis.

Options for Reducing GHG Emissions from Medium- and Heavy-Duty Vehicles

In addition to these benefits, Roundtable members emphasized the important role that natural gas can play in helping various entities comply with environmental regulations that aim to reduce GHG emissions from medium- and heavy-duty vehicles. Figure 2 compares diesel fuel GHG emissions with emissions produced by biodiesel (5 percent blend), compressed natural gas (CNG), and liquefied natural gas (LNG). For each fuel, the figure includes upstream emissions (i.e. emissions produced during resource recovery, refining, and shipping) and vehicle operation emissions (i.e. emissions produced at the tailpipe). As the figure indicates, natural gas produces between 21 to 30 percent fewer GHG emissions on a well-to-wheels lifecycle basis compared with diesel.

Due to the low carbon content of natural gas relative to gasoline and diesel, the production of NGVs could help truck and bus manufacturers meet yet-to-be-developed fleet average GHG standards. The Government of Canada recently announced its intention to implement GHG fleet average standards, which will come into effect in 2014; however, the structure of the medium- and heavy-duty standards is unknown at this time.

In addition to the incoming GHG vehicle standards, there are other environmental regulations for which natural gas could receive favourable treatment. Natural gas use in vehicle fleets could provide an important

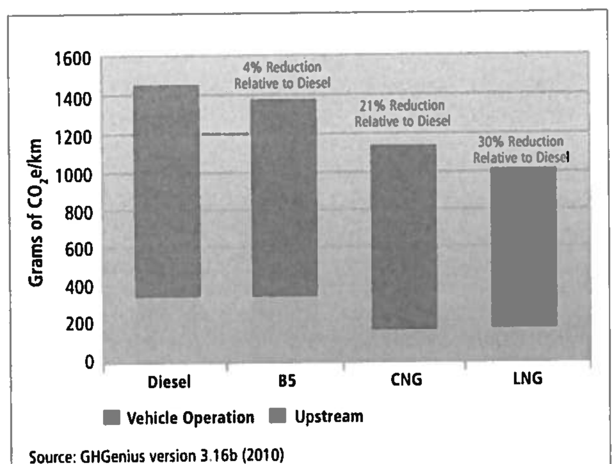


FIGURE 2 Alternative Fuel Options to Reduce GHG Emissions from Heavy-Duty Trucks

Why GHG Emissions Are Lower from Natural Gas than Diesel

As Figure 2 indicates, the upstream extraction and processing of natural gas, as well as combustion of it in a vehicle (as either CNG or LNG), produces fewer GHG emissions compared with diesel. With regard to **upstream emissions**, natural gas is typically processed only to remove impurities, a process that is less energy-intensive than the refining that is necessary to produce diesel.

Natural gas also produces fewer **vehicle operation emissions** than diesel, for two reasons. First, natural gas consists primarily of methane, which has the lowest carbon content of any fossil fuel. By comparison, diesel contains long chain hydrocarbons and a high level of carbon-content aromatics. Second, natural gas also has a higher energy content by mass than diesel. As a result of these two factors, natural gas produces fewer vehicle operation emissions than diesel: 13.68 grams of carbon per megajoule (g-C/MJ) and 18.79 g-C/MJ respectively, although there may be engine efficiency differences compared with diesel, depending on the type of natural gas engine technology.

Source: GHGenius version 3.16b (2010)

contribution to reaching climate change policy goals in Canada at a reasonable cost. For example, if one out of every 10 new medium and heavy-duty vehicles sold in Canada over the next 10 years were natural gas-powered (36,000 vehicles), carbon emissions could be reduced by an estimated 1.99 megatonnes annually by 2020.[6] Similarly, fuel providers are already preparing to meet new regulations for low-carbon fuels in British Columbia, as well as forthcoming regulations being developed in some other provinces. The inclusion of natural gas for transportation in the mix of fuels sold by fuel suppliers could help them meet standards where the regulations permit.

It is worth noting that in addition to using alternative fuels such as natural gas, further GHG emission reductions can be achieved through the use of supplemental options that improve the fuel efficiency of end-use applications, such as aerodynamic devices and design, fuel-efficient tires, and driver training. The U.S. Environmental Protection Agency has estimated the benefits of some of these options. For example, aerodynamic devices such as trailer end fairings can provide an estimated 5 percent or greater reduction in fuel use. Low rolling resistance tires can lead to fuel savings of approximately 3 percent or greater. The application of these technologies, coupled with driver training, can lead to additional fuel-saving benefits.[7]

Conclusion

Within the transportation sector, medium- and heavy-duty vehicles were found to have the greatest potential for increased natural gas use in the near term. There a number of reasons why the transportation sector would benefit from expanded natural gas use, such as:

- Diversifying energy use and responding to increasing energy demand;
- Reducing carbon emissions;
- Introducing a cost-effective Canadian-sourced fuel that has historically traded at a discount to crude oil-based fuels on an energy equivalent basis into a new market (this issue is discussed in detail in Chapter 4); and
- Providing an alternative compliance option as carbon-related regulations enter the transportation sector.

In addition to these benefits, the list of drivers leading stakeholders to expand natural gas use in the transportation sector is compelling. Individual stakeholders can realize benefits, but only if the other stakeholders agree to participate in developing the market. The likely extent and strength of such cooperation will depend on the needed investments, perceived risks and economic returns — issues that are explored in Chapter 5. The next chapter reviews the current state of natural gas in transportation technology and policy in Canada, and provides valuable contextual information that will lay the foundation for the Roadmap's subsequent analysis and recommendations.

[6] Calculated value based on GHGenius (version 3.16b) and historical vehicle sales data from the Canadian Vehicle Manufacturers Association.
[7] U.S. Environmental Protection Agency (2010), *Verified Technologies*. Available online http://epa.gov/smartway/transport/what-smartway/verified-technologies.htm.

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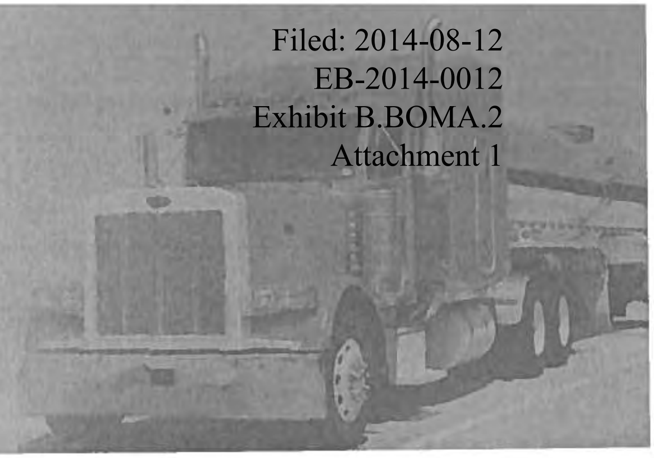


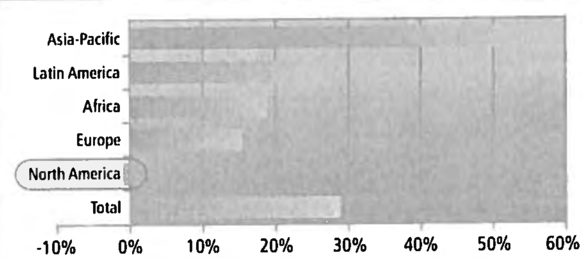
Chapter 3

The State of Natural Gas Use in Transportation

This chapter provides an overview of the current state of natural gas use in the transportation sector from a global perspective — then more specifically from a Canadian and U.S. market perspective — with emphasis on existing NGV policies and programs. The latter part of the chapter describes the current state of natural gas vehicle and infrastructure technology, as well as codes and standards.

Global Market for NGVs

As of December 2009, there were more than 11 million natural gas vehicles in operation globally.[1] The use of natural gas as a road transport fuel currently accounts for 1 percent of total vehicle fuel consumption worldwide. The average growth rate in the number of NGVs between 2000 and 2009 was 28.7 percent, with Asia-Pacific ranking highest at +50.9 percent and North America ranking lowest at -0.1 percent (see Figure 1). This trend is expected to continue at an average rate of 3.7 percent per year to 2030, with most of the growth coming from non-OECD countries that already account for most natural gas use for on-road transportation. See Appendix B for a cross-jurisdictional analysis of NGV policies and programs.



Source: International Association for Natural Gas Vehicles (2010), "NGV by Region." Accessed June 2010.

FIGURE 1 Average NGV Growth by Region Since 2000

Canadian Context

With assistance from federal and provincial research programs, demonstration projects, and NGV market deployment programs during the 1980s and 1990s, the population of light-duty NGVs grew to over 35,000 by the early 1990s. This assistance resulted in a significant adoption of natural gas transit buses as well. The NGV market started to decline after 1995, eventually reaching today's vehicle population of about 12,000.[2] This figure includes 150 urban transit buses, 45 school buses, 9,450 light-duty cars and trucks, and 2,400 forklifts and ice-resurfacers. The total fuel use in all NGV markets in Canada was 1.9 petajoules (PJs) in 2007 (or 54.6 million litres of gasoline litres equivalent), down from 2.6 PJs in 1997. Public CNG refuelling stations have declined in quantity from 134 in 1997 to 72 today. There are 22 in British Columbia, 12 in Alberta, 10 in Saskatchewan, 27 in Ontario, and 1 in Québec. There are only 12 private fleet stations.[3]

[1] International Association for Natural Gas Vehicles (2010), "Natural Gas Vehicles Statistics," http://www.iangv.org/tools-resources/statistics.html.

[2] International Association for Natural Gas Vehicles (2010), "Natural Gas Vehicles Statistics," http://www.iangv.org/tools-resources/statistics.html.

[3] Marbek (March 2010), "Study of Opportunities for Natural Gas in the Transportation Sector."

Several factors have led to the decline of the Canadian NGV market since the 1990s:

- The price advantage of natural gas over gasoline and diesel in Canada eroded after world oil prices collapsed;
- Vehicle costs increased as vehicle modifiers added technology to meet tighter vehicle exhaust emission requirements;
- R&D support to NGVs diminished in the 1990s;
- Public refuelling station use declined as the number of new NGVs decreased, which led to a deterioration of refuelling station revenues and station closings;
- There was a limited choice of factory-made NGV models available; and
- The restrictive regulation of the natural gas distribution industry limited non-core business activities, including NGV business development activities, following industry deregulation.

Current Support in Canada

There is little remaining federal support for natural gas in transportation, apart from the continuing exemption from the excise tax on fuels (10¢/litre on gasoline and 4¢/litre on diesel). However, as the fuel tax chart (Figure 7) in Chapter 4 indicates, the combination of the exemptions from excise and provincial fuel taxes for natural gas constitutes a substantial price advantage.

Québec's 2010 budget increased the capital cost allowance rate for freight hauling trucks and tractors, with additional deductions for LNG-fuelled trucks. British Columbia's *Clean Energy Act*, introduced in May 2010, includes a provision that could be used to support NGVs. Within the private sector, natural gas distribution utilities continue to provide a range of services and, in some cases, financial support that is recovered through gas sales to fleet end-users. However, these utilities are now limited in terms of the activities they can undertake due to the restrictions within the regulated business model under which they operate.

U.S. Market for NGVs

Similar to Canada, the United States has implemented various NGV initiatives and programs since 1980 but has had limited success in sustaining the market. There were 105,000 NGVs in operation in 2000; this figure peaked at 121,000 in 2004, and decreased to 110,000 in 2009.[4] At the federal level, vehicle tax credit and fuel incentive policies have provided assistance over the past five years, and the NGV industry is currently working to secure extensions of these measures. In California, a lead state in NGV deployment, LNG and CNG use in heavy-duty trucks and buses has grown in response to the state's aggressive clean air policies.

Current Support in the United States

The U.S. federal government and some state governments continue to support NGVs through vehicle and station incentives and tax credits. The need to reduce dependency on oil imports is an important policy driver in the United States. The recent expansion in domestic natural gas production is one of the reasons that Congress is currently considering renewing and strengthening NGV incentives.

[4] International Association for Natural Gas Vehicles (2010), "Natural Gas Vehicles Statistics," http://www.iangv.org/tools-resources/statistics.html

At the federal level, several key incentives have either recently expired or are about to expire. These include an excise tax credit for CNG and LNG; tax credits for the purchase of a new, dedicated, repowered, or converted alternative fuel vehicle; and an income tax credit for refuelling equipment. Additional programs at the federal level include:

- The Department of Energy's Clean Cities Program, a government-industry partnership that announced 23 cost-share grants (10 related to natural gas), which totalled $13.6 million in 2009.
- The National Renewable Energy Laboratory's April 2010 request for proposals regarding the development of natural gas engines and vehicles. The solicitation includes the potential for $14.5 million in funding for engine development, chassis integration, and demonstration of on-road products.

Infrastructure Technology Readiness

Canada has one of the most extensive natural gas pipeline distribution networks in the world, delivering this resource from Western Canada and the East Coast offshore to markets in the United States and across Canada. The expansion of this pipeline network over the past 30 years has led to increased use of natural gas in North America. The reach of the network, the attractive price of natural gas, and its emission reduction benefits provide an opportunity for the transportation sector to increase its use of this fuel.

In some major transportation corridors, natural gas trunk pipelines coincide with major highways, rail lines and even waterways. Natural gas refuelling stations can be located along these corridors to serve the trucking industry, and in some cases could use high-pressure pipeline gas to reduce the cost of providing CNG. In urban areas such as Toronto and Vancouver, there are already approximately 50 CNG public stations serving light- and medium-duty vehicles, as well as a smaller number of private fleet refuelling facilities.

Currently there are no fuelling facilities that provide LNG to vehicles on a regular basis. LNG is available at three locations in Canada where there are peak-shaving plants operated by natural gas utilities. It appears that these facilities may have some excess LNG capacity that can be diverted to transportation markets; two of the utilities[5] are in the process of securing approvals from regulators to allow this use. If the demand for LNG in specific vehicle applications develops as envisioned in this Roadmap, this fuel could be manufactured from pipeline gas or sourced from LNG import terminals such as Canaport in Saint John, New Brunswick. It could then be transported in LNG tanker trucks, rail cars or marine vessels to be distributed to refuelling facilities. LNG can also be vaporized (gasified) and pressurized at a refuelling facility to provide CNG.

Natural gas, for use as a transportation fuel in either CNG or LNG form, is typically sold to the end-user in one of three ways:

- **"Do-It-Yourself"** — End-users can purchase natural gas from a utility or gas marketer (delivered by a utility) and source the fuelling station equipment separately. The end-users invest their own capital to install a refuelling station and access a service provider to maintain the station equipment on a contract or fee basis. However, the customers are expected to develop specifications, build, and operate the CNG or LNG fuelling station equipment themselves.
- **"Utility Package"** — Gas utility companies deliver and sell natural gas and may also provide fuelling infrastructure. Under this model, normal distribution services can be expanded to make the product usable as a vehicle fuel. The utility provides compression/dispensing systems for CNG or storage/dispensing systems for LNG. It may also provide support in developing specifications or building/operating the system in return for natural gas at special rates.
- **"Third-Party Service Provider"** — Companies such as Clean Energy build, operate, and maintain end-user fuelling stations and facilitate the purchase of natural gas on a long-term contract basis.

[5] Terasen Gas has obtained approval to sell LNG into the transportation market from its plant in the port area of Vancouver. Gaz Métro is in the process of obtaining similar approvals for its Montreal peak-shaving LNG plant. A third peak-shaving LNG facility in Northern Ontario is owned by Union Gas. If, in the future, LNG plants are built to export natural gas to overseas markets, LNG could also be sourced from those plants.

Several Canadian companies are suppliers of natural gas fuel delivery, compression, storage, and dispensing equipment.

Vehicle Technology Readiness

There are two types of NGVs available to end-users: 1) retrofitted vehicles (also called conversions), and 2) those developed specifically by original equipment manufacturers (OEMs), and delivered to customers as factory-built vehicles. Aftermarket vehicle conversions fall under provincial jurisdiction in Canada. Industry must take care to ensure that only high-quality and low-polluting vehicle conversion technologies are offered to the market. OEM vehicles must comply with Transport Canada regulations.

Dedicated NGVs are designed to run only on natural gas, while bi-fuel NGVs have two separate fuelling systems that enable the vehicle to use either natural gas or a conventional fuel (gasoline or diesel), but not both fuels at the same time. In general, dedicated NGVs demonstrate better performance and have lower emissions than bi-fuel vehicles because their engines are optimized to run on natural gas. In addition, the vehicle does not have to carry two types of fuel, thus reducing weight and allowing increased cargo capacity.

There are two engine technologies that can be used to power natural gas vehicles: spark-ignited (SI) engines use the same combustion cycle as gasoline engines, while compression ignition (CI) engines are based on the diesel cycle. While CI engines tend to have a higher overall efficiency than SI engines, their higher acquisition costs tend to make them more suited for large fuel consumption applications.

For cars and light-duty trucks, there are no factory-produced (OEM) products available in Canada, although GM is now offering two cargo vans with dedicated natural gas fuel systems installed by a third-party converter. Ford has announced that it will make at least one natural gas "prepped" engine available to upfitters in the near future. A number of small- and medium-capacity vehicle upfitters serve the U.S. market by converting mostly new gasoline light-duty vehicles to natural gas at an incremental price in the range of $12,000 to $15,000.

The natural gas vehicle industry in Canada includes a number of companies whose natural gas vehicle- and station-related products and services are exported to NGV markets around the world. These include:

- Alternative Fuel Systems (alternative fuel automotive components)
- Cummins Westport (CNG/LNG engines)
- Dynetek Industries (lightweight CNG storage vessels)
- ECO Fuel Systems (CNG vehicle conversion systems)
- Enviromech Industries (modular vehicle fuel storage systems)
- FTI International Group (CNG dispensers and stations)
- IMW Industries (oil-free CNG compressors, dispensers and stations)
- Kraus Global (CNG dispensers)
- Powertech Labs (cylinder testing and certification)
- Saskatchewan Research Council (neural control and dual-fuel technologies)
- Viridis Technologies (CNG dispensers and RFID systems)
- Westport Innovations (LNG engine systems)
- Xebec Adsorption (natural gas dryers and biogas upgrading equipment)

Medium- and heavy-duty natural gas engines are available as options from an estimated 15 North American truck and transit bus manufacturers at an incremental cost of $35,000 to upwards of $60,000. However, there are currently a limited number of models available to end-users, which include:

- SI engines that are fuelled purely by natural gas and can serve the medium- and heavy-duty engine market; and
- Higher-horsepower heavy-duty engines that use dual-fuel injectors to initiate combustion with a small amount of diesel fuel, followed by the main injection of natural gas — these engines typically use 95 percent or more natural gas.

To maximize driving range for heavy-duty trucks, the preferred way to store natural gas onboard is in its denser liquid form (LNG) in cryogenic stainless steel tanks. These tanks are costly to manufacture and account for a significant share of the incremental cost of natural gas trucks. CNG can also be used as a fuel for heavy trucks, depending on the fleet's range requirements and duty cycle. Transit buses typically use several roof-mounted fibre-wound tanks to store compressed gas (CNG), while medium-duty trucks use one or more chassis-mounted tanks (CNG). The main reason for using natural gas in its compressed form is that it is widely available by installing compression equipment wherever there is pipe in the ground based on Canada's gas distribution system. In addition, there are some operational differences between CNG and LNG as vehicle fuels that may determine which form of the fuel is selected for use by a fleet.

LNG has been used successfully in trucking demonstrations in Canada, but general commercial uptake has not yet occurred, even though the main suppliers of the engine technologies are based here. However, there has been some uptake in markets such as California and parts of Australia and China. Significant LNG use by the trucking industry would require an expansion of existing fuelling facilities and construction of new LNG plants specifically to serve this market.

Codes and Standards

As new technologies are developed, there is a need for concurrent development of related design/safety codes and standards. During the 1990s, significant work was done to develop codes, standards and regulations for CNG storage for use onboard vehicles, as well as those pertaining to dispensing and refuelling infrastructure.[6] Over the last decade, however, due to a decrease in demand for NGVs, the relevant codes and standards committees have grown dormant. There are currently no codes, standards or regulations in place in Canada that specifically address LNG vehicles, refuelling stations, and fuel supply. The lack of harmonized codes and standards across Canadian jurisdictions, as well as in the United States, is an additional barrier to NGV market penetration.

What are CNG and LNG?

In transportation applications, natural gas is used as either CNG or LNG. The goal of creating CNG or LNG is to increase the density of the fuel to get more energy onboard the vehicle, which increases its driving range.

CNG is formed by compressing natural gas to high pressures in the range of 3,000 to 3,600 pounds per square inch (psi). Compression reduces the volume by a factor of 300 (or more) compared with gas at normal temperature and pressure. It is stored in steel or fibre-wound cylinders at high pressures (3,000 to 3,600 psi). Onboard an NGV, the gas travels through a pressure regulator and into a spark-ignited or compression ignition engine.

LNG is made by cooling the natural gas temperature to -162°C. The liquefaction process reduces the volume by a factor of 600 compared with gas at normal temperature and pressure. The LNG is stored on vehicles in a double-walled stainless steel tank and vaporized before injection into the engine.

Conclusion

Mature, cost-effective, market-leading natural gas technologies are available from Canadian suppliers for fuel delivery, compression, storage, dispensing, and medium- and heavy-duty engine applications. These technologies are exported to many countries, but sales in Canada have been limited in recent years. Natural gas refuelling infrastructure is available in some major urban markets but overall is limited in quantity. LNG supply for vehicles is limited and will need to be expanded if the market potential in heavy-duty vehicles is to grow beyond a few demonstration projects. While a number of codes and standards are available to cover CNG fuelling stations and vehicle conversions, LNG codes and standards for transportation applications have yet to be fully developed.

[6] As part of this Roadmap, a complete listing of codes and standards was assembled.

ANALYSIS

Chapter 4

Natural Gas Fundamentals

Canada is the world's third-largest producer and exporter of natural gas. As part of a fully integrated and continental natural gas market, Canada moves its natural gas resources seamlessly across provincial and national borders, from supply basins to demand centres. Regional prices reflecting market forces, including transmission costs, are established within this market. This chapter provides further detail on natural gas supply and demand outlooks, as well as taxation and environmental implications related to the extraction process.

Natural Gas Supply Outlook

The North American natural gas supply portfolio is shifting from one dominated by conventional reservoirs in sandstone or carbonate rock to one dominated by unconventional resources, particularly natural gas from shale, or shale gas. Shale deposits holding significant amounts of natural gas are widely spread across North America. Until recently, this natural gas was difficult to extract, since the gas does not readily flow into wells drilled by conventional methods. Technological advancements in areas such as horizontal drilling and multi-stage hydraulic fracturing now permit economic extraction of this resource in many areas. See Figure 1 for an explanation of shale gas extraction technology.

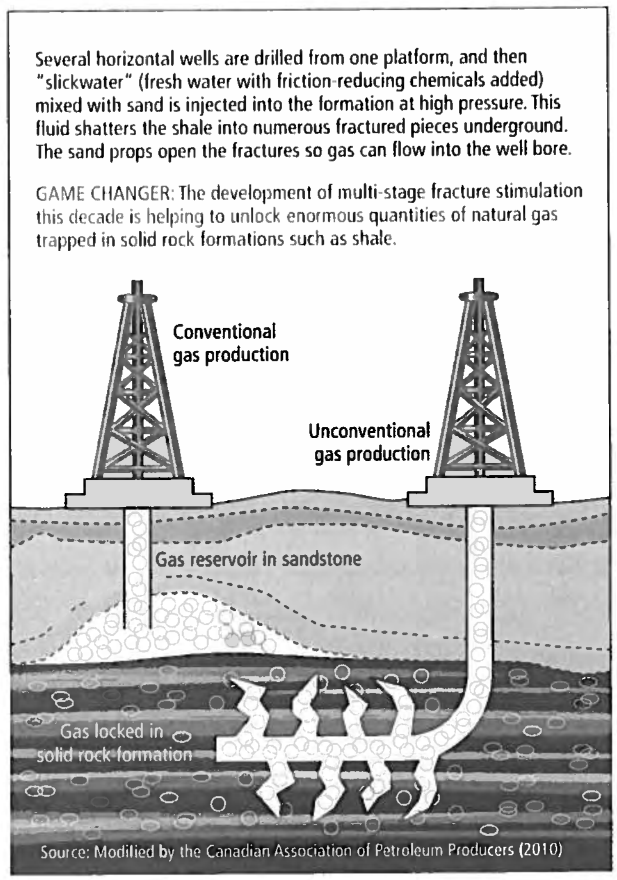


FIGURE 1 Shale Gas Extraction Technology

Technological advancements in areas such as horizontal drilling and multi-stage hydraulic fracturing now permit economic extraction of this resource in many areas.

FIGURE 2 Shale Gas Deposits in North America

Only a few years ago, natural gas production in North America was forecast to decline steadily as conventional reservoirs were being depleted. More recent forecasts, taking into account shale gas and coal-bed methane, have changed the outlook to increasing North American natural gas production for the foreseeable future. Shale gas development began in Texas with the Barnett shale and quickly spread throughout the United States and more recently into Canada.

Shale deposits cover much of the Western Canadian Sedimentary Basin and are also present in Ontario, Québec, New Brunswick, and Nova Scotia. Commercial development in Canada is currently focused in the Horn River Basin and Montney formation in north-eastern British Columbia. Figure 2 shows some of the other shale gas deposits that are spread across the continent; each area has unique geological and geographical characteristics that affect extraction costs. Even at today's low natural gas prices, production is already economically sustainable in many locations. Incremental improvements in drilling techniques, such as longer horizontal wells and increases in the number of fracturing stages, should bring other fields into economic range in the future. Figure 3, which presents one view of North American natural gas supply costs, shows that there is a large amount of supply available, even at today's relatively low natural gas prices.

Natural Gas Price Outlook

The rate at which natural gas is developed depends not only on extraction technology and cost, but also on anticipated market prices for natural gas. Higher market prices encourage more natural gas development, but if prices rise too high, they dampen demand from industrial and commercial gas users, some of whom have fuel-switching capability. Current natural gas prices are attractive to users given the relatively higher prices of oil products and electricity and the robust natural gas supply picture. Figure 4 highlights the substantial forecasted price differential between crude oil and natural gas on a barrel-of-oil equivalent (BOE) basis for the years 2011 to 2015. The price differential between natural

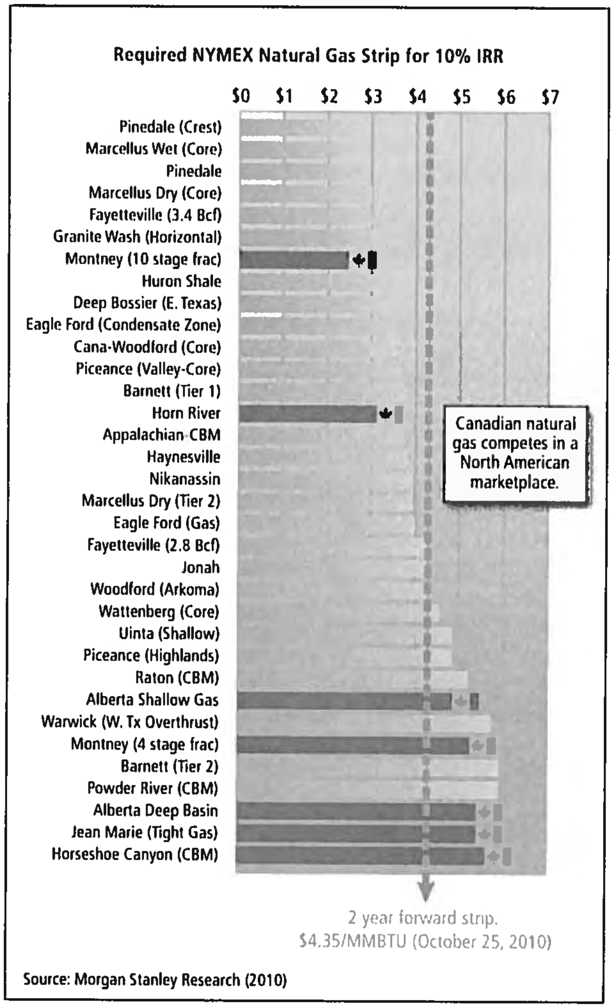


FIGURE 3 North American Natural Gas Supply Costs

gas and crude oil is expected to remain steady, according to industry estimates based on go-forward natural gas pricing contracts through 2015. This trend should go a long way towards satisfying end-user concerns about the future price of natural gas versus crude-derived fuels. Increases in natural gas demand in the transportation sector could have some inflationary effect on natural gas prices; however, this effect is likely to be minor, since gas volumes going into transportation will be relatively small in comparison with the main markets for natural gas in the industrial, power generation, commercial, and residential sectors, and given the robust supply context.

The final price of natural gas for transportation end-users is the sum of the unregulated producer price, regulated pipeline tariffs, certain taxes (in Canada, either Goods and Services Tax/Harmonized Sales Tax or Québec Sales Tax, depending on the province), local distribution charges, liquefaction and/or compression costs, plus retail margin if infrastructure is not owned by the end-user. The natural gas value chain is summarized in Figure 5. For transportation users, the charges for storage and dispensing of compressed and liquefied gas at transport terminals and fleet yards can be a significant component of the final gas price. The respective roles of producers, brokers, and marketers in serving large road transport fleets, as well as rail or marine markets, have yet to be determined and may differ by province. Depending on the availability of services, the end-user may pay a price for natural gas that includes certain services such as rental of compression and dispensing equipment, or amortized incremental cost of vehicles. Smaller fleets may purchase natural gas at a cardlock facility shared by other users, while larger fleets may negotiate a unique contract price. Whatever the arrangement, it appears that there is scope for attractive prices for fleets and other bulk users.

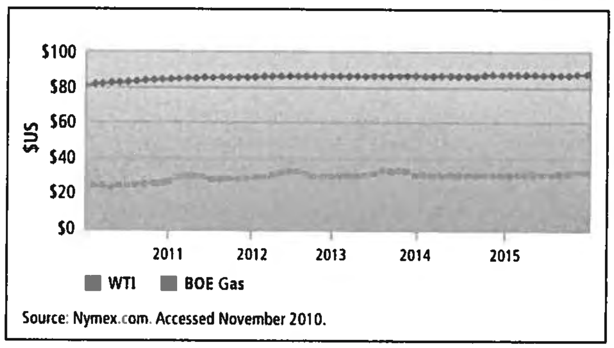


FIGURE 4 NYMEX Futures Prices: WTI vs. Natural Gas (Barrel-of-Oil Equivalent)

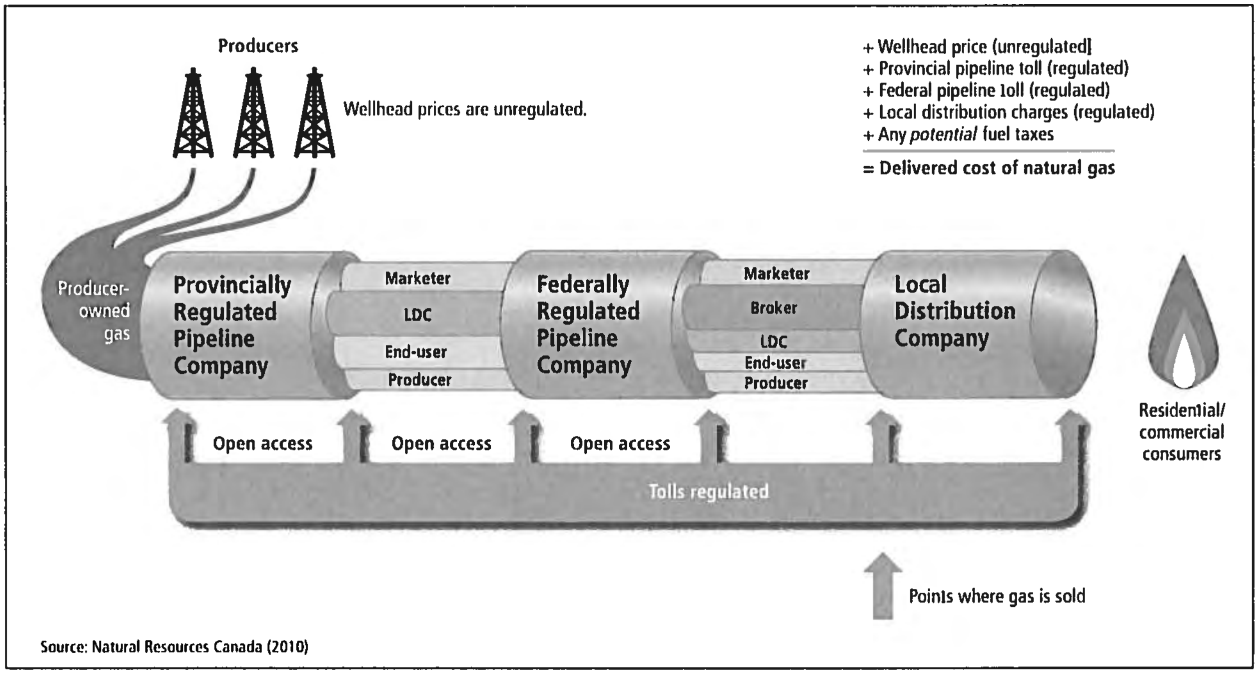


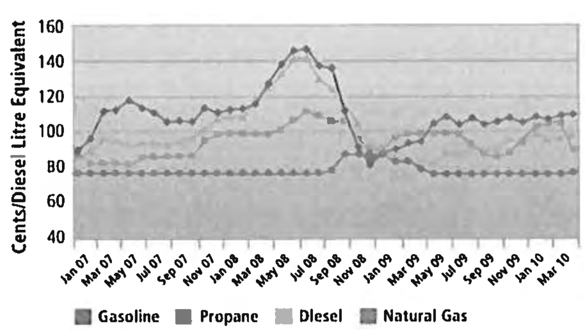
FIGURE 5 Natural Gas Value Chain

For transportation users, particularly truck fleets, the cost of fuel is a major concern. The prospect of a significant or growing natural gas-to-diesel price differential is attractive to all stakeholders. To justify initial investments in new equipment, end-users would like some assurance that compressed or liquefied natural gas prices will be predictable and stable. Figure 6 shows recent fuel prices, based on a survey at retail filling stations in Toronto. While natural gas prices appear to be relatively low and stable, this could be a consequence of how few retail filling stations exist. If the natural gas for vehicles market were to grow significantly, increased competition among a greater number of retail filling stations could result in more price movement.

Contract gas prices for in-yard fleet fuel deliveries can be lower than those in the chart. Since truck fleet and other large end-users are accustomed to delivery and storage prices for diesel amounting to just a few cents per litre, there is likely to be pressure on natural gas suppliers to reduce the gap between wholesale and delivered compressed and liquefied natural gas. While there are good reasons for higher prices for delivered natural gas, based on the different fuelling equipment, storage tanks, and code requirements, there should be some room for cost and margin reductions as natural gas volumes grow.

Role of Taxation

Part of the price advantage of natural gas for transportation is that it is taxed at a lower rate than diesel and gasoline. While this tax treatment gives an advantage to natural gas as a transportation fuel in the short term, if natural gas usage grows to the point that it significantly constrains fuel tax revenues, there could eventually be pressure for natural gas to be taxed by provinces and the federal government at similar rates to diesel fuel. However, preferential tax treatment would help further develop this market.



Source: Natural Resources Canada (2010)

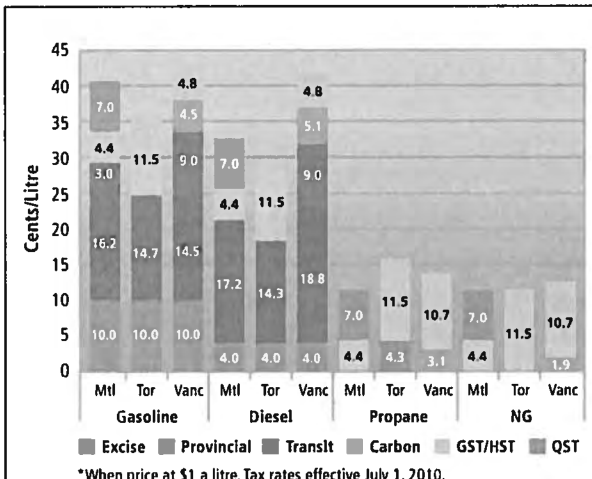
FIGURE 6 Toronto Fuel Prices Including Taxes

Environmental Outlook

Natural gas can provide an advantage for companies that are investing in GHG emission reductions, as conventional natural gas vehicles emit about 20 to 30 percent less carbon on a well-to-wheels basis compared with diesel or gasoline. Both conventional and unconventional raw natural gas require processing to remove impurities, including CO_2. The CO_2 content of shale gas, for example, varies considerably by deposit. In Canada, the approximate range of CO_2 content of shale gas is anywhere from less than 1 to 12 percent. Since some shale gas contains more CO_2 than conventional gas, mitigation methods will need to be developed for high-CO_2 shale formations.

When considered along with the GHG impact of the final combustion of natural gas, the upstream contributions are relatively small, and differences between conventional and unconventional natural gas represent, at most, 3 percent of the total GHG footprint. Further analysis in this area is warranted, but such work is beyond the scope of this Roadmap.

Concerns have been raised surrounding the environmental impact of shale gas development, particularly with respect to water usage and potential impact on water quality. These issues have received more attention in the United States than in Canada, as shale gas development is further advanced and takes place on a larger scale there. In Canada, most aspects of shale gas development fall under provincial jurisdiction and are subject to stringent regulation and enforcement specifically designed to protect Canada's environment and water resources. Evolving drilling technology improvements and improvements in water treatment and recycling continue to help reduce the overall impacts of shale gas development.



Source: Natural Resources Canada (2010)

FIGURE 7 Fuel Tax Comparison by City

Biogas and Biomethane

Biogas is readily available and is derived from landfills and sewage treatment, and through the anaerobic digestion of waste from municipal and agricultural sources. Established technology exists that can be used to upgrade biogas to pipeline-specification renewable natural gas, which is also known as "biomethane." Biomethane is a renewable fuel that provides significant GHG reduction benefits.[1] The displacement of a carbon positive fuel such as natural gas through the use of this fuel results in a net reduction of GHG emissions. Biomethane is considered carbon neutral, since it is derived from methane that would otherwise be released into the atmosphere. Biomethane is already being used in vehicles in North America, such as in fleets of garbage compactors that can conveniently refuel at landfill sites. In locations close to natural gas pipelines, biomethane can be injected into the pipeline for distribution. This renewable gas can then be managed and marketed to end users anywhere on the distribution grid and sold in a blend with fossil gas to meet end user needs.

Conclusion

The outlook for natural gas has changed significantly, from gradually declining natural gas production to rapidly growing production, enabled by drilling technology advances that allow producers to tap into huge unconventional resources distributed across Canada and North America more broadly. The production of much of this natural gas is economically sustainable at prevailing natural gas prices and at expected future prices, and therefore the outlook is for fairly stable or slow growth in market prices. It is anticipated that the price differential between natural gas and petroleum fuels will grow in future years, allowing natural gas to enter new markets. Biogas and biomethane are becoming increasingly available and can be used directly in stationary and transportation applications to achieve significant GHG benefits.

[1] Lifecycle GHG emissions from the production and use in heavy-duty vehicles of biomethane from landfills or anaerobic digestion are approximately 90 percent lower than GHG emissions from the use of diesel fuel. Source: "The Addition of Biomethane to GHGenius," (S&T) Consultants Inc, March 2009.

A N A L Y S I S

Chapter 5

Business Case Modelling

The objective of the business case analysis task was to examine the value proposition for natural gas as a fuel in various fleet applications to identify which applications have the strongest value proposition and greatest likelihood of being developed in an economically sustainable fashion, and demonstrate for the most promising applications that there is a strong underlying business case capable of generating a significant internal rate of return (IRR). The analysis focused on medium- and heavy-duty vehicles, since they were identified, through the working group's scoping analysis described in Chapter 2, as offering the greatest opportunities for increased natural gas use.

Value Proposition Analysis

1) Model Description

Change Energy Incorporated conducted the value proposition analysis using its proprietary lifecycle costing model, which was used to calculate costs over a 10-year period for NGVs, with diesel vehicles as a comparative baseline. The results of the analysis are summarized by a measure known as a Fuel Value Index (FVI), which combines all incremental operating and capital costs, as well as any differences associated with engine efficiencies and operating practices. The model allows all costs associated with natural gas use to be consolidated and reflected in a cost-per-diesel-litre equivalent (DLE). This comprehensive approach to total cost of ownership allows for a direct, all-in comparison with diesel fleet ownership costs on an energy equivalent basis and goes beyond simple payback measures to consider all operational costs.

Fuel Value Index (FVI): A measure that allows all costs associated with natural gas use to be consolidated and reflected as a cost-per-diesel-litre equivalent as used in the business modelling. For those vehicle applications with FVI values greater than 1, the value proposition for natural gas is equivalent to or better than that for a comparable diesel fleet.

2) Model Inputs – Jurisdictions and End-Use Applications

To conduct this work, a steering group with representation from each of the Roadmap working groups was formed to develop the statement of work, provide advice to the consultant regarding model inputs and assumptions, and review the results. As a first step, four provinces (British Columbia, Alberta, Ontario, and Québec) were chosen for the modelling based on the likelihood that they could support market launch and early development. The selection was based on a weighted evaluation of the following parameters:

- Existence of natural gas distribution infrastructure (e.g. local and transmission);
- Existence of LNG infrastructure and proximity to potential market;
- Existence of natural gas refuelling stations (public and private);
- Transportation fuel demand for medium- and heavy-vehicles in local area; and
- Identification of supportive policies and programs.

To ensure the integrity of the modelling results, a separate sensitivity analysis was conducted to assess the impact of a range of projected fuel price differentials on the business case.

Based on input from the End-User Working Group, 13 vehicle end-use applications were modelled. An end-use application was defined not only as a type of vehicle (e.g. tractor versus truck), but also by the way in which the vehicle is refuelled (e.g. public corridor versus private onsite station) and how the vehicle is used (e.g. highway goods movement versus urban distribution of goods). Only vehicles operating in return-to-base and regional corridor fleets were considered for the analysis, since the business case for natural gas hinges on amortizing the cost of the refuelling station over projected fuel volumes. It was assumed that all LNG applications used the Westport system, and all CNG applications used the Cummins Westport engine. This arbitrary distinction was made to simplify the number of modelling scenarios. In addition, the low-mileage applications were assumed to be CNG applications. In reality, a fleet's selection of a CNG or LNG vehicle would depend on a number of factors.

3) Model Inputs – Commodity Price Forecasts

Projected commodity pricing for natural gas and diesel fuel were key inputs for the modelling. While only a single set of forecasted values for each fuel could be incorporated in the analysis, it was recognized that there are a range of credible third-party fuel price forecasts. To ensure the integrity of the modelling results, a separate sensitivity analysis was conducted to assess the impact of a range of projected fuel price differentials on the business case. Further details regarding the results of this sensitivity analysis are included later in this chapter.

Two publicly available forecasts of long-term oil and natural gas pricing (GLJ and Sproule) were considered for the model. When plotted against each other, the forecasts were reasonably similar in expectations about future energy prices. For both oil and gas, the difference in 2020 prices

TABLE 1 Data from Sproule Forecast

YEAR	OIL 40° AMERICAN PETROLEUM INSTITUTE $/Bbl EDMONTON PAR	INFERRED DIESEL PRICE BY JURISDICTION ($/Litre) B.C.	ALBERTA	ONTARIO	QUÉBEC	NATURAL GAS $/mmbtu AB – AECO
2010	79.12	1.082	0.849	1.022	1.042	4.32
2011	86.34	1.181	0.926	1.115	1.137	4.50
2012	88.57	1.211	0.950	1.144	1.166	4.98
2013	90.69	1.240	0.973	1.171	1.194	6.00
2014	94.67	1.294	1.015	1.222	1.246	7.75
2015	96.1	1.314	1.031	1.241	1.265	7.88
2016	97.55	1.334	1.046	1.260	1.284	8.01
2017	99.02	1.354	1.062	1.279	1.304	8.14
2018	100.52	1.374	1.078	1.298	1.323	8.27
2019	102.03	1.395	1.094	1.317	1.343	8.41
2020	103.57	1.416	1.111	1.337	1.364	8.55
2021 (extrapolated)	104.95	1.435	1.126	1.355	1.382	8.68

Source: Change Energy Inc. (2010)

between the two forecasts was significantly less than 10 percent. These two forecasts were also compared to and found to be quite similar to forecasts produced by other consulting firms. Based on a review of the various forecasts, members of the Natural Gas Fundamentals Working Group, which included representatives of the upstream natural gas industry and Natural Resources Canada, recommended the Sproule forecast for natural gas pricing. Similarly, it was recommended that the Sproule forecast be used for diesel forecasting to provide information on projected crude oil pricing. Based on the historic relationship between diesel prices and crude oil prices, a factor was derived for each jurisdiction to develop projected diesel prices. Values incorporated in the model are shown in Table 1.

Inputs to the Modelling – Vehicle, Station, Fuel, and Operating Costs

The elements of cost that are incorporated in the FVI are: 1) delivered cost of natural gas via pipe, 2) cost to liquefy or compress gas, 3) truck delivery of LNG, 4) applicable taxes, 5) incremental capital cost for vehicles, 6) incremental operating and maintenance cost for vehicles, 7) capital cost for station sized to meet total fleet fuel demand, 8) incremental operating and maintenance cost for station, 9) cost of training personnel, 10) opportunity cost associated with additional fuelling time where applicable, and 11) residual value impact. These various cost elements can be broadly categorized into fuel-related costs and vehicle-related costs. Figure 1 provides a comparison of fuel-related costs for three return-to-base end-use applications.

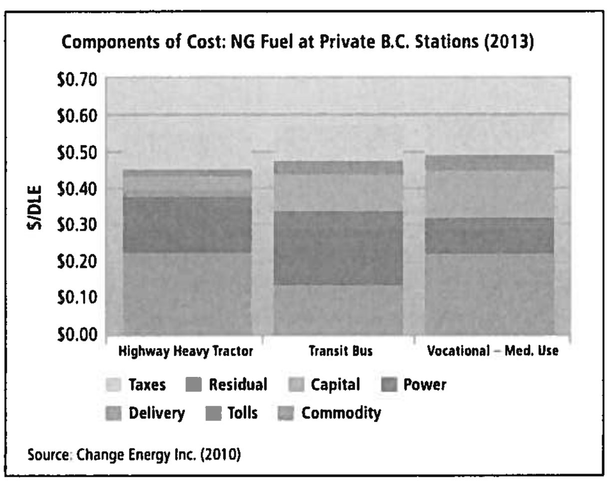


FIGURE 1 Components of Cost: Natural Gas Fuel at Private B.C. Stations

TABLE 2 Comparison of Fuel and Vehicle-Related Costs

	HIGHWAY HEAVY TRACTOR	TRANSIT BUS	VOCATIONAL – MEDIUM USE
Station capital cost	$0.820 million	$1.6 million	$0.545 million
Fleet size	Small – 30	Small – 35	Small – 25
Annual mileage per vehicle	200,000 km	55,000 km	30,000 km
Annual fuel use	2,220,000 DLE	1,160,000 DLE	325,000 DLE
Vehicle-related costs ($/DLE)	$.235/DLE	$.538/DLE	$1.404/DLE
FVI for given year	1.58	1.02	0.56

Source: Change Energy Inc. (2010)

Assumptions

- LNG for highway heavy tractor; CNG for all other.
- Assumed 1 diesel litre (DLE) = .969 m^3 natural gas on an energy equivalency basis.
- Tolls include transmission and local delivery charges plus cost to liquefy for LNG.
- "Delivery" refers to delivery via tanker truck, which applies to LNG only.

Fuel-related costs are driven by fleet size, fuel consumption, and station scale assumptions. Medium-use vocational trucks have the highest capital component in their fuel-related costs, as station capital is amortized over a relatively few number of vehicles (25) that travel only 30,000 km per year per vehicle. For vehicle-related costs, vehicle incremental and operating costs have been aggregated and calculated on a DLE basis. By adding the fuel-related costs per DLE to the vehicle-related costs per DLE, the total cost of ownership for natural gas can be calculated and compared with projected diesel pricing. This information is then used to determine the FVI value for that application (see Table 2).

TABLE 3 Application Ranking Table

APPLICATION	FLEET SIZE	MILEAGE (km/YEAR)	RANK	COMMENTS (FVI RANGE)
LNG Highway Heavy Tractor RTB	Large – 200	200,000	1	Very Good 1.01–1.63
LNG Urban Heavy Tractor RTB	Large – 200	140,000	2	Very Good 0.90–1.45
LNG Highway Heavy Tractor COR	Large – 200	200,000	3	Very Good 0.89–1.43
CNG Transit Bus RTB	Large – 150	55,000	4	Very Good 0.84–1.29
CNG Refuse – Private RTB	Large – 100	30,000	5	Good 0.70–1.04
CNG Urban Heavy Tractor RTB	Large – 200	60,000	6	Good 0.70–1.03
CNG Vocational – High Use RTB	Large – 100	50,000	7	Fair 0.65–1.01
LNG Port Drayage RTB	Large – 200	60,000	8	Fair 0.63–1.03
CNG Refuse – Public RTB	Large – 100	20,000	9	Weak 0.48–0.85
CNG Vocational – Medium Use RTB	Large – 100	30,000	10	Weak 0.45–0.74
CNG School Bus RTB	Large – 100	15,000	11	Very Weak 0.31–0.61
CNG Port Drayage RTB	Large – 200	20,000	12	Very Weak 0.31–0.57
CNG Vocational – Low Use RTB	Large – 100	15,000	13	Very Weak 0.23–0.46

Ranking categories relative to average FVI values:
FVI > 1.05 Very Good
FVI > 0.85 but < 1.05 Good
FVI > 0.75 but < 0.85 Fair
FVI > 0.60 but < 0.75 Weak
FVI > 0.60 Very Weak

The fleet sizes and mileage assumed for the above applications were used for modelling purposes and may vary among fleets.
Source: Change Energy Inc. (2010)

Modelling Results

Of the applications modelled, four applications were found to have average FVI results that were equal to or better than 1, which suggests that the value proposition for natural gas is equivalent to or better than that for a comparable diesel fleet over the 10-year time frame considered. Rankings for all applications modelled are shown in Table 3. The top four end-use applications in order of ranking were:

1. LNG highway tractors refuelling at a private onsite station (return-to-base);
2. LNG return-to-base urban tractors;
3. LNG highway tractors refuelling at public stations on highway corridors; and
4. CNG return-to-base transit buses.

An additional four applications reached an FVI greater than 1 by the end of the 10-year period, which suggests that there is a business case, but that the time frame for payback may be quite lengthy.

5. CNG return-to-base refuse haulers — private ownership;
6. CNG return-to-base urban tractor;
7. CNG return-to-base vocational trucks; and
8. LNG return-to-base port drayage trucks.

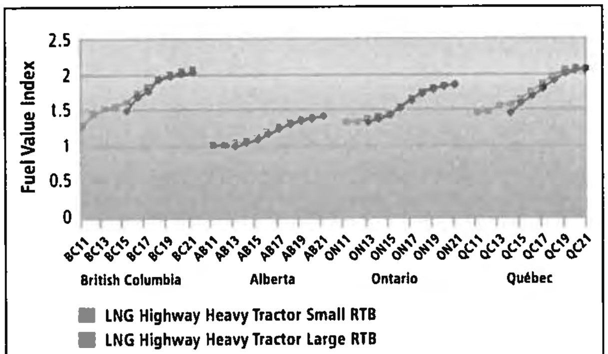
The FVI results are significant, since they indicate that there are medium- and heavy-duty NGVs that have strong value propositions and can be economically self-sustaining if the barriers to market adoption are addressed. Other applications were less attractive on the basis of economics alone, as indicated by FVI values below 1 for the 10-year time frame modelled.

Natural gas use in heavy trucks is a particularly interesting opportunity, since there are some key regional trucking corridors in Canada where infrastructure could be well used by an existing high-demand market. Over the past decade, the structure of the trucking industry has swung increasingly towards return-to-base operations as opposed to long-distance hauling. In addition, CNG in transit buses had a very strong FVI. Although the economic case for buses is very good, the past negative experience of some transit properties with CNG buses must be overcome for this application to succeed. This issue was noted by transit end-users through the consultations described in Chapter 6.

Modelling Detail

The degree to which the FVI is greater than 1 indicates the degree that a natural gas option will offer greater economic value compared with a diesel fleet.[1] An FVI of less than 1 indicates that the value proposition is not as great for natural gas as it is for the diesel fuel baseline. Since costs of inputs can vary over the 10-year forecast period, the FVI changes in value over time. Thus, if the price differential between natural gas and diesel increases over 10 years, the FVI will also increase. Figure 2 illustrates the evolution of FVI values over time.

FVI values may also differ between provinces due to jurisdictional differences in key inputs such as diesel fuel pricing and the cost of electricity. For example, Alberta has lower diesel fuel prices than the other three provinces. The impact of this difference on the FVI is shown in Figure 2. FVI results for LNG applications are strongest in Québec and British Columbia, where LNG production infrastructure is already established, with utility-owned and -depreciated facilities. FVIs for LNG applications in Ontario and Alberta are relatively low, partly because of the additional costs associated with delivering LNG from the existing points of supply.[2] The model does not take into account the effect of new liquefaction facilities and the fuel supply capacity requirements that might eventually be required to support growing market demand. Incremental LNG supply from a new facility would have higher capital recovery costs, perhaps as much as $0.10 to $0.15/DLE higher[3] than current prices. However, higher capital costs may be partly offset if revenue is derived from other markets such as rail and marine freight, off-grid gas supply, "portable main" applications, and gas utility supply reinforcements. Both Alberta and Ontario have strong chemical industry capacity that could accommodate the establishment, operation, and use of LNG facilities.



Source: Change Energy Inc (2010)

FIGURE 2 FVI Results for LNG Highway Heavy Tractors by Jurisdiction (2011–2021)

[1] There are other non-economic factors, such as environmental or social goals, that may encourage a fleet to use natural gas even if the FVI is 1 or less.

[2] There is a liquefaction facility in Northern Ontario owned by Union Gas, but it was not included as a potential supply source for the Ontario market based on utility input.

[3] Based on analysis conducted by Encana Corporation.

The IRR values demonstrate that there is a strong business case, particularly for high-mileage applications that operate along corridors or in return-to-base fleets.

Business Case Analysis

As an alternative fuel, natural gas is relatively complex, since end-users must consider not only the costs and issues related to vehicles, but also refuelling infrastructure. The FVI modelling provided a way to incorporate all costs of ownership and compare the value propositions for a range of end-use applications.

The next step involved an analysis of the business case for each of the four most promising end-use applications. Given that the modelling demonstrated that these applications had a lower all-in cost of ownership than that of a comparable diesel fleet, the following questions needed to be addressed:

1. How significant was the business case, and could the most promising end-use applications compete for market capital based on their projected internal rate of return (IRR)?
2. For end-users, what was the payback on vehicle capital cost based on fuel savings, and would this payback fall within an acceptable range in term of tolerable levels of risk?

Table 4 provides both IRR values and payback estimates for the four highest-ranked end-use applications. Both five- and 10-year IRR values are shown to demonstrate savings that were not realized if the fleet chose to dispose of the vehicles after five years, which was identified as a common practice in major for-hire trucking fleets.

The IRR values demonstrate that there is a strong business case, particularly for high-mileage applications that operate along corridors or in return-to-base fleets. Capital investments can earn an attractive rate of return. Payback ranges varied depending on the scenario modelled, but in each case, payback values demonstrate that the incremental cost for natural gas would be recovered well within the vehicle's life.

TABLE 4 IRR Summary for "Very Good" Ranked End-Use Applications (British Columbia, 2011)

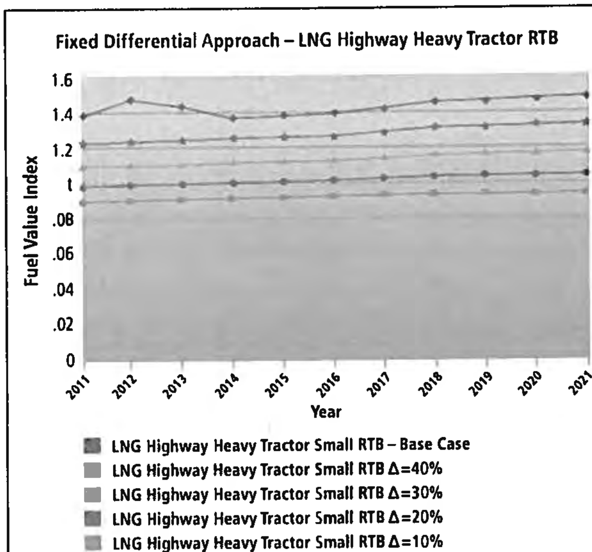
FVI RANKING	APPLICATION	FLEET SIZE	CAPITAL INVESTMENT	5-YEAR	10-YEAR	PAYBACK (YEARS)
1	LNG Highway Heavy Tractor (return-to-base) ($0.80 million station; $2.05 million vehicle increment)	30	$2.85 million	48%	58%	1.77
2	LNG Urban Heavy Tractor (return-to-base) ($4.13 million station; $13.66 million vehicle increment)	200	$17.79 million	18%	30%	3.10
3	LNG Highway Heavy Tractor (corridor) ($5.78 million station; $13.66 million vehicle increment)	200	$19.44 million	19%	32%	2.98
4	CNG Transit Bus (return-to-base) ($3.06 million station; $6.75 million vehicle increment)	150	$9.81 million	0%	13%	7.32

Source: Change Energy Inc. (2010)

Sensitivity Analysis

Sensitivity of the FVI results to key assumptions was tested by modelling 1) the effect of carbon credits, 2) the impact of a fiscal measure that reduced incremental vehicle cost by 50 percent, and 3) the potential for a lower projected differential in natural gas pricing compared with diesel pricing. Findings of this analysis are as follows:

- A carbon credit based on British Columbia's approach to carbon taxation had little benefit for low-mileage vehicles (typically driven less than 30,000 km/year), but high-mileage applications (typically greater driven more than 100,000 km/year) showed a 6 percent benefit by the end of the 10-year period. These findings indicate that the economic case for natural gas in the transportation sector is not dependent on pricing carbon, but would be further enhanced by the monetization of carbon.
- Measures that reduced the capital cost premium of a truck or bus by 50 percent had a significant impact on FVI values, increasing them from 6 to 20 percent, depending on the end-use application.
- The base modelling incorporated separate forecasts for each of natural gas and diesel fuel. The differential between these projected fuel costs varied from a range of approximately 45 percent in 2011 to 54 percent in 2021. To test the robustness of the business case against a range of potential fuel price scenarios, four scenarios were modelled using 40 percent, 30 percent, 20 percent, and 10 percent differentials between diesel fuel and LNG pricing. Key findings were that a minimum 20 percent fuel price differential would be needed for high-use vehicles such as LNG return-to-base tractors to be economic, while low-use vehicles would need a 30 to 40 percent fuel price differential. As Figure 3 indicates, LNG tractors that refuel at a private station had FVI values greater than 1 for all modelled scenarios except the 10 percent differential scenario.



Source: Change Energy Inc. (2010)

FIGURE 3 Impact of Varying Differential in Natural Gas and Diesel Pricing on FVI

The impact of factoring a range of projected differentials between natural gas and diesel pricing was also assessed for the IRR calculations for the four top-ranked end-use applications. Table 5 summarizes these findings.

Assumptions

- Base case for LNG applications assumed 45 percent differential with diesel in 2011 and 54 percent differential in 2021.
- Base case for CNG applications assumed less-than-optimal station utilization in early years, so differential values with diesel much less favourable.

Conclusion

The modelling results are intended for illustrative purposes only, and this work was undertaken to identify whether medium- and heavy-duty NGVs have positive value propositions, as well as the potential to be economically self-sustaining. In addition, the IRR analysis demonstrated that capital invested in the top-ranking end-use applications will generate an attractive rate of return. The potential for good rates of return stands up under a range of projected price differentials between natural gas and diesel fuel. Given the robustness of the overall business case, it is clear that natural gas can be an economically sound alternative for fleets of the right scale and in the right or "optimal" end-use applications.

The demonstrated favourable rates of return, combined with the lack of capital flowing to these opportunities, indicates that there are some underlying barriers that are limiting investment and uptake of medium- and heavy-duty natural gas vehicles. The barriers in the transit industry have already been mentioned, but there are other equally important issues that must be resolved for other markets to succeed:

- Of key importance to trucking operators is the residual value of an NGV at the end of its cycle, which is typically five to seven years. Will the vehicle need to be repowered to diesel before it is sold, or will there be a valuable market for used natural gas trucks?
- Can economies be realized by transferring high-value components such as dual-fuel injectors and cryogenic storage tanks from trucks being retired to new trucks?
- How quickly will the prices of natural gas components decrease as production volumes increase?
- Can the significant capital cost of new natural gas trucks and buses be easily accommodated within the existing financial structure of fleets?
- Can GHG emission reductions from the use of natural gas in vehicles be translated into monetary value for end-users?

These issues have technical and economic aspects that will need to be addressed through comprehensive information and education initiatives in order for the NGV market to develop successfully. Education and outreach is discussed in Chapter 7. Other issues that were not quantified in the economic analysis can be important to end-users. One example is the low noise of natural gas engines compared with diesel, and this issue is important in the transit, port drayage, and refuse hauling markets. Also, some urban fleets may be able to use biomethane produced from local waste sources. A triple bottom line analysis[4] may be conducted to account for such environmental and social factors and their potential benefits to end-users.

TABLE 5 Ten-Year IRR Summary with Sensitivity Analysis (British Columbia, 2011)

FVI RANKING	END-USE APPLICATION	BASE CASE	40%	30%	20%	10%
1	LNG Highway Heavy Tractor (return-to-base)	58%	50%	39%	28%	16%
2	LNG Urban Heavy Tractor (return-to-base)	32%	30%	22%	14%	4%
3	LNG Highway Heavy Tractor (corridor)	32%	29%	22%	14%	5%
4	CNG Transit Bus (return-to-base)	13%	26%	18%	8%	0%

Source: Change Energy Inc. (2010)

[4] A triple bottom line analysis, also known as "people-planet-profit," captures an expanded spectrum of values and criteria for measuring organizational and societal success: economic, ecological, and social.

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Exhibit B.BOMA.2
Attachment 1

A N A L Y S I S

Chapter 6

End-User Needs

As part of the Roadmap's development, consultations were conducted with the following end-user groups that operate medium- and heavy-duty fleet vehicles: 1) highway trucking, 2) municipal, 3) transit, 4) vocational truck, and 5) school bus. The objective of these consultations was to identify barriers to NGV adoption and deployment and to determine the conditions that would be needed for end-users to partake in market transformation. Information regarding past experience with natural gas vehicles was also gathered from three of the groups (municipal, transit, school bus).

End-User Consultations: Key Findings

During the consultation process, end-users provided the following perspectives regarding NGV deployment:

1. Vehicle incremental cost must be addressed. Payback requirements varied considerably, but end-users were unanimous in identifying incremental vehicle cost as a barrier to adoption. Some public sector fleets also noted fixed budget constraints.
2. Existing fuel tax exemptions need to be maintained in the near to medium term. However, end-users recognize that there could be pressure to eliminate the exemption in the long term as natural gas usage grows and begins to displace diesel consumption. This point was most clearly articulated by highway trucking end-users, who also had the most aggressive payback requirements. Environmental benefits related to GHG reduction were cited as a rationale.
3. Credit for using a lower-carbon fuel needs to accrue to fleets. Natural gas use should benefit fleets through carbon credit generation and compliance with regulations. Mandates requiring low-carbon fuels for public contracts were also suggested.
4. Aligned federal and provincial measures are needed. Suggestions included support for vehicle trials, programs that are accessible to both public and private sector fleets, and aligned measures that help ensure that GHG reductions are achieved.
5. Assistance is needed related to regulations and approval processes. End-users noted that refuelling facilities represent a challenge in terms of approvals. It was suggested that government could play a role in facilitating refuelling station approvals. Governments could also assist in addressing the regulations governing vehicle weights and dimensions to allow some overweight margins for LNG-fuelled trucks.
6. Past and current challenges are significant and must be addressed. Inadequate support for stations, parts, and vehicles was noted. Also highlighted were slow refuelling times relative to liquid fuels, and unreliable, maintenance-intensive early-generation engines.
7. Available NGV models may not suit all end-users' needs. School bus end-users noted the lack of natural gas Class C-type school buses as a barrier.
8. Natural gas use must mesh with fleet operational practices. Transit and vocational truck users both noted that other vehicle maintenance tasks are carried out in conjunction with refuelling. Maintaining operational efficiencies is a key driver for end-users.

End-User Consultation Results

It was evident from the consultations that there are significant differences in end-user awareness regarding the current availability, capabilities, and benefits of medium- and heavy-duty NGVs. In addition, while the consultation process was not intended to gauge intent, it was clear from these discussions that natural gas has the potential to be a viable option for medium- and heavy-duty vehicles in Canada if end-user needs can be addressed. The following charts summarize verbatim comments made by end-users within the group consultation process.

HIGHWAY TRUCKING	
Overall Business Case	It is critical that the trucking industry be able to take advantage of a carbon credit system and get credits if truckers use natural gas as fuel. The cost of premium, green technology cannot be passed on, so truckers need other direct benefits to support investment.
Fuel Costs	There will eventually be a tax on natural gas, but the social good of lower GHG emissions should relate to the level of tax on this fuel. Government needs to take advantage of our huge domestic natural gas reserves.
Vehicle Capital Costs and Financing	Québec offers incentives for trucks hauling freight to switch to LNG vehicles, but this is only for the Québec portion of corporate income taxes. The federal and provincial governments need to get onboard. There also need to be more than just road tax exemptions. Industry is making investments, and it needs governments to open doors and take away roadblocks.
Operational Issues	With the size of the fuel tanks, and changes in technology using more "real estate" on the frames, consideration must be given to weight allowances or increased wheel bases – vehicles are running out of room.
Refuelling Requirements	Refuelling facilities and infrastructure are one of the biggest challenges. Government needs to take the initiative in development of refuelling facilities. Also, a facilitator is needed to get through all the permits and legislation.
Training	It takes training to get technicians up to speed, but this is not a huge issue. It is part of doing business.
MUNICIPAL	
Overall Business Case	There is a generally held belief that new technologies are so clean (100 new vehicles = 1 old vehicle) that there is no sense of the advantage of natural gas or other alternative fuels. Diesel tends to beat LNG or CNG on a strict business case basis.
Fuel Costs	With some station financing models, end-users must commit to buying a minimum amount of natural gas. This creates an unacceptable risk, especially if government support changes, the technology is inadequate, or the business case changes.
Operational Issues	Perception that equipment downtime is still a common issue, since natural gas systems are not very durable. Also, fuelling infrastructure does not exist in large quantities.
Training	Training for mechanics is an issue.
Facilities and Refuelling Stations	Maintenance and safety infrastructure needs to be upgraded when introducing CNG/LNG to a garage. Maintenance infrastructure upgrades were costly ($80,000 for methane detectors in garages). Hamilton found CNG quite costly to maintain, specifically the fuelling stations.
Perspective on Roles	Mandates and incentives must be realistic, long-term, and helpful. In the 1980s, vehicles had to be produced by OEMs, which was good but also limiting. The business case changes dramatically when new fuel taxes are imposed and incentives are withdrawn. There is a need for a solid, long-term commitment that at least matches vehicle life (10 years).
TRANSIT	
Vehicle Refuelling	Estimated fill times ranged from three to nine minutes, with an average of 4.4 minutes. The reported fuelling time of nine minutes was specifically attributed to CNG, and that transit provider also reported a fill-time of three minutes for diesel.
Experience with Natural Gas Refuelling Stations	Fuelling station reliability was reported to be good for one operator and below expectations for another. A third operator reported problems with winter use, including the need to adjust compressor regulators to compensate for fuel flow. Support from the fuelling station operator was rated as poor but improving by one current operator. The former operator indicated that service was helpful but not timely. Parts availability was rated as poor but improving by one current operator and good by another. A third operator indicated that it carried additional stock, which was expensive.

Operational Issues	Infrastructure to fuel and park buses indoors is expensive; Technical Standards and Safety Authority(TSSA) required numerous inspections; and pressure relief valves required annual testing at a cost of $500 per test.
Training	Specialized training was required for fuelling. Also, a licensed TSSA compressor operator needed to be on duty even when the station was not running.
Experience with Natural Gas Transit Buses	One current operator reported average reliability. The other two were not so positive: "Natural gas is nowhere near as reliable as diesel. Runs very hot and multiple problems during the summer months. Required increasing bus spare ration due to multiple problems and long lead times for parts." Warranty issues were cited a significant by all three operators: "Huge problems historically." "Yes, poor engine life." "Numerous meetings with manufacturer to attempt to resolve issues."
VOCATIONAL TRUCKS	
Acceptable Payback Period	Due to the increased risk associated with new fuel-efficient technologies, a payback period of 12 years (average life of a vehicle) is not practical, as the durability of the technology is unknown. Three years is the preferred payback period for new technology. The Ontario Government ended an incentive program that offered up to 33 percent of the price differential between an NGV and diesel. With the rebate, the payback period is four years. Without this incentive, the implementation of NGV would be risky.
Vehicle Performance and Refuelling	Have driven new trucks and the technology is much better. After driving, knew they had to have these trucks; however, there is difficulty finding the appropriate model.
Implementation Challenges	Fuel capacity. Will the vehicle be able to conduct a full day's work without refuelling? Will it be able to make longer journeys? Related to this is the issue of refuelling; currently, the infrastructure is not sufficiently widespread to ensure easy access. Pricing, availability, refuelling infrastructure, no crash test information, and the question of who does maintenance and repair work on NGVs. Other challenges include costs, the competitive nature of the industry, and the need to bid against other firms for contracts. The only way to get NGVs regularly used is to mandate their use for residential (collection) contracts.
Government Role	There is a lingering sentiment that NGVs are "pieces of junk." The government needs to help educate people about the improvement in the technology to get past this stigma. Follow the lead of the U.S., which offers incentives, rebates, and tax breaks.
Additional Comments	There is a green initiative throughout the economy, and NGVs are a good way to market a company to companies and municipalities that are interested in being more environmentally friendly.
SCHOOL BUS	
Acceptable Payback Period	School bus fleets have fixed purchasing allowances. They replace 6 percent of their fleet per year but have fixed budgets to purchase new vehicles, which are dictated by the province. There is little leeway to purchase high-cost vehicles such as NGVs.
Implementation Challenges	The lack of a Class C NGV school bus is the biggest hurdle. NGVs are not made in a model that they use, and the model that is available (Class D) has higher operating costs by 37 percent. CNG vehicles are only available in pusher buses, and these vehicles are unpopular with drivers. There needs to be more variety in vehicle options. If conversion to natural gas were more accessible and easier, it would facilitate increased NGV use.
Experience with Natural Gas	One fleet had a CNG bus for two or three years and may buy 11 more. Relative to diesel, the NGV is slower to refuel by roughly six minutes, and drivers don't like that. However, the NGV's performance and power are good, and operators enjoy driving the 84-seaters.
Government Role	Incentives, tax breaks and grants. Federal incentive programs generally seem to be inaccessible to school bus operators. Governments should pay for trial adoption of the vehicles. The school board is currently working with Nova Scotia on driver monitoring and training to reduce fuel consumption. It is willing to experiment with NGVs, but it is not in the budget to do so.
Operational Issues	Vehicle cleaning and light maintenance are performed in conjunction with refuelling, including vehicle washing, light service, fluids, and repairs to sticky doors.
Information Needs	There is insufficient information or knowledge (on natural gas school buses) available.

End-User Decision-Making Process

Heavy-duty trucking fleets are looking for a two- to three-year payback on their investment, in addition to the inclusion of strategies that will reduce risk and uncertainty associated with NGVs. Relative to the other end-user groups, the transit industry has a longer payback period, and the economic calculations for new buses include other considerations that are not typically within the transit property's control. A comprehensive education and outreach initiative is essential to provide end-users with the economic, operational, and technical information they need to calculate payback and reduce risks and uncertainty. Table 1 describes the "5A Approach,"[1] which can be used to distinguish key questions in the end-user decision-making process, as well as the broader approach to market transformation.

Conclusion

Understanding and addressing end-user needs is fundamental to increasing the use of natural gas in transportation and ensuring successful deployment. Medium- and heavy-duty vehicle fleets tend to be conservative when considering the adoption of new technology, and natural gas (particularly LNG) is unfamiliar and unavailable for most end-users. The uncertainty about fuel availability and prices, combined with the high incremental vehicle prices, limited marketing, and lack of financial incentives for natural gas trucks, helps explain the low NGV uptake to date. The potential for market growth for natural gas vehicles will not be realized unless the attitudes, knowledge, and key concerns of end-users are addressed.

It was evident from the consultation process that an extensive amount of information is needed to support end-users who are considering deployment of medium- and heavy-duty natural gas vehicles. Of the information needs identified, some requirements are common to all end-users, while others are unique and applicable only to certain groups. In addition, end-users with past experience using natural gas in their fleets require additional information that identifies how natural gas vehicle and refuelling technologies have improved in recent years. The next chapter discusses NGV education and outreach issues in greater detail.

TABLE 1 5A Approach

AVAILABILITY	
Does the technology/fuel exist?	▪ Are benefits documented? ▪ Does policy support markets? ▪ What market intelligence is available?
AWARENESS	
Are end-users aware of this technology?	▪ What is the degree of awareness along the value chain with respect to the key elements – benefits, policy, and market intelligence?
ACCESSIBILITY	
Is there something preventing interested consumers from getting access to the product?	▪ Where in the distribution network are there barriers preventing goods from reaching the hands of interested customers?
AFFORDABILITY	
Does the higher purchase price present a large market barrier?	▪ What is the relationship between production volumes, costs, and price compared with perceived benefits (e.g. energy savings)? ▪ What level of price reduction is necessary to affect this barrier? ▪ What financing structures can help break down this barrier? ▪ How can manufacturing costs be reduced? ▪ How do we improve the value proposition to consumers?
ACCEPTANCE	
If it meets the previous four A's, why are people still not buying? Is it providing an acceptable service to the end-user?	▪ Does it meet customer requirements? ▪ Is it reliable? ▪ Will it readily fit into existing fleets?

[1] 5A Approach adapted from material developed by Natural Resources Canada and Navigant Consulting.

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Exhibit B.BOMA.2
Attachment 1

ANALYSIS

Chapter 7

Education and Outreach

As discussed in previous chapters, medium- and heavy-duty NGVs have potential to offer economic and environmental benefits to end-users and society. However, to enable Canada's NGV market to develop, various stakeholders have important information and knowledge requirements that must be met, and these stakeholders influence vehicle purchase decisions in direct or indirect ways. This chapter reviews what information needs to be provided to stakeholders, or target audiences (TAs) as they are called here, to inform their decisions, and how best to provide it. Following a background section that provides the rationale for NGV education and outreach, this chapter highlights the key components of this strategy, including the objective, target audiences, and approach. To obtain the information for this section, a teleconference involving all working groups took place in July 2010. The purpose of this call was to identify key target audiences, key messages, and potential dissemination strategies.

Background

Past efforts to encourage NGV adoption have included education and outreach elements, with the federal government partnering with industry to implement programs targeting fleet owners. For example, in the past, information brochures were developed and distributed at trade shows targeting municipal fleet contacts. While activities of this nature were undoubtedly helpful, on their own they are insufficient to effect meaningful change. In addition, several aspects of the natural gas vehicle story have changed recently, and these changes need to be communicated:

- The turnaround in the outlook for natural gas means that supply is no longer a barrier to considering natural gas use in transportation.
- Technologies for medium- and heavy-duty natural gas vehicles have improved significantly in terms of reliability, power, fuel efficiency, and availability from OEMs. Canadian suppliers have developed leading engine, storage and compression, and dispensing technologies that are sold around the world.
- There is renewed interest from industry in the potential for natural gas as a transportation fuel. This interest is aligned with government priorities in terms of carbon reduction as a public policy priority.
- The full natural gas value chain is interested and engaged, with producers (e.g. Encana), transmission companies (e.g. TransCanada), and local distribution companies (e.g. Gaz Métro, Terasen Gas, ATCO Gas, Enbridge) all actively involved in the Roadmap process.

In particular, the changes in natural gas supply and vehicle technology are not necessarily well known to end-users or to the wide range of stakeholders that influence the market. Similarly, natural gas as a fuel is not as well understood as conventional liquid fuels in terms of its properties, differences from other fuels, delivered cost, lower-carbon nature, and renewable form. Finally, some stakeholders may request information pertaining to upstream issues, such as the impact of shale gas development, since this topic has received significant media attention of late.

Key Components of a Natural Gas Vehicle Education and Outreach Strategy

To address these knowledge gaps, a comprehensive and sustained education and outreach strategy focused on key target audiences is essential in order to effect change and begin to transform the vehicle market.

Objective

The objective of this strategy would be to:
"Educate and inform stakeholders to ensure that they have the necessary information and tools at their disposal to make informed decisions that will support the deployment of natural gas vehicles in Canada."

Target Audiences

The education and outreach matrix identifies 14 key target audiences that can be organized into the following five categories: 1) end-users, 2) vehicle supply chain, 3) authorities and regulatory bodies, 4) industry, and 5) general interest.

1) End-Users

This category includes public and private sector fleets such as municipal transit, short-distance delivery, long-distance delivery, industrial, school bus, and vocational. Education and outreach efforts for this category would need to focus on basic education and outreach needs in the context of both knowledge gaps and past experiences with NGVs (see Figure 1). The former group would include those fleet managers who have little, or out-of-date, information about NGVs. These individuals need information to assist them with investment decisions related to NGV fuelling, including information about natural gas resources and prices, vehicle technology availability and price, operating experiences of other users, applicable codes and standards in their region, equipment and fuel suppliers, and environmental and other benefits of natural gas as a vehicle fuel.

The latter group includes those who have had previous negative experiences with NGVs and remain skeptical about the potential benefits associated with using this fuel. These individuals would likely require information regarding the experience of contemporary fleets that use natural gas, as well as details about technological advancements, current vehicle and infrastructure offerings, and opportunities to receive support for transition in their region.

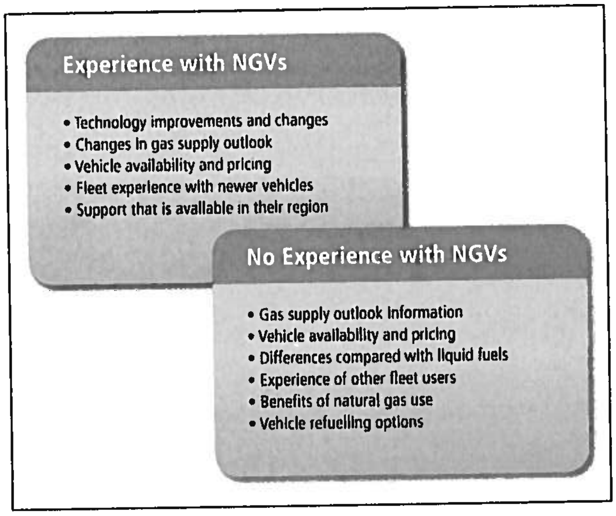

FIGURE 1 How the Degree of End-User Experience with NGVs Affects Outreach

2) Vehicle Supply Chain

This category includes OEM dealers, many of whom have limited experience with NGVs. Therefore, these target audiences require information that would enable them to address the needs and concerns of potential purchasers of these vehicles. Examples include information about the potential environmental and economic benefits associated with natural gas vehicle use, impact on vehicle range, and weight and dimensions, as well as other details that would help individuals make informed decisions about vehicle purchases.

3) Authorities and Regulatory Bodies

This category includes authorities with jurisdiction, regulators, governments, the Canada Border Services Agency, and emergency response providers. These target audiences may not have a major role in the market for natural gas for vehicles once the market has been developed. However, they are important target audiences, as their involvement in the initial stages of market development is crucial; the standards for which they are responsible must be met during the approval, construction, and operational phases of a project such a refuelling station.

4) Industry

This category includes companies active in the upstream, midstream, and downstream portions of the natural gas industry. It also includes equipment manufacturers, consultants, and research organizations. This target audience works with end-users to assess and deploy natural gas vehicles, so it needs to understand its role in the decision-making and deployment process, working to ensure that implementation is coordinated and that it effectively meets end-user needs.

5) General Interest

This category includes the public, media, and environmental groups. The target audiences in this category, especially the media, play a role in forming the opinions of others, so they need to have accurate information at their disposal.

Figure 2 describes the process continuum for end-users, such as fleet managers, who are considering the purchase of a medium- and or heavy-duty vehicle. When going through the process of purchasing such a vehicle, these end-users receive information from a variety of target audiences. If this information is insufficient or inaccurate, a communication breakdown will occur that may undermine the end-user's decision to purchase an NGV.

STEP 1

The first step in the continuum is for the end-user to gather information. All TAs are involved at this stage because each channel is a possible source of information that can be used to inform and influence the end-user.

STEP 2

There must be a supportive environment for the use of the NGVs. Regulations need to be in place and the possible incentives or programs identified. Positive references to NGV use in the media help generate awareness and interest.

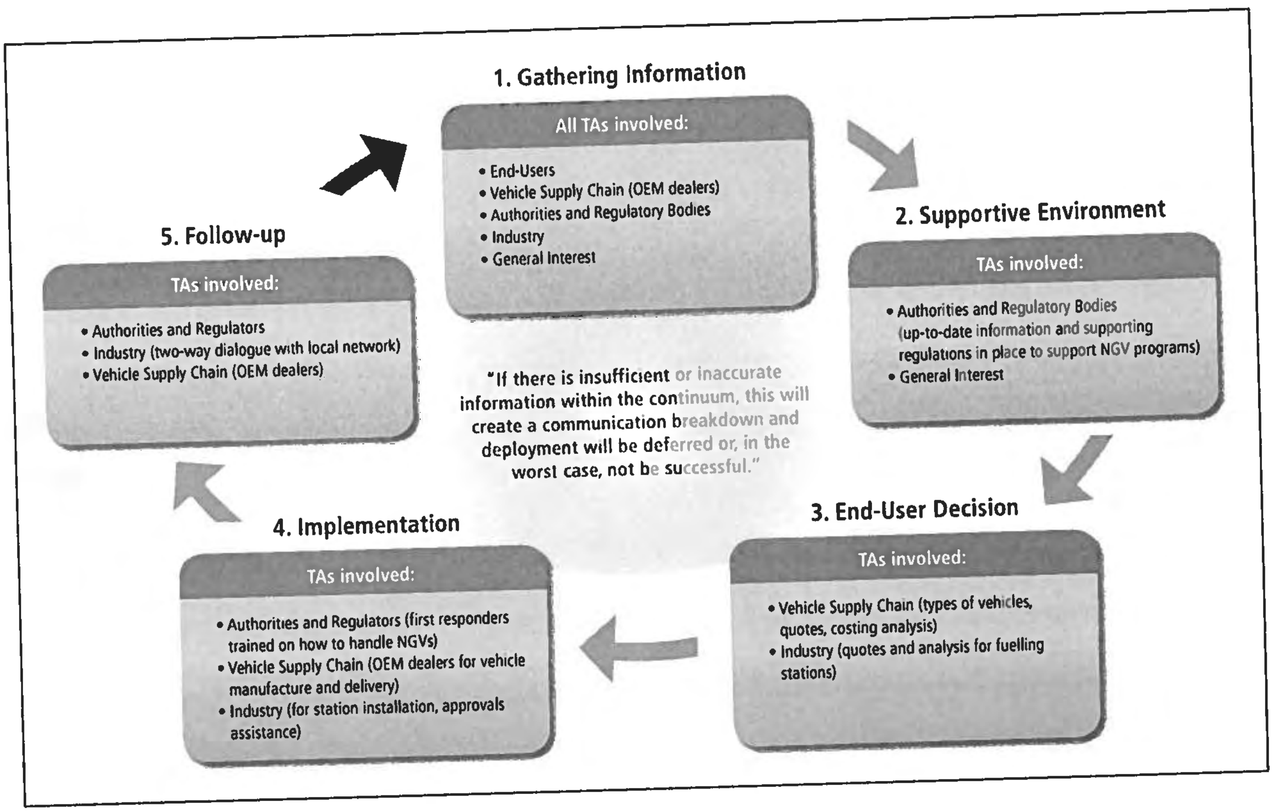

FIGURE 2 Process Continuum for Deploying a Medium- or Heavy-Duty NGV in Canada

STEP 3

End-users need to have costing and analysis done that incorporates vehicles, fuel, and possibly a refuelling station. Payback scenarios must be developed. Benefits must be weighed against costs and perceived risks in order to make a decision.

STEP 4

Dealers must deliver vehicles and industry needs to work with end-users to ensure that required approvals are secured for vehicles and station. Proper support for emergencies must be in place. First responders need to be trained to recognize and handle an emergency involving an NGV.

STEP 5

There needs to be continued follow-up involving industry, the vehicle supply chain, and end-users with respect to vehicle and station performance, maintenance, warranty issues, and product updates. There must also be follow-up involving authorities and regulators, depending on inspection and certification requirements in local regulations.

Approach

A holistic education and outreach strategy that targets end-users as well as market influencers and other key stakeholders should be developed. The strategy should have two main elements:

- A "top-down" approach that includes a central website for all target audiences with local content tailored to specific jurisdictions. This website should focus on basic education and outreach needs in the context of both knowledge gaps and past experiences with NGVs. It would serve as a central access point for all information related to NGVs (properties, benefits, suppliers, case studies, reports, news, refuelling stations, etc.) and provide real-time information on events such as announcements or upcoming workshops. The website could house brief videos (five or six minutes) that are educational and focused on "101" types of topics.

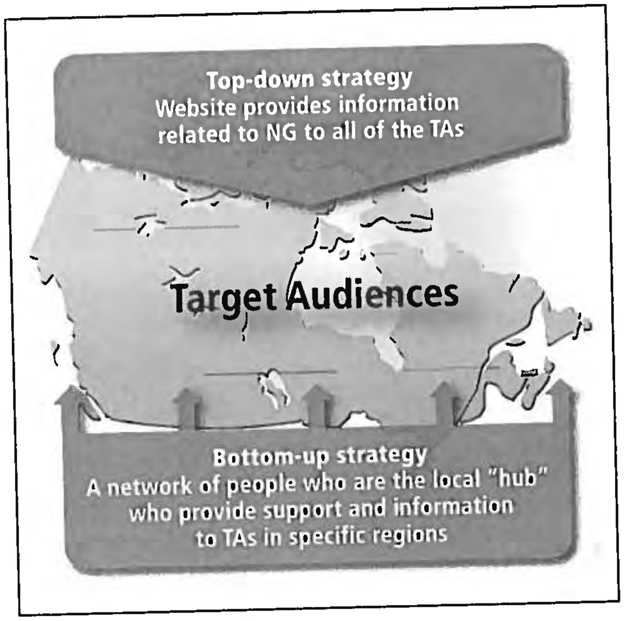

FIGURE 3 Information Dissemination: Top-Down and Bottom-Up Approach

- A "bottom-up" approach, which features a national support network that will provide access to resources at the local level for end-users, including workshops and meetings. This network — which could be similar to that of the Clean Cities Program in the United States — would be overseen by an umbrella organization. The network would have provincial coordinators who would provide customized support to users of NGVs. The coordinators would pool information and collect data that would be relevant for end-users, host workshops and meetings, disseminate education and outreach information, and provide technical assistance and other resources. See Figure 3.

Conclusion

To avoid competing messaging, there should be a branding exercise to ensure that all elements and tools have a common and unique look and feel. Branding would help TAs differentiate new and outdated information. Delivery of the education and outreach programs, including website hosting, would ideally involve an objective third party with resources and overall management provided by industry and government on a collaborative basis.

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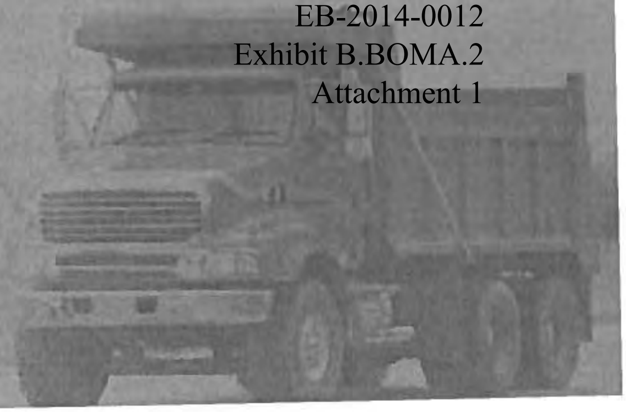
ANALYSIS

Chapter 8



Technology Research and Development Needs

During the 1970s, governments in Canada began funding R&D on alternative fuels — such as propane, hydrogen, and natural gas — to reduce dependency on petroleum resources. Since that time, governments in Canada and the United States have funded R&D on NGVs to achieve environmental benefits, as this technology was viewed as a means to improve air quality in urban areas. Initial R&D on gaseous fuels focused on developing codes and standards that would govern vehicle conversions, station design, and siting. These efforts also focused on addressing several shortcomings for natural gas as a vehicle fuel, including:

- Power loss;
- Incomplete combustion of methane;
- Limitations associated with natural gas conversions of diesel engines; and
- Heavy gas storage tanks.

Other R&D work funded by federal and provincial governments — in some cases with participation from U.S. agencies, engine manufacturers, and universities — resulted in large natural gas-diesel bi-fuel engines, lightweight fibre-wound CNG tanks, high-capacity fuelling facilities for transit buses, and other important innovations. Despite this progress, NGV R&D in Canada and the United States declined to very low levels beginning in 2000 due to the declining outlook for natural gas resources. With the turnaround in the gas resource outlook over the past two years, U.S. governments have begun to increase funding support for NGV R&D. Although public sector support in this area in Canada remains minimal, Canadian companies are world-leading producers of NGV technology because of past R&D investments.

Current Status of NGV Technology and Codes and Standards

Natural Gas Engines and Infrastructure

Current NGV refuelling station technology, as well as light- medium-, and heavy-duty vehicle technologies, is available, reliable, and economical. NGV refuelling station technology is mature and is in use worldwide for both CNG and LNG applications. Similarly, NGV technology has reached maturity. Vehicles with modern NGV technology have horsepower, acceleration, and cruise speeds that are equivalent to conventional fuel vehicles. Natural gas engines have been certified to exhaust emission standards established by the U.S. Environmental Protection Agency and Environment Canada, which are among the most stringent in the world. And recent innovations such as Westport Innovations' High Pressure Direct Injection (HPDI) have addressed fuel efficiency limitations associated with older natural gas engines.

Moreover, OEMs have increased the number of NGV options that are currently on the market. Examples include highway tractors from Freightliner, Kenworth,

and Peterbilt; refuse trucks from Autocar and Mack; school buses from Thomas Built and Bluebird, and specialty vehicles from Capacity. Westport Innovations has also recently entered into an agreement with Volvo to develop heavy natural gas engine systems for Volvo.

Natural gas engines and LNG technologies are also available for LNG short-sea shipping through multi-fuel compression-ignition engines (diesel-HFO-gas) and dedicated lean burn spark-ignited engines, as well as for rail applications through diesel dual-fuel and gas turbines. However, these technologies still need to be integrated into platforms that are primarily custom-built.

Codes and Standards

Due to the significant efforts undertaken by Natural Resources Canada and other stakeholders in the early 1990s, a number of codes and standards for natural gas vehicles and CNG refuelling stations were developed. A list of existing codes, standards, and regulations for CNG vehicles, CNG refuelling infrastructure, and fuel quality has been compiled as part of this Roadmap process. These codes represent a mature state of development; however, limited market adoption for natural gas vehicles in Canada in the past five to seven years has led to a decline in committee activity for natural gas vehicle, refuelling station, and fuel codes and standards. In some instances, formerly active codes and standards committees have become dormant. In other instances, there are no existing committees whose scope of work explicitly includes emerging areas of interest such as codes and standards for LNG vehicles and refuelling stations. In addition, known issue areas, such as impact loading requirements, have gone unaddressed in the absence of committee activity.

The Need for Ongoing Technology Support

Engines and Infrastructure

Environmental standards pertaining to the transportation sector continue to evolve, as evidenced by the recent announcements related to the development of GHG regulations for medium- and heavy-duty vehicles in both Canada and the United States. While NGV technologies are currently-market ready, they would benefit from R&D investments to reduce their incremental cost. Assistance is also needed to sustain market development through the expansion of the number of NGV offerings for end-users.

These issues were taken into account by the California Energy Commission (CEC) as it developed its Natural Gas Vehicle Research Roadmap[1] in 2009. The CEC roadmap describes the strategic research, development, demonstration, and deployment (RDD&D) needed to enhance the viability of the NGV market in California. Results from the CEC roadmap's research suggests that there is a lack of heavy-duty and off-road engine size and capacity, and that vehicle integration of new engines is a significant hurdle to greater natural gas vehicle availability and market penetration. Specific research topics include engine development and vehicle integration, fuelling infrastructure, and storage, technical, and strategic studies.

[1] Prepared for the California Energy Commission, Public Interest Energy Research Program, August 2009, CEC-500-2008-044-F.

TABLE 1 Canada's NGV-Related R&D Needs

	SHORT-TERM (0–5 YEARS)	LONGER-TERM (5–10 YEARS)
Engine Development and Vehicle Integration	▪ Develop engines and NGVs with improved economics, efficiency, and emissions ▪ Integrate available natural gas technologies (e.g. Westport HPDI, Cummins Westport ISL G, Emission Solutions technologies) into a broader range of NGV engine sizes and applications of OEMs ▪ Develop NGV high-efficiency clean combustion (HECC) engine technology	▪ Develop NGV versions for off-road applications, particularly large engine solutions for the rail and marine sectors ▪ Develop a variety of hybrid natural gas HDVs
Fuelling Infrastructure and Storage	▪ Develop fuelling infrastructure upgrades to accommodate fuel variability ▪ Develop improved CNG storage designs that integrate superior safety features and improved handling (with concurrent cost reduction) ▪ Develop higher-efficiency NG compression technology, with recovery of energy in compression ▪ Develop improved efficiency, handling, reliability, and durability of LNG dispensing and onboard storage	▪ Develop small-scale liquefaction technology that uses the waste energy from the pressure differential in natural gas transmission pipelines to liquefy pipeline gas ▪ Commercialize low-energy station technologies that minimize energy inputs for CNG and LNG refuelling stations

Although the Canadian market opportunities for NGVs are different from those in the United States, many of the findings of the CEC roadmap are applicable to Canada's efforts to increase the use of natural gas in its transportation sector (see Table 1).

These R&D opportunities are of great interest to the Canadian NGV industry, which has historically shown leadership in this area, but is now experiencing pressure to export much of its expertise abroad since the markets for Canadian NGV companies are primarily located in China, India, the United States, and Europe. The United States and Europe have well-developed RD&D programs that Canadian products may be able to access; however, continued access to them often involves relocating (in at least some capacity) to the country funding the work.

Codes and Standards

There is a strong link between codes and standards committee activity and R&D efforts. R&D generates the necessary data on issues like safe distances and component failure, from which the committee members can adapt existing codes and develop new ones. As new technologies are developed, there is also a need for concurrent development of related safety codes and standards to ensure that possible gaps in regulations do not impede new products from coming to market. The symbiotic and iterative relationship between the R&D community and the codes and standards committees is essential for the creation of pertinent regulations.

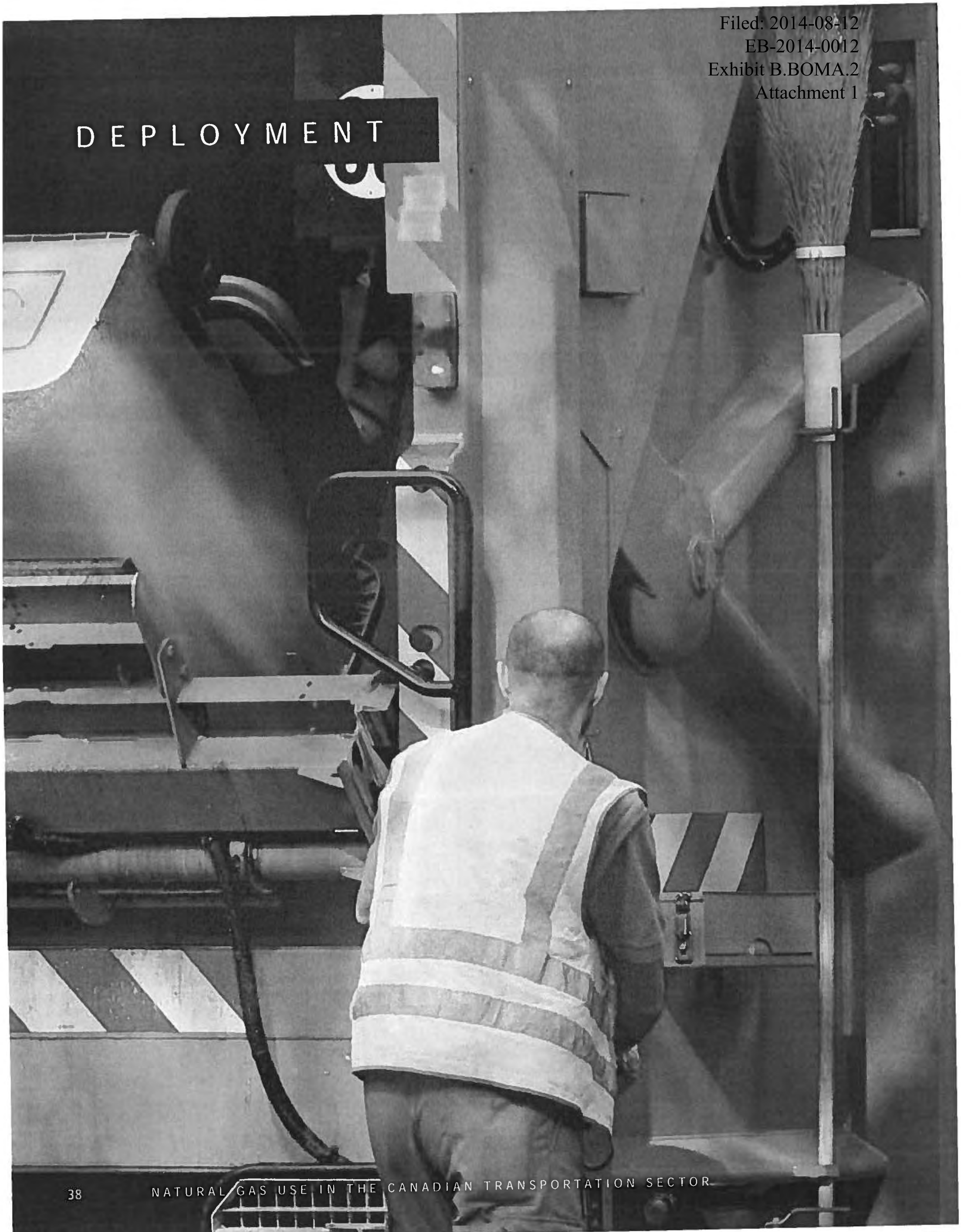
Next Steps

Moving forward, it will be important for industry, government, and universities to collaborate to achieve the RD&D priorities described in this chapter. One way to achieve such collaboration would be through the formation of a technical advisory group, which is a proven vehicle to help establish priorities and provide guidance to a federal R&D effort on the needs of industry.[2]

With regard to codes and standards, focused effort at the committee level will be required to address and resolve codes and standards issues and gaps related to natural gas vehicles and refuelling stations. Having an active and appropriate committee structure that is properly resourced will be an important prerequisite to achieving progress.

[2] Examples in the transportation and energy field are the Rail Research Advisory Board and the Hydrogen Technical Advisory Group (HYTAG).

DEPLOYMENT



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Chapter 9

Market Transformation

Markets are dynamic and characterized by new products, changing end-user demands and fluctuating prices. Generally, markets move toward technologies that provide a net increase in social welfare, but occasionally, market dynamics are insufficient to achieve a desired objective that is projected to be in the greater social interest. In these cases, barriers and/or failures prevent the market from achieving the societal objective. Governments may choose to intervene in the market when it is evident that there is a market failure and that market transformation will have a lasting impact and serve the greater societal interest. This chapter aims to determine whether there is a rationale for government involvement to assist industry in transforming the portion of the transportation market that involves medium- and heavy-duty vehicles operating in corridors and return-to-base fleet applications.

Is There a Market Failure in Canada's Transportation Sector?

Market failure is a concept in economic theory where the allocation of goods and services by a free market is inefficient. Market failures have been identified in the vehicle efficiency and alternative fuels area in academic literature.[1] In many of these cases, the market failure is associated with one or any combination of the following factors:

1. Perceived risk associated with early adoption — where there is potential for a positive return on investment, but the market does not act to achieve this return because of the perceived risks;
2. Imperfect information — this can occur where an entity lacks the relevant information to judge returns on a specific investment;
3. Lack of choice — where the demand for a good or service is supplied by a market with limited options; and
4. Externalities — where there are impacts on society, such as climate change, that are not considered in the price of the good being sold and that may be an advantage or disadvantage to society more broadly.

With regard to natural gas use in transportation, other jurisdictions have identified a need for intervention to address market failure and secure societal benefits, so they have introduced various policies to support NGV deployment, ranging from mandates to incentives. For example, the U.S. *Energy Policy Act* of 2005 introduced alternative fuel motor vehicle tax

[1] See, for example, Chapter 11 of *Reducing Climate Impacts in the Transportation Sector*, by Daniel Sperling, James S. Cannon, 2009.

In summary, the business modelling work showed that over a reasonable range of credible price forecasts, the overall business case for use of natural gas in specific transportation applications is robust relative to other fuels.

credits to de-risk the early adoption of a range of lower-emission vehicle technologies, including natural gas technologies. Analysis included in this report points to a range of potential benefits associated with natural gas use for medium- and heavy-duty vehicles, including energy diversification, energy supply, emission reductions, and regional economic benefits. In addition, the business case modelling shows that there are end-use applications that have a favourable IRR, yet the market is not moving to adopt these applications. Altogether, these findings suggest that there is evidence of market failure, or at least evidence of significant market barriers to NGV adoption, within the medium- and heavy-duty vehicle portion of Canada's transportation sector.

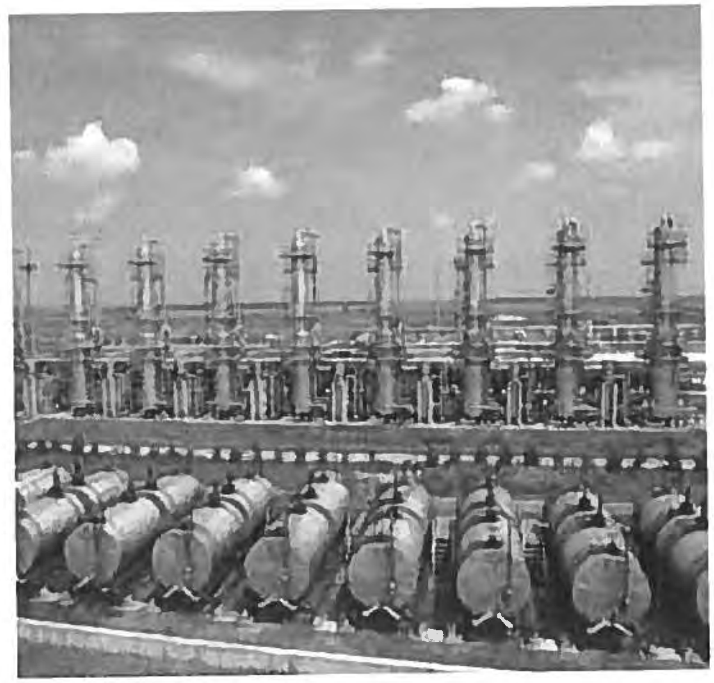
Putting the Business Modelling in Context

If one concludes that the transportation sector demonstrates a failure with regard to fleet adoption of medium- and heavy-duty NGVs, the focus then turns to identifying those markets that have the strongest business case and the greatest potential to become self-sustaining in the long term. The business case modelling summarized earlier in this report aimed to identify the medium- and heavy-duty end-use applications with the greatest likelihood of being economically self-sustaining.

The modelling generated a value, the FVI, that captures the all-in economic costs of natural gas fleet ownership relative to diesel fleet ownership. In the case of this study the FVI was, by necessity, limited to providing an indication of the economic value proposition only. In this context, applications that are not achieving market uptake despite having FVI values greater than 1 and favourable IRRs may be impeded by market failure. Conversely, if a market is developing in spite of having a FVI of less than 1, it would be worthwhile to examine market conditions to determine what factors are driving it.

The business modelling work determined the IRR for the top four end-use applications. The IRR values demonstrated that there is a strong business case, particularly for high-mileage applications that operate along corridors or in return-to-base fleets. Capital investments can earn attractive rates of return. Payback ranges varied depending on the scenario modelled, but in each case, payback values demonstrated that the incremental cost for natural gas would be recovered well within the vehicle's life.

In summary, the business modelling work showed that over a reasonable range of credible price forecasts, the overall business case for use of natural gas in specific



transportation applications is robust relative to other fuels. The economic case for the application of natural gas in the transportation sector is not dependent on pricing carbon, but this would further enhance the business case. Notwithstanding the above, attitudinal barriers and upfront capital risk exposure are such that obstacles to broader deployment remain. Market intervention should then focus on targeted measures to mitigate upfront risks, rather than to support the overall business case, with potential public and private sector responses to address this issue. This assistance would be of broader economic benefit to Canadians.

Moving Beyond Market Failure: Addressing Barriers and Building a Competitive NGV Industry

To facilitate widespread NGV deployment in Canada, policy tools are needed not only to address market barriers, but also to ensure that this industry becomes self-sustaining and competitive over the long term. Options for consideration by governments are described in Table 1. For example, as a first step towards market transformation, temporary fiscal measures could be implemented to de-risk NGV investment and encourage early adoption of these vehicles in greater numbers. In doing so, these temporary measures would help industry achieve the economies of scale required to reduce the cost of vehicles. Another example would be measures to address information gaps and non-market barriers to NGV adoption. These information-related measures would help ensure that end-users have the information necessary for the NGV market to function properly.

As the NGV industry continues to evolve, additional measures will be needed to increase this market's capacity to become self-sustaining. For example, end-users will need to feel supported in their purchasing decision, and all of the required codes and standards will need to be in place. Finally, measures will be needed to ensure that the NGV industry remains competitive on an ongoing basis. RD&D is required to ensure that NGV technology remains competitive relative to diesel and to expand the number of NGV offerings.

Details regarding potential policy tools — which include fiscal measures, regulation, information, and research, development and demonstration — are included in Table 1.

If implemented individually, each of these measures could help support NGV deployment, albeit on a limited scale. To maximize deployment potential,

TABLE 1 Potential Policy Tools to Support NGV Market Development

TOOL	DESCRIPTION/ROLE/RATIONALE	EXAMPLES
Fiscal Measures	▪ Fiscal measures reduce the main economic barrier to market entry by reducing financial risk. ▪ End-users perceive early adoption as being risky and, in particular, they attach uncertainty and high risk to: ▪ The residual value of an NGV after the initial ownership period of, for instance, four to five years for highway tractors; and ▪ The lack of refuelling infrastructure relative to diesel fuel infrastructure. ▪ Fiscal measures may lower upfront vehicle cost, guarantee residual vehicle values, assist with access to refuelling infrastructure, or ensure fuel savings relative to incumbent fuels. ▪ Increased early adoption of NGVs in larger quantities would help industry achieve the economies of scale required to bring down the cost of vehicle systems.	▪ Tax measures (e.g. accelerated capital cost allowances and investment tax credits) and cash rebates that may apply to the vehicle, refuelling infrastructure, or fuel price differential. ▪ In its 2010 budget, the Province of Québec announced adjustments to its accelerated capital cost allowances in support of LNG Class 8 trucks. The capital cost allowance measure allows for asset write-down within a significantly reduced time frame compared with a conventional truck, with the goal of de-risking upfront capital investment for the fleet. ▪ Cash rebates have been provided in the past to reduce the incremental cost of the vehicle.
Regulation	▪ Regulation for GHG reduction is being developed for medium- and heavy-duty vehicles in the 2014 period. With careful design, these regulations could recognize and include the GHG benefits of natural gas vehicles. ▪ The rationale for regulating these vehicles is similar to that for light-duty vehicle regulation – most major governments have intervened with fuel economy or GHG standards to overcome the market failure of consumers not valuing fuel savings beyond the three-year period. ▪ Benefits of regulation include market certainty in terms of acceptable levels of environmental performance and equal treatment of technologies, as all must meet the same standard. ▪ With regard to another regulatory issue, governments could provide assistance by addressing regulations governing vehicle weights and dimensions to allow some overweight margin for LNG-fuelled trucks.	▪ Fuel economy and GHG regulations for light-duty vehicles. ▪ Low-carbon fuel standards as implemented in California and British Columbia and under consideration in Ontario.
Information	▪ End-users identified gaps in terms of information and awareness concerning NGVs as an option that could serve their needs. ▪ It is also the responsibility of governments to provide essential information to enable markets to function efficiently, especially where there is the absence of a single private sector actor that operates across the entire spectrum of the natural gas vehicle value chain. ▪ Governments are regarded as unbiased providers of information in the vehicle and fuels market arena, and this is important to end-users. ▪ Benefits of these measures include the development of a broader understanding of the benefits and commercial applicability – and therefore a greater consideration/adoption of – NGVs.	▪ Websites and fleet information hubs. ▪ Examples of these initiatives already in progress include the Clean Cities Program in the United States.
RD&D	▪ RD&D assistance for NGVs can leverage existing private sector spending and help position Canadian technologies to be more competitive and, ultimately, generate regional economic benefits. ▪ Diesel technologies have been assisted by substantial R&D funding over the past decade to meet more stringent tailpipe standards; R&D assistance for natural gas technologies would extend similar treatment and help level the playing field. ▪ End-users have identified the need for a greater range of natural gas products from which to choose, and targeted R&D investment can assist market development by increasing model availability. Production-oriented R&D investments could reduce the incremental cost of NGVs and break through the low volume/high upfront cost barrier faced by innovative lower-emission technologies trying to enter the market.	▪ The National Renewable Energy Laboratory's Natural Gas Engine Research and Development Program.

a coordinated and holistic approach is needed. For example, the regulation of the medium- and heavy-duty vehicle sector will take significant time to implement, so market opportunities may be missed in the interim. Given the likely time frame for regulation, temporary fiscal measures, for example, could assist early market entry for several years and a regulatory GHG framework could be examined for long-term market encouragement based on GHG reduction potential. These measures would also need to be supported by capacity-building measures such as codes and standards development, as well as training and outreach and education activities. While there are many precedents for market intervention by governments to assist in developing scale and removing barriers to entry, there are potentially market-based solutions that should also be given consideration going forward. One such example would include arrangements between end-users and fuel suppliers that would lock in the fuel price differential over a given volume of fuel.

Over the longer term, it will be important for natural gas as a transportation fuel to compete on a level playing field with other fuels — based on its own merits. This principle should be considered by policy-makers in terms of the design and duration of any policies moving forward.

Market Potential

In 2009, Canada had an estimated 830,000 registered medium- and heavy-duty vehicles, which represented 4 percent of on-road vehicles.[2] More than 80 percent of these vehicles were in use in one of four provinces: Alberta, British Columbia, Ontario, or Québec. As the primary technology focus for natural gas use in medium- and heavy-duty vehicles is on new factory-produced vehicles, market potential for natural gas must be considered in the context of the medium and heavy vehicle replacement cycle. The sale of medium- and heavy-duty vehicles varies considerably by year, as shown in Figure 1. Based on the past 10 years of sales, an average of 36,000 medium- and heavy-duty vehicles are sold in Canada each year.[3]

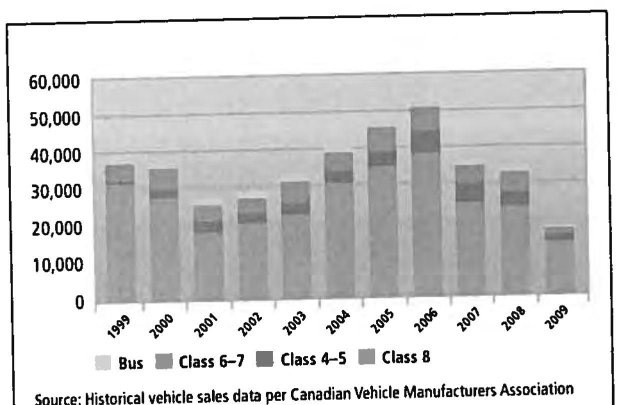


FIGURE 1 Medium- and Heavy-Duty Vehicle Sales in Canada (1999–2009)

[2] Statistics Canada, Canadian Vehicle Survey – Annual 2009
[3] Historical vehicle sales data per Canadian Vehicle Manufacturers Association

As previously noted, natural gas works well in return-to-base and corridor applications. There is no data available that identifies what portion of Canada's medium- and heavy-duty vehicle population operates in return-to-base mode or along regional corridors. Nonetheless, it is evident that the potential for NGV sales can best be described as a subset of total vehicle sales, given that many applications will not be suitable for natural gas (such as long-haul trucking).

Given these considerations, a range of potential penetration rates for natural gas vehicles, as a percentage of total medium- and heavy-duty vehicle sales, are shown in Table 2. The resulting energy use and carbon emission reductions are also noted. At a 15 percent penetration rate, natural gas use would be 122.5 billion cubic feet per year, which represents about 6 percent of Canada's 2009 domestic natural gas consumption.[4] The projected carbon reduction benefit is material in the context of Canada's 2020 GHG emission reduction goals. GHG emissions from heavy diesel vehicles in 2005 were 39 megatonnes of CO_2e.[5] To achieve a 17 percent reduction in GHG emissions from this portion of the economy by 2020, an estimated 6.6 megatonne reduction is needed. Approximately one-third of this goal could be achieved if one out of every 10 new medium- and heavy-duty vehicles sold in Canada over the next 10 years were an NGV (see Table 2).

Natural gas is one of several potential solutions to reducing emissions from medium- and heavy-duty vehicles in Canada. This domestic fuel offers a niche opportunity for return-to-base and corridor fleets.

TABLE 2 Estimated NGV Market Potential in Canada

ANNUAL NG TRUCK SALES AS % OF TOTAL SALES	TOTAL NG VEHICLES OVER 10 YEARS	ENERGY USE (THOUSANDS DLE)	ENERGY USE (Bcf)	ANNUAL GHG BENEFIT (Mt CO_2e)
1%	3,599	238,668	8.2	0.1997
3%	10,796	716,003	24.5	0.5992
5%	17,994	1,193,338	40.8	0.9986
7%	25,191	1,670,673	57.2	1.3981
10%	35,987	2,386,676	81.7	1.9973
15%	53,981	3,580,014	122.5	2.9959

1. Assumed 70 percent Class 8; 30 percent Class 3–7 based on historical split in sales.
2. Fuel use for Class 8 estimated at 78,800 diesel litres/year @39.4 DLE/100 km.
3. Fuel use for all other estimated at 37,300 diesel litres/year @ 62 DLE/100 km.
4. Carbon benefit based on GHGenius values of 25 percent for Westport LNG system and 18 percent for Cummins Westport engine.
5. Class 8 estimated 200,000 km/year and 72-tonne GHG reduction.
6. All other medium-and heavy-duty vehicles estimated at 60,000 km/year and 17-tonne GHG reduction.

Source: Calculated based on data from Canadian Vehicle Manufacturers Association and GHGenius (version 3.16b)

The actual market potential for natural gas could be higher or lower depending on what policy measures are employed, and their strength and duration, as well as the relative prices of natural gas versus diesel fuel over the decade.

Conclusion

As discussed, there are a number of reasons why deploying NGVs in Canada will require market intervention by a range of stakeholders, including governments, industry, and other key organizations. To facilitate NGV deployment in Canada, the following chapter contains key recommendations, as well as roles and responsibilities for key stakeholders.

[4] Canadian Gas Association.
[5] Environment Canada, Canada's National GHG Inventory.

DEPLOYMENT

Chapter 10

Recommendations

The following set of recommendations was developed in consultation with stakeholders representing all Roadmap working groups as well as Roundtable members. These recommendations reflect findings related to business modelling work; capacity-building needs; and research, development, and demonstration (RD&D) requirements. Recommendations have been proposed in four key areas: 1) De-risking Investment and Early Adoption, 2) Addressing Information Gaps, 3) Increasing Capacity to Sustain Markets, and 4) Ensuring Ongoing Competitiveness.

De-risking Investment and Early Adoption

1. Analysis has demonstrated that investment in medium- and heavy-duty NGVs can provide environmental and over-vehicle-life economic benefits, but the upfront capital cost vehicle premium and the risks associated with operating costs and achieving ongoing fuel savings are barriers to adoption. Fiscal measures implemented on a temporary basis could address these barriers and de-risk decision-making for early fleet adopters.
2. To introduce natural gas into the new market of over-the-road trucking, coordinated investments are needed to ensure that the development of key corridor infrastructure is consistent with projected demand, strategically located to support end-users, and installed in a timely manner across jurisdictions.
3. Existing industry players could provide private onsite refuelling stations. Fleets could further improve the business case for natural gas adoption by allowing other fleets to use these stations via cardlock and other arrangements. However, there are implementation details (e.g. liability issues) that would need to be addressed by the parties involved.
4. Demonstration of the use of natural gas is needed to address technical barriers, develop standards, and conduct feasibility studies and business cases.

Rationale

Temporary fiscal measures would help de-risk adoption and lower economic barriers to market entry. End-users perceive early adoption as risky and, in particular, they attach uncertainty and risk to 1) the residual value of an NGV after the initial ownership period (e.g. four to five years for highway tractors), 2) the potential for ongoing fuel savings, and 3) the lack of refuelling infrastructure relative to diesel fuel infrastructure. Temporary fiscal measures would encourage early adoption of NGVs in larger quantities, which in turn would help the NGV industry achieve the economies of scale required to reduce the cost of vehicle systems. While there is a positive internal rate of return for several end-use applications, temporary fiscal measures would also be necessary to surmount the barriers to adoption if they are determined to be

Recommendations have been proposed in four key areas: 1) De-risking Investment and Early Adoption, 2) Addressing Information Gaps, 3) Increasing Capacity to Sustain Markets, and 4) Ensuring Ongoing Competitiveness.

the result of market failure within the medium- and heavy-duty portion of Canada's transportation sector. While there are many precedents for market intervention by governments to assist in developing scale and removing barriers to entry, over the longer term, it will be important for natural gas as a transportation fuel to be able to compete on a level playing field with other fuels — based on its own merits. This principle should be considered by policy-makers in terms of the design and duration of any policies moving forward.

Addressing Information Gaps

5. An education and outreach strategy would be needed to target end-users as well as market influencers and other key stakeholders. This strategy should consist of both a "top-down" and a "bottom-up" approach. A top-down approach would include a central website for all target audiences with local content tailored to specific jurisdictions. A bottom-up approach would feature a local support network for end-users and provide access to resources including workshops and case studies of local fleets.

Rationale

End-users identified gaps in their knowledge and awareness concerning NGVs as an option that could serve their needs. In addition, end-users with past experience using natural gas had additional information requirements related to recent NGV developments, particularly technological innovations. It would provide momentum if governments and other players were to provide essential information to enable markets to function efficiently, especially since there is no single private sector actor that operates across the entire spectrum of the NGV value chain. Governments are regarded as unbiased providers of information in the vehicle and fuel market arenas, and this neutrality is important to end-users. Benefits of this measure include the development of a broader understanding and increased awareness of the applicability of NGVs, which would facilitate adoption of these vehicles in greater numbers.

Increasing Capacity to Sustain Markets

6. A "safety codes and standards" working group should be established to collaborate with existing Canadian Standards Association technical committees to address gaps and issues in existing codes and standards identified during the Roadmap process. Separate committees for liquefied natural gas (LNG) and compressed natural gas (CNG) may need to be formed to review existing codes and revise or develop new codes and standards. An umbrella committee is needed to ensure that codes and standards for CNG, LNG, liquefied compressed natural gas, and biomethane are coordinated and comprehensive.
7. Appropriate training materials for stations, vehicle repairs, and NGV fleet operations, as well as for cylinder inspection, need to be developed and delivered.

8. An NGV implementation body — consisting of Roundtable members and other key stakeholders — should be established to:
   - Support the implementation of the Roadmap's recommendations and assess progress against key milestones;
   - Provide recommendations to stakeholders regarding how the natural gas community could respond to future developments, such as changes in market conditions and technological innovations;
   - Act as an umbrella organization for the local support network for end-users; and
   - Serve as a forum for stakeholders to discuss issues pertinent to the natural gas community.

Rationale

To encourage NGV adoption, end-users need to be supported during their purchasing decisions, and adequate codes and standards need to be in place to ensure a successful technology rollout. Over the past decade, very little work has been done in Canada to update CNG codes and standards, while LNG codes and standards require even more fundamental development. As NGV technology becomes increasingly available, fleets will require support, since this technology features specific maintenance and safety requirements that will necessitate training of operators and mechanics. An NGV implementation body is recommended as a way to coordinate the work of governments and stakeholders along the NGV value chain to ensure the successful deployment of this technology and mitigate the risks borne by end-users or by any individual player.

Ensuring Ongoing Competitiveness

9. The NGV industry funds R&D activities at present. Further investment by others including governments has the potential to enhance the competitive position of the industry through targeted R&D investment. Priorities for future R&D include reducing/eliminating the cost differential between natural gas and diesel vehicles over the long term and maximizing NGVs' operational and environmental benefits.
10. Potential for natural gas use in other transportation applications should continue to be explored.

Rationale

While NGV technology is already mainstream and commercially proven, support for NGV R&D is needed to further reduce the incremental cost of NGV-related technologies. In addition, assistance is needed to sustain market development through the expansion of the number of NGV offerings for end-users. NGV technologies would also benefit from R&D investments to reduce the incremental cost of these vehicles, which would ensure ongoing competitiveness for innovative low-emission Canadian technologies. By continuing to explore the potential for natural gas use in other transportation applications, the natural gas community will help expand the benefits of natural gas as a fuel and potentially leverage infrastructure and R&D investments made for the medium- and heavy-duty vehicle market.

TABLE 1 Natural Gas Use in Transportation: Roles and Responsibilities

		GOVERNMENTS	NG PRODUCERS, TRANSPORTERS, AND DISTRIBUTORS	INFRASTRUCTURE AND VEHICLE SUPPLY STREAM	END-USERS
De-risking Investment and Early Adoption	Vehicle Premium	■	■		■
	Corridor Infrastructure	■	■	■	
	Return-to-Base Infrastructure		■	■	■
	Demonstrations	■		■	■
Addressing Information Gaps	Education and Outreach	■	■	■	
Increasing Capacity to Sustain Markets	Codes and Standards	■	■	■	
	Training	■	■	■	
	Implementation Committee	■	■	■	■
Ensuring Ongoing Competitiveness	R&D	■		■	
	Use of NG in Other Applications	■	■	■	■

Roles and Responsibilities

The stakeholders in Table 1 were identified as parties who could take on roles and responsibilities as they relate to moving the recommendations of this Roadmap forward. For many of these activities, numerous stakeholders could play a role; however, the table aims to provide a general overview of the roles that key stakeholders could play during the early stages of NGV market development.

DEPLOYMENT

Chapter 11

Next Steps

As mentioned at the outset of this report, a number of factors have renewed interest in natural gas as a transportation fuel, including the changing supply story for natural gas, projected high oil prices, and the need to reduce GHG emissions and criteria air contaminants. While there are various societal benefits that can be derived by increasing natural gas use in the transportation sector, there are also a number of market and non-market barriers that must be addressed before widespread NGV deployment can be achieved.

The Roadmap analysis found that medium- and heavy-duty vehicles offer the greatest opportunities for increased natural gas use in the immediate term. To optimize natural gas use in these vehicle applications, the Roadmap:

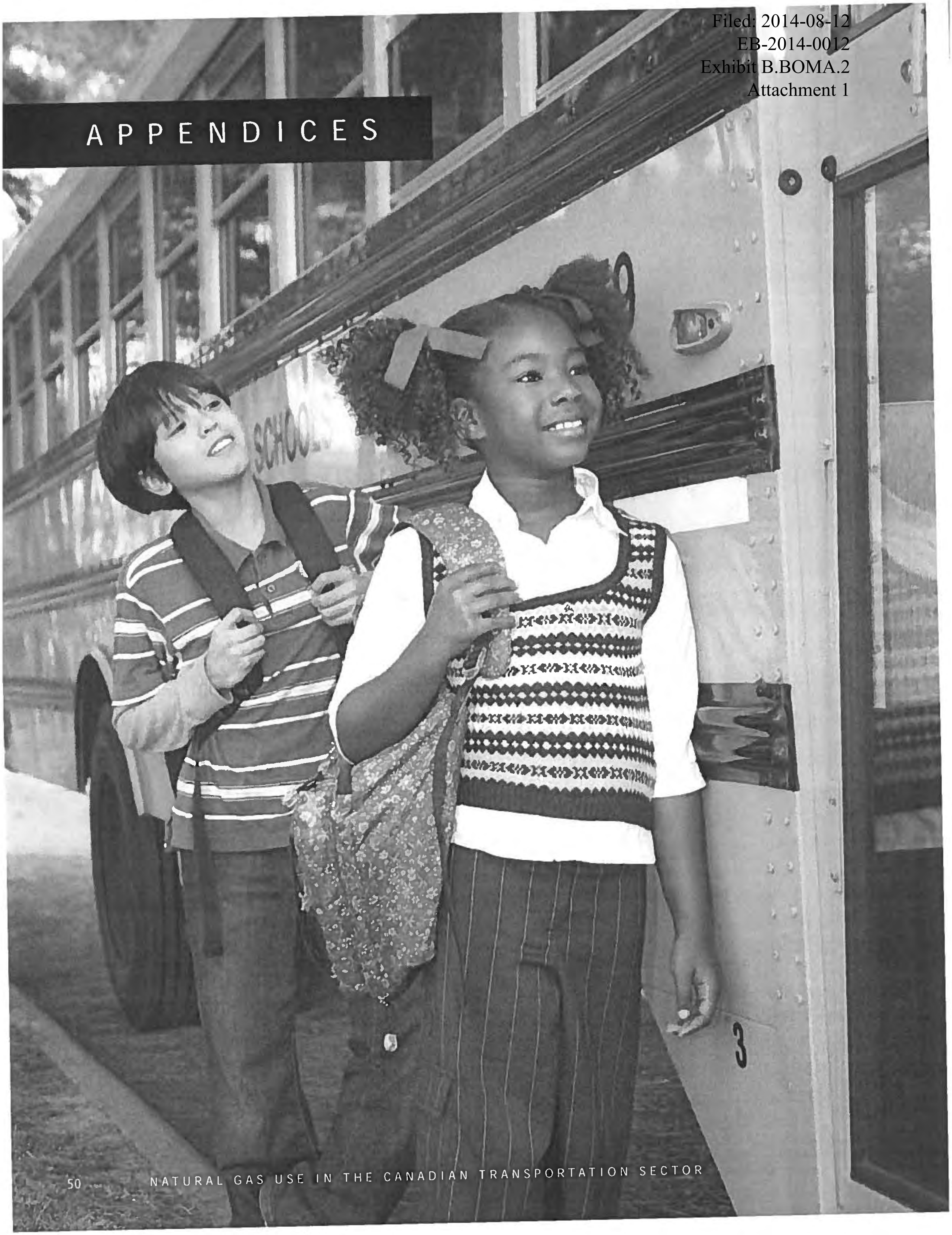
- Provides analysis regarding end-use business modelling, education and outreach, and R&D needs;
- Offers governments and industry recommendations related to de-risking investment and early adoption, addressing information gaps, increasing capacity to sustain markets, and ensuring ongoing competitiveness of the NGV industry; and
- Defines the future roles and responsibilities of major stakeholders.

While Canada has technologies at all stages of the supply chain to build this market, the combined efforts of industry, government, and other stakeholders will be essential to achieve widespread medium- and heavy-duty deployment in the coming years. The NGV Implementation Committee will provide a forum for key stakeholders to meet and carry out other activities that will support the recommendations described in this report. In addition to increasing the deployment of medium- and heavy-duty vehicles, the committee will work to address the technological and market barriers that currently impede widespread adoption of natural gas vehicles in light-duty vehicles, marine vessels, and locomotives.

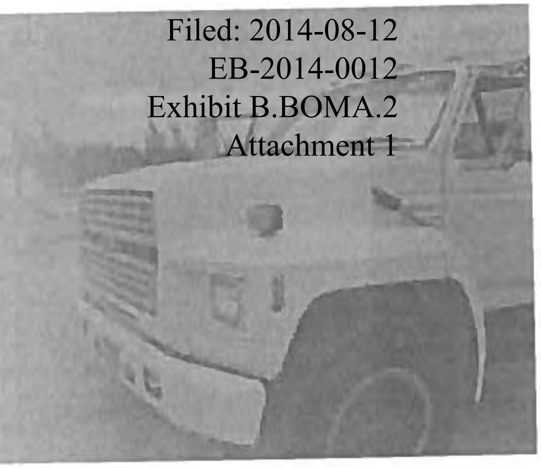
In the coming years, the prospect for increased NGV deployment in Canada is extremely promising. The Roadmap process has shone a light on the excellent products that Canadian companies build and export for NGVs in other parts of the globe. The task ahead will be for the natural gas community to apply this expertise towards using natural gas in our transportation market for the further benefit of Canadians.

Filed: 2014-08-12
EB-2014-0012
Exhibit B.BOMA.2
Attachment 1

APPENDICES



APPENDICES



Appendix A

Results of the Scoping Analysis

Roadmap working groups assessed the potential for increased natural gas use in various vehicle segments based on the following criteria: technology availability, market potential, environmental benefits, energy use, and economics. The vehicle segments included heavy-, medium-, and light-duty vehicles, marine vessels, and locomotives. The principal findings follow.

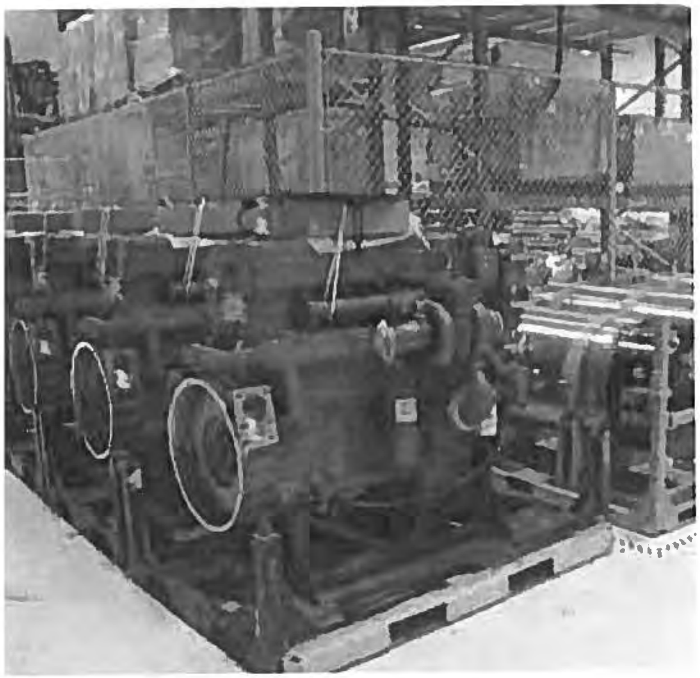
Heavy-Duty Vehicles

A growing number of OEMs are offering factory-produced and emissions-certified natural gas heavy-duty vehicles in a variety of power ratings. These vehicles use a significant amount of fuel, so the potential savings from choosing natural gas are substantial, but there are significant perceived risks associated with early adoption for end-users. For these vehicles, the IRR is high, but the initial incremental cost of the vehicle could be a deterrent to fleets that tend to be conservative in their investment decisions. Natural gas fuel tanks are heavier than those used for diesel, and for those trucks that travel close to the weight limit, some tradeoff in cargo weight may be required.[1] The significant volume of heavy-duty vehicles along the Windsor-Québec corridor and the coincident natural gas pipeline network provide the key elements that could support a targeted market transformation initiative that leverages existing natural gas infrastructure to extend use of this lower-carbon fuel into a new market. Return-to-base fleets, such as transit buses, are also a large potential market for natural gas, since buses use significant amounts of fuel, are centrally fuelled, and have longer lifetimes for amortizing the initial investment.

Medium-Duty Vehicles

OEMs that manufacture trucks and buses are also offering a growing number of medium-duty NGVs. In urban areas where public refuelling stations exist (e.g. Vancouver and Toronto), medium-duty vehicles may be able to access existing refuelling stations for demonstrations or early-stage fleet adoption. Many medium-duty vehicles operate in urban areas, where the low emissions of NGVs are most beneficial. In addition, medium-duty vehicles can achieve significant fuel savings, particularly when they are operated over longer distances (e.g. airport buses and some package delivery fleets). Medium-duty vehicles operating in return-to-base fleets are particularly well positioned to take advantage of central refuelling and low natural gas prices.

[1] Some provinces and states are examining this issue and whether to allow some overweight margin for LNG trucks.



Marine – Short-Sea Shipping

Natural gas propulsion technology is commercially available for large marine engines. One ship can use as much fuel as 50 heavy-duty trucks. The fuel savings potential for ships using natural gas is significant, since fuel costs for marine vessels are expected to increase due to compliance requirements associated with new emission regulations. While some expensive emission control equipment can be avoided, this saving must be balanced by additional investment cost in LNG tanks and dual-fuel injection systems. There are good opportunities for LNG in shipping on the Great Lakes with the proximity of natural gas pipelines and the possibility of shared LNG infrastructure with heavy-duty vehicles. Ships have very long lifetimes (25 to 40 years) to amortize the high investment costs ($40 to $50 million). Although LNG is best fitted during ship construction, retrofits are feasible when a major refit is scheduled. However, the additional LNG tank volume could force cargo reductions in some cases.

Light-Duty Vehicles

Light-duty vehicles for consumers and commercial fleets would need to be converted on an aftermarket basis to natural gas since there are no OEM vehicles sold in Canada. Public refuelling infrastructure is available in urban centres such as Vancouver, Calgary, and Toronto, but is limited elsewhere. Because private vehicles use relatively little fuel, it would be difficult to justify making investments in additional refuelling infrastructure unless large numbers of vehicles were converted or manufactured to use natural gas. In addition to natural gas, consumers have a choice of other technologies to reduce their GHG emissions via their new vehicle purchase decision: hybrid-electric, advanced diesel, and electric vehicles. If OEM NGVs are brought to market in future at a price that is competitive with other choices, there could be some market interest.

Rail

The technology for natural gas in locomotives is at the prototype stage. For this market to develop, OEM locomotive manufacturers must become interested in providing integrated technology solutions for storing and using LNG on trains. Fuel injection and metering technologies are similar, but larger, than those used in heavy-duty vehicles. The potential market for LNG use in locomotives is attractive, since one of these vehicles uses as much fuel as 20 heavy-duty vehicles. Also, natural gas locomotives will produce significantly fewer criteria air contaminants than their diesel counterparts. Rail routes parallel to major trucking corridors could share LNG infrastructure to reduce the cost. Even with high investment costs, long locomotive service life and high fuel use should yield attractive rates of return.

Filed: 2014-08-12
EB-2014-0012
Exhibit B.BOMA.2
Attachment 1

Appendix B

NGV Cross-Jurisdictional Analysis

	NGV STATUS/PENETRATION RATES[1]	POLICIES AND PROGRAMS	OUTCOMES
Argentina	Other than Pakistan, no other country in the world has as many NGVs in operation than Argentina. This country had 462,168 NGVs in use in 2000, and this figure has increased steadily each year, reaching 1,807,186 in 2009. NGVs as % of total vehicle population: 21.7. Number of refuelling stations in 2009: 1,851.	Since the 1980s, the government has kept the price of NG artificially low, facilitated the installation of equipment needed for service stations, and created a program for several thousand taxis in Buenos Aires to convert to NG. Another project, "Blue Corridors," will connect major cities in several South American countries with routes of NG fuelling stations.	The savings realized by taxi drivers was enough to convince car owners to convert their vehicles, which in turn, prompted more service stations to offer NG. Local industry is now working to gradually replace diesel in heavy-duty vehicle fleets.
Brazil	Brazil ranks third in the world in terms of the number of NGVs in use. This country had 60,000 NGVs in use in 2000, and this figure increased on an annual basis, reaching 1,632,101 in 2009. NGVs as % of total vehicle population: 9.6. Number of refuelling stations in 2009: 1,704.	In some large cities (e.g. Sao Paulo and Rio de Janeiro), the government is planning to promote programs to displace diesel with NG in city buses. Strategies are also being developed to make NG attractive to fleet operators by resolving issues such as technology, price differentials to diesel engines and fuel, taxation, and operating and maintenance practices. The Blue Corridors project (see Argentina) will also have an impact on the NGV market in Brazil.	NG was first used in LDVs in 1996; most of the NGVs now are aftermarket converted taxis or commercial medium-duty vehicles.
India	In 2000, India had 10,000 NGVs in operation. By 2009, this figure had increased to 725,000. NGVs as % of total vehicle population: 2.3. Number of refuelling stations in 2009: 520.	In addition to a Supreme Court mandate, government support was provided through further measures such as: ▪ Sales tax exemption on conversion kits; ▪ Concessional custom duty on CNG conversion kits; ▪ Allotment of land for CNG stations and pipelines on priority basis; and ▪ Banned old vehicles from registering in New Delhi.	The mandate resulted in 10,000 CNG buses on New Delhi's roads and has been credited with making significant improvements in the city's air quality. In 2003, another Supreme Court order acknowledged the success of the New Delhi CNG project and issued a directive to introduce clean fuels in 11 additional cities.
Italy	This country had 320,000 NGVs in operation in 2000, and this figure increased to 580,000 by 2009. NGVs as % of total vehicle population: 1.1. Number of refuelling stations in 2009: 730.	The government has adopted several direct funding initiatives to support NGV use, including subsidies for the construction of NG refuelling stations, taxi and commercial vehicle conversions, and replacement of public buses with those filled with NG. Italy has also mandated a tax-based differential between NG and petroleum-based transport fuels that makes NG retail prices approximately 50% of those for diesel.	In Europe, Italy has the greatest number of NGVs in use.

[1] National statistics: International Association for Natural Gas Vehicles: http://www.iangv.org/tools-resources/statistics.html;
State-level statistics: U.S. Energy Information Agency: http://www.eia.doe.gov/;
Number of refuelling stations at the state level: U.S. Department of Energy Alternative Fuels Data Center: http://www.afdc.energy.gov/afdc/fuels/stations_counts.html?print

Pakistan	Pakistan has the largest number of NGVs in the world. In 2000, Pakistan had 120,000 NGVs in use, and by 2009, this figure had increased to 2,400,000. NGVs as % of total vehicle population: 52.0. Number of refuelling stations in 2009: 3,105.	Among NGV policies in Pakistan are liberal licences for CNG retailing, free market consumer price of CNG, natural gas tariff for CNG linked to petrol, priority of natural gas connection for CNG, and exemption of import duty and sales tax on import of machinery and kits can be enumerated.	Despite being the global leader in NGV use, Pakistan continues to face a number of operational, implementation, and pricing issues. For example, certain stations are unable to deliver gas at adequate pressure, which extends refuelling times and causes queues. Deployment of CNG buses has been delayed due to insufficient funding. The government has also allowed producers to increase wholesale CNG prices to station operators, which has caused the discount of CNG prices to those of gasoline to fall from 50% to approximately 20%.
Peru	In 2006, Peru had 7,823 NGVs in use, and this figure has increased to 81,024 in 2009. NGVs as % of total vehicle population: 0.65. Number of refuelling stations in 2009: 94	The government has fixed the cost of natural gas $1.50 per gallon, compared with about $4.55 per gallon for 90 octane gasoline. Other initiatives that support NGVs include: ▪ Reduced taxis on the import of NGVs to Peru. ▪ Government-sponsored "My Taxi Program" is designed to help drivers convert their engines to natural gas. ▪ Funding is available to individuals who scrap old diesel vehicles.	The number of NGVs in Peru has skyrocketed over the last few years. The My Taxi Program has led 45,509 drivers to convert their engines in only 32 months.
United States	The U.S. had 105,000 NGVs in operation in 2000. This figure peaked at 121, 249 in 2004, and decreased to 110,000 in 2009. NGVs as % of total vehicle population: 0.06. Number of refuelling stations in 2009: 1,300.	Federal Incentives: ▪ *Safe, Accountable, Flexible, Efficient Transportation Equity Act:* Includes an excise tax credit of $0.50 per gasoline gallon equivalent of CNG or liquid gallon of LNG for use as a motor vehicle fuel. This credit was introduced in 2006 and expired December 31, 2009. ▪ *Energy Policy Act:* includes a qualified alternative fuel motor vehicle tax credit for the purchase of a new, dedicated, repowered, or converted AFV. It also includes an income tax credit to help cover the cost of NG refuelling stations. These credits will expire December 31, 2010. ▪ *American Recovery & Reinvestment Act (ARRA):* increases the credit value for purchasing equipment used to store and dispense qualified alternative fuels placed in service in 2009–10. Federal Programs: ▪ Clean Cities: government-industry partnership sponsored by the DoE, which strives to reduce dependence on petroleum resources. NGV projects will be featured in 19 of 25 cost-share projects announced in the Clean Cities program that will be funded with approximately $300M from the ARRA. ▪ ARRA provides funding to a variety of other programs that may benefit NGVs. State Programs: ▪ State tax credits for fuels, vehicles, infrastructure, and business development exist in 25 states.	NGV strategy in the U.S. has generally focused on high-fuel-use, return-to-base fleets that operate in urban areas. Numerous programs and initiatives have been introduced at the federal and state levels over the last several decades; however, these efforts have not led to success in fostering a sustainable NGV market.

UNION GAS LIMITED

Answer to Interrogatory from
Building Owners and Managers Association ("BOMA")

Reference: A-1-1

Does Union have Agreements signed with each of the six parties that responded to the RFI? From how many? Please file copies of the Precedent Agreements.

Response:

There are no signed agreements in place at this time.

UNION GAS LIMITED

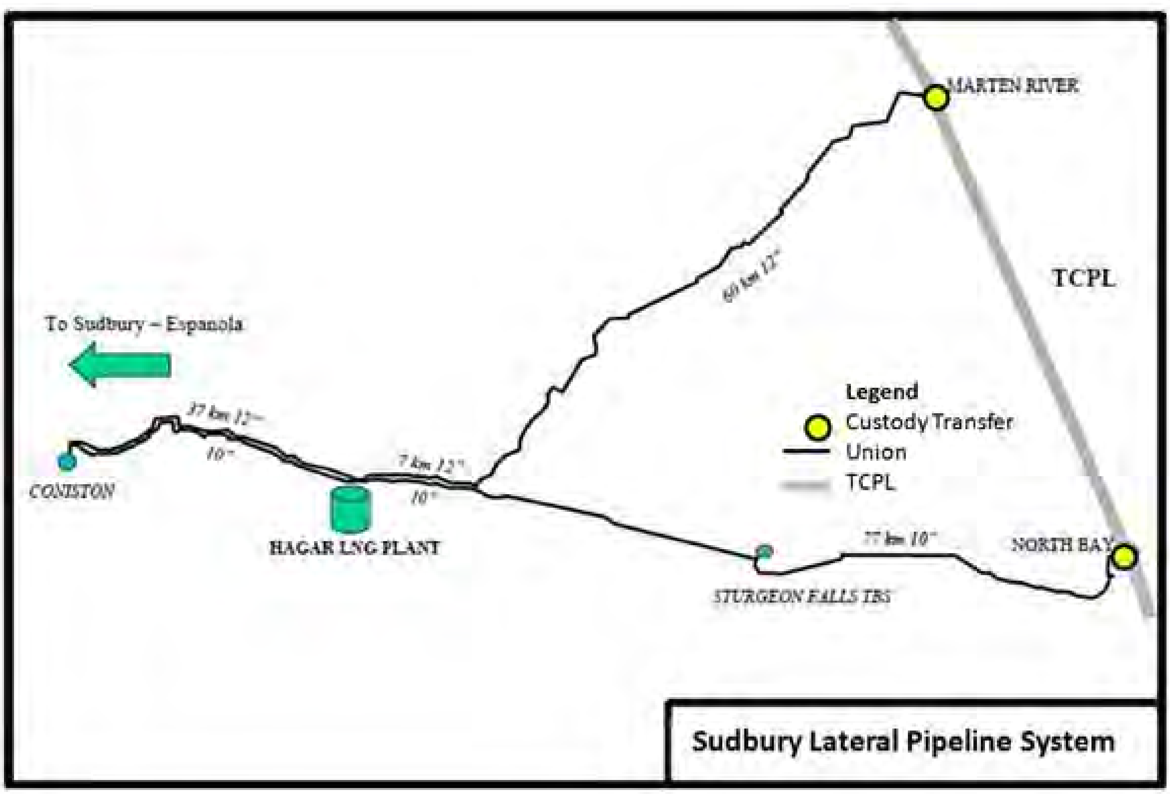
Answer to Interrogatory from
Building Owners and Managers Association ("BOMA")

Reference: A-1-1

Please provide a map that shows the custody transfer point from TCPL to the Hagar plant.

Response:

The map below shows the custody transfer points between Union and TCPL. Union interconnects with TCPL at North Bay and Marten River. Hagar does not connect directly to TCPL and is approximately 70km downstream of both of Union's North Bay and Marten River interconnects with TCPL on the Sudbury Lateral Pipeline system.



UNION GAS LIMITED

Answer to Interrogatory from
Building Owners and Managers Association ("BOMA")

Reference: A-1-1

In addition to the "Roadmap", please file any other studies or analyses that Union used in the formulation of its plans for the proposed LNG fuel business.

Response:

In addition to the Roadmap and discussions with other industry participants, Union is a member of the Canadian Natural Gas Vehicle Alliance ("CNGVA") and the Natural Gas Vehicle Working Group of the Energy Solutions Center. The Ontario truck market consists of approximately 90,000 Medium Duty Vehicles and 106,000 Heavy Duty Vehicles ("HDV") that consume the equivalent of 3.1 billion m3 of natural gas annually. The fleet is renewed by the addition of approximately 8,000 new Class 8[1] vehicles each year that could be natural gas (LNG or CNG) powered. In addition, there is a greater number of out of province registered HDV's that travel along the 401 corridor (48,000 truck trips per week between Montreal and Toronto) that require a source of fuel.

Union continues to work with other market participants through the CNGVA and others to address those barriers that are preventing LNG adoption. These barriers include the following.

a) Lack of codes and standards focused on the use of LNG.

Through the 1990's, a significant volume of work was completed to develop complete codes and standards for compressed natural gas and its use as a vehicle fuel. This body of work is largely intact today but there is very little work that has been completed on the same codes and standards as they apply to LNG. Updates need to be developed and accepted for Refuelling Stations, Vehicle installation Codes (B108 & B109), trade measurement of LNG, as well as updates to CSA Z276 (primary code for LNG plant equipment). To this end, the CNGVA working with NR Can and other market participants has established a broad working group and several technical advisory groups to work on this development.

[1] Class 8 – gross vehicle weight rating anything above 33,000lbs (14,969 Kg). These vehicles include most tractor trailer trucks. (source Government of Canada – Heavy duty vehicle and engine greenhouse gas emission regulations).

b) Cost premiums for LNG equipment

As a developing market, there is a premium cost associated with natural gas fuelled trucks. This is from the engine manufacturer, to the fuel tank suppliers and through to the OEM vehicle manufacturer. For example, each LNG fuel tank adds approximately $20,000 to the cost of an LNG fuelled Class 8 tractor. Engine premiums add an additional $20,000 to $30,000 to the overall cost. With two tanks per tractor, this adds up to $70,000 (additional 60%) to the cost of a Class 8 tractor. Very closely associated with this premium is the expected payback the carrier can expect. Even with overall fuel savings of 30% – 40%, the projected payback can be up to four years, depending on service, annual mileage, etc.

Large fleet operators routinely keep tractors for five to seven years and they are then resold to the used vehicle market. There is a risk that the operators may not be able to recoup the expected resale value of the units, if the market does not develop as projected.

c) Availability of approved OEM products

At the present time, there is one engine supplier to the OEM market, Westport Cummins. They have developed dedicated natural gas engine options covering a broad range of applications up to 400 HP. They are the dominant supplier in this market. In September 2013, Westport Innovations, a supplier of duel fuelled LNG engines ceased production of their higher horsepower, 15L engine leaving a void in the available market technology. (http://www.truckinginfo.com/channel/fuel-smarts/news/story/2013/10/westport-dropping-15-liter-lng-engine-for-north-america.aspx). Other manufacturers have competitive products in development or under trial, but the development of the LNG market has been delayed.

An alternative to new equipment is the use of after-market conversion products for existing diesel equipment. There are several options available but few are approved for use in Ontario. Their deployment needs to be closely monitored to ensure they meet the environmental standards expected.

d) A lack of refuelling infrastructure options and market participants

As stated in the response to Exhibit B.CME.6, there are only three refuelling stations in Ontario today and one is a private, single user facility. It is always described as the “chicken and the egg” dilemma when this market is reviewed. Without refuelling infrastructure, users will not invest in LNG equipment, and without consumers, companies are reluctant to invest in refuelling facilities. Development of the infrastructure will require market participants willing to invest in marginal projects until demand matches the supply.

UNION GAS LIMITED

Answer to Interrogatory from
Building Owners and Managers Association ("BOMA")

Reference: A-1-1

a) When did the Board give Union interim and final approval to research, pursue, and proceed with the business including seeking necessary regulatory approvals? When did Union first seek approval of its Board to pursue the LNG fuel business at Hagar?

b) When did it obtain final approval of its Board to proceed?

c) Please provide a copy of any of Union's business submissions to its Board, or the Sempra Board, for approvals to investigate, and to launch, the LNG initiative.

Response:

a) Projects of this scale do not require Spectra Board of Director approval as they are within the authority of the Union Gas executive. Union's executive supported developing a deeper understanding of the market and the role Hagar could play in Q1 2013. In Q4 of 2013, Union's executive supported filing an OEB application for an approved rate and conducting a non binding open season to determine market interest.

b) N/A

c) N/A

UNION GAS LIMITED

Answer to Interrogatory from
Building Owners and Managers Association ("BOMA")

Reference: A-2-19

Please provide the basis for Union's forecast of 416,000 GJ/year of interruptible liquefaction activity from September 2015 to December 2018.

Response:

Please see the response to Exhibit B.Energy Probe.10. The 416,000 GJ/year is an average of the years shown at Exhibit A, Tab 2, Schedule 5, line 9.

UNION GAS LIMITED

Answer to Interrogatory from
Building Owners and Managers Association ("BOMA")

Reference: A-2-21

Union estimates that the interruptible liquefaction service will generate approximately $2.1 million per year. If that amount is not sufficient to provide the utility return on the costs assigned or allocated to the liquefaction business, will Union be inputting revenue for the difference, so that the shareholders will assume the underperformance risk? Please discuss fully.

Response:

No, Union will not be imputing revenue if the $2.1 million per year in forecasted revenue is not sufficient to generate a utility return. Based on Union's current forecast of revenues and costs, including a utility return on rate base, Union's project is economic.

During Union's 2014-2018 IRM term, Union is assuming risk with the development of the interruptible liquefaction service. Specifically, Union is taking the risk on any cost overruns associated with the forecasted capital investment and the volume risk associated with the forecasted level of liquefaction activity. Should the costs of the capital investment exceed the forecast of $8.7 million or the level of liquefaction activity fall below the average annual forecast of approximately 415,000 GJ per year, Union's utility earnings will be reduced.

The forecasted revenues and costs associated with the liquefaction service will also be subject to a full review during Union's next cost of service proceeding.

UNION GAS LIMITED

Answer to Interrogatory from
Building Owners and Managers Association ("BOMA")

Reference: A1-T1

a) Page 1 - Please provide the justification for Union's comment at line 13 that "However, as liquefaction at Union's Hagar facility will be provided within a regulated regime the use of LNG could expand beyond motor vehicle fuel without further regulatory approvals".

b) Why does Union make the statement as part of this evidence?

Response:

a) – b) As stated in Union's evidence (Exhibit A, Tab 1, p. 1), the primary use of the LNG in the context of this application is a vehicle transportation fuel. The wording, "*However as liquefaction at Union's Hagar facility will be provided within a regulated regime the use of LNG could expand beyond motor vehicle fuel without further regulatory approvals.*", was included to ensure all parties, including the Board, were aware that although Union is seeking Board-approval for the liquefaction service as a regulated activity, there may be examples where the use of LNG can be expanded beyond motor vehicle fuel without requiring further regulatory approval. Such examples include power generation (ie. mining operations in remote areas); in industry for steam generation and to feed combined heat and power facilities; and, for domestic and commercial use.

For additional background, please see the response to Exhibit B.Staff.6.

UNION GAS LIMITED

Answer to Interrogatory from
Building Owners and Managers Association ("BOMA")

Reference: A1-T1

Page 6 - Please provide the calculation to support the statement at line 13, page 6 re: LNG competitiveness with diesel.

Response:

At current natural gas prices, LNG is approximately 30% to 40% less costly than diesel on an energy equivalent basis.

The comparison in the following chart is built up using actual data and several assumptions on delivery costs, recovery of capital and usage. In addition, large consumers of diesel do not pay the "retail pump price" but rather a negotiated rate with the refiner.

	$/GJ	$/DLE
Gas Year Nov14/Oct15 - Empress (Enerdata - July 27/2014)	$ 3.635	$ 0.132
TCPL tolls to NDA (including Fuel)	$ 1.411	$ 0.051
Liquefaction Tolls	$ 5.096	$ 0.185
Wholesale Price (FOB Hagar)	$ 10.14	$ 0.367
LNG Transportation Cost (300 km)		$ 0.100
Retail Markup		$ 0.300
LNG Cost to Consumer		**$ 0.767**
Diesel Price (MOE Gasoline Report for Week ended July 21, 2014)		**$ 1.289**
Savings		**40%**

UNION GAS LIMITED

Answer to Interrogatory from
Building Owners and Managers Association ("BOMA")

Reference: A1-T1

Page 6 - What would the reduction of net CO_2 emissions in Ontario by achieving Union's 2015-18 forecast of LNG production?

Response:

According to Environment Canada, the emission factors for the National Inventory Report (2011) are 2,663 g CO_2/litre of diesel and 1,879 g CO_2/m^3 of natural gas. On an energy equivalent basis, there is approximately 1.02 m3 natural gas per litre of diesel (DLE). The net CO_2 reduction is 2663 – (1879 * 1.02) = 746 g CO_2 /DLE or 21,034 g CO_2 /GJ of natural gas (LNG) consumed.

Based on Union's demand forecast shown in Exhibit A Tab 2 Schedule 5 the net annual CO_2 reductions are:

		2015	2016	2017	2018
Demand Forecast	GJ	67,840	339,200	576,640	678,400
CO_2 reduction	tonne	1,427	7,135	12,129	14,270

UNION GAS LIMITED

Answer to Interrogatory from
Building Owners and Managers Association ("BOMA")

Reference: A1-T1

Please discuss the insurance requirements, including the costs, Union needs to put in place for the new business.

Response:

The provision of this service at Hagar falls within Union's current insurance requirements. Union has not forecasted any incremental insurance costs related to this service.

UNION GAS LIMITED

Answer to Interrogatory from
Building Owners and Managers Association ("BOMA")

Reference: A1-T1

Please provide information on regulatory jurisdictions in Canada and the US that have approved "LNG for trucks" businesses:

a) as part of regulated utility;

b) as a separate affiliate company.

Response:

a) and b) Please see the response to Exhibit B.Staff.3.

UNION GAS LIMITED

Answer to Interrogatory from
Building Owners and Managers Association ("BOMA")

Reference: A1-T1

Please explain the calculation of the amount of LNG required at Hagar prior to the peak winter season, for system integrity purposes. Please use specific numbers.

Response:

Union's total system integrity space required was provided in EB-2011-0210, Exhibit D1, Tab 9 as 9.5 PJ's. Of this amount, the Hagar LNG volume of 0.6 PJ's (referenced in Exhibit A, Tab1, p. 12) was allocated to Union North. This volume is required to be in place prior to the peak winter season in order to ensure 90,000 GJ/d of vapourization capacity (also referenced in Exhibit A, Tab 1, p. 12) is available to meet unforeseen operational risks.

UNION GAS LIMITED

Answer to Interrogatory from
Building Owners and Managers Association ("BOMA")

Reference: A1-T1

Page 15 - Please confirm the amount by which the new measuring technology will increase the estimated storage space in the Hagar tank. What is the basis for the statement?

Response:

The current tank level gauge allows accuracy of +/- .97 ft = +/- 7,000 GJ's. The new radar measurement gauge will be accurate to +/-.007 ft = +/- 47 GJ's. After rounding, this results in Union having an increased working capacity of 7,000 GJ.

UNION GAS LIMITED

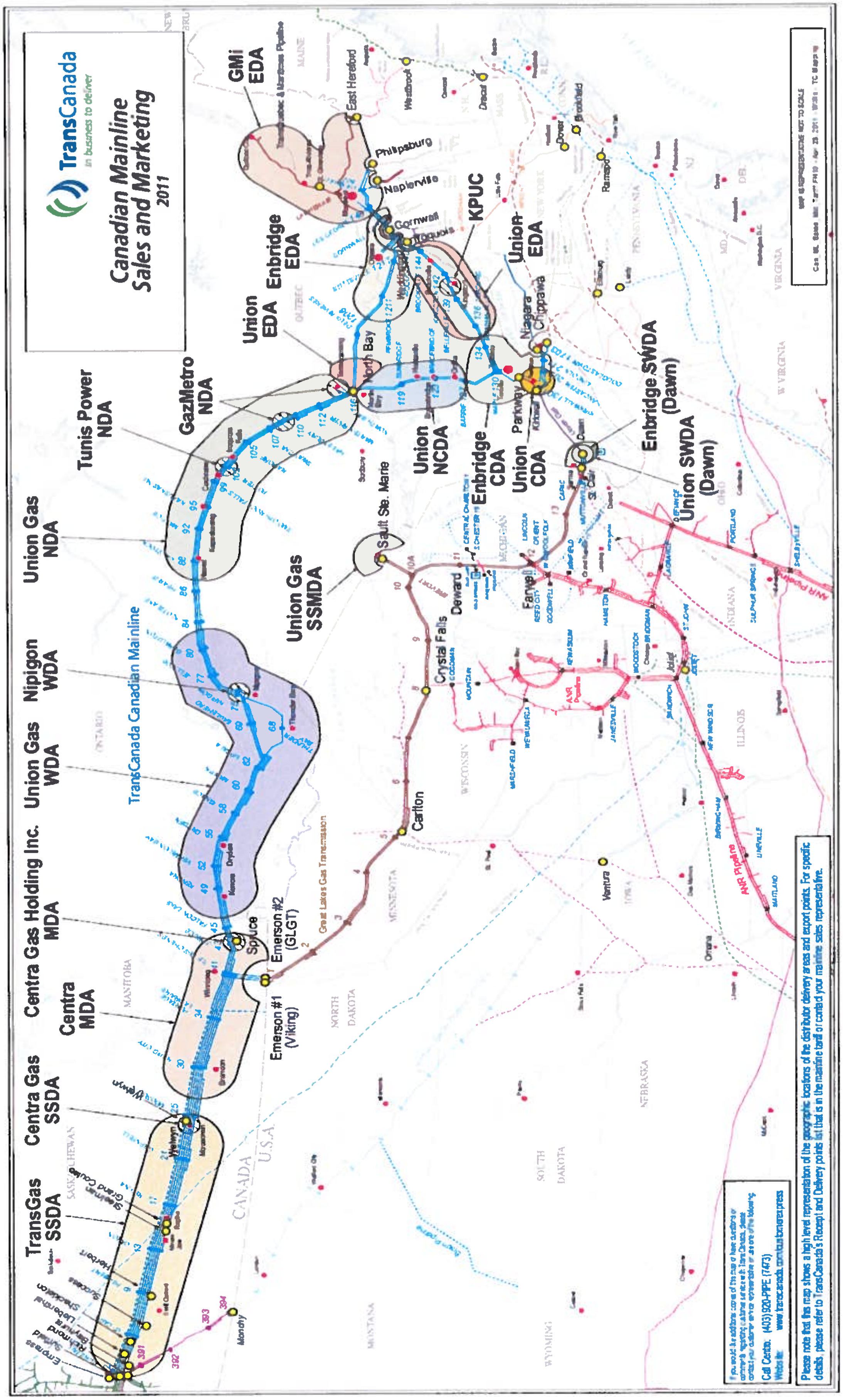
Answer to Interrogatory from
Building Owners and Managers Association ("BOMA")

Reference: A1-T1

What are the approximate boundaries of the Union NDA?

Response:

Union's NDA extends from North Bay, Ontario along the Highway 11 corridor to Hearst, Ontario. Attachment 1 is a map showing the location of the Union NDA.


TransCanada
In business to deliver
Canadian Mainline
Sales and Marketing
2011
TransGas SSDA
Centra Gas SSDA
Centra MDA
Centra Gas Holding Inc. MDA
Union Gas WDA
Nipigon WDA
Union Gas NDA
Tunis Power NDA
GazMetro NDA
Union EDA
Enbridge EDA
GMi EDA
KPUC
Union-EDA
Union NCDA
Enbridge CDA
Union CDA
Enbridge SWDA (Dawn)
Union SWDA (Dawn)
Union Gas SSMDA
TransCanada Canadian Mainline
Great Lakes Gas Transmission
ANR Pipeline
Empress
Monchy
Emerson #1 (Viking)
Emerson #2 (GLGT)
Spruce
Carlton
Crystal Falls
Deward
Farwell
Sault Ste. Marie
North Bay
Cornwall
Iroquois
Napierville
Philipsburg
East Hereford
Niagara
Chippawa
Parkway
Kirkwall
Dawn
St. Clair
Ventura
Dracut
Waddington
Ramapo
Please note that this map shows a high level representation of the geographic locations of the distributor delivery areas and export points. For specific details, please refer to TransCanada's Receipt and Delivery points list that is in the mainline tariff or contact your mainline sales representative.
Call Centre: (403) 920-PIPE (7473)
Website: www.transcanada.com/customerexpress

UNION GAS LIMITED

Answer to Interrogatory from
Building Owners and Managers Association ("BOMA")

Reference: A1-T1

Page 18 - What provisions will Union make to supply truck fleet customers who are interrupted? Are customers expected to have their own storage facilities?

Response:

Union is not making any provisions to supply fleet customers that are interrupted. Customers will need to manage the risk of interruption in a manner they deem appropriate.

UNION GAS LIMITED

Answer to Interrogatory from
Building Owners and Managers Association ("BOMA")

Reference: A1-T1

Page 20 - How is the maximum 1,860 daily delivery to all customers determined?

Response:

At page 19 of Exhibit A, Tab 1, Union states that "On a customer aggregated basis, the sum of all daily supplies cannot exceed 1,860 GJ/day. The 1,860 GJ/day total is based on the total annual liquefaction capacity less boil off replacement less an assumed amount of vapourization for system integrity needs. The remainder (678,400 GJ as shown at Exhibit B.Energy Probe.10) is then divided by 365.

UNION GAS LIMITED

Answer to Interrogatory from
Building Owners and Managers Association ("BOMA")

Reference: A1-T1

Page 21- Of the estimated $1.5 million contingency and IDC, how much is each component? Is there a true up, if not all the contingency is used?

Response:

Contingency level of 20% is a pre-determined level of contingency Union applies to all projects at this stage of development. It applies equally to all estimate components.

There is no true up of the forecasted capital investment of $8.7 million. Union is taking the risk on any cost overruns associated with the project during the 2014-2018 IRM term.

Please see the response to Exhibit B.BOMA.8 for additional detail.

UNION GAS LIMITED

Answer to Interrogatory from
Building Owners and Managers Association ("BOMA")

Reference: A1-T1

Page 22 - What are the TSSA requirements referred to? Please provide a copy.

Response:

The Hagar plant is registered as R19 with the TSSA. This requires the plant to be attended as per Ontario Regulation 219/01 – Director's Orders. A copy is provided at Attachment 1.

TECHNICAL STANDARDS &
SAFETY AUTHORITY
4th Floor, West Tower
3300 Bloor Street West
Toronto, Ontario
Canada M8X 2X4

IN THE MATTER OF:

**THE *TECHNICAL STANDARDS AND SAFETY ACT* 2000,
S. O. 2000, c. 16**

- and -

**ONTARIO REGULATION 219/01 made under the
Technical Standards and Safety Act 2000
(The Operating Engineers Regulation)**

DIRECTOR'S ORDER

The Director, of the Operating Engineers Regulation, *Technical Standards and Safety Act, 2000*, S.O. 2000, c. 16, pursuant to his authority as provided for in Section 36 (3) (c) of the *Technical Standards and Safety Act, 2000*, hereby orders the following:

1. The previous Director's Order varying the Operating Engineers Regulation (219/01) and dated June 27th, 2001 is hereby revoked and replaced with the following order.

2. Effective immediately Ontario Regulation 219/01 (being the Ontario Regulation made under the *Technical Standards and Safety Act* 2000 for Operating Engineers) is hereby varied as follows:

   i) The definition of dual control boiler is replaced with the following; "dual control boiler" means a steam or hot water boiler intended to be operated at high pressure or high temperature that is equipped with a control device that allow its operation either at high pressure or high temperature or low pressure or low temperature and includes a device for recording pressure or temperature.

ii) In the definition Temporary Heating Plant in parts (a and b) the reference to BHP is replaced with bhp.

iii) In Section 6 (2) (f) the reference to "the power rating" is replaced with "the engine power rating";

iv) In Section 9 (2) the reference to "P.L.A.N./3300 X 2" is replaced with "P.L.A.N./33000 X 2"

v) `Subsection 15 (3) is replaced with "Despite subsection (2), an alternative arrangement may be made for replacing the absent person as long as that arrangement is consistent with the safe operation of the plant and is approved by the Chief Officer";

vi) In Section 23 (1) the reference to Sections 39, 40 or 43 is replaced with Sections 39, 42 or 45;

vii) In Section 24 (2) the reference to Sections 39, 43 or 45 is replaced with Sections 39, 42 or 45;

viii) In Section 31 (4) the reference to "use of a registered plant" is replaced with "user of a registered plant";

ix) In Subsection 42 (3) the reference to subsection 45 (4) is replaced with subsection 45 (3);

x) In subsection 43 (1) the reference to "1471 kW (150 BHP, 50 TH)" is replaced with "1471 kW (150 bhp, 50 TH)", the reference to 15 psi (103 kpa) is replaced with "15 psi (103 kpa) or less than 212°F (100°C) and the reference to "(a) a hard wired low pressure control device that restricts the operating pressure of the dual control boiler to 15 psi (103 kpa); and" is replaced with "(a) a hard wired low pressure or temperature control device that restricts the operating pressure of the dual control boiler to 15 psi (103 kpa) or temperature to 212°F (100°C)."

xi) In subsection 43 (2) the reference to "the results obtained from the pressure recording device" is changed to "the results obtained from the pressure or temperature recording device".

xii) In Section 45 (1) the reference to Sections 39 and 42 is replaced with Sections 39 and 45;

TABLES

TABLE 1

xiii) The "Form 1" attached to this Director's Order is added to the regulation before Table 1

xiv) Under the column "To Convert" the following changes are made:

(a) After the word Therm/hour add (TH);
(b) After the word Kilowatt add (kW);
(c) After the word Boiler horsepower add (bhp);
(d) After the word Kilowatt add (kW);
(e) After the word Brake horsepower add (BHP); and
(f) After the word kilowatt add (kW)

TABLE 2

xv) The instructions for use of Table 2 and 3, 4, 5, 6 and 7, attached to this Director's Order are added to the regulation before Table 2;

xvi) On Table 2 in Section A under 4th Class for Limited combined Plant rating (L.V. & H.W. boilers excluded) the reference to "<4856 kW-LP" is replaced with "<5005 kW-LP";

xvii) On Table 2 in Section A under 4th Class for Limited combined Plant Rating (L.V. & H.W. boilers excluded) the reference to "<2403 kW-HP" is replaced with "<2552 kW-HP";

xviii) On Table 2 in Section A under 2nd Class the words "Limited boiler Plant Rating, Unlimited Prime Mover Plant Rating" are replaced with "Limited Boiler Plant rating, Unlimited Prime Mover Plant rating."

xix) On Table 2 in Section D under 3rd Class for Hot Water Boilers the reference under Low Temp. to "<23,543 kW (240 bhp 803TH)" is replaced with "<23,543 kW (2400 bhp, 803TH)";

xx) On Table 2 in Section E under 4th Class for Refrigeration the reference to "<149kW (200 bhp 5TH)" is replaced with "<298 kW (400 BHP, 10TH)";

xxi) On Table 2 in Section E under 3rd Class for Refrigeration the reference to "<597 kW (800 BHP, 20TH)" is replaced with:

"R13 and R18 = <597 kW (800 BHP, 20TH)
R7 = <746 kW (1000 BHP, 25TH)"

xxii) On Table 2 in Section F under 3rd Class for Class B Refrigeration Operator the reference to "<597 kW (800 BHP, 20TH)" is replaced with:

"R13 and R18 = <597 kW (800 BHP, 20 TH)
R7 = <746 kW (1000 BHP, 25 TH)"

TABLE 3

xxiii) On Table 3 under Explanatory Notes and Additional Requirements the reference to "Certificate Operating Engineer" is replaced with "Certified Operating Engineer".

xxiv) On Table 3 under Explanatory Notes And Additional Requirements the reference to, "A low water tube boiler shall be equipped with the fail safe devices specified in Section 39" is replaced with, "A water tube low water volume boiler shall be equipped with the fail safe devices specified in Section 39".

xxv) On Table 3 under Plant Requirements for Registration (C) the reference to "ATTENDED – 8HR/DAY OF OPREATION – 4TH CHIEF" is replaced with, "ATTENDED – 8HR/DAY OF OPERATION – 4TH CHIEF".

xxvi) On Table 3 under Plant Requirements for Registration (C) the reference to "ATTENDED – 8HR/DAY OF OPREATION – 2ND CHIEF" is replaced with "ATTENDED – 8HR/DAY OF OPERATION – 2ND CHIEF".

xxvii) On Table 3 under Plant Code B20 the reference to "ATTENDED - 4TH CHIEF 4TH SHIFT" as a plant requirement for registration is replaced with "ATTENDED – 2ND CHIEF & 3RD SHIFT".

xxviii) On Table 3 under Rating for Plant Code "B23 < 3924 (400 bhp, 134TH)" is replaced with "<3924 kW (400 bhp, 134TH)".

xxix) On Table 3 under Plant Code B26 the reference to "<294kW (30 BHP 10TH)" under rating (B) is replaced with "<294 kW (30 bhp 10TH)".

xxx) On Table 3 under type of Boiler Plant (A) (to the left of B30) under Hot water boilers the reference to "Boiler and systems water content greater than 750 Gal (3410 L) or less," is replaced with, "Boilers and systems water content greater than 750 Gal (3410 L)".

xxxi) On Table 3 under type of Boiler Plant (A) (to the left of B29) under hot water boilers the reference to "Flooded volume boiler water greater than 150 Gal (682 L) or less," is replaced with, "Flooded volume boiler water content greater than 150 Gal (682 L)".

Addendum to Table 3:

xxxii) On Table 3 reference to Table 3 (cont) is changed to addendum to Table 3.

xxxiii) "In the event steam boilers systems water capacity of 750 Imperial Gallons (3401 L)," is replaced with "In the event steam boiler systems water capacity of 750 imperial gallons (3410 L)."

Table 4

xxxv) On Table 4 under Plant Code P4 the reference to "<7kW (10 bhp, 25TH)" under rating (B) is replaced with "<7 kW (10 BHP, 25TH)".

xxxvi) On Table 4, under Requirements (C), in the vertical columns the word "Registration" is changed to "Registered".

Table 5

xxxvii) Under Explanatory Notes the reference to operator is changed to Operator.

Table 6

xxxviii) On Table 6 Explanatory Notes the reference to "Compressor Operator Certificate of Qualification are not" is replaced with "Compressor Operator Certificate of Qualification is not".

xxxix) On Table 6 under Explanatory Notes and Additional Requirements the reference to "Plants R 9, R 13, R 14 may have guarded controls applied in order to allow operator attendance as prescribed in Sections 23-24" is replaced with "Plants R 9, R 14, R 18, R 19, R 22 may have guarded controls applied in order to allow operator attendance as prescribed in Section 23-24".

xl) On Table 6 the enclosed Plant Codes R 15 – R 22 are added to the Table.

Table 8

xli) On Table 8 under Minimum Plant Size Code and Service Time in the time column beside Code B24 for First Class, the reference to "move than 6 m of total" is replaced with "not more than 6 m of total

xlii) On Table 8 under Minimum Plant Size Code and Service Time in the time column beside Code B24 for Second Class, the reference to "total as chief" is replaced with "total".

xliii) Under exemptions to Practical Qualifying Time Experience Training Course Practical Time Reduction (see B) "24 months" is replaced with "24 hours".

xliv) The chart code requirements for Table 8 is replaced with the "Instructions for Use of Table 8" which is attached to this Director's Order.

2. The form a Testimonial of Qualifying Experience referred to in Section 33 of Ontario Regulation 219/01 shall be in the form attached to this Director's Order as Form 1.

Dated at Toronto this 3rd day of February, 2003

ORIGINAL SIGNED

John W. B. Coulter
Chief Officer, Operating Engineers Regulation
Technical Standards and Safety Act

Form 1

Technical Standards and Safety Act, 2000

TESTIMONIAL OF QUALIFYING EXPERIENCE

Company Name ....

Company Address ....

Plant Registration No. .... Total kW Rating ....

Type of Plant ....

This will certify that ....
(Print name of person receiving experience)

was engaged as a ....
(Position held – Operating Engineers, Operator or Operating Assistant)

in the operation of the indicated registered plant equipment from .... to
(Date)

.... and has attained a total .... full time equivalent
(Date) *(No. of Months)*

months training and/or operating time experience required for .... class certification.
(Class of Certificate Desired)

Registered Equipment Experience	Regulations Designated Equipment Code	Registered kW Power Rating	Experience Time						
			Operating			Maintenance			Academic
			Days	Weeks	Mths	Days	Weeks	Mths	Months
Boilers									
Steam Prime Movers									
Compressors									
Refrigeration									
Steam Traction			Hours			Hours			Hours
An official testimonial letter from the approved course authority indicating a passing completion of the course must support qualifying time credit for academic courses.									
Boiler operation is mandatory for Operating Engineers and Steam Traction Operators									

As the applicant for certification as a .... I certify
(Class of Certificate Desired)
that my indicated plant equipment, experience and academic time testimony is true and correct.

....
(Applicant's Signature) *(Date)*

As the .... Certificate Class .... Number .... of
(Chief Operating Engineer/Operator or Company Official)

Registered Plant R- .... I .... certify that the information provided on this testimonial of service
(Print Name)
relating to operating and maintenance experience is true and correct and I recommend that .... be granted the requested certificate.
(Applicant Name)

....
(Signature) *(Date)* *(Telephone)*

CHIEF OPERATING ENGINEERS AND CHIEF OPERATORS CERTIFICATE OF QUALIFICATION LIMITED PLANT OPERATING AUTHORITY

INSTRUCTIONS FOR THE USE OF TABLE 2

Sections A - B - C - D - E have been column aligned to indicate the Limited Operating Authority of a specific class of Operating Engineer, 1st, 2nd, 3rd, 4th, relative to the combined energy items [excluding low water volume water tube boilers (LV) and hot water boilers (HW)] in Section (A) and the specific energy items Steam Boilers (B), Low Water Volume Water Tube Boilers (C), Hot Water Boilers (D) and Steam Prime Movers - Compressors - Refrigeration (E).

Limited operating authority when using L.V. or H.W. boilers, add column C or D to E rather than B.

Each energy item B - C - D - E is restricted within a max >, min < kW, high pressure (HP), low pressure (LP) or temperature range for each class of Operating Engineer.

In order to determine the Limited Operating Authority of any Operating Engineer one simply observes the power or temperature limits designated in the vertical columns below the Operating Engineer Classification.

The separate boxes (F) for Compressor Operator, Class B and A Refrigeration Operator and Steam Traction Operator clearly present the Limited Plant Operating Authority of each class.

PLANT REQUIREMENTS FOR REGISTRATION

INSTRUCTIONS FOR USE OF TABLES 3 – 4 – 5 – 6 - 7

Type of Plant (Column A) presents the type of energy item plant (Boiler, Steam Prime Mover, Compressor, Refrigeration, Traction) and the technical conditions related to its plant **Registration**.

Rating (Column B) presents the range of kW energy ratings of the item in A.

Plant Requirements for **Registration** (Column C) presents the range of **operating** requirements which will apply to a specific kW energy rating as presented in column B relative to the Type of Plant as presented in column A.

Type of Plant "A" + rating "B" = Plant Requirements for **Registration** "C."

The Plant Code within Column C allows a convenient locator and reference to a specific type of **registered or unregistered** plant. The prefix before the code number indicates the type of plant. ("B" = Boilers,
"P" = Steam Prime Movers, "C" = Compressors, "R" = Refrigeration, "T" = Traction).

REFRIGERATION PLANTS REGISTRATION REQUIREMENTS
TABLE 6

PLANT TYPE (A) IS POWER RATED (B) TO DETERMINE REGISTRATION REQUIREMENT (C)

EXPLANATORY NOTES AND ADDITIONAL REQUIREMENTS | PLANT REQUIREMENTS FOR REGISTRATION (C)

TYPE OF PLANT REFRIGERATON PLANT (A)	RATING & REFRIGERATON CAPACITY (B)	PLANT CODE	UNREGISTERED	UNATTENDED	REGISTERED	GUARDED CONTROLS	MAINTENANCE PROGRAM	ATTENDED - 8HR/DAY OF OPERATION - 4TH CLASS/B-CHIEF	ATTENDED- 8HR/DAY OF OPERATION - 3RD CLASS/B-CHIEF	ATTENDED - 8HR/DAY OF OPERATION-2ND CLASS/A-CHIEF	ATTENDED-3RD CLASS/B-CHIEF & 4TH CLASS/B-EACH SHIFT	ATTENDED - 2ND CLASS/A-CHIEF & 3RD CLASS/B-EACH SHIFT
BUILT UP PLANT	< 22 kW (30 BHP, 0.76TH)	R10	✓	✓								
	> 22 kW (30 BHP, 0.76 TH) < 149 kW (200 BHP, 5TH)	R11		✓	✓	✓	✓					
• No refrigerant field piping (Indirect)	> 149 kW (200 BHP, 5TH) < 298 kW (400 BHP, 10TH)	R12			✓	✓		✓				
• All units or installations	> 298 kW (400 BHP, 10TH) < 597 kW (800 BHP, 20TH)	R13			✓	✓			✓			
	> 597 kW (800 BHP, 20TH)	R14			✓							✓
BUILT UP PLANT	< 22 kW (30 BHP, 0.76TH)	R15	✓	✓								
	> 22 kW (30 BHP, 0.76TH) < 75 kW (100 BHP, 2.5TH)	R16		✓	✓	✓	✓					
• Refrigerant piping outside machinery room (Direct)	> 75 kW (100 BHP, 2.5TH) < 298 kW (400 BHP, 10 TH)	R17			✓	✓		✓				
• All units or installations	> 298 kW (400 BHP, 10 TH) < 597 kW (800 BHP, 20TH)	R18			✓						✓	
	> 597 kW (800 BHP, 20TH)	R19			✓							✓
MODULAR BUILT UP PLANT	< 22 kW (30 BHP, 0.76TH)	R20	✓	✓								
• Must be independent systems	> 22 kW (30 BHP, 0.76TH) < 597 kW (800 BHP, 20TH)	R21		✓	✓	✓	✓					
• Each compressor unit < 30 BHP • Each system < 100 BHP	> 597 kW (800 BHP, 20TH)	R22			✓							✓

Refer to Instructions on Page

INSTRUCTIONS FOR USE OF TABLE 8

- As prescribed, all candidates for a **Certificate of Qualification** must pass an examination determined by the Chief Officer.
- Candidates for 4th Class Operating Engineer, Compressor Operator and Refrigeration Class B Operator examination must be at least 18 years of age.
- A person who is the holder of a certificate issued by the Canadian Armed Forces that the Chief Officer considers equivalent to the practical qualifying time and examinations for 1-2-3-4 Operating Engineer shall be deemed to have met those qualifications.
- A person who is the holder of a 2nd or 1st Class Marine Engineers certificate according to S.T.C.W. or is a mechanical engineering C.E.T., professional or chartered engineer, acceptable to the Chief Officer, is exempt from the mathematics and science theory components of the 2nd and 1st Class examinations.
- Candidates for 1st - 2nd - 3rd Class Operating Engineer or Class A Refrigeration Operator certification may commence writing the respective class of examination upon receiving their 2nd - 3rd - 4th Class Operating Engineer or Class B Refrigeration Operator certificate, as the case may be.
- Candidates for a 4th Class Operating Engineer, Compressor Operator, Refrigeration Class B Operator or Steam Traction Operator may commence writing the respective class of examination at any time.
- Candidates for any class of certification as an Operating Engineer or Operator who have passed the required examinations, or any parts thereof, must obtain their certificate of qualification within five (5) years of such passing or re-writing of the examination will be required.
- A candidate for certification as a Compressor Operator or Refrigeration Operator, (Class A or B) who has completed a period of practical plant energy rating experience time in a registered attended compressor or refrigeration plant as prescribed by the former *Operating Engineers Act* and Regulations 904, will be permitted to apply such time rating to the changed practical plant energy rating experience time requirements prescribed by the Operating Engineers Regulation (O.Reg. 219/01) until the plant is re-registered to conform with the registration requirements of the Operating Engineers Regulation. Upon the plant re-registration, the candidate may retain the practical plant energy rating experience time gained prior to re-registration for application to the requirements of certification.

Part A = The practical qualifying time experience required for each certificate of Qualification.

Part B = The maximum full time attendance at a training course approved by the Chief Officer, which may be subtracted from practical (A) time. A further time reduction incentive has also been granted on the 1 – 2 – 3 – 4 Operating Engineers and Traction Operator Certificates. The full time course for 1st and 2nd Class may be substituted for 126 hours per examination paper of evening school course for 1st Class and 84 hours per examination paper for 2nd Class. Courses shall be approved by the Chief Officer and no incentive time reduction will be granted for evening school training. With the approval of the Chief Officer the approved training course school which operates a registered shift engineer attended plant providing full time operating services may provide the minimum three month for 4th Class and the minimum one month for 3rd Class practical experience. Such approval shall be governed by the number of shift scheduled trainees relative to plant size/rating and shift time period. Registered attended plants shall not be used as an approved course training plant lab and practical operating experience plant simultaneously.

Part C = The maximum full-time registered plant installation, service and repair time approved by the Chief Officer which may be subtracted from the required compressor or refrigeration practical (A) time.

Part D = The class of Marine Engineering Officer certificate (steam or motor with steam endorsement) according to the S.T.C.W. requirements which will allow the candidate to write an equal class of certification with no further qualifying experience time (N.Q.T.) required. Operating experience on motorship steam plants will be considered equivalent provided it is equal to the experience time, power and equipment rating required for Operating Engineers.

Part E = The non certified officer (rating rank) Marine Operating experience time on boilers, engines and auxiliaries of merchant and naval ships which may be subtracted from the maximum required practical (A) time. No further qualifying experience time (N.Q.T.) required.

Part F =· Shall be at least 16 years of age.

- A holder of a Certificate of Qualification as any class of Operating Engineer or Marine Engineer (steam or motor with steam endorsement according to the S.T.C.W.), with acceptable experience, is exempt from writing the examination and shall be issued on application and upon payment of the appropriate fee, a Certificate of Qualification as a Steam Traction Operator.

- In order to quality for exemption from the examination the authorized candidate must provide satisfactory proof of practical operating experience on fire tube boilers, solid fuel firing, reciprocating steam engines, injectors and steam pumps. Failure to provide such proof will require the candidate to pass examination questions based on those subjects.

UNION GAS LIMITED

Answer to Interrogatory from
Building Owners and Managers Association ("BOMA")

Reference: A2, T2, Sch 5

What is the basis of:

a) Union's forecast of liquefaction days?

b) Union's forecast of annual average liquefaction activity?

c) Please provide copies of any Union or third party studies used to underpin these forecasts.

d) Will the daily liquefaction capacity vary from one month to another? Please explain.

Response:

a) The liquefaction days forecast is detailed in Exhibit A, Tab 2, Schedule 5, Line 10 and shows an annual average of 167 days at a rate of 3,186 GJ/d. This is the average of the number of days required to liquefy the Forecast Liquefaction Sales Activity volume specified in Exhibit A, Tab 2, Schedule 5, Line 9 columns b) – d). Additionally, liquefaction is needed to replace 104,000 GJ/year of boil-off as detailed in Exhibit A, Tab 2, Schedule 6, Note (2). This adds another 33 days to the schedule which results in a total average annual requirement of 200 days per year. This assumes that in an average or normal year the LNG capacity is not required for the firm use to support system integrity.

b) Please see the response to Exhibit B.Energy Probe.10.

c) No studies were completed.

d) Yes, liquefaction capacity will vary depending on the need to re-fill System Integrity LNG space.

UNION GAS LIMITED

Answer to Interrogatory from
Building Owners and Managers Association ("BOMA")

Reference: A2, T2, Sch 5

Under what circumstances would the liquefaction service be interrupted? Please provide details, including numerical calculations. How is the risk of interruption quantified? What is it, and would it vary throughout the year?

Response:

The liquefaction service would be interrupted when liquefaction capacity is not available due to scheduled maintenance or Union needs to re-fill the tank after a system integrity event. The risk of interruption is completely dependent on the risk of a system integrity event.

The risk of interruption has not been quantified. It would vary throughout the year depending on maintenance schedules, the amount of boil-off and the volume requiring liquefaction to satisfy system integrity requirements.

UNION GAS LIMITED

Answer to Interrogatory from
Building Owners and Managers Association ("BOMA")

Reference: A2, T2, Sch 5

What is the term Union contemplates for long term liquefaction service contract?

Response:

Any contract greater than one year is considered a long term liquefaction service contract.

UNION GAS LIMITED

Answer to Interrogatory from
Building Owners and Managers Association ("BOMA")

Reference: A2, T2, Sch 5

Please show the calculation that underpins Union's revenue forecast.

Response:

Please see the response to Exhibit B.Energy Probe.2 b).

UNION GAS LIMITED

Answer to Interrogatory from
Building Owners and Managers Association ("BOMA")

Reference: Cost Allocation and Rate Design

Please indicate the number of times, and the extent to which, the Hagar plant as regasified and supplied gas to the distribution system to maintain system integrity, in each of the last ten years.

Response:

This information is available for the past five years.

Date	Vapourized Volume, GJ
23-Feb-11	14,015
2-Oct-11	5,376
24-Jan-13	19,006
14-Dec-13	21,118
2-Jan-14	35,325

UNION GAS LIMITED

Answer to Interrogatory from
Building Owners and Managers Association ("BOMA")

Reference: Cost Allocation and Rate Design

What percentage of the boil-off gas in last ten years was compressed and reinjected into the distribution system?

Response:

The boil-off gas is compressed and re-injected into the distribution system whenever possible. The only exception would be during periods of maintenance. The exact percentage is unknown.

UNION GAS LIMITED

Answer to Interrogatory from
Building Owners and Managers Association ("BOMA")

Reference: Cost Allocation and Rate Design

How many days of interruptible storage capacity is Union offering to the wholesale distributors as a fraction of the liquefaction capacity they purchase?

Response:

As stated at Exhibit A, Tab 2, p. 20, Union forecasts that customers will use up to 7,000 GJ of storage space. This amount represents approximately 1.1% of the forecasted annual sales activity in 2018 of 678,400 GJ. Storage space will not be assigned to individual customers, but rather the storage space will be used by Union to manage timing differences between natural gas deliveries and LNG dispensing.

UNION GAS LIMITED

Answer to Interrogatory from
Building Owners and Managers Association ("BOMA")

Reference: Cost Allocation and Rate Design

What is Union's understanding of the competition for the service it intends to provide in Ontario:

a) currently;

b) over the next three years.

Response:

a) and b) Currently, there are no LNG plants located in Ontario other than Hagar. LNG is available for purchase from either Gaz Metro Transport Solutions (in Montreal) or from the Citizen's Gas affiliate in Indianapolis. In either case, transportation costs are higher than would be available from the Hagar facility for Ontario based customers. A new LNG facility is being proposed by Northeast Midstream in Thorold Ontario. This facility is still in the planning stages and will not be constructed until 2016 or later. The lack of LNG supply in Ontario is currently a barrier to market adoption of LNG as a transportation fuel. The introduction of LNG from Hagar could provide the necessary stimulus to the market to support additional LNG facilities in Ontario.

UNION GAS LIMITED

Answer to Interrogatory from
Building Owners and Managers Association ("BOMA")

Reference: Cost Allocation Study KPMG, pp 8-9

a) Please provide the cost of, and describe, each asset, or each group of assets if they are smaller fungible assets, that were directly assigned to the processes of liquefaction, storage, or vaporization.

b) Please describe the common assets by cost item that were allocated to liquefaction, storage, or vaporization, based on the percentages of assets directly assigned to each process.

Response:

a) Please see Attachment 1.

b) Please see Attachment 2.

UNION GAS LIMITED
Directly Assigned 2013 Hagar Net Plant by Function

Line No	Direct Assigned Plant ($000's)	Gross Plant	Accumulated Depreciation	Net Plant
		(a)	(b)	(c) = (a-b)
	Liquefaction			
1	Compressors (Cycle Gas and Boil Off)	2,173	1,297	877
2	Purification (Salt Bath Heater and Molecular Sieves)	157	191	(34)
3	Cool and Liquefy (Cold Box and Cooling Towers)	1,184	812	372
4	Safety Upgrades	428	15	413
5	Nitrogen Generator	170	65	104
6	Other	37	45	(8)
7	Regulator Overheads	392	26	365
8	Total Liquefaction	4,541	2,452	2,089
9	**Storage**			
10	Storage Tank	4,574	3,302	1,272
11	Boil Off Compressor	1,813	67	1,745
12	Regulator Overheads	336	9	327
13	Total Storage	6,722	3,379	3,344
14	**Vapourization**			
15	LNG Vapourizers	410	205	204
16	LNG Pump	316	384	(68)
17	Safety Upgrades	214	11	203
18	Solar Equipment	359	436	(77)
19	Regulator Overheads	123	11	111
20	Total Vapourization	1,421	1,047	374
21	**Total Direct Assigned Plant**	12,684	6,878	5,807

UNION GAS LIMITED
2013 Hagar Remaining Net Plant by Function

Line No	Remaining Plant ($000's)	Gross Plant	Accumulated Depreciation	Net Plant	Liquefaction 36%	Storage 58%	Vapourization 6%	Total
		(a)	(b)	(c) = (a-b)	(d)	(e)	(f)	(g)=(d+e+f)
1	Backup Generator and Electrical Equipment	4,415	1,540	2,875	1,034	1,656	185	2,875
2	Valves and Yard Piping	533	399	135	48	77	9	135
3	Metering	97	123	(26)	(9)	(15)	(2)	(26)
4	Structures (Building Expenses)	3,299	1,756	1,543	555	889	99	1,543
5	Land	7	-	7	3	4	0	7
6	Other (Integrity Upgrades, Compressed Air, etc)	926	487	439	158	253	28	439
7	Regulator Overheads	806	39	767	276	442	49	767
8	Total Remaining Plant	10,084	4,344	5,740	2,065	3,305	370	5,740

UNION GAS LIMITED

Answer to Interrogatory from
Building Owners and Managers Association ("BOMA")

Reference: Ibid, p10, Table 2, Note 1 – The Hagar LNG costs include the Iroquois Falls Compression Station

How many miles is the Iroquois Falls ("IF") compression station from Hagar?

Response:

The Iroquois Falls compressor station is approximately 400 km from Hagar.

UNION GAS LIMITED

Answer to Interrogatory from
Building Owners and Managers Association ("BOMA")

Reference: Ibid, p10, Table 2, Note 1 – The Hagar LNG costs include the Iroquois Falls Compression Station

What is the cost of the IF station in rate base? What is the revenue requirement in 2013?

Response:

There is no cost associated with the Iroquois Falls compressor station in Union's 2013 Board-approved Hagar rate base. The Iroquois Falls compressor station is in Union North distribution rate base.

There is $0.019 million in Iroquois Falls compressor O&M included in the 2013 Board-approved Hagar revenue requirement of $5.098 million.

UNION GAS LIMITED

Answer to Interrogatory from
Building Owners and Managers Association ("BOMA")

Reference: Ibid, p10, Table 2, Note 1 – The Hagar LNG costs include the Iroquois Falls Compression Station

Why is it included in the Hagar facility costs?

Response:

In Union's 2013 Board-approved cost allocation study the Iroquois Falls compressor O&M costs are included in Union's Hagar O&M budget.

Union did not adjust the 2013 Hagar facility costs to remove the Iroquois Falls compressor O&M costs because the costs are included in Union's 2013 Board-approved Hagar O&M budget and the costs are immaterial (less than 1%) to Union's cost allocation and rate design proposals in this proceeding.

UNION GAS LIMITED

Answer to Interrogatory from
Building Owners and Managers Association ("BOMA")

Reference: Ibid, p10, Table 2, Note 1 – The Hagar LNG costs include the Iroquois Falls Compression Station

How many compression stations lie between IF and Hagar?

Response:

Union does not own or operate any compressor stations between Iroquois Falls and Hagar.

UNION GAS LIMITED

Answer to Interrogatory from
Canadian Manufacturers and Exporters ("CME")

Reference: Exhibit A, Tab 1, pages 15 to 18

We wish to gain a better understanding of all of the natural gas supply and liquefaction scenarios whereby Union could be providing the natural gas liquefaction services and the delivery of LNG to customers under its proposal. In this connection, please provide the following further information:

a) Could Union liquefy its own system gas at Hagar and sell Union-owned LNG to LNG customers at Hagar under the auspices of a Board-approved LNG sales rate?

b) Could Union sell system gas to potential LNG customers at the Hagar plant under the auspices of an existing Board-approved sales rate and then retain custody of that gas for the purposes of converting it to LNG under the auspices of a Board-approved liquefaction services rate for subsequent re-delivery of the LNG to its owner?

c) Could Union sell system gas to customers seeking LNG services at some other point on Union's system and then transport the customer owned natural gas to Hagar for liquefaction and re-delivery as LNG to the customer at Hagar?

d) Could customers directly purchase the natural gas to be liquefied at a point off the Union system and then use Union's transportation to carry the gas to Hagar to be liquefied and delivered to the customer as LNG at Hagar?

e) For each of the foregoing scenarios, please provide the prices that Union proposes to charge for each of the utility services it provides in connection with such transactions.

Response:

a) No. The service requires the customer to supply gas to Union at Union's NDA.

b) Yes. A rate has been added to Union's Schedule "A" Gas Supply Charges shown in Exhibit A, Tab 2, Schedule 4, pg. 2 of 2. The proposed minimum and maximum Rate L1 gas supply charges are \$3.7382/GJ and \$36.7099/GJ respectively.

c) No, the gas required for LNG services must be provided to Union at Union's NDA. Please see response to Exhibit B.CME.7 for additional detail.

d) Yes. For example, a customer could purchase gas at Dawn and utilize Union's C1 service to transport the gas to the NDA. The current OEB approved C1 rate for transportation from Dawn to Parkway is $0.08/GJ plus applicable fuel. The exchange from Parkway to the NDA would be a market based service and would be charged at the then current market rate.

e) The only scenario where Union could charge for transportation is that identified in part d) above. Transportation rates would be based on Union's Board approved C1 rate schedule. The C1 cross-franchise rate provides short term transportation services between two points. As an example, firm transportation from Dawn to Parkway is $2.42/GJ monthly demand charge plus fuel.

UNION GAS LIMITED

Answer to Interrogatory from
Canadian Manufacturers and Exporters ("CME")

Reference: Exhibit A, Tab 1, page 1, lines 13 to 15

The evidence states:

> *"However, as liquefaction services at Union's Hagar facility will be provided within a regulated regime, the use of the LNG could be expanded beyond motor vehicle fuel without further regulatory approvals."*

a) What are the uses of LNG beyond motor vehicle fuel referenced in this statement?

Response:

a) Please see the response to Exhibit B.Staff.1.

UNION GAS LIMITED

Answer to Interrogatory from
Canadian Manufacturers and Exporters ("CME")

Reference: Exhibit A, Tab 1, page 2, line 12

The evidence indicates that Union proposes to dispense LNG to LNG wholesalers or customers. What are the differences between an LNG wholesaler and an LNG customer?

Response:

An LNG wholesaler distributes LNG to end-use customers either through bulk tank loads or dispensing at a refuelling station. An LNG customer is one that consumes the LNG in their equipment or facility (i.e. mining operation).

UNION GAS LIMITED

Answer to Interrogatory from
Canadian Manufacturers and Exporters ("CME")

Reference: Exhibit A, Tab 1, page 19

Union asks the Board to approve both a cost-based rate and a range rate for liquefaction services. It also asks the Board to empower Union to require customers to commit to a Minimum Annual Volume ("MAV") of liquefaction services for each year. In connection with this evidence, please provide the following information:

a) Please distinguish between a case where Union proposes to charge a cost-based rate for liquefaction services from the cases where Union proposes to charge a rate for such services up to three times the cost-based interruptible liquefaction rate.

b) Will some customers be entitled to a cost-based rate while others must pay a negotiated rate for the services, or will all customers be subject to a negotiated rate for liquefaction services?

Response:

a) Union is proposing to charge the L1 rate of $5.096/GJ (cost-based) for liquefaction services with a contract term greater than one year.

b) All customers contracting for one year or greater will be entitled to cost based rates. Only those customers utilizing liquefaction services for one year or less will be subject to the negotiated rate.

UNION GAS LIMITED

Answer to Interrogatory from
Canadian Manufacturers and Exporters ("CME")

Reference: Exhibit A, Tab 1, pages 20 to 24
Exhibit A, Tab 2, pages 1 to 15

Traditionally, the Board has required that the differential between prices for ancillary services provided by a natural gas utility which fail to recover the fully allocated costs of providing such services and not simply the incremental costs be absorbed by the utility shareholder. In this connection, please provide the following information:

a) Redo the Cost Allocation and Rate Design exhibits and, in particular, Exhibit A, Tab 2, Schedules 5 and 6 to recover all fully allocated costs and a full utility return from the proposed LNG liquefaction services and indicate the extent to which the cost-based liquefaction charge will increase in that scenario.

b) Provide the forecast year-over-year liquefaction revenue totalling $8.470M shown in Exhibit A2, Tab 2, Schedule 6, line 20 with the revenues segregated between the following:

    i) Revenues from Union's sale of natural gas to the purchaser;

    ii) Revenues from Union's transportation of that gas from the point of sale to the Hagar plant;

    iii) Revenues from any other natural gas services Union provides such as storage;

    iv) Revenues from the provision of liquefaction services and the delivery of LNG to the customers; and

    v) Revenues from Union's sale of its own LNG to a customer at Hagar if that is one of the services Union will be providing.

c) Please indicate the extent to which revenues from the provision of liquefaction services only is or is not sufficient to recover the fully allocated costs of providing such services.

d) If the revenues associated with the provision of liquefaction services only does not recover the fully allocated costs of providing such services, then how will such revenues contribute to earnings subject to earnings sharing?

e) If the fully allocated costs exceed such revenues, will Union's proposals not erode regulated earnings subject to earnings sharing?

Response:

Union does not agree with the statement that the Board has required that the differential between prices for ancillary services provided by a natural gas utility which fail to recover the fully allocated costs of providing such services and not simply the incremental costs are to be absorbed by the utility shareholder.

Union's proposed rate design is intended to provide a contribution to the recovery of fully allocated 2013 Board-approved costs at the Hagar facility, as well as recover all incremental costs associated with the provision of the liquefaction service. This rate design is consistent with the rate design of the C1 Dawn to Dawn-TCPL firm transportation rate approved by the Board in EB-2010-0207 during Union's 2008-2012 IRM term.

a) For the purposes of this response only, Union has assumed:

- Incremental 2018 liquefaction costs of $1.872 million, forecast liquefaction activity of 678,400 GJ per year, and a change in the functionalization of 2013 Board-approved costs. In other words, this cost allocation analysis has been completed based on post expansion costs.
- A re-allocation of 2013 Board-approved indirect costs, such as general plant and administrative and general O&M costs.
- The inclusion of the system integrity demands of 751,950 GJ and the 2018 liquefaction demands of 678,400 GJ in estimating the contribution towards existing Hagar costs. This approach is consistent with the cost allocation approach provided at Attachment 1.

This approach is consistent with the manner in which Union expects to include the Rate L1 liquefaction service in its cost allocation study at its next cost of service proceeding in 2019.

Accordingly, Union updated Exhibit A, Tab 2, Schedule 1 to include the 2018 incremental revenue requirement associated with the liquefaction service, excluding compressor fuel. Specifically, Union added $1.377 million of the total 2018 incremental revenue requirement of $1.872 million (per Exhibit A, Tab 2, Schedule 5) to the total Hagar costs.

The inclusion of the 2018 incremental liquefaction costs results in a change in the functionalization of the $4.789 million presented at Exhibit A, Tab 2, Schedule 1. With the inclusion of the 2018 incremental liquefaction costs, $3.138 million (or 66%) of the $4.789 million would be allocated to the liquefaction function, $1.446 (or 30%) would be allocated to the storage function and $0.205 (4%) would be allocated to the vapourization function. A comparison of the proposed net plant by function relative to the updated net plant by function including the 2018 incremental liquefaction costs is provided at Attachment 1, page 1. The detailed functionalization of Hagar LNG costs including the 2018 incremental liquefaction costs is provided at Attachment 1, page 2.

Union also updated Exhibit A, Tab 2, Schedule 5 to include an allocation of indirect costs, such as general plant and administrative and general O&M costs, to Rate L1. To estimate the allocation of indirect costs, Union added the incremental 2018 Hagar liquefaction costs of $1.872 million to the 2013 Board-approved cost allocation study. Based on this analysis, Union estimates that the allocation of indirect costs would be approximately $0.690 million, which results in a total 2018 Hagar liquefaction cost of $2.562 million. The calculation of the 2018 incremental project costs and the allocation of 2013 Board-approved costs is provided at Attachment 2.

Lastly, Union updated Exhibit A, Tab 2, Schedule 6 to incorporate this analysis. Based on these results and the assumptions listed above, Union estimates that the 2018 liquefaction rate would be $6.313 ($/GJ) (Attachment 3, line 17).

b) i) Union cannot forecast the gas supply revenue related to the liquefaction service as gas supply charges will be negotiated with customers based on the proposed Rate L1 gas supply charges. Negotiated Rate L1 gas supply charges will fall within Union's proposed minimum and maximum gas supply charge.
   ii) N/A
   iii) N/A
   iv) Union is forecasting $8.5 million in utility revenue related to the provision of the liquefaction service from September 1, 2015 to December 31, 2018.
   v) Union will not be providing this service.

c) Union cannot determine whether revenues from the proposed liquefaction service are sufficient to recover the fully allocated costs of providing the service at this time. As described in evidence, Union's proposed rate design is intended to provide a contribution to the recovery of fully allocated 2013 Board-approved costs at the Hagar facility, as well as recover all incremental costs associated with the provision of the service. This rate design is consistent with the rate design of the C1 Dawn to Dawn-TCPL firm transportation rate approved by the Board in EB-2010-0207.

   Union will determine the fully allocated costs associated with the proposed liquefaction service at its next rebasing proceeding in 2019, when it completes a cost allocation study. To the extent that the approved liquefaction rate does not recover the fully allocated costs at that time, the liquefaction rate will increase to ensure there is no revenue deficiency.

d) As Union's rate design is intended to provide a contribution to the recovery of fully allocated Hagar costs and recover all incremental costs (return, taxes, depreciation and operating expenses), it is Union's expectation that the proposed liquefaction service will contribute to earnings subject to sharing over Union's 2014-2018 IRM term.

e) Please see part d) above.

UNION GAS LIMITED
Comparison of the Proposed 2013 Board-Approved Hagar Net Book Value by Function and the Updated
2013 Board-Approved Hagar Net Book Value by Function Including 2018 Incremental Hagar Liquefaction Costs

Line No.	Particulars ($000's)	Liquefaction	Storage	Vapourization	Total
		(a)	(b)	(c)	(d)
	Proposed Hagar Net Plant Allocation (1)				
1	Direct Assigned Net Plant	2,089	3,344	374	5,807
2	Remaining Net Plant (2)	2,065	3,305	370	5,740
3	Total Net Plant	4,155	6,649	743	11,547
4	Total Net Plant (%)	36%	58%	6%	100%
	Updated Hagar Net Plant Allocation				
5	Direct Assigned Net Plant	2,089	3,344	374	5,807
6	2018 Incremental Hagar Net Plant (3)	7,763	-	-	7,763
7	Total Net Plant Including 2018 Incremental Project Costs	9,852	3,344	374	13,570
8	Remaining Net Plant (4)	4,168	1,414	158	5,740
9	Total Net Plant (line 7 + line 8)	14,020	4,758	532	19,310
10	Total Net Plant (%)	73%	25%	3%	100%

Note:
(1) Exhibit A, Tab 2, page 7, Table 2.
(2) Functionalized in proportion to the direct assigned net plant (line 1).
(3) Exhibit A, Tab 2, Schedule 5, column (d), line 2.
(4) Functionalized in proportion to the updated direct assigned net plant including 2018 incremental Hagar net plant (line 7).

UNION GAS LIMITED
Proposed 2013 Board-Approved Hagar Revenue Requirement Including 2018 Incremental Hagar Liquefaction Costs by Function

Line No.	Particulars ($000's)	2013 Board-Approved Hagar LNG Costs	2018 Incremental Hagar Costs (1)	Total Hagar Costs	Allocation Methodology	Liquefaction	Storage	Vapourization	Total
		(a)	(b)	(c) = (a + b)	(d)	(e)	(f)	(g)	(h) = (e+f+g)
	Rate Base Calculation								
	Hagar LNG Plant								
1	Gross Plant	22,768	8,685	31,454	Direct Assignment	20,548	9,207	1,699	31,454
2	Accumulated Depreciation	11,221	922	12,144	Direct Assignment	6,528	4,449	1,167	12,144
3	Hagar LNG Net Plant	11,547	7,763	19,310		14,020	4,758	532	19,310
4	Hagar LNG Net Plant (%)					73%	25%	3%	100%
	General Plant								
5	Gross Plant	1,095	-	1,095	Hagar LNG Net Plant (line 4)	795	270	30	1,095
6	Accumulated Depreciation	502	-	502	Hagar LNG Net Plant (line 4)	365	124	14	502
7	General Net Plant	593	-	593		431	146	16	593
8	Total Net Plant	12,140	7,763	19,903		14,451	4,905	548	19,903
9	Working Capital								
10	Gas In Storage	3,093	-	3,093	Direct Assignment	-	3,093	-	3,093
11	Other	235	-	235	Hagar LNG Net Plant (line 4)	171	58	6	235
12	Total Working Capital	3,328	-	3,328		171	3,151	6	3,328
13	Rate Base	15,469	7,763	23,232		14,622	8,055	555	23,232
14	Rate Base Excluding 2018 Incremental Costs	15,469	-	15,469		6,858	8,055	555	15,469
15	Rate Base (%)					44%	52%	4%	100%
	Revenue Requirement Calculation								
	Return and Taxes								
16	Return on Rate Base	1,132	448	1,580	Rate Base (line 15) (2)	950	590	41	1,580
17	Income Tax	131	(1)	131	Rate Base (line 15) (2)	58	68	5	131
18	Property Tax	80	45	126	Property Tax Allocator (3)	96	25	5	126
19	Total Return and Taxes	1,344	493	1,836		1,103	683	50	1,836
	Depreciation Expense								
20	Hagar - Local Storage	734	307	1,041	Direct Assignment	684	285	73	1,041
21	General Plant	148	-	148	Hagar LNG Net Plant (line 4)	108	37	4	148
22	Total Depreciation Expense	882	307	1,190		791	322	77	1,190
	Hagar O&M								
23	Hagar O&M	1,463	-	1,463	Hagar LNG Net Plant (line 4)	1,062	360	40	1,463
24	Hagar O&M	57	577	634	Direct Assignment	634	-	-	634
25	Administrative and General O&M	1,353	-	1,353	Hagar LNG Net Plant (line 4)	982	333	37	1,353
26	Total O&M Expenses	2,872	577	3,449		2,678	694	78	3,449
27	Total Revenue Requirement Excluding Compressor Fuel	5,098	1,377	6,476		4,572	1,698	205	6,476
28	Total Revenue Requirement Excluding Compressor Fuel (%)					71%	26%	3%	100%
	Costs Direct Assigned to System Integrity								
29	Gas in Storage Working Capital (4)	253	-	253	Direct Assignment	-	253	-	253
30	Variable O&M Costs	57	-	57	Direct Assignment	57	-	-	57
31	Total Costs Direct Assigned to System Integrity	310	-	310		57	253	-	310
32	Costs Direct Assigned to Rate L1 (1)	-	1,377	1,377	Direct Assignment	1,377	-	-	1,377
33	Total Revenue Requirement Excluding Direct Assigned Costs (line 27 - line 31 - line 32)	4,789	-	4,789		3,138	1,446	205	4,789
34	Total Revenue Requirement Excluding Direct Assigned Costs (%)					66%	30%	4%	100%

Notes:
(1) 2018 incremental Hagar liquefaction costs of $1.872 million (Exhibit A, Tab 2, Schedule 5, Column d) excluding $0.495 compressor fuel ($1.872 - $0.495 = $1.377).
(2) Direct assigned 2018 incremental rate base and income taxes to liquefaction. Functionalized 2013 Board-approved income taxes in proportion to rate base excluding incremental 2018 costs.
(3) Functionalized 2013 Board-approved property tax in proportion to gross plant.
(4) $3.093 million in gas in storage working capital represents a revenue requirement of $0.253 (return of $0.226 million and income taxes of $0.026 million).

UNION GAS LIMITED
2018 Incremental Hagar Liquefaction Costs Including an
Allocation of 2013 Board-approved Indirect Costs

Line No.	Particulars ($000's)	
	Incremental Revenue Requirement Calculation	
	Rate Base Investment	
1	Average Investment	7,763
	Revenue Requirement Calculation	
2	Return on Rate Base (1)	448
3	Income Tax (2)	(1)
4	Depreciation Expense (3)	307
5	Municipal Taxes	45
6	Liquefaction O&M (4)	1,072
7	Total Revenue Requirement (5)	1,872
8	Allocation of Indirect Costs and Taxes (6)	690
9	Total Revenue Requirement Including an Allocation of Indirect Costs and Taxes (line 7 + line 8)	2,562
	Forecast Liquefaction Activity	
10	Forecast Liquefaction Sales Activity (GJ)	678,400
11	Number of Liquefaction Days per Year (7)	213

Notes:
(1) The required return assumes a capital structure of 64% long-term debt at 4% and 36% common equity at the 2013 Board-approved return of 8.93%.
(2) Taxes related to the equity component of the return at a tax rate of 26%. Taxes related to utility timing differences are negative as the capital cost allowance deduction in arriving at taxable income exceeds the provision of book depreciation in the year.
(3) Depreciation expense at 2013 Board-approved depreciation rates.
(4) Incremental liquefaction O&M costs as provided in Exhibit A, Tab 1, Table 4.
(5) Total 2018 Incremental Revenue Requirement as per Exhibit A, Tab 2, Schedule 5, Column (d).
(6) Includes a shift of indirect costs associated with the 2018 incremental Hagar LNG costs, such as general plant and administrative and general O&M, and an adjustment for 2018 property and income taxes, which are allocated based on 2013 Board-approved cost allocation methodology.
(7) Days of liquefaction assumes daily liquefaction capacity of 3,186 GJ/day. Average number of days is based on the first full 3 years of activity.

UNION GAS LIMITED
Estimation of the 2018 Liquefaction Rate Including an
Allocation of Indirect Costs based on the Incremental 2018 Hagar Liquefaction Costs

Line No.	Particulars		
	Liquefaction Service Commodity Charge:		
	Existing Liquefaction Costs		
1	Hagar Liquefaction Revenue Requirement ($000's)	(1)	3,138
2	Annual Liquefaction Demands (GJs)	(2)	1,430,350
3	Average Rate per Unit ($/GJ) (line 1 * 1000 / line 2)		2.194
	Incremental Liquefaction Costs		
4	Average Annual Revenue Requirement ($000's)	(3)	2,562
5	Average Annual Forecast Liquefaction Sales Activity (GJs)	(4)	678,400
6	Average Rate per Unit ($/GJ) (line 4 * 1000 / line 5)		3.776
7	Liquefaction Commodity Charge ($/GJ) (line 3 + line 6)		5.970
	Storage Space Cost:		
	Existing Storage Service Costs		
8	Hagar Storage Revenue Requirement ($000's)	(5)	1,446
9	Annual Liquefaction Demands (GJs)	(2)	1,430,350
10	Average Rate per Unit ($/GJ) (line 8 * 1000 / line 9)		1.011
11	Hagar Maximum Storage Space (GJ)	(6)	648,000
12	LNG Storage Space (GJ)		7,000
13	Storage Rate per Unit ($/GJ) (line 12 / line 11 * line 10)		0.0109
	Distribution Service Cost:		
	Existing Distribution Costs		
14	Average Distribution Revenue Requirement ($000's)	(7)	225
15	Average Annual Forecast Liquefaction Sales Activity (GJs)	(4)	678,400
16	Distribution Commodity Rate ($/GJ) (line 14 * 1000 / line 15)		0.3316
17	Total Bundled Liquefaction Commodity Charge ($/GJ) (line 7 + line 13 + line 16)		6.313
	Liquefaction Revenue:		
18	Total Liquefaction 2018 Revenue ($000's) (line 15 * line 17 / 1000)		4,283

Notes:

(1) Exhibit B.CME.5 a) Attachment 1, line 33, column (e).
(2) Forecast of liquefaction includes activity reserved for system integrity and incremental 2018 liquefaction demands. The system integrity demands assumes one storage cycle and approximately 104,000 GJ for boil off gas.
(3) Exhibit B.CME 5 a) Attachment 2, line 9.
(4) Schedule 5, line 9, column (d).
(5) Exhibit B.CME.5 a) Attachment 1, line 33, column (e).
(6) Storage space calculation assumes maximum storage capacity of 610 mcf and a heat value of 37.51.
(7) Schedule 2, line 24, column (c).

UNION GAS LIMITED

Answer to Interrogatory from
Canadian Manufacturers and Exporters ("CME")

Reference: Exhibit A, Tab 1, pages 8 to 10

In the evidence, Union refers to FortisBC and Gaz Métro ("GMi") press releases pertaining to their role in LNG development. The press releases indicate that, in the cases of each of these utilities, the LNG development activities are being undertaken by affiliates. The Fortis press release indicates that the LNG dispensing rate has been set at $4.35/GJ and that customers will also pay the natural gas commodity cost per GJ. The GMi press release suggests that GMi sells its LNG output to an affiliate, Gaz Métro Transport Solutions, LP ("GMTS") which operates two LNG fuelling stations in Québec and one in Ontario.

In connection with this evidence, please provide the following:

a) A detailed description of the regulated LNG services Fortis and GMi provide and the rate schedules which their regulators have approved pertaining to the provision of such services;

b) The approximate range of prices at which GMTS sells LNG at its fueling station near Mississauga;

c) Are GMi's sales of LNG from its Mississauga fueling station unregulated?;

d) Are there any other unregulated LNG fueling stations in Ontario and, if so, at what prices is LNG being sold from those fueling stations?

e) How will Union's proposed sale of liquefaction services at its Hagar plant affect the operation of the LNG fuel market in Ontario?

Response:

a) The following is a list of the British Columbia Utilities Commission decisions included in the research Union completed:

Order G-118-11 (July 8, 2011)
http://www.bcuc.com/Documents/Decisions/2011/DOC_28147_G-118-11_FEI_AES%20Offering%20Scoping%20Order.pdf

Order G-128-11 (July 19, 2011)

http://www.bcuc.com/Documents/Decisions/2011/DOC_28195_G-128-11-FEI-CNG-LNG_Reasons.pdf

Order G-165-11A (September 26, 2011)
http://www.bcuc.com/Documents/Decisions/2011/DOC_28770_G-165-11A_FEI-Compression-Rate-for-NGV-Reasons-WEB.pdf

Decision (April 12, 2012)
http://www.bcuc.com/Documents/Decisions/2012/DOC_30356_04-12-2012-FEU-2012-13RR-Decision-WEB.pdf

Order G-156-12 (October 22, 2012)
http://www.bcuc.com/Documents/Decisions/2012/DOC_32176_10-22-2012-G-156-12_FEI-Vedder-Temporary-LNG-Service-WEB.pdf

The current rates for FortisBC can be found at -
http://www.fortisbc.com/NaturalGas/Business/Rates/Pages/default.aspx

The GMi decisions included in the research are:

Decision D-2010-144 (November 4, 2010)
http://www.regie-energie.qc.ca/audiences/decisions/D-2010-144.pdf

Decision D-2011-030 (March 17, 2011)
http://publicsde.regie-energie.qc.ca/projets/15/DocPrj/R-3751-2010-A-0005-DEC-DEC-2011_03_17.PDF

GMi's current rates can be found at - http://www.gazmetro.com/residentiel/raccorder-votre-residence/tarifs.aspx

b) GMTS is a non-regulated affiliate and all sales are to a single party under contract. Pricing is not published.

c) GMi is not selling LNG in Mississauga. The affiliate GMTS is. The refuelling facilities are part of Robert Trucking's Mississauga yard and sales of LNG to Robert are unregulated.

d) There are two other "stations" in Ontario. One each in Cornwall and Woodstock. These have been set up using non-stationary, refuelling units until such time as the market demand will support a permanent facility. LNG is sold under dedicated contracts and pricing is not public.

e) The LNG service from Hagar will provide a local, affordable and reliable source of LNG to the Ontario market. The volumes available from Hagar will be small relative to the Ontario market. Although these volumes are not expected to affect the overall operation of the LNG fuel market in Ontario, the proposed service is expected to help stimulate demand and encourage other participants to enter the Ontario market, from both the supply side and demand side.

UNION GAS LIMITED

Answer to Interrogatory from
Canadian Manufacturers and Exporters ("CME")

Reference: Exhibit A, Tab 2, Schedules 3 and 4

The proposed L1 Rate Schedule appears to contemplate charges for the following:

- Liquefaction rate
- Short-term (1 year or less) liquefaction rate
- Minimum annual charge
- Gas supply charge

In connection with this evidence, please provide the following:

a) Please show how the charges in this Rate Schedule will be applied in each of the scenarios to be provided in response to question 1;

b) How do the various charges in Schedule A to Rate L1, being Exhibit A, Tab 4, Schedule 4, compare to the Board-approved charges for the other transportation and storage services Union provides to its customers under the auspices of Board-approved Rate Schedules?

Response:

a) and b)

Liquefaction Rate:

Union's proposed interruptible liquefaction rate of $5.096/GJ will apply to any sales service or direct purchase customer utilizing the Rate L1 liquefaction service for a term greater than one year. The proposed liquefaction rate is cost-based, consistent with other transportation (e.g. Rate T1, Rate T2, Rate M12) and storage (e.g. Rate T1, Rate T2) rates approved by Board. The liquefaction rate is not directly comparable to cost-based transportation and storage rates in that the costs reflect the costs associated with providing the new liquefaction service, which may be different than the costs associated with the provision of transportation and storage services.

Short-term (1 year or less) Liquefaction Rate

Union's proposed short-term maximum liquefaction rate of $15/GJ will apply to any sales service or direct purchase customer utilizing the Rate L1 liquefaction service for a term of one year or less. The proposed maximum liquefaction rate is market-based and intended to enable Union to respond to the potential market value of its short-term interruptible liquefaction service. This approach is consistent with the Board-approved C1 transportation rate schedule, which enables Union to sell interruptible or short-term (one year or less) firm transportation up to a rate of $75/GJ.

Minimum Annual Charge

The proposed minimum annual charge under the Rate L1 rate schedule will apply to any sales service or direct purchase customer who commits to a minimum annual volume of liquefaction service, but does not take delivery of that volume. Should this occur, the customer shall pay an amount equal to the deficiency from the minimum volume times a commodity charge. A Rate L1 minimum annual charge is consistent with other Board-approved rate schedules (e.g. Rate M4, Rate M5, Rate T1).

Gas Supply Charge

The proposed Rate L1 minimum and maximum gas supply charges, per Union North Schedule "A" at Exhibit A, Tab 2, Schedule 4 will apply to sales service customers only. The Rate L1 gas supply charge will be a negotiated rate within the Board-approved minimum and maximum range.

As described at Exhibit A, Tab 1, page 17 under "Gas Supply Commodity and Upstream Transportation Arrangements" there are two options available for customers to manage their gas supply commodity and upstream transportation. The first option is for the customer to contract with Union for the provision of utility sales service under the proposed Rate L1 rate schedule and the Union North Schedule "A". Under this option, Union would provide both gas supply commodity and upstream transportation.

The second option, a direct purchase arrangement, is for customers to contract directly with gas suppliers or marketers for the provision of gas supply commodity and upstream transportation to deliver natural gas to the Union NDA. Under this option, the customer will manage its own gas supply and upstream transportation arrangements in a manner similar to other Union North direct purchase (T-Service) customers.

The proposed Rate L1 gas supply charges (expressed in $/GJ) are equivalent to the Board-approved interruptible Rate 25 gas supply charges (expressed in cents/m^3). Accordingly, both interruptible gas supply services in Union North are priced consistently.

UNION GAS LIMITED

Answer to Interrogatory from
Energy Probe

Reference: Exhibit A, Tab 1, Page 1, Line 11ff

Preamble: The sale, transmission, distribution or storage of motor vehicle fuel gas by a person other than a Class A distributor is exempted from Section 36 of the OEB Act by Section 2. (2) (b) of O. Reg. 161/99.

a) Why does Union want to provide this proposed LNG Transportation Fuel Service as a Regulated Service/Rate rather than as a non-utility business? Please provide the regulatory case/rationale for this.

b) Assuming Union would provide the LNG Transportation Fuel as a non-regulated service and Union "LNG" paid Union Gas for the appropriate costs for use of the utility assets at the Hagar facility, what would be the reduction in the annual revenue requirement related to Hagar? Please provide a schedule that shoes the allocated costs and shows the annual revenue requirement change over the IRM period.

c) Would this change to revenue (assuming Union "LNG" is responsible for capital) be considered a Y factor under the IR regime? Please discuss in detail and in particular alternative regulatory treatments assuming LNG Transportation Fuel is a non-utility business.

Response:

a) Please see the response to Exhibit B.Staff.6.

b) Under a scenario where Union provided LNG for transportation fuel as a non-regulated service and Union "LNG" paid Union for the appropriate costs for the use of the utility assets at Hagar, there would be no reduction in the 2013 Board-approved revenue requirement related to Hagar during Union's 2014-2018 IRM term.

As described at Exhibit A, Tab 1, page 1, the revenue from the proposed liquefaction service will contribute to utility earnings subject to sharing over the IRM term. Regardless of whether Union provides the liquefaction service to LNG wholesalers/customers or Union "LNG", the revenue will be included in utility earnings subject to sharing.

Upon rebasing, Union anticipates that there will be a reduction in the revenue requirement at Hagar allocated to existing ratepayers. The revenue from the liquefaction service will also form part of regulated revenue for ratemaking purposes.

c) Under the assumption that Union would provide the LNG transportation fuel as a non-regulated service, the revenue from a non-regulated service would not be considered as a Y factor.

UNION GAS LIMITED

Answer to Interrogatory from
Energy Probe

Reference: Exhibit A, Tab 1, Page 1

Preamble: Further, this new service will result in better utilization of Hagar. This better utilization will benefit Union's ratepayers over the Incentive Regulation Mechanism ("IRM") term (2014-2018) by contributing to regulated earnings subject to sharing. On rebasing, the revenue from this service will form part of regulated revenue for ratemaking.

a) Please summarize, under the regulated service option, what the annual change in revenue requirement 2015-18 will be. Please provide details of the Y factor adjustment that is being sought to the Ratebase and Return.

b) Please provide a Schedule showing the projected volume sales and incremental revenues 2015-2018 from the LNG Transportation Service.

c) Please provide a Schedule that shows under the ESM Mechanism, how much Union and Ratepayers will receive. Clearly state any assumptions regarding the base earnings and incremental earnings related to the LNG Service.

Response:

a) Union does not have a forecast of the annual change in revenue requirement at Hagar from 2015 to 2018. Union has provided the annual revenue requirement from 2015-2018 associated with the incremental project costs at Exhibit A, Tab 2, Schedule 5.

Union is not proposing a Y factor adjustment for the proposed liquefaction service. Under Section 6 of Union's EB-2013-0202 IRM Settlement Agreement items that will be treated as Y factors are:

- Upstream gas costs
- Upstream transportation costs
- Incremental DSM costs
- LRAM for the contract rate classes
- Unaccounted for Gas volume variances
- Major Capital Additions

The development of a new regulated service is not subject to a Y factor adjustment. The treatment of new energy services is described at Section 13.2 of the EB-2013-0202 Settlement Agreement, which states:

"Union agrees that all new regulated energy services will require Board approval. Accordingly, Union will make an application, on notice with supporting material, for all new regulated energy services".

In accordance with Section 13.2, Union has made an application requesting Board approval of a new regulated liquefaction service.

b) The schedule with the projected liquefaction sales volumes and incremental revenues for 2015-2018 is provided at Attachment 1.

c) As described at Exhibit A, Tab 1, page 3 Union is forecasting an average of approximately $2.1 million per year in utility revenue from 2015 to 2018 related to the provision of the proposed liquefaction service. However, Union cannot forecast base utility earnings and any incremental earnings associated with the liquefaction service for 2015 to 2018. Accordingly, Union has not provided a response.

UNION GAS LIMITED

Forecasted Liquefaction Revenue from September 2015 - December 2018

Line No.	Particulars	2015	2016	2017	2018	Total	Annual Average
		(a)	(b)	(c)	(d)	(e)	(f) = (e / 4)
1	Liquefaction Commodity Charge ($/GJ) (1)	5.096	5.096	5.096	5.096	5.096	5.096
2	Forecast Liquefaction Sales Activity (GJ) (2)	67,840	339,200	576,640	678,400	1,662,080	415,520
3	Forecasted Liquefaction Revenue ($000's) (line 1 x line 2 / 1000)	346	1,729	2,938	3,457	8,470	2,117

Notes:

(1) As per Exhibit A, Tab 2, Schedule 6, line 19.

(2) As per Exhibit A, Tab 2, Schedule 5, line 9.

UNION GAS LIMITED

Answer to Interrogatory from
Energy Probe

Reference: Exhibit A, Tab 1, Page 4

Preamble: As per Exhibit A, Tab 2, Schedule 5, line 9, column (e). The liquefaction forecast is based on 415,520 GJ of average annual activity from September 1, 2015 to December 31, 2018.

Please provide the sales/volume forecast for each year 2015-2018.

Response:

The sales volume forecast is based on amounts shown at Exhibit A, Tab 2, Schedule 5, line 9, columns (a) through (d) inclusive.

UNION GAS LIMITED

Answer to Interrogatory from
Energy Probe

Reference: Exhibit A, Tab 1, Pages 8/9

Preamble: A FortisBC press release dated November 28, 2013, highlights key changes issued by the British Columbia government and the British Columbia Utilities Commission ("BCUC") designed to "boost" the use of LNG as a transportation fuel. These changes include updates to the greenhouse gas reduction regulation as well as a direction that would exempt the planned expansion of Fortis BC's Tilbury LNG facility from a review by the BCUC.

a) Please provide a Copy of the BC Government Direction to the BCUC.

b) Please provide a copy of the BCUC Order Fortis BC Order (G-165-11A)

Response:

a) Please see Attachment 1 for a press release from the British Columbia Ministry of Energy and Mines addresses the government's intent to support FortisBC's investment of up to $400 million in the expansion of the Tilbury liquefied natural gas (LNG) facility. As referenced in the attached press release, the following link **http://www.gov.bc.ca/ener/popt/down/natural_gas_strategy.pdf** is to the BC government's *"Natural Gas Strategy – Fuelling BC's Economy for the Next Decade and Beyond"* (dated February 3, 2012). This document includes a complimentary strategy focusing specifically on the development of the LNG sector.

b) Please see Attachment 2 for a copy of the BCUC Order (G-165-11A).

Filed: 2014-08-12
EB-2014-0112
Exhibit B.Energy Probe.4
Attachment 1

Ministry of Energy and Mines, Economy Sector, Cariboo Chilcotin Coast Region, Kootenay Rockies Region, Northern B.C. Region, Provincewide, Thompson / Okanagan Region, Vancouver Coast & Mountains Region, Vancouver Island / Coast Region

$400-million investment in LNG creates B.C. jobs

/2013/11/400-million-investment-in-lng-creates-bc-jobs.html

Thursday, November 28, 2013 1:00 PM

VICTORIA - Government is supporting FortisBC's investment of up to $400 million in the expansion of the Tilbury liquefied natural gas (LNG) facility that will create over 300 person-years of jobs and economic development in the province, announced Bill Bennett, Minister of Energy, Mines and Minister responsible for Core Review.

Government is exempting FortisBC's expansion of its Tilbury LNG facility from a certificate of public convenience and necessity review by the BC Utilities Commission (BCUC). The facility, located on Tilbury Island in Delta, has been used for natural gas storage since 1971. It takes natural gas from the pipeline during periods of low demand and converts it into a liquid that can be stored. This exemption positions FortisBC to begin construction of an expansion that will provide LNG to transportation customers as a cleaner alternative to diesel. The facility is expected to be providing LNG fuel by mid-2016.

To increase the adoption of natural gas in British Columbia's transportation sector and deliver on the Province's Natural Gas Strategy, government is also updating the greenhouse gas reduction regulation. It will now allow utilities to expand their incentives to include trains and mine-haul trucks and to provide tanker-truck delivery services to trucking, mining and marine-transportation customers. Government is also directing the BCUC to set an LNG dispensing rate of $4.35/gigajoule.

These actions will support new jobs and economic development by making it easier for the transportation sector, industrial facilities and remote communities to use natural gas.

Quotes:

Bill Bennett, Minister of Energy and Mines and Minister Responsible for Core Review -

"*Government wanted to get out of the way and allow the transportation fuel component of the LNG industry develop quickly.*

"This $400-million investment in FortisBC's Tilbury LNG facility will build B.C.'s market place for the world's cleanest fuel, LNG, and create over 300 person years of employment in the Lower Mainland."

Rich Coleman, Minister of Natural Gas Development -

"British Columbia has a vast supply of natural gas to meet global demands and local markets. The FortisBC's Tilbury LNG facility is a good example of how the diversification of our natural-gas sector is creating cleaner transportation options and economic advantages at home."

Quick Facts:

- Natural gas will result in a 30-40 per-cent cost savings for customers.
- Natural gas produces up to 20-30 per cent less in greenhouse gas emissions than diesel.
- Government's May 2012 greenhouse gas reduction regulation included opportunities for utilities to:
  - Offer incentives to transportation fleets that would use natural gas, such as buses, trucks or ferries.
  - Build, own and operate compressed natural-gas fuelling stations or liquefied-natural-gas fuelling stations.

- Promoting natural gas as a transportation fuel is a key action in British Columbia's Natural Gas Strategy.

Learn More:

Find out about the Natural Gas Strategy at: www.empr.gov.bc.ca/OG/NGS/Pages/default.aspx (http://www.empr.gov.bc.ca/OG/NGS/Pages/default.aspx)

Contact:

Jake Jacobs
Media Relations
Ministry of Energy and Mines
250 952-0628

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BRITISH COLUMBIA UTILITIES COMMISSION

BRITISH COLUMBIA
UTILITIES COMMISSION

ORDER
NUMBER G-165-11A

TELEPHONE: (604) 660-4700
BC TOLL FREE: 1-800-663-1385
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IN THE MATTER OF
the Utilities Commission Act, R.S.B.C. 1996, Chapter 473

and

An Application by FortisBC Energy Inc.
for Approval of a Compression Rate Schedule,
Compression & Dispensing Rate Calculation, and
Resulting Effective Rate to Provide for Public Natural Gas Vehicle
Refuelling at the FortisBC Energy Inc. Surrey Operations Centre

BEFORE: A.A. Rhodes, Panel Chair/Commissioner
D.A. Cote, Commissioner
D. Morton, Commissioner

September 26, 2011

ORDER

WHEREAS:

A. On July 8, 2011, FortisBC Energy Inc. (FEI) applied to the British Columbia Utilities Commission (Commission) for approval of:

- a new rate schedule (proposed Rate Schedule 6P) to allow it to provide Compressed Natural Gas (CNG) fuelling service to the general public at its Surrey Operations Centre,
- the calculation of the rate to be charged for Compression and Dispensing service within the proposed new Rate Schedule 6P, and
- the resulting effective rate

pursuant to sections 59-61 of the *Utilities Commission Act* (the Application);

B. By Letter L-62-11 dated August 2, 2011, the Commission ordered, inter alia, that the Application proceed by way of a short written hearing process;

C. The written hearing process concluded with the filing of FEI's reply submissions on September 7, 2011;

D. The Commission Panel has reviewed the evidence and submissions of the Parties.

BRITISH COLUMBIA UTILITIES COMMISSION

ORDER NUMBER G-165-11A

NOW THEREFORE for the Reasons attached hereto as Appendix A, the Commission:

1. Declines to approve the proposed calculation for a Compression and Dispensing rate.
2. Orders that if FEI elects to sell CNG to the public from its Surrey Operations Centre, it is to include a Compression and Dispensing charge of $7.628 per Gigajoule in new tariff 6P.
3. Orders that new tariff 6P is to be restricted to sales of CNG from FEI's Surrey Operations Centre and directs that the wording of proposed new tariff 6P be modified to reflect this restriction.
4. Directs FEI to track and record all incremental costs and revenues associated with making CNG available to the public at its Surrey Operations Centre to the end of 2012 and to file a written report no later than March 31, 2013 outlining such costs and revenues and also including information on the volumes and bundled rates charged to the public over that period of time.

DATED at the City of Vancouver, in the Province of British Columbia, this 26th day of September 2011.

BY ORDER

Original signed by:

A.A. Rhodes
Panel Chair/Commissioner

Attachment

In The Matter Of

FortisBC Energy Inc.
Application for Approval of a Compression Rate Schedule Compression and Dispensing Rate Calculation and Resulting Effective Rate to provide for Public Natural Gas Vehicle Refuelling at the Surrey Operations Centre

REASONS FOR DECISION

September 26, 2011

Before:

A.A. Rhodes, Panel Chair / Commissioner
D.A. Cote, Commissioner
D. Morton, Commissioner

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1.0 INTRODUCTION

FortisBC Energy Inc. (FEI) owns and operates a Compressed Natural Gas (CNG) fuelling station at its operations centre in Surrey, BC (Surrey Operations Centre). The fuelling station was formerly owned and operated by Clean Energy Fuels Inc. (Clean Energy), prior to FEI's purchase of it in September 2010 for a price estimated to be approximately $107,000. FEI uses the fuelling station to fuel its own fleet of Natural Gas Vehicles (NGVs). When the fuelling station was owned by Clean Energy, it also provided service to the general public. FEI, as a public utility, cannot do so without Commission approval. FEI therefore now applies for:

- approval of a new Rate Schedule (Rate Schedule 6P) to provide CNG fuelling service to the general public,
- approval of the calculation used to determine the Compression and Dispensing charge which forms part of the rate, and
- the resulting effective rate.

2.0 BACKGROUND

Clean Energy itself, after various name changes, was originally a creation of FEI. It was a wholly-owned unregulated subsidiary which acquired a large portion of FEI's NGV utility assets on January 1, 2000, at a loss to FEI [which was borne by its ratepayers] of $2.13 million. FEI sold what remained of its interest in Clean Energy in 2005. (BCUC Order G-143-99; FEI CNG/LNG Application, Exhibit B-1, p. 9; Exhibit B-6, BCUC IR 2.6.1, 2.29.2)

When Clean Energy owned the fuelling station at the Surrey Operations Centre it provided service to the general public as an ancillary function. Its primary purpose was to provide fuelling service to FEI's fleet of CNG vehicles, which it did pursuant to a service agreement which pertained to two separate FEI sites (Burnaby and Surrey). As Clean Energy was not "otherwise a public utility" engaged in the petroleum industry, it was not required to be regulated. It charged a bundled rate to the general public that did not separate the various components, such as Compression and Dispensing, and fuel. The rate in place in September of 2010 was $0.653 per gasoline litre equivalent (GLE). FEI "does not believe that a meaningful comparison can be drawn between [its] proposed rate and Clean Energy's former rate in or about September 2010 as commodity prices have since changed and Clean Energy's rate was both bundled and unregulated." (Exhibit B-2, BCUC IR 1.2.5)

3.0 CALCULATION OF NEW TARIFF RATE

FEI proposes to calculate the rate for compression and dispensing services included in new Rate Schedule 6P based on the forecast cost of service and total annual volume of CNG used (both by FEI's own fleet and the general public). The calculation is based on the following inputs:

Capital Cost of Fuelling Station	$106,801.50
Revenue Requirement	$28,865 per annum
Forecast Volume	4,725 GJs per annum
Life of Fuelling Station Remaining	10 years

The resulting rate for Compression and Dispensing service to be included in new Rate Schedule 6P is $5.239 per Gigajoule (GJ). (Exhibit B-1, p. 3) This rate is a then added to other rates and charges to come to a final price to be charged at the dispenser:

Commodity (from Rate Schedule 6)	$4.568/GJ
Delivery (from Rate Schedule 6, net of riders)	$3.609/GJ
Midstream (from Rate Schedule 6)	$0.353/GJ
Compression & Dispensing (new Rate Schedule 6P)	$5.239/GJ
Carbon Tax (as of July 1, 2011)	$1.247/GJ
HST at 12%	$1.802/GJ
TOTAL	**$16.818/GJ**

$16.818 per GJ equates to a price of $0.58 per Gasoline Litre Equivalent (based on 28.8 litres per GJ). This also equates to approximately $0.87/kg based on the formula "multiply by 0.67 to convert $/kg to $/GLE." (Exhibit B-2, BCUC IR 1.2.5, 1.5.2.1)

By using the above formula, the price at the dispenser will vary as the prices in the relevant underlying rate schedules change, and will also reflect any changes to the Carbon Tax.

FEI also proposes to post the terms and conditions of new Rate Schedule 6P in a clearly visible location on the fuel pump.

New Rate Schedule 6P contains a provision which states that the Rate Schedule applies in "[t]he Lower Mainland Area, including, but not limited to, the following locations: Surrey". (Exhibit B-1, Appendix A -Proposed Rate Schedule 6P Clause 1.2) FEI submits that, although only the Surrey location is currently capable of providing CNG service to the public, in the event that it was able to reconfigure its facilities in another location, such as Burnaby, to also be amenable to serving the general public, the regulatory process for approval of that service would be "somewhat more efficient." (Exhibit B-2, BCUC IR 1.3.1)

3.1 Existing Market

As discussed above, the Surrey Operations Centre CNG fuelling facility was open to the public when it was owned and operated by Clean Energy, prior to its purchase by FEI on September 30, 2010. There are currently several other facilities in the lower mainland with public access. These are:

Chevron	Burnaby
Chevron	Cloverdale
Chevron	Vancouver
Christie Adams	Burnaby
PetroCanada	Coquitlam
PetroCanada	North Vancouver

(Source: Exhibit B-2, BCUC IR 1.4.2)

The nearest public access refuelling station to the Surrey Operations Centre is located in Cloverdale. It is owned by Clean Energy and operated by Chevron. FEI advises that Clean Energy may close this station in the near term. (Exhibit B-2, BCUC IR 1.5.2)

The posted rate at the Chevron facility in Cloverdale as of August 18, 2011 [the date of FEI's response to BCUC IR 1] was $0.75 per GLE. This rate is higher than the rate which was charged to the public at the Surrey Operations Centre in September of 2010, which was $0.65 per GLE [although the figures are not directly comparable given the difference in time. For example, the Carbon Tax, which applies to natural gas, increased as of July 1, 2011.] (Exhibit B-2, BCUC IR 1.5.2.1)

As noted above, FEI proposes to charge the public $0.58 per GLE based on its Cost of Service model.

3.2 Cost of Service Model/Levelized Rate

FEI proposes to price its CNG service to the public based on its own cost of service, using a ten year levelized rate calculation. FEI is of the view that this treatment is appropriate for the Surrey Operations Centre for the following reasons:

1. A levelized rate is stable and predictable.
2. A ten-year levelized tariff balances the desire for a cost of service based rate with the materiality of the costs and revenues. [As this facility is intended primarily for FEI's own use, the Compression and Dispensing costs are for the most part already borne by existing ratepayers and the annual revenues are expected to be in the minimal range of $7,000 to $8,000.]
3. A levelized rate provides a simple approach for applying future delivery rate changes, contributing to administrative and regulatory efficiency.
4. As the public service is ancillary, the recoveries from the general public are also ancillary, and offset costs borne by existing customers. The levelized rate represents a reasonable estimate of the annual cost of service, and therefore a reasonable recovery for the public use of this asset.

This base Compression and Dispensing rate would then be adjusted annually by the general percentage change in the Company's revenue requirements as part of the revenue requirement process.
(Exhibit B-2, BCUC IR 1.8.1; 1.8.2)

3.3 Costs Included in Cost of Service Model

FEI has estimated the annual revenue requirement of the fuelling station based on the capital cost of the facility and estimated operating and other costs such as income tax and earned return. (Exhibit B-1, Appendix B, Schedule 1)

<u>3.3.1 Capital Cost</u>

FEI purchased the refuelling stations for both its Burnaby and Surrey sites as a package. It allocated 50% of the $213,603 purchase price to each station, resulting in a capital cost for the Surrey Operations Centre of $106,801.50. The remaining estimated useful life of the fuelling station is 10 years, [which is half the estimated 20 year useful life of a new refuelling station]. (Exhibit B-1, p. 3)

Depreciation expense of these capital costs is calculated on a straight line basis at $10,700 per annum.

FEI advises that the fuelling station located at the Surrey Operations Centre is capable of dispensing up to roughly 18,000 GJs of CNG per year, but that the number of dispensers associated with the fuelling station may need to be expanded before that capacity is reached. FEI estimates that its current dispenser "is more than capable of serving the 2012 forecast of 65 CNG vehicles (50 FEI vehicles, plus an estimated 15 third party vehicles)" [Footnote omitted]. However, it also notes that "additional dispensers or a "time-fill" station with multiple fill posts...may need to be installed if the number of vehicles grows beyond the forecast." (Exhibit B-3, BCUC Supplemental IR.2.3)

No amounts are included in the forecast for potential additional capital additions. (Exhibit B-1, Appendix B-Schedule 6)

3.3.2 Operating and Maintenance Costs

FEI estimated its annual operating and maintenance cost at $9,000 per annum (rounded) for the first six years of the analysis and $10,000 per annum (rounded) thereafter based in large measure on a private contractor's estimate of Operations and Maintenance requirements for the station of $8,500 per year. The O&M cost estimate for the years 2011 to 2020 "includes all routine and preventative maintenance, parts and service as recommended by the manufacturer and the contractor who completed the performance evaluation in 2010." (Exhibit B-2, BCUC IR 1.7.1)

The O& M cost estimate does not include the cost of electricity required to operate the compressors. FEI has not included this cost because "they cannot be isolated from other electricity consumption costs at the Surrey Operations Centre," as the CNG equipment is not metered separately. (Exhibit B-3 BCUC Supplemental IR.3.1)

3.3.3 Other Costs

The other costs included in the revenue requirements calculation relate to income taxes and earned return.

4.0 REVENUE REQUIREMENTS

The annual revenue requirement over the ten year period is then calculated by summing the estimated costs set out above for each year. (Exhibit B-1 Appendix B Schedule 1) This cost stream is then discounted back to the present at FEI's after-tax weighted average cost of capital. The resultant figure is the present value of the revenue requirements over the contract term.

5.0 VOLUME

FEI has assumed a constant annual usage volume of 4,725 GJs of CNG for itself and third party customers over the ten year analysis. The estimate assumes FEI's fleet will use 3,175 GJs per year and that third party customers will purchase an additional 1,550 GJs per year. FEI estimates that each of its own vehicles will use approximately 106 GJs per year. Its current fleet of 30 vehicles as of mid 2011 therefore consumes 3,180 GJs of CNG. (However, FEI also estimates that it will have 50 vehicles running from the Surrey Operations Centre by the end of 2012). As noted above, FEI has assumed that third party customers will consume 1,550 GJs per year, which is more than double the 738 GJs of CNG which Clean Energy sold to the public during the six month period from April 01, 2010 to September 30, 2010. (Exhibit B-3 BCUC Supplemental IR 2.1)

6.0 LEVELIZED TARIFF

Finally, to calculate the levelized tariff rate, FEI has discounted the assumed volume stream back to the present, again using its after tax weighted average cost of capital. FEI has then divided the present value of the revenue requirement by the present value of the volume to arrive at its proposed levelized rate in dollars per GJ. (Exhibit B-1, Appendix B, Schedule 10)

7.0 COMMISSION PANEL DISCUSSION

The Commission Panel is concerned that FEI is proposing to enter an otherwise unregulated market with a product which it proposes to price significantly below that which is currently being charged in this market. However, the Commission Panel agrees with FEI that additional fuel sales should provide a benefit to existing customers, assuming the facility has the excess capacity and the price to be charged recovers any additional costs.

In that regard, however, the Commission Panel does not agree with FEI that the levelized cost model which it proposes to use is appropriate in these circumstances. FEI's main argument in this regard is that the analysis is simple, and the proposed revenues from providing this service to the general public are not material.

In the Panel's view, however, the levelized cost model may be simple from a computer model perspective, but it is not conceptually simple and does not follow the model normally used in a revenue requirements application. Further, the analysis is based on a significant number of assumptions over a ten year period which have little or no historical basis. As well, the Panel does not find the argument that this method will favour price stability or that price stability is even possible or desired persuasive, given the fact that the Compression and Dispensing charge represents only a portion of the tariff cost and other suppliers use a bundled rate.

Further, since FEI is forecasting that the cost of service of the facility will be relatively stable over the ten year period of the analysis, it is not clear what additional stability will be provided by using the proposed levelized cost model.

The Panel prefers a simpler model for the short term which relies on fewer estimates and is more flexible and capable of adjustment as events unfold.

The Panel therefore considers a straight-forward approach to be more appropriate at this point in time. The Panel is not convinced, however, that over the longer term a cost of service model is necessarily appropriate in circumstances such as these where FEI is proposing to enter a competitive market as a regulated entity to recover a portion of its own costs.

The Panel notes FEI's assumptions include the assumption that Clean Energy's customers "who have come to expect refuelling service" from FEI's Surrey Operations Centre will revert back to purchasing more (annualized) CNG service than they did in 2010, even though they have not had that facility available for the better part of a year and finds the assumption lacks justification and may well be overly optimistic. This is problematic because the assumption of Gigajoules consumed/sold is critical to the cost calculation.

The Panel further notes that FEI has made no effort to estimate the cost of electricity required to run the compressor station. This cost is an integral variable cost to the operation and ought not to be ignored. Further, the Panel indicated in its Reasons for Decision for Order G-128-11 (which was not released until after this Application was made) that it was concerned about cross subsidization and required that, to the extent possible, CNG/LNG customers bear the full cost of the service offering. FEI has made no attempt in this application to estimate additional overheads which may be necessitated by opening the CNG service to the public, such as modification or addition of billing systems, additional insurance costs, advertising etc. As well, the cost of this Application was not tracked separately and no amounts have been estimated for this regulatory process.

Given its agreement with FEI that sales of excess CNG to the public should provide some benefit to existing ratepayers, as noted above, the Panel would be prepared to approve a tariff rate for the Compression and Dispensing component of the service which uses fewer, more conservative assumptions, is based as closely as possible on the current situation and better reflects the total additional cost of providing CNG service to the general public. In that regard, to avoid additional time and delay, the Panel proposes that the Compression and Dispensing component of the tariff be calculated as follows:

2011

Revenue Required	$32,000	(Source: Exhibit B-2, BCUC IR 1.11.1 (Attachment 11.1 adjusted upward by 10% to reflect potential costs not included.)
Gigajoules sold/used	3,500 GJs	(Source: Exhibit B-3 BCUC Supplemental IR 2.1 - adjusted downward to reflect fact that only 3 months remain for sales to public, outside sales may not be experienced to the extent assumed and FEI's CNG fleet had not expanded to 30 trucks until mid 2011)
C&D Cost per Gigajoule	$9.14	
Resulting Price at Dispenser	$0.736 per GLE	

2012

Revenue Required	$29,000	(Source: Exhibit B-2, BCUC IR 1.11.1 (Attachment 11.1 adjusted upward by 10% to reflect potential costs not included.)
Gigajoules sold/used	4,000 GJs	(Source: Exhibit B-3 BCUC Supplemental IR 2.1 - adjusted downward to reflect fact that outside sales may not be experienced to the extent assumed and that it may take longer than estimated for FEI to increase its CNG fleet)
C&D Cost per Gigajoule:	$7.25	
Resulting Price at Dispenser	$0.662 per GLE	

<u>Tariff Rate for 2011-2012</u>

Based on the above, the Compression and Dispensing Portion of the Tariff for 2011 and 2012 will be $ $7.628 per GJ in new tariff 6P which will result in a current price at the dispenser of **$0.68 per GLE** based on a weighted average cost for 2011 and 2012. (i.e. ($0.736 + (4x$0.662))/5 =$0.68). (The Commission Panel recognizes that the price at the dispenser will vary with changes to other components of the total price, such as the commodity cost.)

In the Panel's view this amount is more reflective of the actual additional cost of service associated with opening the Surrey Operations Centre CNG facility to the public. It is also more in line with the existing market price of $0.75 per GLE at the nearest public service Chevron station in Cloverdale, which, in the Panel's opinion is relevant and can be viewed as a benchmark.

8.0 COMMISSION PANEL DETERMINATION

The Commission Panel orders that if FEI elects to sell CNG to the public from its Surrey Operations Centre, FEI is to include a Compression and Dispensing charge of **$7.628** per GJ in new tariff 6P.

The Commission Panel declines to approve the levelized rate calculation proposed by FEI.

The Commission Panel also orders that, should FEI elect to proceed with a new tariff based on the calculation outlined in these Reasons, new tariff 6P is to be restricted to the Surrey Operations Centre, as the Compression and Dispensing charge to be approved is based on forecast operations and sales at that facility. The Panel directs that the wording of new tariff 6P be modified to reflect this restriction.

FEI is directed to track and record all the incremental costs and revenues associated with making CNG available to the public at its Surrey Operations Centre to the end of 2012 and to file a written report, which report should also include information on the volumes sold to and bundled rates charged to the public over that time period, by March 31, 2013.

UNION GAS LIMITED

Answer to Interrogatory from
Energy Probe

Reference: Exhibit A, Tab 1, Page 10

Preamble: Union indicates it had discussions with several parties looking to enter Ontario's LNG distribution market. To assess and verify the market interest in the service, Union conducted a non-binding call for Expressions of Interest ("Expression") for volumes of LNG from the Hagar plant.

a) Please provide the specific details of the "Expressions of Interest" and provide the document issued in the non-binding call.

b) Please outline Union's next steps and timing in the process beyond the "Expressions of Interest" phase.

c) For each Party identified, please discuss readiness i.e. the timing of when the minimum annual commitment could be realized.

Response:

a) Attachment 1 is the Expression of Interest package. This document, along with the details of the Expression of Interest is available at the following link: http://www.uniongas.com/storage-and-transportation/news/open-seasons/2014/feb-18

b) Union is currently in negotiations with all parties to review and complete final binding contracts for the service.

c) Please see the response to Exhibit B.Northeast.12.

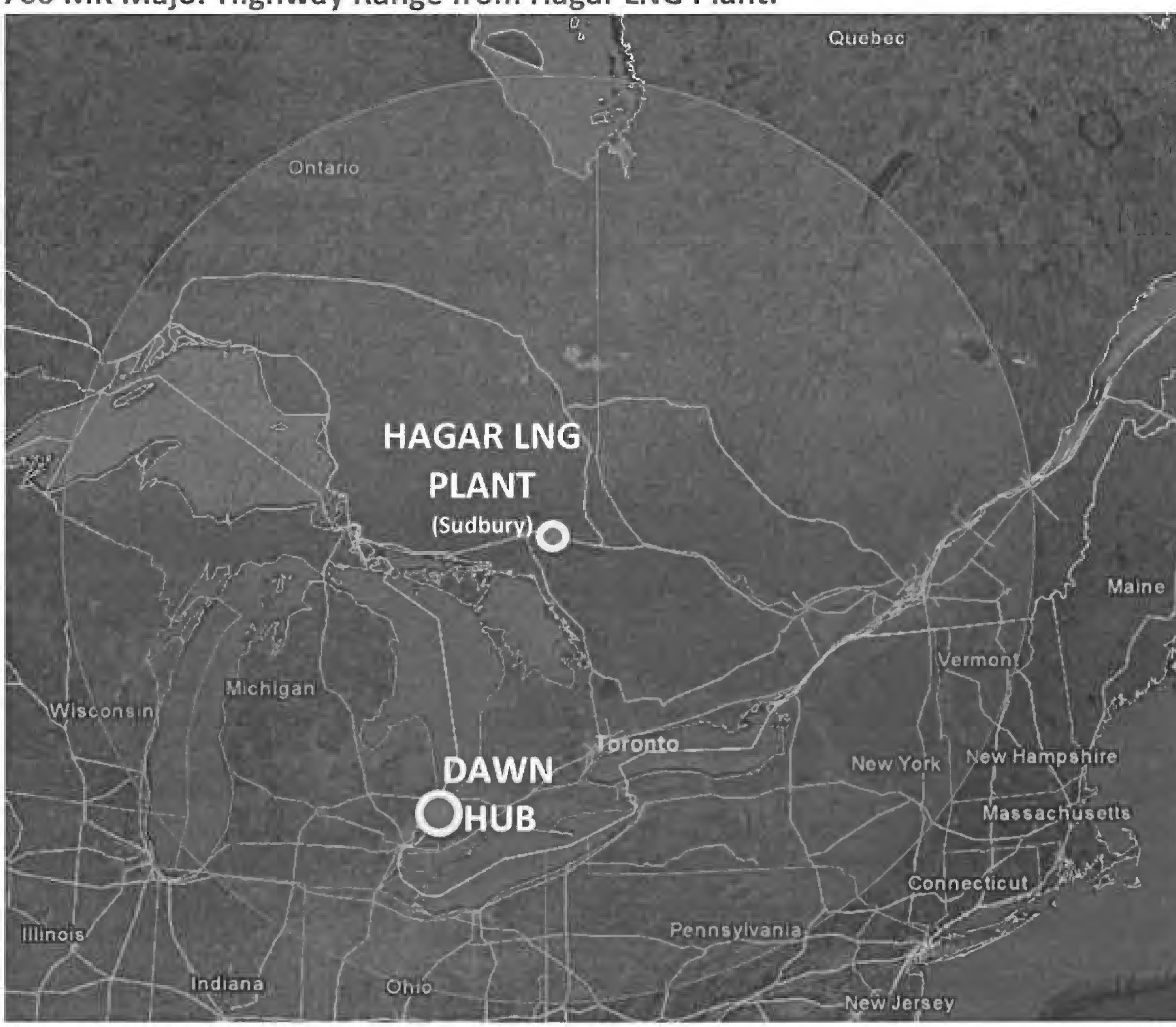
uniongas
A Spectra Energy Company

Non-Binding Call for Expressions of Interest for Liquefied Natural Gas (LNG) Services

February 18th, 2014

Union Gas Limited ("**Union Gas**") is conducting this non-binding call for expressions of interest in support of a proposal to offer liquefaction (LNG) services at the Hagar LNG Plant located near Sudbury, Ontario. Interested parties are asked to express interest in this liquefaction service dispensed by Union Gas FOB at the Hagar LNG Plant.

700 MK Major Highway Range from Hagar LNG Plant:



Map data: Google, National Institute of Statistics and Geography

Terms of Service:

- Services beginning as early as Q3 2015 to accommodate a variety of consumption patterns
- An initial contract term of up to 10 years
- Minimum annual commitment required
- Customers are expected to adhere to provincial & federal standards in effect, tankers used must be in good condition and drivers must be qualified
- For the purposes of billing, the LNG is considered to be sold, delivered and billed at the Hagar LNG Plant (FOB) in CAD/GJ

Price of Service:

Liquefaction Service

Liquefaction fee expected to be in the range of $5.54-$6.93 CAD/GJ ($0.20-0.25 CAD/DLE) subject to Ontario Energy Board approval*

+

Natural Gas Commodity

Delivered to the Hagar LNG Plant/TransCanada's Union Northern Delivery Area

- The 1 year average same day price of natural gas commodity in Ontario at the Dawn Hub as of February 10, 2014 was $4.58 CAD/GJ ($0.17 DLE)
- Transportation fees from the Dawn Hub are currently $0.44 CAD/GJ ($0.016 CAD/DLE)
- Transportation fees are subject to Ontario Energy Board Regulation

NOTE:
** Diesel Litre Equivalent (DLE) to GJ Conversion Factor Used = 27.7 as per* ***Go For Natural Gas***
http://www.gowithnaturalgas.ca/getting-started/understanding-energy-equivalency/

Additional Information:

Flexible liquefied natural gas services are being offered to customers in order to serve a variety of consumption patterns. In order to assess market interest in the service, Union Gas requests that interested parties provide a maximum daily quantity required as well as annual and monthly consumption estimates where possible.

Customers have the option of either supplying their own natural gas commodity to the Hagar LNG Plant, or of having Union Gas provide natural gas commodity to the Hagar LNG Plant on their behalf. Customers interested in liquefaction service and natural gas commodity supply should stipulate this on their bid form along with any conditions to this effect.

Once expressions of interest have been received Union Gas will determine the feasibility of the service and contact all interested parties directly. If Union Gas determines that sufficient interest has been received Union Gas will proceed with negotiation of contracts with interested parties. In no way does this Call for Expressions of Interest oblige Union Gas to execute any contract with interested parties. Respondents may, in their expression, indicate any other terms and conditions they wish to add or modify.

Interested parties are asked to complete the attached bid form and return to Union Gas no later than 2 pm on March 7, 2014. Respondents may, in their submission, indicate any other terms and conditions they may wish to add or modify. If you have any questions, please contact either Murray Smith or Steve Kay.

uniongas
A Spectra Energy Company

Expressions of Interest for Liquefied Natural Gas Services:

Please complete, sign and return this Expression of Interest on or before 2:00 p.m. EDT on March 7, 2014, via email or fax to:

ATTN: Murray Smith via **Email:** msmith@uniongas.com **Fax:** (519) 436-4645

Dear Murray:

In response to the letter from Union Gas regarding Expressions of Interest, dated February 18, 2014, **(Please enter your company name here)**______________________________ ("Customer") Customer requests the opportunity to express interest in interruptible LNG services at the Hagar LNG Plant, as outlined below.

Start Date mm/dd/yyyy		**Term** Up to 10 Years	
Maximum Daily Quantity(GJ or DLE*)		**Minimum Annual Commitment**	
Monthly Consumption Estimates			
Commodity Preference Interest in sourcing from Union Gas?		**Commodity Delivery Point Preference** Dawn vs. Union NDA	
Conditions Of Interest Expressed *Attach additional conditions to your submission as required*			

**If using DLE, Union Gas will convert to GJ of natural gas using 27.7 conversion factor*

It is understood that Union Gas will review interest and acknowledge all requests received by 2:00 pm EDT on March 12, 2014.

Yours truly,

____________________ **Name** (printed)	____________________ **Phone**
____________________ **Signature**	____________________ **Fax**
____________________ **Title**	____________________ **Date**
____________________ **Email**	

Background

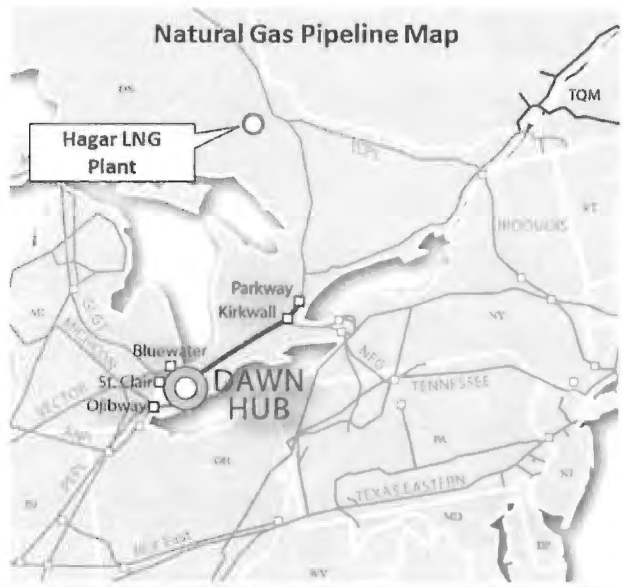
About Union Gas:

Union Gas Limited is a major Canadian natural gas storage, transmission and distribution company based in Ontario with 100 years of experience and service to customers. The distribution business serves about 1.4 million residential, commercial and industrial customers in more than 400 communities across northern, southwestern and eastern Ontario. Union Gas, named one of Canada's Top 100 Employers for 2014, is a Spectra Energy (NYSE: SE) company with assets of $5.8 billion and approximately 2,200 employees. For more information, visit uniongas.com.

The Dawn Hub

Where supply meets demand

- The largest integrated natural gas storage facility in Canada
- The 3rd most physically traded gas market hub in North America
- Connected to all major North American natural gas supply basins
- Supply reliability and price transparency
- Union Gas alone brings 135 PJ/year of gas onto the system



Dawn, one of the most liquid hubs in North America, has the capacity to export more than 6 PJ/d to eastern markets
(this equates to roughly 5% of peak N.A. demand and over 50% of average daily Canadian demand)

What is LNG:

- LNG is natural gas that is cooled to -162°C.
- LNG is up to 1/600th the volume of natural gas, making it easy to store and safe to transport.
- LNG is clear, colourless, non-toxic and non-corrosive. In its liquid state, LNG is non-flammable.
- Depending on its end use, LNG can be converted back to a gas state.
- LNG's high storage density makes it a viable alternative to diesel fuel for heavy duty transport, marine, mining and rail applications.

Cost Advantage:

When compared to alternative fuels like diesel and gasoline, LNG use can lower energy costs by 30-40 percent. As a result of abundant natural gas supply in North America, the price of natural gas is expected to remain low and stable over the long term relative to historic levels.

Environmental Advantages:

Union Gas is committed to minimizing the effects of our operating facilities on the environment. Any environmental impacts of new construction or ongoing operations will be taken seriously and protective measures will be developed to avoid or minimize effects. LNG can also help address environmental concerns like climate change and smog, offering green house gas emissions reductions of up to 28%.

LNG Safety:

Our highest priority is the safe operations of our facilities for the public and our workers.

The Hagar LNG Plant is designed to meet stringent safety codes and requirements of the Canadian Standards Association and the Technical Standards and Safety Authority. The facility is manned 24/7 and has multiple safeguard measures in place, including the ability to shut down the system at anytime.

Customers will be responsible for the transportation of the LNG from the Hagar LNG Plant to market.

Who Will Benefit:

Local Communities

- Experienced contractors will use local resources to construct the facilities, and where possible, will procure material from the local community.
- Local communities also benefit from taxes that Union Gas pays to the municipality annually for its existing Hagar LNG Plant.

Ontario

- Liquefied natural gas will play a key role in meeting Ontario's future transportation fuel needs and in helping the province meet greenhouse gas emissions targets.
- The benefits of LNG have prompted plans to build refueling stations in the United States and Canada along main trucking corridors. The Hagar Project will help support such initiatives.
- The Union Gas Hagar facility is currently the only existing Ontario based LNG plant and it presents an opportunity to offer a service without the need to construct a new facility.
- The use of LNG is limited to transportation fuels.

UNION GAS LIMITED

Answer to Interrogatory from
Energy Probe

Reference: Exhibit A, Tab 1, Pages 12/ 13 and
Exhibit A, Tab 2, Page 4

Preamble: The 2013 Board-approved revenue requirement for Hagar is approximately $6.2 million and is recovered from Union North customers in delivery rates.

a) Please provide the detailed Revenue Requirement Calculation for the Hagar Facility for 2015-2018.

b) Please provide the actual use of the liquefaction facility for the historic years 2010-2013 and projections for 2015-2018.

c) Please define and illustrate what capacity (Space and Deliverability) is required and what is excess to system integrity by month for 2015-2018.

d) Please illustrate what capacity space and deliverability and volumes are available to provide LNG Transportation Fuel on an interruptible service basis over a typical year. Please clarify assumptions regarding base System Integrity requirements

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Response:

a) Please see the response to Exhibit B.Energy Probe.2 a).

b)

Year	Liquefaction (GJ)
2010	115,958
2011	133,812
2012	104,055
2013	90,616

These actual quantities of LNG are also shown at Exhibit B.Staff.10.

Please see the response to Exhibit B.Northeast.78 that shows a breakdown of these actuals showing both the quantities of LNG vapourized for system integrity and the quantities lost to boil-off.

The 2015 to 2018 liquefaction forecast assumes 104,000 GJ/year for boil-off replacement and Union's forecast liquefaction activity per Exhibit A, Tab 2, Schedule 5. These forecast totals do not include the liquefaction of volumes required for system integrity. Forecasting these volumes is not possible since system integrity events are uncertain and unplanned.

Year	Liquefaction (GJ)
2015	171,840
2016	443,200
2017	680,640
2018	782,400

c) As provided at Exhibit A, Tab 1, p. 12, 0.6 PJ of LNG space and 90,000 GJ/d of deliverability is required to meet system integrity requirements. Since system integrity events are uncertain and unplanned a monthly forecast is not possible. For this reason, 0.6 PJ of LNG space and 100% of the vapourization capacity is reserved for system integrity purposes.

d) LNG space capacity available for LNG Transportation Fuel customers will be 7,000 GJ as per Exhibit A, Tab 1, p. 18, line 14. Liquefaction capability available on a typical day will be 3,186 GJ/day except when scheduled maintenance is required or a system integrity event requires the LNG tank to be re-filled. It is expected that the annual average days the liquefaction will be available is 167 days over the forecast period as shown at Exhibit A, Tab 2, Schedule 5.

UNION GAS LIMITED

Answer to Interrogatory from
Energy Probe

Reference: Exhibit A, Tab 1, Page 14/15

Preamble: Union proposes to replace the current height measurement equipment with a radar measurement system. This radar measurement system can measure the height of LNG in the tank without any physical contact with the LNG surface, and without the need for inside-tank components that require service. Union proposes to recover the $200,000 capital cost as part of the liquefaction rate.

a) Please confirm the costs of this upgrade.

b) Please indicate whether this upgrade is required for System Integrity Service.

c) Please indicate the upgrade is required for LNG Transportation Service.

d) If this upgrade is desirable for SE purposes, confirm the costs are below the threshold under the IRM Plan.

e) If required for the unregulated LNG Transportation Fuel Business, confirm the fully allocated costs will be recovered from that non-utility business.

Response:

a) The estimated cost for the upgrade to the LNG tank level measurement is $200,000. This estimated cost includes supply and installation of the radar gauge.

b) No. It is not required for system integrity.

c) Yes. The upgrade is required for the LNG service.

d) The upgrade is not “desirable” for Spectra’s purposes. The measurement upgrade is required to provide Union’s proposed liquefaction service. Accordingly, the costs will be recovered in the proposed rate.

e) N/A

UNION GAS LIMITED

Answer to Interrogatory from
Energy Probe

Reference: Exhibit A, Tab 1, Page 17

Preamble: The first option is for the customer to contract with Union for the provision of utility sales service under the proposed L1 rate schedule and the Union North Schedule “A”. Under this option, Union would provide both gas supply commodity and upstream transportation. The second option is for the customer to contract directly with gas suppliers or marketers for the provision of gas supply commodity and upstream transportation to deliver natural gas to the Union NDA. Under this option, the customer will manage its own gas supply and upstream transportation arrangements in a manner similar to other Union North direct purchase.

Please provide a copy of the draft modifications to Union North Schedule “A” to accommodate gas supply charges in dollars per gigajoule ($/GJ) in order to charge customers for this service as:

- sales service or
- direct purchase customers.

Response:

Please see Exhibit A, Tab 2, Schedule 4 for a black-line version of Union North Schedule “A”.

The proposed Rate L1 gas supply charges would be applicable to Rate L1 sales service customers only. Direct purchase customers that utilize Union’s proposed liquefaction service will be responsible for their own gas supply commodity and upstream transportation arrangements. Please also see Exhibit A, Tab 1, page 17.

UNION GAS LIMITED

Answer to Interrogatory from
Energy Probe

Reference: Exhibit A, Tab 1, Page 19

Preamble: At Page 19, Union discusses customer forecast and minimum annual volumes.

Please provide the forecast annual revenues for each of the years 2015 to 2018 based on the minimum annual commitment from the six Parties that expressed interest in purchasing LNG.

Response:

The table below is a summary of the forcast annual revenues from the six parties that expressed interest in Union's non binding open season to purchase LNG at Hagar. Please see the response to Exhibit B.Northeast.12.

Non Binding Open Season

Party	Minimum Annual Commitment	Annual Revenue
Proposed L1 Rate		$ 5.096
"A"	106,180	$ 541,093
"B"	55,000	$ 280,280
"C"	90,253	$ 459,929
"D"	150,000	$ 764,400
"E"	190,000	$ 968,240
"F"	109,200	$ 556,483
Total	700,633	$ 3,570,426

UNION GAS LIMITED

Answer to Interrogatory from
Energy Probe

Reference: Exhibit A, Tab 2, Schedule 5

Preamble: In Schedule 5 Union provides the forecast liquefaction sales activity and number of liquefaction days per year for the years 2015 to 2018.

Please provide the calculation that supports the forecast liquefaction sales activity amounts for each year and number of liquefaction days for each year and include all assumptions.

Response:

Year	LNG Available (,000's GJ) (1)	Load Factor for Sales (2)	Forecast Sales Activity (3)
2015	226.1	30%	67.8 (4)
2016	678.4	50%	339.2
2017	678.4	85%	576.6
2018	678.4	100%	678.4

Notes:	(1) Assumes 344 days liquefaction times average daily liquefaction (3,186 GJ/day) less boil off replacement and System Integrity vapourization replacement = 678,400 GJ (2) Projected load factor based on Expressions of Interest (3) Forecast Sales Activity (Exhibit A, Tab 2, Schedule 5, Line 9) (4) 2015 includes 4 months of sales activity due to in-service date

UNION GAS LIMITED

Answer to Interrogatory from
Energy Probe

Reference: Exhibit A, Tab 1, Page 19

Preamble: At the end of the contract year, if the customer has not met its Minimum Annual Volume commitment within the 12 months, any quantity shortfall will be invoiced in the month for the liquefaction component only (i.e. no natural gas commodity or transport fees).

By way of example, please provide the calculation for the liquefaction component only under this scenario.

Response:

The liquefaction component will be the regulated L1 Rate ($5.096 GJ) times the shortfall volume. The table below provides an example.

Shortfall Volume (GJ)	L1 Rate ($5.096/GJ)	Total MAV Payment ($)
1,000	$ 5.096	$ 5,096.00

UNION GAS LIMITED

Answer to Interrogatory from
Energy Probe

Reference: Exhibit A, Tab 1, Page 20 and Table 3

Preamble: Union will invest an estimated $8.7 million in project capital costs. These costs include the installation of the radar measurement system as well as valves and piping that will allow LNG to flow to dispensing facilities plus the construction and installation of piping and a LNG dispensing/pumping skid and weigh scales required to measure the LNG transferred into the tanker truck.

Please indicate the basis of and level of confidence in the Capital Costs.

Response:

The capital costs are based on preliminary designs as well as courtesy quotations from equipment suppliers and construction contractors. Union has a high level of confidence in the estimated capital costs for this project

UNION GAS LIMITED

Answer to Interrogatory from
Energy Probe

Reference: Exhibit A, Tab 1, Page 20 and Table 4

Preamble: Union is forecasting total incremental O&M expenses of $1.072 million per year by 2018. These incremental O&M expenses are driven by the increased usage of the liquefaction equipment at Hagar associated with the provision of the proposed liquefaction service. Table 4 provides a detailed breakdown of the forecasted incremental O&M expenses from September 2015 to December 2018.

a) Please provide details of the Salary and Wage costs in terms of FTEs.

b) Indicate why/whether the employees are dedicated or incremental to existing staff for Hagar Operations (Manager, one supervisor, one administration staff and eight operators).

c) Please provide explanation as to why the Road Upgrade Capital is Expensed.

d) Please provide details of the incremental Insurance costs for the LNG Transportation Fuelling Facility

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Response:

a) As stated at Exhibit A, Tab 1, p. 21, Union estimates it requires one additional operator at the plant in 2015 and 2016 and two additional operators in 2017 through 2018. The costs of these incremental employees are included in Exhibit A, Tab 1, Table 4, line 1.

b) These employees are incremental to the existing staff. They are required to safely liquefy and comply with TSSA requirements.

c) Please see the response to Exhibit B.Staff.8 a). The $500,000 is a one-time expense. The municipality owns the road and is required to maintain the road in the future.

d) Please see the response to Exhibit B.BOMA.12.

UNION GAS LIMITED

Answer to Interrogatory from
Energy Probe

Reference: Exhibit A, Tab 2, Page 6 and Table 2, Page 7 and
Exhibit A, Tab 2, Schedule 1

Preamble: For 2013 Board-approved Hagar costs that support the overall operations of the Hagar facility and cannot be directly attributed to a particular function, Union is proposing to functionalize those costs in proportion to the functionalization of directly assigned costs.

a) Please provide a copy of the KPMG Cost Allocation study.

b) For other LNG facilities in BC and Quebec compare the functionalization of directly assigned assets to those proposed for Hagar.

c) Please compare the Other Asset allocations to the directly assigned assets for these facilities.

d) Confirm the KPMG CA study is for 2013.

Response:

a) The KPMG cost allocation analysis is provided at Exhibit A, Tab 2, Attachment A. KPMG did not complete a cost allocation study.

b) Union does not have the information required to compare the functionalization of directly assigned assets at other LNG facilities in BC and Quebec to Union's proposal for the Hagar facility.

c) Please see the response to part b) above.

d) The KPMG cost allocation analysis is based on Union's 2013 Board-approved cost allocation study.

UNION GAS LIMITED

Answer to Interrogatory from
Energy Probe

Reference: Exhibit A, Tab 2, Schedule 1 and
Exhibit A, Tab 2, Schedule 5

Please provide a Schedule with the proposed 2015 in-service allocation and Revenue Requirement for the Hagar System Integrity facility.

a) Confirm Exhibit A, Tab 2, Schedule 5 shows the fully allocated Incremental Cost for the Transportation Fuel Service.

b) What are the incremental Insurance Costs?

c) Please provide a version of Schedule 5 including these incremental insurance costs.

Response:

a) Not confirmed. Exhibit A, Tab 2, Schedule 5 includes the incremental costs associated with the project. It does not include an allocation of 2013 Board-approved costs.

b) Please see the response to Exhibit B.BOMA.12.

c) Please see response to part b) above.

UNION GAS LIMITED

Answer to Interrogatory from
Energy Probe

Reference: Exhibit A, Tab 2, Page 11

Preamble: The second step in the cost allocation review was to determine the function of Hagar (2013) operating and maintenance expenses. Examples of operating and maintenance expenses include salary and wages, materials, electricity costs and equipment maintenance.

Please provide a Schedule that shows the 2013 Operating Expenses functionalized by function as well allocation of any non-functionalized costs.

Response:

Please see Exhibit A, Tab 2, Schedule 1, lines 22 to 25 for the functionalization of 2013 Board-approved Hagar O&M costs.

UNION GAS LIMITED

Answer to Interrogatory from
Energy Probe

Reference: Exhibit A, Tab 2, Page 21 and
Exhibit A, Tab 2, Schedule 6

Preamble: The derivation of the interruptible liquefaction rate can be found at Schedule 6. Based on the average forecast level of liquefaction activity of approximately 416,000 GJ per year and Union's proposed interruptible liquefaction rate of $5.096/GJ, Union estimates that the interruptible liquefaction service will generate approximately $2.1 million per year in utility revenue (Schedule 6, line 21).

a) Please list all the rate design assumptions for the base case and indicate why these are appropriate values for each of the three years.

b) Please indicate what will happen if either the 7,000 GJ/day or 170 days of interruptible service are found to be inappropriate after the RFP has been issued.

Response:

a) The proposed interruptible liquefaction rate is intended to make a contribution towards the recovery of existing 2013 Board-approved Hagar liquefaction and storage costs, Union North distribution costs and to recover all the incremental costs associated with the provision of the interruptible liquefaction service.

The rate design assumptions include:

- Board approval of Union's proposed cost allocation methodology used to allocate 2013 Board-approved costs between liquefaction, storage and vapourization functions performed at Hagar, and Union North distribution costs to the Rate L1 service;
- Incremental annual liquefaction costs of $1.460 million;
- Average annual forecast liquefaction activity of 415,520 GJ per year;
- 167 days per year of liquefaction service provided to customers and;
- 7,000 GJ of storage space capacity utilized by liquefaction customers.

Union's proposed cost allocation methodologies are consistent with the principles of cost causality and ensure that the costs allocated to each function (liquefaction, storage, vapourization and distribution) reflect the costs to perform that function. Union's forecast of average annual liquefaction activity, the number of days of liquefaction service and the storage space utilized by liquefaction customers is based on the best available information regarding:

a) Union's available liquefaction capacity and storage space; and,

b) how customers intend to utilize the liquefaction service.

b) If the Board found the 7,000 GJ or 167 days of interruptible service to be inappropriate, Union would need to reassess whether it can offer the service as contemplated.

UNION GAS LIMITED

Answer to Interrogatory from
Northeast Midstream LP

Reference: Exhibit A, Tab 1, Page 1, Lines 9-11

Spark ignited engines have limitations on the amount of ethane, nitrogen and C6+ components that are acceptable in LNG. These components are not an issue for utility uses of LNG, but can cause engine issues when LNG is used as a transportation fuel. Notwithstanding historical gas quality information and current tariff limits of TCPL, there is a trend in the western Canadian sedimentary basin (WCSB) toward the production of much richer unconventional natural gas. The share of ethane and heavier components in this sales gas from WCSB is expected only to increase over time on the TCPL Mainline that feeds Hagar. Please indicate whether the current capital estimate includes the cost to add a dethanizer, nitrogen rejection column, and a C6+ stripper to the existing liquefaction unit.

Response:

When the Hagar plant was originally built, it included an ethane removal skid. Shortly after Hagar went into operation the ethane removal skid was decommissioned and has not been required since.

The current capital cost estimate does not include costs to add a dethanizer, nitrogen rejection column, and/or a C6+ stripper to the existing liquefaction unit.

UNION GAS LIMITED

Answer to Interrogatory from
Northeast Midstream LP

Reference: Exhibit A, Tab 1, Page 1, Lines 9-11

Please state how Union plans to dispose of any of the heavier components stripped from the feed gas in order to comply with transportation fuel specifications. What are the estimated disposal costs and where are they reflected in Union's rate proposal?

Response:

The gas arriving at Hagar does not require Union to strip out the heavier components from the gas. Accordingly, there are no forecasted disposal costs to be recovered in the proposed liquefaction rate.

UNION GAS LIMITED

Answer to Interrogatory from
Northeast Midstream LP

Reference: Exhibit A, Tab 1, Page 1, Lines 9-11

Please state how the energy content of the heavier components that are stripped out of the gas will be accounted for on a rate making basis?

Response:

Please see the response to Exhibit B.Northeast.2. There is no requirement to strip out the heavier components of the gas.

Heating value of LNG will be measured and will provide the basis for billing. The energy content of the heavier components will be accounted for in measured heating value.

UNION GAS LIMITED

Answer to Interrogatory from
Northeast Midstream LP

Reference: Exhibit A, Tab 1, Page 1, Lines 9-11

As unconventional gas ethane content and gas density changes on a daily basis and to the extent that these changes are not blended out through mixing within the TCPL system, please indicate the capability of the Hagar plant to change its refrigerant composition to accommodate transportation fuel specifications. To the extent that this capability does not exist, what are the estimated costs of creating this capability and where are those costs reflected in Union's rate proposal?

Response:

Hagar utilizes a mixed refrigeration system. The cycle mix is composed of a number of constituents that can be changed depending on liquefaction requirements.

UNION GAS LIMITED

Answer to Interrogatory from
Northeast Midstream LP

Reference: Exhibit A, Tab 1, Page 1, Lines 9-11

Please specify the extent to which producing transportation grade LNG will increase the cost of the liquid in storage that is held for system integrity use. Are such costs, if any, reflected in Union's rate proposal?

Response:

Union is currently producing transportation grade LNG. As a result, there are no incremental costs reflected in Union's rate proposal.

UNION GAS LIMITED

Answer to Interrogatory from
Northeast Midstream LP

Reference: Exhibit A, Tab 1, Page 1, Lines 13-15

Please describe sales plans for LNG from Hagar beyond the on-highway market, since no other markets are identified in the application.

Response:

Please see the response to Exhibit B.Staff.1.

UNION GAS LIMITED

Answer to Interrogatory from
Northeast Midstream LP

Reference: Exhibit A, Tab 1, Page 1, Lines 13-15

Please specify which other markets under consideration do not require regulatory approval and that might require regulatory approval.

Response:

Please see the response to Exhibit B.BOMA.9 a).

UNION GAS LIMITED

Answer to Interrogatory from
Northeast Midstream LP

Reference: Exhibit A, Page 4, Table 1

Union forecasts a total demand of 1,662,080 GJ over a period of 40 months. Exhibit A, Tab 2, shows the demand growing from 203,520 GJ in 2015 (annualized) to 678,400 in 2018, yielding a levelized demand of 425,520 GJ per year to 2018.

a) Please describe how Union arrived at the annual liquefaction sales figures that underpin the sales forecast in Table 1.

b) Please provide the expected sales forecast for 2019 to 2035.

c) Please describe what, if anything, would prevent Union's LNG customers from switching to new, lower cost sources of liquefaction services, leading to an erosion of customers supporting the L1 rate.

d) Please provide the assumptions Union makes about market forces, including but not limited to the barriers facing customers converting to LNG, the ability of OEMs, engine companies and others to deliver LNG solutions at a reasonable price, and the price of oil versus natural gas.

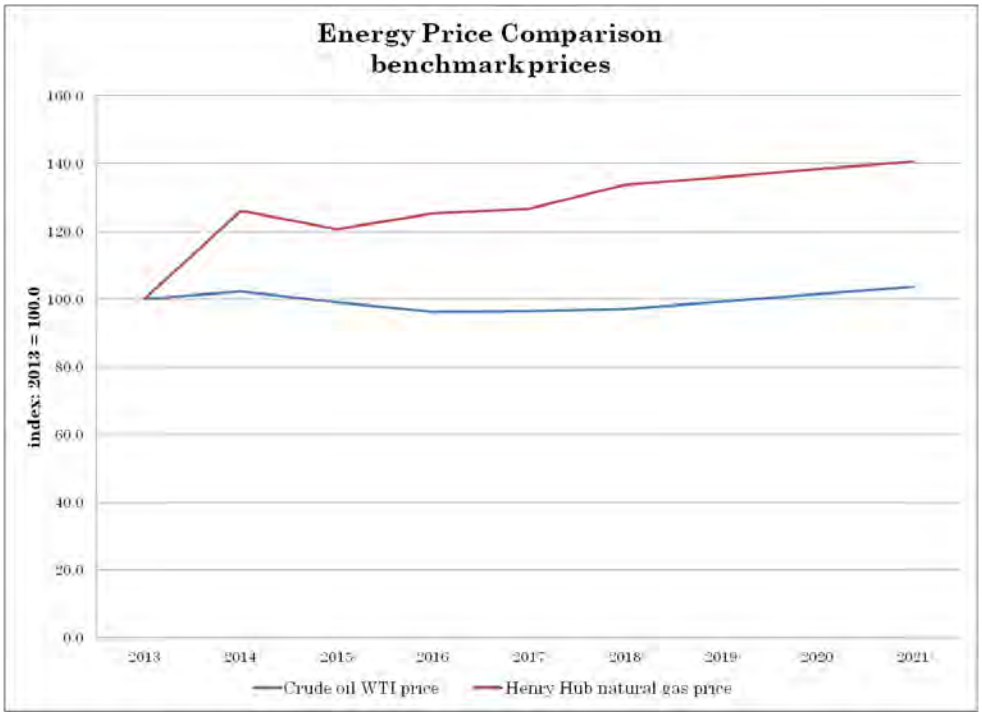
Response:

a) Please see the response to Exhibit B.Energy Probe.10.

b) A sales forecast has not been prepared for 2019 to 2035.

c) Union's LNG customers are free to switch to any other source of LNG provided the terms of their contracts (e.g. term, MAV) are fulfilled. As stated previously, Union views the small quantity of LNG available from Hagar as only sufficient to help start a more robust and competitive LNG market.

d) Please see the response to Exhibit B.BOMA.5. The chart below provides future oil and natural gas pricing.



Source of benchmark prices:
Consensus Economics Inc. / Energy & Metals Consensus Forecasts June 2014 report page 5
benchmark price estimates are copyrighted and require prior publisher permission for sharing purposes

UNION GAS LIMITED

Answer to Interrogatory from
Northeast Midstream LP

Reference: Exhibit A Tab 1, Page 8, Lines 14-16

In the United States in recent years, a number of local distribution companies have either sold their LNG assets to private companies or spun-off their LNG assets into un-regulated businesses to market and sell LNG as a replacement for diesel. For example, In 2011 Pivotal LNG purchased a 5,000 GJ/day LNG facility located in Trussville, Alabama, from the Utilities Board of the City of Trussville. In 2013, Citizens Energy Group in Indianapolis vested its LNG assets with Kinetrex Energy to supply LNG to fuel UPS tractor trailers in the Midwest. Please identify to what extent Union has evaluated the cost-effectiveness of selling the Hagar facility to a private entity and then contracting back the required system integrity services on behalf of Union North customers.

Response:

Union did not evaluate the cost-effectiveness of selling Hagar to a private entity and then contracting back the required system integrity service as the primary purpose of the Hagar facility is for system integrity needed to support regulated operations. Union did however review, at a high level, the possibility of contracting for a firm system integrity service in the marketplace. Initial indications revealed it was extremely difficult to find a party who could offer this service on a firm basis. Further, the costs of such a service would be extremely expensive. For these reasons, Union determined that contracting a system integrity service was not a reasonable alternative.

UNION GAS LIMITED

Answer to Interrogatory from
Northeast Midstream LP

Reference: Exhibit A Tab 1, Page 10-11

Northeast Midstream is an Ontario limited partnership that has been approved to build a new LNG production facility in Thorold, Ontario, to serve the Great Lakes region, including all of Ontario. Thorold will have the capacity to liquefy up to 33,000GJ/day of natural gas, or 12 million GJ per year, which is ten-times the total capacity of Hagar. Please state whether Union's revenue projections take into account the operation of the Thorold facility.

Response:

No. Union's revenue projections do not take into account Thorold or any other proposed facility. The revenue projections are limited by the amount of LNG that Hagar is capable of liquefying while maintaining system integrity needs.

UNION GAS LIMITED

Answer to Interrogatory from
Northeast Midstream LP

Reference: Exhibit A Tab 1, Page 10, Lines 5-11

Union has obtained six expressions of interest for a total of 700,633 to 810,633 GJ per year. Contract tenors range from three to ten years, although two of the six respondents declined to specify a term. The open season document provides an indicative price of $5.54 to $6.93 /GJ, plus the natural gas commodity, which is 10% to 20% higher than the proposed L1 Rate, and Union has not yet signed a precedent agreement with any customer. Please specify whether the minimum annual commitments in Table 2 reflect the price indicated in the open season or the price of the proposed L1 Rate.

Response:

The minimum annual volume commitments (MAV) in Table 2 are non-binding volume commitments made during the open season. The open season documents did provide an indicative price but clearly stated this price would change to reflect Union's application to the OEB and subsequent OEB approval.

UNION GAS LIMITED

Answer to Interrogatory from
Northeast Midstream LP

Reference: Exhibit A Tab 1, Page 10, Lines 5-11

Please explain why Union hasn't waited until it signed precedent agreements sufficient to support the planned expansion before making its application for the L1 Rate.

Response:

As part of Union's efforts to assess the viability of offering a liquefaction service at Hagar, it conducted a non-binding Expression of Interest. As shown in the results filed at Exhibit A, Tab 1, p. 10, Table 2, Union is aware that interest in this service exists in the marketplace. Union is in the process of exploring the positive results it received from the Expression of Interest through ongoing discussions with the various respondents. Through these discussions it is clear parties are reluctant to make a long-term commitment to the service without a Board-approved rate. A Board-approved rate is essential for these parties to proceed with firm commitments and precedent agreements. Once a rate is approved Union can properly assess the demand and determine whether there is sufficient interest to proceed.

UNION GAS LIMITED

Answer to Interrogatory from
Northeast Midstream LP

Reference: Exhibit A Tab 1, Page 10, Lines 5-11

Without one or more precedent agreements for capacity as evidence to support the rate application, please indicate what probability Union assigns to each of these expressions of interest that it will convert into a precedent agreement.

Response:

Please see response to Exhibit B.Northeast 12.

UNION GAS LIMITED

Answer to Interrogatory from
Northeast Midstream LP

Reference: Exhibit A Tab 1, Page 10, Lines 5-11

Please provide a template precedent agreement that Union is using with potential customers.

Response:

The draft contract documents are attached:

a) Liquefaction & Dispensing Contract (June 24, 2014) – Attachment 1
b) Liquefaction General Terms & Conditions (June 24, 2014) – Attachment 2

These documents are draft and are subject to change.

Contract No. LD___

THIS LIQUEFACTION AND DISPENSING AGREEMENT (this "**Agreement**") dated as of the ____ day of [Month], [year],

UNION GAS LIMITED, a company existing under the laws of the Province of Ontario,
(hereinafter referred to as "**Union**")

- and -

[CUSTOMER NAME], a [type of entity] existing under the laws of the
(Province, State, Country) of [ ],
(hereinafter referred to as "**Customer**")

WHEREAS, Union owns and operates liquefaction and dispensing facilities in Hagar, Ontario, through which Union offers "Liquefaction Services", as defined in the Liquefaction General Terms and Conditions;

AND WHEREAS, Customer wishes to retain Union to provide such Liquefaction Services, as set out herein, and Union has agreed, subject to the terms and conditions of this Agreement, to provide the Liquefaction Services requested;

NOW THEREFORE, this Agreement witnesses that, in consideration of the mutual covenants and agreements herein contained and for other good and valuable consideration, the receipt and sufficiency of which is hereby acknowledged, the parties hereby agree as follows:

ARTICLE 1
INTERPRETATION AND DEFINITIONS

1.1 Divisions, Headings and Index:

The division of this Agreement into Articles, Sections and Subsections, and the insertion of headings and any table of contents or index provided are for convenience of reference only, and shall not affect the construction or interpretation hereof.

1.2 Defined Terms

Capitalized terms used but not defined herein shall have the meaning given to them in the Liquefaction General Terms and Conditions.

1.3 Industry Usage:

Words, phrases or expressions which are not defined herein or in the Liquefaction General Terms and Conditions and which, in the usage or custom of the businesses of the transportation, storage, and distribution or sale of natural gas and LNG have an accepted meaning shall have that meaning.

1.4 Extended Meaning:

Unless the context otherwise requires, words importing the singular include the plural and vice versa, and words importing gender include all genders. The words “herein” and “hereunder” and words of similar import refer to the entirety of this Agreement, including the Schedules incorporated into this Agreement, and not only to the Section in which such use occurs.

1.5 Conflict:

In the event of any conflict between the provisions of the main body of this Agreement (including Schedule 1) and Union’s L1 Rate Schedule, as defined below, the provisions of Union’s L1 Rate Schedule shall prevail over the main body of this Agreement.

1.6 Currency:

All reference to dollars in this Agreement shall mean Canadian dollars unless otherwise specified.

1.7 Agreement Schedules:

Refers to the schedules attached hereto which are specifically included as part of this Agreement, and include:

Schedule 1 – Agreement Parameters

1.8 Rate Schedule:

“Union's L1 Rate Schedule” or the “L1 Rate Schedule” or “L1” shall mean Union’s L1 Rate Schedule, (including the L1 Liquefaction Rate, the L1 Gas Supply Charge, Schedule “A” (“**General Terms and Conditions**”), Schedule “B”(“**Nominations**”)), or such other replacement rate schedule which may be applicable to the Liquefaction Services provided hereunder as approved by the Ontario Energy Board (if required), and shall apply hereto, as amended from time to time, and which is incorporated into this Agreement pursuant to Section 8.3 hereof.

ARTICLE 2
LIQUEFACTION SERVICES

2.1 Liquefaction Services:

Union shall, subject to the terms and conditions herein, provide the Liquefaction Services to Customer. Customer agrees to the following:

(a) Negotiated Liquefaction Rate (if applicable), Minimum Annual Volume, First Annual Forecast, Gas Supply for First Contract Year, Term, Customer's Additional Representations and Warranties, Receipt Point and Delivery Point shall be as set out in Schedule 1.

(b) **LNG Dispensed by Union:**

(i) Union agrees, on any Day, and subject to Sections 2.1(b)(ii) and 2.1(b)(iii), to Dispense to Customer at the Delivery Point, such quantity of LNG set out on the Dispensing Schedule which both Customer and Union have confirmed;

(ii) Under no circumstances shall Union be required to store any LNG on behalf of Customer; and

(iii) Under no circumstances shall Union be required to deliver a quantity of LNG in excess of the Minimum Annual Volume or accept any gas at the Receipt Point except as set out in the Annual Forecast as subsequently confirmed by Union or as otherwise set out in the Liquefaction General Terms and Conditions.

2.2 Accounting for Liquefaction Services:

All quantities of gas and LNG handled by Union shall be accounted for on a daily basis.

2.3 Commingling:

Union shall have the right to commingle (i) the quantity of gas and (ii) the quantity of LNG referenced herein with gas or LNG, as applicable, owned by Union or gas or LNG, as applicable, being stored and/or transported by Union for third parties.

ARTICLE 3
TERM

3.1 Initial Term

The Initial Term of this Agreement will be as specified in Schedule 1 and will expire on the Expiry Date.

3.2 Renewal

Not later than three (3) months prior to the Expiry Date, Customer may request that Union extend the term of this Agreement on terms acceptable to both parties. Agreements with a Term of five (5) years or greater may continue in full force and effect beyond the Initial Term, at the request of Customer (such request to be received by Union no later than three (3) months prior to the Expiry Date), automatically renewing for a period of one (1) year, and every one (1) year thereafter, in each case, at the Liquefaction Rate for agreements with a term greater than one (1) year (as set out in the L1 Rate Schedule). For agreements which have been automatically extended in such a manner, Customer may terminate the Agreement with notice in writing to Union at least one (1) year prior to the expiration thereof.

3.3 Early Termination

The term of this Agreement is subject to early termination in accordance with Section 16 (Default or Bankruptcy) of the Liquefaction General Terms and Conditions.

ARTICLE 4
CONDITIONS PRECEDENT

4.1 Conditions for Union's Benefit

The obligations of Union to provide the Liquefaction Services are subject to the following conditions precedent, which are for the sole benefit of Union and may be waived or extended in whole or in part in the manner provided for in this Agreement:

(a) Union shall have obtained, in form and substance satisfactory to Union, and all conditions shall have been satisfied under, all governmental, regulatory and other third party approvals, consents, orders, and authorizations that are required to:

(i) construct and operate any new facilities to be constructed by Union in order to provide the Liquefaction Services (the "**Expansion Facilities**"); and

(ii) provide the Liquefaction Services, under a regulatory framework satisfactory to Union, in its sole discretion;

(b) Union shall have obtained all internal approvals that are necessary or appropriate to construct and operate the Expansion Facilities and provide the Liquefaction Services;

(c) Union shall have completed and placed into service the Expansion Facilities;

(d) Customer shall have executed this Agreement and provided Union with notification of the satisfaction or waiver of the conditions precedent for the benefit of Customer outlined in this Agreement;

(e) Union shall have received from Customer the requisite financial assurances reasonably necessary to ensure Customer's ability to honor the provisions of this Agreement as provided in Section 9.3 of the Liquefaction General Terms and Conditions.

(f) Customer shall have represented and warranted to Union that it is purchasing LNG for use in accordance with its representation at Schedule 1.

4.2 Conditions for Customer's Benefit

The obligations of Customer herein are subject to the following conditions precedent, which are for the sole benefit of Customer and may be waived or extended in whole or in part in the manner provided for herein:

4.3 Satisfaction of Conditions Precedent

Union and Customer shall each use due diligence and reasonable efforts to satisfy and fulfill the conditions precedent, if applicable, specified in Section 4.1 (a), (c), (d), (e) and (f) the conditions precedent specified in Section 4.2 (if any). Each party shall notify the other forthwith in writing of the satisfaction or waiver of each condition precedent for such party's benefit. If a party concludes that it will not be able to satisfy a condition precedent that is for its benefit, that party may, upon written notice to the other party, terminate this Agreement and upon the giving of such notice, this Agreement shall be of no further force and effect and each of the parties shall be released from all further obligations hereunder; provided however, that such termination shall be without prejudice to any rights or remedies that a party may have for breaches of this Agreement prior to such termination and any liability a party may have incurred before such termination shall not thereby be released.

4.4 Termination for Non-Satisfaction of Conditions Precedent

If any of the conditions precedent in Section 4.1(d), (e) and (f) are not satisfied or waived by Union by the date set out in this Agreement (or if any of the conditions precedent in Section 4.2 are not satisfied or waived by Customer by the date set out in this Agreement), then either party may, upon written notice to the other party, terminate this Agreement and upon the giving of such notice, this Agreement shall be of no further force or effect and each of the parties shall be released from all further obligations hereunder; provided however, that such termination shall be without prejudice to any rights or remedies that a party may have for breaches of this Agreement prior to such termination and any liability a party may have incurred before such termination shall not thereby be released.

ARTICLE 5
REPRESENTATIONS AND WARRANTIES

5.1 Customer represent and warrants that:

(a) it is duly formed and organized and validly subsisting under the laws of its jurisdiction of organization.

(b) it has all requisite corporate power and authority to execute and deliver this Agreement, to carry out its obligations hereunder, and to consummate the transactions contemplated hereby.

(c) it has obtained all necessary corporate approvals for the execution and delivery of this Agreement, the performance of its obligations hereunder, and the consummation of the transactions contemplated hereby.

(d) this Agreement has been duly executed and delivered by it and constitutes it's legal, valid and binding obligation, enforceable against it in accordance with its terms.

(e) the execution, delivery and performance by it of these this Agreement does not conflict with, violate or result in the breach of, any agreement, instrument, order, judgment, decree, law or governmental regulation to which it is a party or is subject.

ARTICLE 6
CHARGES AND RATES

6.1 Except as otherwise stated herein, the charges and rates to be billed by Union and paid by Customer for the Liquefaction Services provided under this Agreement will be those specified in the Liquefaction General Terms and Conditions.

ARTICLE 7
NOMINATIONS

7.1 Liquefaction Services provided hereunder shall be in accordance with the prescribed nominations procedure as set out in Union's L1 Rate Schedule "B" (Nominations).

ARTICLE 8
MISCELLANEOUS PROVISIONS

8.1 Notices:

All communications provided for or permitted hereunder shall be in writing, personally delivered to an officer or other responsible employee of the addressee or sent by registered mail, charges prepaid, by email or other means of recorded electronic communication, charges prepaid, to the applicable address or to such other address as either party hereto may from time to time designate to the other in such manner, provided that no communication shall be sent by mail pending any threatened, or during any actual, postal strike or other disruption of the postal service. Customer contact information, as provided to Union, shall be found on the secured portion of Union's website (the secured portion of Union's website is known as "**Unionline**"). Union's contact information shall be displayed on the unsecured portion of Union's website. Any communication personally delivered shall be deemed to have been validly and effectively received on the date of such delivery. Any communication so sent by email or other means of electronic communication shall be deemed to have been validly and effectively received on the Business Day following the day on which it is sent. Any communication so sent by mail shall be deemed to have been validly and effectively received on the seventh Business Day following the day on which it is postmarked.

Notwithstanding the above, nominations shall be made by email or other recorded electronic means, subject to execution of an agreement for use of Unionline, or such other agreement, satisfactory to Union, and will be deemed to be received on the same Day and same time as sent. Each party may from time to time change its address for the purpose of this Section by giving notice of such change to the other party in accordance with this Section.

8.2 Law of Contract:

Union and Customer agree that this Agreement is made in the Province of Ontario and that the courts of the Province of Ontario shall have exclusive jurisdiction in all matters contained herein. The parties further agree that this Agreement shall be construed exclusively in accordance with the laws of the Province of Ontario.

8.3 Entire Agreement:

This Agreement (including Schedule 1), all applicable rate schedules and price schedules constitute the entire agreement between the parties hereto pertaining to the subject matter hereof. This Agreement supersedes any prior or contemporaneous agreements, understandings, negotiations or discussions, whether oral or written, of the parties in respect of the subject matter hereof.

8.4 Enurement

This Agreement will enure to the benefit of and be binding upon the parties and their respective successors and permitted assigns, including without limitation, successors by merger, amalgamation or consolidation.

8.5 Governing Law and Submission to Jurisdiction

(a) Governing Law. This Agreement, including all applicable rate schedules and price schedules, shall be governed by, and construed in accordance with, the laws of the Province of Ontario and the laws of Canada applicable therein.

(b) Submission to Jurisdiction. Each party hereto irrevocably and unconditionally submits, for itself and its property, to the exclusive jurisdiction of the courts of Ontario, in any action or proceeding arising out of or relating to this Agreement, including all applicable rate schedules and price schedules, or for recognition or enforcement of any judgment, and each party hereto irrevocably and unconditionally agrees that all claims in respect of any such action or proceeding may be heard and determined in such court (and each party hereto agrees not to commence any proceeding relating thereto except in such courts). Each party hereto, hereby irrevocably waives, to the fullest extent it may effectively do so, the defence of inconvenient forum to the maintenance of such action or proceeding.

8.6 Trial by Jury

Each party hereto hereby irrevocably waives, to the fullest extent permitted by applicable law, any right it may have to a trial by jury in any legal proceeding directly or the transactions contemplated hereby (whether based on contract, tort or any other theory). Each party hereto (i) certifies that no representative, agent or attorney of any other person has represented, expressly or otherwise, that such other person would not, in the event of litigation, seek to enforce the foregoing waiver and (ii) acknowledges that it and the other party hereto have been induced to enter into this agreement by, among other things, the mutual waivers and certifications in this section.

8.7 Time of Essence:

Time shall be of the essence hereof.

8.8 Counterparts:

This Agreement may be executed in any number of counterparts, each of which when so executed shall be deemed to be an original but all of which together shall constitute one and the same agreement. This Agreement may be executed by electronic communication and this procedure shall be as effective as signing and delivering an original copy.

8.9 Severability:

If any provision hereof is invalid or unenforceable in any jurisdiction, to the fullest extent permitted by law, (a) the other provisions hereof shall remain in full force and effect in such jurisdiction and shall be construed in order to carry out the intention of the parties as nearly as possible and (b) the invalidity or unenforceability of any provision hereof in any jurisdiction shall not affect the validity or enforceability of any provision in any other jurisdiction.

8.10 General Liability:

The liability of the parties hereunder is limited to direct damages only and all other remedies or damages are waived. In no event shall either party be liable for consequential, incidental, punitive, or indirect damages, in tort, contract or otherwise.

[signature page follows]

THIS AGREEMENT SHALL BE BINDING UPON and shall enure to the benefit of the parties hereto and their respective successors and permitted and lawful assigns.

IN WITNESS WHEREOF this Agreement has been properly executed by the parties hereto by their duly authorized officers as of the date first above written.

UNION GAS LIMITED

Per:____________________________
Authorized Signatory

[NAME OF CUSTOMER]

Per:____________________________
Authorized Signatory

Schedule 1

Agreement Parameters

Negotiated Liquefaction Rate (for Agreements with a Term of 1 year or less)

- $ ________________ (GJ)

Minimum Annual Volume

Union shall, over the term of this Agreement annually, liquefy and Dispense a minimum annual volume of LNG, in accordance with the Dispensing Schedule, such volumes for each Contract Year, the "**Minimum Annual Volume**" and Customer shall, over the term of this Agreement annually, deliver, or arrange for Union to deliver a quantity of gas, in accordance with the First Annual Forecast or Annual Forecast, as applicable, of:

Contract Year	**Minimum Annual Volume**
20xx-20xx	XXXXXX GJ

First Annual Forecast (in GJ):

	Jan	**Feb**	**March**	**April**	**May**	**June**	**July**	**Aug**	**Sept**	**Oct**	**Nov**	**Dec**
LNG to be Dispensed	[xxx]	[xxx]	[xxx]	[xxx]	[xxx]	[xxx]	[xxx]	[xxx]	[xxx]	[xxx]	[xxx]	[xxx]

Gas Supply For First Contract Year

- [by Customer]

  OR

- [by Union]

Receipt Points, Delivery Points and Liquefaction Services Paths

A "**Receipt Point**", as noted in the chart below, shall mean the point where Union shall receive gas from Customer or from Union's system on a firm basis and a "**Delivery Point**", as noted in the chart below, shall mean the point where Union shall Dispense LNG to Customer, which points are more particularly described in the Liquefaction General Terms and Conditions.

The Liquefaction Services are available for the following paths:

Path	**Receipt Point(s)**	**Delivery Point(s)**
1.	Union NDA	Hagar Delivery Point

<u>Term</u>

This Agreement shall be effective as of the date of execution hereof; however, the obligations, terms and conditions for the Liquefaction Services herein shall commence on the later of:

- [Month day, year]; and
- the day following the date that all of the conditions precedent set out in Article 4 herein have been satisfied or waived by the party entitled to the benefit thereof;

(such later date being referred to as the "**Commencement Date**") and shall continue in full force and effect until [Month day, year] (the "**Expiry Date**"), the time between the Commencement Date and the Expiry Date, the "**Initial Term**".

<u>Conditions Date</u>

As referred to in Section 4.1 (d), (e) and (f) [Month day, year]

[***insert if Customer has CPs under Section 4.2)***][As referred to in Section 4.2 (a) and (b) [Month day, year]]

<u>Customer's Representations and Warranties</u>

[Customer represents and warrants to Union that it is purchasing LNG as a transportation fuel for vehicles with a gross weight rating in excess of 3856 kg.]

OR

[Customer represents and warrants to Union that it is purchasing LNG for use ….[insert acceptable useage]]

<u>Special Provisions</u>

[insert any special provisions applicable to this Agreement]

Schedule 2

Annual Forecast

Minimum Annual Volume and Natural Gas Supply

Contract Year	Minimum Annual Volume
20xx-20xx	XXXXXX GJ

Annual Forecast for Contract Year 20xx (in GJ):

	Jan	Feb	March	April	May	June	July	Aug	Sept	Oct	Nov	Dec
LNG to be Dispensed	[xxx]	[xxx]	[xxx]	[xxx]	[xxx]	[xxx]	[xxx]	[xxx]	[xxx]	[xxx]	[xxx]	[xxx]

Gas Supply For Contract Year 20xx

- [by Customer]

OR

- [by Union]

Schedule 3

Monthly Forecast

[CUSTOMER NAME]

Monthly Forecast for [Month]

Heat Value (as provided by Union for the month): ___________ GJs/kg

Monthly Dispensing Amount: ___________ GJs

Monthly Natural Gas Supply: ___________ GJs (if Customer is arranging for supply)

Strike Price (if Union supplies gas) ___________ $/GJ (does not include transport)

Dispensing Date	**Day of Week**	**Time (am/pm)***	**Dispensed (kg)**	**Dispensed (GJ)** (kg x Heat Value)
		Total		

*in accordance with normal Dispensing hours

Schedule "A"

UNION GAS LIMITED

GENERAL TERMS & CONDITIONS FOR INTERRUPTIBLE NATURAL GAS LIQUEFACTION AND DISPENSING SERVICE

Effective ■

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1. Definitions

1.1 Definitions

Except where the context expressly requires otherwise, all words and phrases defined below, when used in these Liquefaction General Terms and Conditions and in any agreement into which these Liquefaction General Terms and Conditions have been incorporated, shall be construed to have the following meanings:

"Act" – has the meaning given in Section 13.2(a).

"Annual Forecast" **–** has the meaning given in Section 2.2.

"Business Day" – means any day, other than Saturday, Sunday or any day on which a holiday is recognized for Hagar employees.

"Change Order" – has the meaning given in Section 8.2.

"Commitment Annual Amount" – has the meaning given in Section 2.7.

"Contract Year" - means a period of twelve (12) consecutive Months commencing as at the first Day of the next Month after the Commencement Date (as that term is defined in the LD Agreement); provided however, that if the Commencement Date falls on the first day of a calendar month, the Contract Year shall commence on that first Day.

"cricondentherm hydrocarbon dewpoint" - means the highest hydrocarbon dewpoint temperature on the phase envelope.

"cubic metre" - means the volume of gas which occupies one cubic metre when such gas is at a temperature of 15 degrees Celsius, and at a pressure of 101.325 kilopascals absolute.

"Day" - means a period of twenty-four (24) consecutive hours beginning at 10:00 a.m. EST. The reference date for any Day shall be the calendar date upon which the twenty-four (24) hour period shall commence.

"Delivery Point" – means, unless otherwise specified in the LD Agreement, the point or points of delivery for all LNG to be Dispensed under the LD Agreement, which shall be on the outlet side of the LNG measuring station(s) where possession of the LNG changes from one party to the other.

"Dispensing" - means the act of filling a cryogenic vessel with LNG.

"Dispensing Schedule" – means the schedule provided to Customer pursuant to Customer's Monthly Forecast and subsequently confirmed by Union pursuant to Section 2.3, indicating Dispensing amounts and times during a Month.

"EST" – means Eastern Standard Time or Eastern Daylight Time, as applicable.

"Firm Daily Amount" - has the meaning given in Section 3.

"Force Majeure" - means acts of God, strikes, lockouts or any other industrial disturbance, acts of the public enemy, sabotage, wars, blockades, insurrections, riots, epidemics, landslides, lightning, earthquakes, fires, storms, floods, washouts, arrests and restraints of governments and people, civil disturbances, explosions, breakage or accident to machinery or lines of pipe, freezing of wells or lines of pipe, inability to obtain materials, supplies, permits or labour, any laws, orders, rules, regulations, acts or restraints of any governmental body or authority (civil or military), any act or omission that is excused by any event or occurrence of the character herein defined as constituting force majeure, any act or omission by parties not controlled by the party having the difficulty and any other similar cases not within the control of the party claiming suspension and which by the exercise of due diligence such party is unable to prevent or overcome.

"gas" - means gas as defined in the *Ontario Energy Board Act*, 1998, S.O. 1998, c.15, Sch. B, as amended, supplemented or re-enacted from time to time.

"gross heating value" - means the total heat expressed in megajoules per cubic metre (MJ/m3) produced by the complete combustion at constant pressure of one (1) cubic metre of gas with air, with the gas free of water vapour and the temperature of the gas, air and products of combustion at standard temperature and all water formed by the combustion reaction condensed to the liquid state.

"Hagar Delivery Point" – means the outlet side of the LNG measuring station(s) located at or near the Hagar Facility.

"Hagar Facility" - means the Union facility located in Hagar, Ontario.

"Heat Value" – means quantity of energy per unit mass of LNG expressed in MJs per kilogram.

"hydrocarbon dewpoint" - means temperature at a specific pressure where hydrocarbon vapour condensation begins.

"Interconnecting Pipeline" - means a pipeline that directly connects to the Union pipeline system.

"interruptible service" or "**Interruptible"** - means service subject to curtailment or interruption, after notice, at any time.

"joule" (J) - means the work done when the point of application of a force of 1 newton is displaced a distance of 1 metre in the direction of the force. The term "megajoule" (MJ) shall mean 1,000,000 joules. The term "gigajoule" (GJ) shall mean 1,000,000,000 joules.

"kg" – means kilograms.

"LD Agreement" - means a Liquefaction and Dispensing Agreement entered into by Union and Customer, incorporating by reference, these Liquefaction General Terms and Conditions.

"Liquefaction General Terms and Conditions" - means these General Terms and Conditions for the Interruptible Liquefied Natural Gas Liquefaction and Dispensing Service.

"Liquefaction Rate" – means the charge to liquefy Customer's gas as set out in the Rate Schedule, or the charge negotiated pursuant to the Rate Schedule, as applicable, and to the extent applicable, any additional charge pursuant to Section 2.4 of these Liquefaction General Terms and Conditions.

"Liquefaction Services" - means the interruptible services of the liquefaction and Dispensing of LNG from the Hagar Facility, as further specified in Section 2.1 of these Liquefaction General Terms and Conditions.

"LNG" - means liquefied natural gas.

"M12 Rate Schedule" - means Union's M12 Rate Schedule as that term is defined in Union's Firm M12 Transportation Contract.

"Minimum Annual Volume" – has the meaning given in Section 2.2.

"Month" - means the period beginning at 10:00 a.m. EST on the first Day of a calendar month and ending at 10:00 a.m. EST on the first Day of the following calendar month;

"Monthly Charge" – has the meaning given in Section 9.1(a).

"Monthly Gas Price" – has the meaning given in Section 2.6.

"Monthly Forecast" – has the meaning given in Section 2.3.

"Monthly Dispensing Amount" – means, subject to these Liquefaction General Terms and Conditions, the quantity of LNG (measured in GJs) that Customer may take delivery of over the period of one Month which quantity shall be determined by Union based on Customer's Monthly Forecast.

"NAESB" – means the North American Energy Standards Board.

"Nomination" – has the meaning given in L1 Schedule B - Nominations.

"OEB" - means the Ontario Energy Board.

"pascal" (Pa) - means the pressure produced when a force of 1 newton is applied to an area of 1 square metre. The term "kilopascal" (kPa) shall mean 1,000 pascals.

"Rate Schedule" - means the Rate L1-Natural Gas Liquefaction Service Rate Schedule as modified and approved by the OEB from time to time.

"Receipt Point" – means, unless otherwise specified in the LD Agreement, the point or points of receipt for all gas to be liquefied hereunder, which shall be on the outlet side of the measuring station(s) located at the point of connection with TransCanada Pipelines Limited's facilities and Union's distribution system where (i) possession of the gas changes from Customer to Union or (ii) to which Union delivers the gas pursuant to the Annual Forecast.

"Regulations" – has the meaning given in Section 13.2(a).

"Strike Price" – means the maximum commodity price, expressed in $/GJ, that Customer is willing to pay for gas for the upcoming Month.

"Suppliers" – means companies from whom Union buys gas.

"Taxes" – means any tax (other than tax on income or tax on property), duty, royalty, levy, license, fee or charge not included in the charges and rates as per the applicable rate schedule (including but not limited to charges under any form of cap and trade, carbon tax, or similar system) and that is levied, assessed or made by any governmental authority on the gas itself, or the act, right, or privilege of producing, severing, gathering, storing, transporting, handling, selling or delivering gas under the LD Agreement.

"Union" - means Union Gas Limited.

"Union NDA" - means the outlet side of the measuring station at the junction of TransCanada Pipeline Limited's facilities and Union's distribution system which feeds the Hagar Facility in Union's Northern Delivery Area.

"Wobbe Number" - means gross heating value of the gas divided by the square root of its specific gravity.

2. Conditions of Service

2.1 Description of Service

These Liquefaction General Terms and Conditions apply to the Liquefaction Services at the Hagar Facility at Hagar, Ontario. For greater certainty, Liquefaction Services means the provision by Union of Liquefaction Services which may be interrupted by Union pursuant to the terms hereof and which encompass:

(a) receipt of gas at the Receipt Point, whether delivered by Customer or Union as set out in the Annual Forecast;

(b) transportation of gas by Union to the inlet side of the Hagar Facility;

(c) liquefaction of gas into LNG (but only in respect of gas received at the Receipt Point);

(d) injection into the tank of the gas received by Union, and liquefied by Union on behalf of Customer, at the Hagar Facility; and

(e) holding any daily variances between the aggregate (in GJs) of gas received and LNG Dispensed on a Day and measuring such Dispensed LNG; and

(f) Dispensing to Customer's cryogenic vessels at the Delivery Point in accordance with the Dispensing Schedule.

2.2 Determination of First Annual Forecast and Annual Forecast

Pursuant to the LD Agreement, Customer will commit to a minimum annual volume of LNG to be Dispensed by Union during each Contract Year (the "**Minimum Annual Volume**") and shall commit to a forecast for the first Contract Year which shall include a delivery schedule for the gas to be delivered to the Receipt Point and the LNG to be Dispensed at the Delivery Point for each Month (both amounts being equal) and such forecast referred to as the "**First Annual Forecast**". Customer shall confirm the First Annual Forecast and an annual forecast for each subsequent Contract Year by providing Union, no later than three (3) months prior to each Contract Year, a monthly delivery schedule for that Contract Year (in the form attached at Schedule 2 of the LD Agreement), setting out the amount of LNG Customer wishes to have Dispensed for each Month together with an election as to whether the Customer, or Union, will be delivering gas to the Receipt Point, as amended pursuant to Section 2.4 (if applicable) (such forecast, the "**Annual Forecast**").

2.3 Monthly Forecast

For each Month of a Contract Year, Customer shall, on or before the 15th Day of the prior Month:

(a) confirm in writing the Monthly Dispensing Amount for the next Month; and

(b) deliver to Union a schedule (in the form attached at Schedule 3 of the LD Agreement) showing:

(i) the expected arrival time of each of Customer's cryogenic vessels for each Day;

(ii) the expected amount of LNG in GJs to be Dispensed into each cryogenic vessel for each Day;

(iii) the aggregate expected amount of LNG in both GJs and kg to be Dispensed to Customer in such Month; and

(iv) the amount of gas supply for the Month in GJs (Monthly Dispensing Amount must equal supply for the Month),

collectively (a "**Monthly Forecast**"). After submission of the Monthly Forecast, Union shall provide Customer with a Dispensing Schedule indicating delivery time and amounts of LNG to be delivered to Customer at the Delivery Point during a Month.

2.4 Increases to Monthly Dispensing Amount

Customer may request an increase to the Monthly Dispensing Amount. For any additional LNG volume requested, the Liquefaction Rate in respect of such additional volume shall be negotiated by the parties in good faith subject to the Rate Schedule. Any such additional LNG volume:

(a) shall be deemed to amend the Annual Forecast and shall form the basis of the Annual Forecast going forward; and

(b) shall only be available to the extent Customer delivers, or arranges for Union to deliver to the Receipt Point, such additional gas as is required for the liquefaction of such additional LNG volume.

2.5 Decreases to Monthly Dispensing Amount

At the time of submitting the Monthly Forecast, Customer may request a decrease to the Monthly Dispensing Amount, provided that (i) irrespective of the actual decrease requested by Customer, for the purposes of the Monthly Charge payable by Customer, the applicable revised Monthly Dispensing Amount, shall be no less than 80% of the Monthly Dispensing Amount originally forecast, pursuant to the Annual Forecast and (ii) Customer shall decrease, or arrange for Union to decrease, the supply of gas to the Receipt Point by such amount as corresponds to Customer's actual decrease. By way of example, if Customer's Annual Forecast originally forecast 10,000 GJs for a Month and Customer subsequently submits a Monthly Forecast for 7,000 GJs for such Month, the Dispensing Schedule will only require Customer to pick up 7,000 GJs for such Month (gas supply will be adjusted accordingly), but Customer's Monthly Charge will be for 8,000 GJs (80% of the original forecast).

2.6 Union Supply of Gas

If Customer has requested Union to supply gas for Contract Year, Union will seek to contract for the requested supply at a fixed price at or below Customer's Strike Price on or before three (3) Business Days after the 15th of the Month prior to flow. Union will obtain prices from at least three Suppliers and choose the lowest price which is at or below Customer's Strike Price (the "Monthly Gas Price"). If Union is not able to transact at or below the Strike Price, the gas will not be purchased for the upcoming month and Customer will pay the Monthly Charge calculated pursuant to Section 2.5 herein.

2.7 Annual True Up

Notwithstanding Section 2.5, above, in respect of a Contract Year Customer shall be liable to Union under the LD Agreement and these Liquefaction General Terms and Conditions for an amount equivalent to the product of the Minimum Annual Volume and the Liquefaction Rate (the "**Commitment Annual Amount**"). To the extent that the aggregate of Monthly Charges during a Contract Year is less than the Commitment Annual Amount, Customer shall incur a charge for such difference in the first month after the end of such Contract Year (13th month), or upon termination of the LD Agreement, and shall remit such charge to Union.

3. Delivery of Gas for Liquefaction

Subject to Customer's election for delivery of gas in the Annual Forecast (which election may not be changed) and to Section 3.1 herein, on the Day before the beginning of each Month, Customer or Union, as applicable, shall nominate, pursuant to L1 Schedule B - Nominations (during a NAESB window only) (i) a firm, even, daily amount of gas to be delivered to the Receipt Point (which amount shall be equivalent to the Monthly Dispensing Amount divided by the number of Days in the Month rounded down to the nearest whole number, if required)(such daily amount the "**Firm Daily Amount**") and (ii) a daily liquefaction amount equivalent to the Firm Daily Amount. In the event that the Firm Daily Amount is not a whole number, Customer shall nominate to deliver and liquefy on the last Day of the Month an amount of gas equivalent to the Firm Daily Amount plus the difference between the Monthly Dispensing Amount and the Firm Daily Amount multiplied by the number of Days in the Month.

3.1 Gas Supply Cancelled

If Customer has elected to supply gas for the Contract Year, Customer may, in it's sole discretion, chose not to supply gas for any Month and not to receive Liquefaction Services for such Month, if Customer provides notice to Union of such decision on or before the 15th of the Month prior to flow; provided however, that Customer will be obligated to pay the Monthly Charge calculated pursuant to Section 2.5 herein.

4. Quantity of Gas Supplied and LNG Received by Customer

The parties hereto recognize that on any Day, deliveries of gas by Customer to Union at the Receipt Point and deliveries of LNG by Union at the Delivery Point may not always be exactly equal, but each party shall cooperate with the other in order to balance as nearly as possible the quantities transacted on a daily basis. Daily variances between the quantity of gas delivered to the Receipt Point and the corresponding amount of LNG Dispensed at the Delivery Point shall be held in the tank at the Hagar Facility provided that (i) at the end of any Month, such imbalances shall equal zero (0) and (ii) if any imbalance persists for three (3) or more consecutive Business Days, Union may suspend the provision of the Liquefaction Services and receipt of any gas at the Receipt Point, hereunder.

5. Gas Quality for Gas Supplied by Customer

5.1 Natural Gas

The minimum gross heating value of the gas delivered to Union hereunder, shall be 36 MJ per cubic meter. The maximum gross heating value of the gas delivered to Union hereunder shall be 40.2 MJ per cubic meter. The gas to be delivered hereunder to Union may be a commingled supply from Customer's gas sources of supply.

5.2 Freedom from Objectionable Matter

The gas to be delivered to Union hereunder,

(a) shall be commercially free from bacteria, sand, dust, gums, crude oils, lubricating oils, liquids, chemicals or compounds used in the production, treatment, compression or dehydration of the gas or any other objectionable substance in sufficient quantity so as to render the gas toxic, unmerchantable or cause injury to, or interference with, the proper operation of the lines, regulators, meters or other appliances through which it flows;

(b) shall not contain more than 7 milligrams of hydrogen sulphide per cubic metre of gas, nor more than 460 milligrams of total sulphur per cubic metre of gas;

(c) shall not contain more than 5 milligrams of mercaptan sulphur per cubic metre of gas;

(d) shall not contain more than 2.0 molar percent by volume of carbon dioxide in the gas;

(e) shall not contain more than 0.4 molar percent by volume of oxygen in the gas;

(f) shall not contain more than 0.5 molar percent by volume of carbon monoxide in the gas;

(g) shall not contain more than 4.0 molar percent by volume of hydrogen in the gas;

(h) shall not contain more than 65 milligrams of water vapour per cubic metre of gas;

(i) shall not have a cricondentherm hydrocarbon dewpoint exceeding -8 degrees Celsius;

(j) shall have Wobbe Number from 47.50 MJ per cubic metre of gas to 51.46 MJ per cubic metre of gas, maximum of 1.5 mole percent by volume of butane plus (C4+) in the gas, and maximum of 4.0 mole percent by volume of total inerts in the gas in order to be interchangeable with other Interconnecting Pipeline gas.

5.3 Non-conforming Gas

In addition to any other right or remedy of a party, Union shall be entitled to refuse to accept delivery of any gas which does not conform to any of the specifications set out in this Section 5.

5.4 Quality of Gas Received

The quality of the gas to be received by Union hereunder is to be of a merchantable quality and in accordance with the quality standards as set out by Union in this Section 5, but, Union will also accept gas of a quality as set out in any other Interconnecting Pipeline's general terms and conditions, provided that all Interconnecting Pipelines accept such quality of gas. In addition to any other right or remedy it may have Union shall be entitled to refuse to accept delivery of any gas which does not conform to any of the specifications set out in Union's M12 Rate Schedule.

6. Purchase and Delivery of LNG

6.1 Purchase of LNG

The Customer will be responsible for the purchase of LNG from Union as per the LD Agreement and the Terms of Payment in Section 9 hereof.

6.2 Monthly Totals

The Customer's Monthly Dispensing Amount in GJs must be equal to the GJ equivalent of gas delivered to the Union NDA on behalf of a Customer pursuant to the LD Agreement.

7. Dispensing

7.1 Dispensing of LNG

Subject to all of the terms herein and the Dispensing Schedule, Union will dispense LNG into cryogenic vessels provided by Customer or Customer's contractor.

7.2 Interruption of Dispensing

If at any time Union, acting reasonably, determines that it does not have the capacity to supply Customer's request or it cannot dispense LNG for other operational reasons applicable to the delivery of gas, liquefaction or Dispensing, Union may, for any length of time, interrupt Liquefaction Services under these Liquefaction General Terms and

Conditions. In the event of any interruption in excess of three (3) consecutive Business Days in a Month and provided Customer's cryogenic vessels were scheduled for Dispensing during such interruption period, Customer's Minimum Annual Volume and Monthly Dispensing Amount will be prorated accordingly.

7.3 Interruption of Supply

For each Month, Customer's Dispensed amount will be tracked against the gas supplied to the Receipt Point and if Customer does not take delivery of its scheduled LNG amounts pursuant to the Dispensing Schedule for three consecutive Business Days, such gas supply may be interrupted, in Union's sole discretion, in an amount of GJs equivalent to GJs of LNG not taken up.

7.4 Notice of Interruption

Each notice from Union to Customer with respect to the interruption of Liquefaction Services by Union will be by telephone and/or electronic communication and will specify the time at which such interruption is to be effective. Union will make reasonable efforts to give Customer as much notice as possible with respect to such interruption, not to be less than four hours' prior notice unless prevented by Force Majeure.

7.5 Maintenance

The Union NDA, Hagar Facility or other Union facilities related to the provision of the Liquefaction Services, from time to time may require maintenance or construction. If such maintenance or construction is required, and in Union's sole discretion, acting reasonably, such maintenance or construction may impact Union's ability to meet the Dispensing Schedule, Union shall provide at least ten (10) days' notice to Customer, except in the case of an emergency. In the event the maintenance impacts on Union's ability to meet the Dispensing Schedule, Union shall not be liable for any damages and shall not be deemed in breach of the LD Agreement.

Union shall use reasonable efforts to determine a mutually acceptable period during which such maintenance or construction will occur and also to limit the extent and duration of any impairments.

7.6 Responsibility for Compliance

It is the sole responsibility of Customer to ensure that any personnel, vehicle or cryogenic vessel presented to Union for Dispensing meets the requirements of any laws, rules, regulations and orders of any legislative body, governmental agency or duly constituted authority now or hereafter having jurisdiction including, but not limited to, the federal Transportation of Dangerous Goods Act and its associated regulations.

7.7 Right to Refuse Dispensing

Notwithstanding Section 7.6 above, Union may at its sole discretion refuse to dispense LNG to Customer, if in Union's opinion, the supply of LNG to Customer, may be contrary to any laws, rules, regulations and orders of any legislative body, governmental agency or duly constituted authority now or hereafter having jurisdiction including, but not limited to, the federal Transportation of Dangerous Goods Act and its associated regulations.

7.8 Required Insurance

Customer or Customer's transportation carriers shall be required to maintain, at their own cost: (i) commercial general liability insurance covering carriers liability for bodily injury and property damage with limits of not less than five (5) million dollars, any one occurrence, such insurance to cover Railway Protective Liability and an endorsement on Pollution Liability on Sudden and Accidental Pollution basis with a minimum one hundred twenty (120) hour period for discovery and reporting; (ii) automobile liability insurance covering all trucking equipment used in connection with the LD Agreement, including these Liquefaction General Terms and Conditions, with limits of not less than five (5) million dollars, any one occurrence. Such policy to cover loading and unloading operations; and (iii) employer's liability coverage of one (1) million dollars for all truckers not covered by workers' compensation. Customer or Customer's transportation carriers shall provide Union with the appropriate workers' compensation board certificates and certificates of insurance for all carriers evidencing such insurance.

All insurance maintained pursuant to this Section shall provide that:

1. Union shall be added as an additional insured;

2. The insurer thereunder waives all rights of subrogation against Union;

3. Union's insurance is primary for all purposes, without right of contribution from any other insurance available to Customer, and will contain cross liability coverage via a separation of insureds clause;

4. thirty (30) days' prior written notice of expiration, modification or termination shall be given to Union; and

5. All insurance carriers shall have a financial rating meeting the insurance industry standard.

Customer's compliance with the provisions of this Section will not constitute a limitation of Customer's liability for its acts or omissions or in any way limit, modify, or otherwise affect Customer's indemnification obligation pursuant to this Contract. The insolvency, bankruptcy, or failure of any insurance company carrying insurance for Customer, or failure of any such insurance company to pay claims asserted, will not abrogate, waive or alter any of Customer's responsibilities or liabilities hereunder.

7.9 LNG Tracking

At the time the LNG is dispensed by Union, the amount dispensed shall be entered into the applicable mechanical recording device at the measuring station. The amount of LNG Dispensed will be sent electronically to Union's head office and tracked in Union's measurement system where a pre-determined Heat Value will be applied to the aggregate of LNG Dispensed to give an energy amount.

7.10 Possession of and Responsibility for Gas and LNG

(a) Union accepts no responsibility (i) for any gas prior to such gas being delivered to Union at the Receipt Point or (ii) for any LNG after its delivery and Dispensing at the Delivery Point. As between the parties hereto, Union shall be deemed to be in control and possession of and responsible for all such gas or LNG, as applicable, from the time that such gas enters Union's system until such LNG is delivered to Customer at the Delivery Point.

(b) Title to and risk of loss of, damage to, or damage caused by the LNG sold and delivered hereunder shall pass from Union to Customer at the Hagar Facility, specifically, delivery and title transfer shall occur at the outlet flange of the cryogenic vessel upon Dispensing of the LNG.

(c) Customer agrees that Union is not a common carrier and is not an insurer of Customer's gas, and that Union shall not be liable to Customer or any third party for loss of gas in Union's possession, except to the extent such loss is caused entirely by Union's gross negligence or willful misconduct.

8. Loading and Scheduling

8.1 Loading

Loading of Customer's cryogenic vessels with LNG shall take place between 8:30 a.m. - 7:30 p.m. (EST) Monday through Friday (excluding any day on which a holiday is recognized for Hagar employees).

8.2 Adjustment of Dispensing Schedule by Customer Request

If Customer requires changes to the Dispensing Schedule for any day on which Customer is scheduled to have LNG Dispensed, Customer or its authorized agents shall, by 10:00 a.m. EST of the prior Day, provide Union by email or other electronic communication such information as may be requested by Union, which will include, but is not limited to:

(a) the change in amount of LNG to be Dispensed for each cryogenic vessel on such Day;

(b) any changes in arrival time for each cryogenic vessel;

(c) the change in the number of cryogenic vessels arriving the next Day;

(d) if the change results in an increase to the amount of LNG to be Dispensed and Customer is delivering or causing gas to be delivered to the Receipt Point, evidence of an equivalent increase to the amount of gas in GJs delivered to the Receipt Point; and

(e) if the change results in a decrease to the amount of LNG to be Dispensed and Customer is delivering or causing gas to be delivered to the Receipt Point, evidence of an equivalent decrease to the amount of gas in GJs delivered to the Receipt Point.

(f) collectively (a "**Change Order**"). All Change Orders shall be subject to prior approval by Union, in Union's sole discretion. Once a Change Order is approved, Union shall deliver a revised Dispensing Schedule to Customer. In respect of each Change Order:

(g) Customer must arrange for a increase or decrease in gas supplied to the Receipt Point, as applicable; and

(h) to the extent a Change Order results in a decrease in the amount to be Dispensed, Customer may not subsequently make up any such decreases other than in accordance with Section 2.4.

8.3 Adjustment of Dispensing Schedule by Union

Union may adjust, in consultation with Customer or its authorized agents, Customer's loading schedule, when in the reasonable opinion of Union such modification is required in order to minimize the costs of Dispensing LNG or if transportation access to the Hagar Facility is restricted.

8.4 Forfeiture

Upon termination of the LD Agreement, if any of Customer's LNG has not been Dispensed to Customer, Customer shall forfeit such LNG to Union.

9. Terms of Payment

9.1 Charges

The Customer will pay to Union as follows:

(a) in respect of LNG Dispensed at the Delivery Point - a monthly charge calculated at the end of each Month by multiplying the Monthly Dispensing Amount (irrespective of whether such amount was Dispensed, or whether Customer delivered sufficient gas to the Receipt Point) by the Liquefaction Rate (the "**Monthly Charge**"). The Monthly Charge will be prorated in the event of interruption by Union pursuant to Section 7.2 and any reduction by Customer pursuant to Section 2.5; and

(b) in respect of gas delivered by Union to the Receipt Point - a commodity charge calculated at the end of each Month by multiplying the amount of LNG in GJs supplied to Customer by the sum of (A) the cost of the gas at Dawn (based on the Monthly Gas Price) plus (B) the cost of transporting the gas from Dawn to Parkway plus (C) the cost of transporting the gas from Union-Parkway Belt to the Union NDA, (determined using the "Gas Supply Charge", as provided in Schedule "A" - Union North, Gas Supply Charges; provided however, that the sum of (A), (B) and (C) must fall within the parameters of the Gas Supply Rate as set out in such Schedule "A"); and

(c) All applicable Taxes, unless exempted therefrom.

9.2 Subject to Change

The charges payable by Customer to Union pursuant to Section 9.1 of these Liquefaction General Terms and Conditions are subject to change by Union and, upon approval of such changes from time to time by the OEB, will be binding on Customer.

9.3 Security

In order to secure the prompt and orderly payment of the charges to be paid by Customer to Union under these Liquefaction General Terms and Conditions, Union may require Customer to provide, and at all times maintain, an irrevocable letter of credit in favour of Union issued by a financial institution acceptable to Union in an amount reasonably necessary to ensure Customer's ability to honour the provisions of the LD Agreement, including these Liquefaction General Terms and Conditions, as determined in Union's sole discretion, and in a form satisfactory to Union. If Customer is able to provide alternative security acceptable to Union, Union may in its sole discretion accept such security in lieu of a letter of credit.

10. Survival of Covenants

Upon termination of the LD Agreement, whether pursuant to Section 16 (Default or Bankruptcy) of these Liquefaction General Terms and Conditions or otherwise,

(a) all claims, causes of action or other outstanding obligations remaining or being unfulfilled as at the date of termination, and

(b) all of the provisions in the LD Agreement and these Liquefaction General Terms and Conditions relating to the obligations of any of the parties to account to or indemnify the other and to pay to the other any monies owing as at the date of termination in connection with these Liquefaction General Terms and Conditions,

will survive such termination.

11. Billing

11.1 Monthly Billing

Union shall render bills each month for all Liquefaction Services furnished during the preceding Month. Such charges may be based on estimated quantities, if actual quantities are unavailable in time to prepare the billing. Union shall provide, in a succeeding month's billing, an adjustment based on any difference between actual quantities and estimated quantities, without any interest charge.

12. Payments

12.1 Monthly Statements

Customer shall pay the invoiced amount to Union on or before the payment date that is identified in the Rate Schedule. If payment date is not identified in the Rate Schedule, it will be as identified on the invoice. If the payment date is not a Business Day, then payment must be received in Union's account on the first Business Day preceding the payment date.

12.2 Remedies for Non-payment

Should Customer fail to pay all of the amount of any bill as herein provided when such amount is due, late payment charges as identified in the L1 Rate Schedule will apply. In addition, if such failure to pay continues for thirty (30) days after payment is due, Union, in addition to any other remedy it may have under the LD Agreement, may (i) suspend the Liquefaction Services until such amount is paid (notwithstanding such suspension, all charges shall continue to accrue hereunder as if such suspension were not in place) and (ii) may terminate the LD Agreement in accordance with Section 16.1.

12.3 Billing Adjustments

If a Customer in good faith disputes a bill or any portion thereof, Customer shall pay the undisputed portions of the bill. Together with such payment, Customer shall provide written Notice to Union setting out the portions of the bill that are in dispute, an explanation of the dispute and the amount that Customer believes is the correct amount.

If it is subsequently determined that a bill or any portion thereof disputed by Customer is correct, then Customer shall pay the disputed portions of the bill with interest within thirty (30) days after the final determination. Such interest shall be calculated, but not compounded, at a rate per annum determined each day during the calculation period to be equal to the minimum commercial lending rate of Union's principal banker.

If it is subsequently determined that Customer has been overcharged and Customer has actually paid the bill(s) containing the overcharge then, within thirty (30) days after the final determination, Union shall refund the amount of any such overcharge with interest.

If it is subsequently determined that Customer has been undercharged, Customer shall pay the amount of any such undercharge within thirty (30) days after the final determination. Such interest shall be calculated, but not compounded, at a rate per annum determined each day during the calculation period to be equal to the minimum commercial lending rate of Union's principal banker.

In the event an error is discovered in the amount billed in any statement rendered by Union, such error shall be adjusted by Union. Such overcharge, undercharge or error shall be adjusted by Union on the bill next following its determination (where the term "bill next following" shall mean a bill rendered at least fourteen (14) days after the day of its determination), provided that claim therefore shall have been made within one (1) year from the date of the incorrect billing.

Customer and Union each expressly disclaim and waive any claim or dispute (including those related to amounts charged for Liquefaction Services or quantities of gas or LNG Distributed or transported (as applicable)) that relate to a period that is earlier than twelve (12) Months prior to the date written Notice to the other party of such claim or dispute is asserted. This applies to the extent allowed under law and whether such claim or dispute is related to a billing error or measurement error or any other error or circumstance whatsoever

12.4 Set Off

If either party shall, at any time, be in arrears under any of its payment obligations to the other party under the LD Agreement, then the party not in arrears shall be entitled to reduce the amount payable by it to the other party in arrears under the LD Agreement, or any other agreement, by an amount equal to the amount of such arrears or other indebtedness to the other party.

13. Measurements

13.1 Storage, Transportation, and/or Sales Unit

The unit of the gas delivered to Union shall be a GJ. The unit of gas delivered by Union shall be a GJ, or as otherwise specified by Union at Union's discretion. The unit of LNG dispensed by Union shall be a kilogram or as otherwise specified by Union at Union's discretion.

13.2 Determination of Gas Volume and Energy of Gas

(a) The gas volume and energy amounts determined under the LD Agreement and these Liquefaction General Terms and Conditions shall be determined in accordance with the *Electricity and Gas Inspection Act* (Canada), RSC 1985, c E-4- (the "**Act**") and the *Electricity and Gas Inspection Regulations*, SOR 86/131 (the "**Regulations**"), and any documents issued under the authority of the Act and Regulations and any amendments thereto.

(b) The supercompressibility factor shall be determined in accordance with either the "Manual for Determination of Supercompressibility Factors for Natural Gas" (PAR Project NX-19) published in 1962 or with American Gas Association Transmission Measurement Committee Report No. 8, Nov. 1992, at Union's discretion, all as amended from time to time.

(c) The volume and/or energy of the gas delivered by/to Union hereunder shall be determined by the measurement equipment designated in Section 14 below.

13.3 Determination of LNG Volume

The quantity of LNG dispensed pursuant to these Liquefaction General Terms and Conditions shall be measured at the scale at the Hagar Facility that is approved and certified by Measurement Canada. The Customer's cryogenic vessel will be weighed at said scale before and after LNG Dispensing. The measurement of the amount of LNG delivered shall be based on the difference, expressed in kilograms, of these two weights.

13.4 Conversion of LNG to Energy Units

In accordance with the Regulations, volumes of LNG dispensed each Day will be converted to energy units by multiplying the net weight by the Heat Value of each unit of LNG. Volumes will be specified in kilograms rounded to the nearest unit and energy will be specified in GJs rounded to zero decimal places. The Heat Value will be as determined by Union on a monthly basis. Union will use the following formula to convert kilograms of LNG to GJs LNG:

Converting Kilograms of LNG to GJs

	tractor/trailer gross weight after LNG Dispensing (kilograms)
minus	tractor/trailer gross weight prior to LNG Dispensing (kilograms)
equals	net weight of the delivered LNG (kilograms)

	net weight of the delivered LNG (kilograms)
multiplied by	Heat Value
equals	delivered LNG (GJs)

14. Measuring Equipment

14.1 Metering of Gas by Union

Union will install and operate meters and related equipment as required and in accordance with the Act and Regulations referenced in Section 13.2(a) herein.

14.2 Metering of Gas by Others:

In the event that all or any gas delivered to Union hereunder is measured by a meter that is owned and operated by an Interconnecting Pipeline, then Union and Customer agree to accept that metering for the purpose of determining the volume and energy of gas delivered to/by Union on behalf of Customer. The standard of measurement and tests for the gas delivered to Union hereunder shall be in accordance with the general terms and conditions as incorporated in that Interconnecting Pipeline's gas tariff as approved by its regulatory body.

14.3 Rights of Parties:

The measuring equipment installed by Union, together with any building erected by it for such equipment, shall be and remain its property. However, Customer shall have the right to have representatives present at the time of any installing, reading, cleaning, changing, repairing, inspecting, testing, calibrating, or adjusting done in connection with Union’s measuring equipment used in measuring or checking the measurement of deliveries of LNG by Union under the LD Agreement. Union will give Customer reasonable notice of its intention to carry out the acts herein specified. The records from such measuring equipment shall remain the property of Union, but upon request by Customer, Union will submit to Customer its records and charts, together with calculations therefrom, for inspection and verification, subject to return within ten (10) days after receipt thereof.

14.4 Calibration and Test of Measuring Equipment:

The accuracy of Union's measuring equipment shall be verified by Union at reasonable intervals, and if requested, in the presence of representatives of Customer, but Union shall not be required to verify the accuracy of such equipment more frequently than once in any thirty (30) day period. In the event either party notifies the other that it desires a special test of any measuring equipment, the parties shall co-operate to secure a prompt verification of the accuracy of such equipment. The expense of any such special test, if called for by Customer, shall be borne by Customer if the measuring equipment tested is found to be in error by not more than 2%. If, upon test, any measuring equipment is found to be in error by not more than 2%, previous recordings of such equipment shall be considered accurate in computing receipts and deliveries of gas, but such equipment shall be adjusted at once to record as near to absolute accuracy as possible. If the test conducted shows a percentage of inaccuracy greater than 2%, the financial adjustment, if any, shall be calculated in accordance with the Act and Regulations, as may be amended from time to time and in accordance with any successor statutes and regulations.

14.5 Preservation of Metering Records:

Union and Customer shall each preserve for a period of at least six (6) years all test data, and other relevant records.

14.6 Error in Gas Metering or Meter Failure:

In the event of an error in metering gas or a gas meter failure, (such error or failure being determined through check measurement by Union or any other available method), then Customer shall enforce its rights as Customer with the Interconnecting Pipeline(s) to remedy such error or failure including enforcing any inspection and/or verification rights and procedures.

15. Representations, Warranties and Covenants

15.1 Union

Union represents and warrants that it has and shall maintain throughout the term of the LD Agreement an Emergency Response Action Plan approved by Transport Canada for the transportation of dangerous goods (the "**ERAP**"). Union agrees that the ERAP shall apply to all LNG and LNG shipments until the LNG is delivered to and received by Customer at its refueling station. Notwithstanding the foregoing, in the event that an accident occurs requiring implementation of the ERAP, Customer shall reimburse Union for all costs incurred to provide emergency response pursuant to the ERAP, including but not limited to, the dispatching of Union personnel to the site of the accident.

15.2 Customer

The Customer warrants and represents that:

(a) in its acceptance, transport, use or storage of the LNG it is in compliance with the requirements of any laws, rules, regulations and orders of any legislative body, governmental agency or duly constituted authority now or hereafter, including, but not limited to, the federal *Transportation of Dangerous Goods Act*.

(b) it will, if required, maintain, or have maintained on its behalf, all external approvals including the governmental, regulatory, import/export permits and other approvals or authorizations that are required from any federal, state or provincial authorities for the gas quantities to be handled under the LD Agreement.

(c) the financial assurances (including the security pursuant to Section 9.3) (if any) shall remain in place throughout the term hereof, unless Customer and Union agree otherwise. Customer shall notify Union in the event of any change to the financial assurances throughout the term hereof.

(d) if applicable, it shall have good and marketable title to, or legal authority to deliver to Union, all gas delivered to Union hereunder. Furthermore, Customer hereby agrees to indemnify and save Union harmless from all suits, actions, debts, accounts, damages, costs, losses and expenses arising from or out of claims of any or all third parties to such gas or on account of Taxes, or other charges thereon.

15.3 Transportation and Safety Documents

Union shall be responsible for preparing and supplying all transportation and safety documents that are the responsibility of a consignor of a dangerous good or a supplier of a hazardous material or product under applicable laws and regulations including without limitation all safety marks, shipping documents and material safety data sheets.

16. Default, Termination and Bankruptcy

16.1 General Default

In case of the breach or non-observance or non-performance on the part of either party hereto of any covenant, proviso, condition, restriction or stipulation contained in the LD Agreement, including these Liquefaction General Terms and Conditions (but not including herein failure to take or make delivery in whole or in part of the gas delivered to Union and the LNG delivered by Union hereunder occasioned by any of the reasons provided for in Section 18 herein) which has not been waived by the other party, then and in every such case and as often as the same may happen, the non-defaulting party may give written notice to the defaulting party requiring it to remedy such default and in the event of the defaulting party failing to remedy the same within a period of thirty (30) days from receipt of such notice, the non-defaulting party may at its sole option declare the LD Agreement to be terminated and thereupon the LD Agreement shall be terminated and be null and void for all purposes other than and except as to any liability of the parties under the same incurred before and subsisting as of termination. The right hereby conferred upon each party shall be in addition to, and not in derogation of or in substitution for, any other right or remedy which the parties respectively at law or in equity shall or may possess.

16.2 Additional Union Remedies

In addition to the remedies set out in Section 16.1 above and any other remedy that it has, Union may at its option and without liability therefor, immediately suspend further Liquefaction Services to Customer and may refuse to Dispense LNG to Customer until the default has been fully remedied, and no such suspension or refusal will relieve Customer from any obligation under the LD Agreement, including these Liquefaction General Terms and Conditions.

16.3 Bankruptcy or Insolvency of Customer

If Customer becomes bankrupt or insolvent or commits or suffers an act of bankruptcy or insolvency or a receiver is appointed pursuant to a statute or under a debt instrument or Customer seeks protection from the demands of its creditors pursuant to any legislation enacted for that purpose or commences proceedings under the *Companies' Creditors Arrangement Act* of Canada, Union will have the right, at its sole discretion, to terminate the Liquefaction Services by giving notice in writing to Customer and thereupon Union may cease further Dispensing of LNG to Customer and the amount then outstanding for Liquefaction Services provided under these Liquefaction General Terms and Conditions will immediately be due and payable by Customer.

17. Indemnity and Limitation on Liability

17.1 Limitation on Liability

Union, its affiliates, employees, contractors or agents are not responsible or liable for any loss, damage, costs or injury (including death) incurred by Customer or any person claiming by or through Customer caused by or resulting from, directly or indirectly, any discontinuance, suspension or interruption of, or failure or defect in the supply or delivery or transportation of, or refusal to supply, delivery or transport gas, or provide Liquefaction Services, unless the loss, damage, costs or injury (including death) is directly attributable to the gross negligence or willful misconduct of Union, its affiliates, employees, contractors or agents provided, however that Union, its affiliates, employees, contractors and agents are not responsible or liable for any loss of profit, loss of revenues, or other economic loss even if the loss is directly attributable to the gross negligence or willful misconduct of Union, its affiliates, employees, contractors or agents.

17.2 Indemnity

The Customer will indemnify and hold harmless each of Union, its affiliates, employees, contractors and agents from and against any and all adverse claims, losses, suits, actions, judgments, demands, debts, accounts, damages, costs, penalties and expenses (including all legal fees and disbursements) arising from or out of

(a) the negligence or willful misconduct of Customer, its employees, contractors or agents; or

(b) the breach by Customer of any of the provisions contained in the LD Agreement, including these Liquefaction General Terms and Conditions including those related to the payment by Customer of all Taxes (or payments made in lieu thereof).

18. Force Majeure

18.1 Notice

In the event that either Customer or Union is rendered unable, in whole or in part, by Force Majeure, to perform or comply with any obligation or condition of the LD Agreement, such party shall give notice and full particulars of such Force Majeure in writing delivered by hand, or other direct written electronic means to the other party as soon as possible after the occurrence of the cause relied on and subject to the provision of this Section 18.

18.2 Interruption Notice

If Union claims suspension pursuant to this Section 18, Union will be deemed to have issued to Customer a notice of interruption.

18.3 Exceptions

Neither party shall be entitled to the benefit of the provisions of Force Majeure hereunder if any or all of the following circumstances prevail: the failure resulting in a condition of Force Majeure was caused by the negligence of the party claiming suspension; the failure was caused by the party claiming suspension where such party failed to remedy the condition by making all reasonable efforts (short of litigation, if such remedy would require litigation); the party claiming suspension failed to resume the performance of such condition obligations with reasonable dispatch; the failure was caused by lack of funds; the party claiming suspension did not, as soon as possible after determining, or within a period within which it should acting reasonably have determined, that the occurrence was in the nature of force majeure and would affect its ability to observe or perform any of its conditions or obligations under the LD Agreement, give to the other party the notice required hereunder.

18.4 Notice to Resume

The party claiming suspension shall likewise give notice as soon as possible after the force majeure condition is remedied, to the extent that the same has been remedied, and that such party has resumed or is then in a position to resume the performance of the obligations and conditions of the LD Agreement.

18.5 Delay of Liquefaction Services

Despite this Section 18, if Union is prevented, by reason of an event of Force Majeure on Union’s system from delivering LNG on the Day or Days upon which Union has accepted gas from Customer and was scheduled to deliver LNG, Union shall thereafter make all reasonable efforts to deliver such quantities as soon as practicable and on such Day or Days as are agreed to by Customer and Union.

18.6 Settlement of Labour Disputes

Notwithstanding any of the provisions of this Section 18, the settlement of labour disputes or industrial disturbances will be entirely within the discretion of the particular party involved and the party may make settlement of it at the time and on terms and conditions as it may deem to be advisable and no delay in making settlement will deprive the party of the benefit of this Section 18.

18.7 No Exemption for Payments

Notwithstanding any of the provisions of this Section 18, Force Majeure will not relieve or release either party from its obligations to make payments to the other.

19. Interpretation

Except where the context requires otherwise or except as otherwise expressly provided, in these Liquefaction General Terms and Conditions:

(a) all references to a designated Section are to the designated Section of these Liquefaction General Terms and Conditions unless otherwise specifically stated;

(b) the singular of any term includes the plural, and vice versa, and the use of any term is equally applicable to any gender and, where applicable, body corporate;

(c) any reference to a corporate entity includes and is also a reference to any corporate entity that is a successor by merger, amalgamation, consolidation or otherwise to such entity;

(d) all words, phrases and expressions used in these Liquefaction General Terms and Conditions that have a common usage in the gas industry and that are not defined in these Liquefaction General Terms and Conditions or the LD Agreement have the meanings commonly ascribed thereto in the gas industry; and

(e) the headings of the Sections set out in these Liquefaction General Terms and Conditions are for convenience of reference only and will not be considered in any interpretation of these Liquefaction General Terms and Conditions.

20. Miscellaneous

20.1 Waiver

No waiver of any provision of the LD Agreement, including these General Terms and Conditions, shall be effective unless the same shall be in writing and signed by the party entitled to the benefit of such provision and then such waiver shall be effective only in the specific instance and for the specified purpose for which it was given. No failure on the part of Customer or Union to exercise, and no course of dealing with respect to, and no delay in exercising, any right, power or remedy under the LD Agreement, including these General Terms and Conditions, shall operate as a waiver thereof.

20.2 Assignment

Union may assign its rights and obligations under these Liquefaction General Terms and Conditions and the LD Agreement in whole or in part at any time without consent.

The Customer may not assign its rights under these Liquefaction General Terms and Conditions or the LD Agreement in whole or in part without the prior written consent of Union.

20.3 Amendments to General Terms and Conditions

Union may revise these Liquefaction General Terms and Conditions and L1 Rate Schedule B (Nominations) at any time in its sole discretion, which revised terms shall be applicable to a Customer on sixty (60) days' notice.

20.4 Time is of Essence

Time is of the essence of these Liquefaction General Terms and Conditions and of the terms and conditions thereof.

20.5 Subject to Legislation

Notwithstanding any other provision hereof, the Union L1 Liquefaction Rate Schedule, including these Liquefaction General Terms and Conditions, the LD Agreement and the respective rights and obligations of the parties hereto are subject to all present and future valid laws, orders, rules and regulations of any competent legislative body, or duly constituted authority now or hereafter having jurisdiction and the Union L1 Liquefaction Rate Schedule, including these Liquefaction General Terms and Conditions and the LD Agreement shall be varied and amended to comply with or conform to any valid order or direction of any board, tribunal or administrative agency which affects any of the provisions of the Union L1 Liquefaction Rate Schedule, including these Liquefaction General Terms and Conditions and the LD Agreement.

20.6 Further Assurances

Each of Union and Customer will, on demand by the other, execute and deliver or cause to be executed and delivered all such further documents and instruments and do all such further acts and things as the other may reasonably require to evidence, carry out and give full effect to the terms, conditions, intent and meaning of these Liquefaction General Terms and Conditions and to assure the completion of the transactions contemplated hereby.

20.7 Paramountcy

To the extent of any conflict or inconsistency between these Liquefaction General Terms and Conditions and the LD Agreement, these Liquefaction General Terms and Conditions shall prevail but only to the extent of such conflict or inconsistency.

UNION GAS LIMITED

Answer to Interrogatory from
Northeast Midstream LP

Reference: Exhibit A Tab 1, Page 10, Lines 5-11

Please state whether there are other potential customers who did not respond to the open season, but who have subsequently indicated they would sign up for capacity at Hagar. If so, please indicate the number of potential customers and their potential minimum annual commitments.

Response:

Union continues to have discussions with other parties that did not respond to the open season. Most potential customers are looking for supply to enable them to pilot new LNG technologies. At this time, no other parties have provided a commitment that they will sign up for capacity at Hagar.

UNION GAS LIMITED

Answer to Interrogatory from
Northeast Midstream LP

Reference: Exhibit A Tab 1, Page 10, Lines 5-11

Please state how Union intends to reconcile the difference between the short-term nature of the indicated tenors with the life of the expanded asset.

Response:

Please see the responses to Exhibit B.Northeast.8 c) and Exhibit B.Northeast.12.

UNION GAS LIMITED

Answer to Interrogatory from
Northeast Midstream LP

Reference: Exhibit A Tab 1, Page 10, Lines 5-11

What is the per GJ market rate for LNG at the present time?

Response:

There is currently no open and transparent LNG market in Ontario, therefore there is no market rate at the present time. Union's introduction of the L1 rate will establish the first publicly available price for LNG where a major component of the LNG, the base commodity price for natural gas, will be established using a price to be determined within a Board-approved range or, should the customer opt to purchase their own supply, at market prices.

UNION GAS LIMITED

Answer to Interrogatory from
Northeast Midstream LP

Reference: Exhibit A Tab 1, Page 11, Lines 5-8

Hagar is connected to the TransCanada (TCPL) Mainline, near Sudbury. In March, 2014, TCPL informed the National Energy Board that it will make an application seeking approval for the Energy East Pipeline, a 4,600-kilometre pipeline that will carry 1.1-million barrels of crude oil per day from Alberta and Saskatchewan to refineries in Eastern Canada. Currently, the Energy East project calls for converting one of the existing pipelines that supplies Union North from natural gas to an oil transportation pipeline. Please indicate the expected impact on gas availability and deliverability for NDA customers if Energy East goes forward and the natural gas flowing from Western Canada to central and eastern Canada is reduced by 30% to 40%.

Response:

The service being applied for in this application is 100% interruptible. Providing this service does not impact Union's ability to support Union's in-franchise market.

UNION GAS LIMITED

Answer to Interrogatory from
Northeast Midstream LP

Reference: Exhibit A Tab 1, Page 11, Lines 5-8

Please state whether the reduction in flow is expected to create new supply constraints and price volatility for NDA customers, especially in the winter months, such as gas customers experienced in New England in 2014.

Response:

TransCanada is expected to file detailed applications with the NEB on their Energy East and Natural Gas Mainline Expansion projects before the end of the year. The impacts on capacity and flows are expected to be forecast at that time.

UNION GAS LIMITED

Answer to Interrogatory from
Northeast Midstream LP

Reference: Exhibit A Tab 1, Page 11, Lines 5-8

Please state whether Union expects the Hagar LNG facility to operate differently than it has in recent years to ensure reliability and deliverability in the NDA if the Energy East Pipeline proceeds.

Response:

The Hagar LNG facility is not expected to operate any differently if the Energy East pipeline proceeds.

UNION GAS LIMITED

Answer to Interrogatory from
Northeast Midstream LP

Reference: Exhibit A Tab 1, Page 11, Lines 5-8

Please indicate whether Union anticipates the need to build additional natural gas infrastructure to alleviate the potential supply shortfall from Energy East, the cost of which will be recovered from NDA customers.

Response:

No. Union does not anticipate the need to build additional natural gas infrastructure to alleviate a potential supply shortfall from Energy East. It is expected that TCPL will be required to remediate enough pipe to replace sufficient capacity to ensure that there is not a market shortfall. Specifically, they will need to ensure sufficient capacity exists in the market to serve both firm needs and discretionary needs.

UNION GAS LIMITED

Answer to Interrogatory from
Northeast Midstream LP

Reference: Exhibit A Tab 1, Page 11, Lines 5-8

How would a supply shortfall in the range of 30-40% affect storage practices at Hagar?

Response:

Union will not have a 30-40% supply shortfall. Please see response to Exhibit B.Northeast.21.

UNION GAS LIMITED

Answer to Interrogatory from
Northeast Midstream LP

Reference: Exhibit A Tab 1, Page 13, Lines 13-21, Page 14 Lines 1-9

Union Gas is proposing to use tank inventory management techniques to make unused liquefaction capacity available for sales of LNG as a transportation fuel. Irrespective of the tank management argument, the interruptible service will increase the duty cycle of the liquefaction equipment, which is 46 years old, and nearing the end of its useful life. Please identify the make, year, and type of liquefaction system at Hagar, as well as the composition of the refrigerant(s) used.

Response:

Hagar is a mixed refrigerant plant that was designed and built in 1968 by Air Liquide. The mixed refrigerant is composed of ethylene, methane, propane, butane and pentane.

UNION GAS LIMITED

Answer to Interrogatory from
Northeast Midstream LP

Reference: Exhibit A Tab 1, Page 13, Lines 13-21, Page 14 Lines 1-9

Please specify the annual load factor of the Hagar liquefaction unit over the past 10 years, including the number of stop/starts per year.

Response:

Year	**Load Factor**
2009	10%
2010	11%
2011	12%
2012	9%
2013	8%
2014	0%

This information is available for the past 5 years. There has been one start and one stop each year.

Note that the Load Factor is calculated from the volume that has been liquefied, and since no liquefaction has yet occurred in 2014, the Load Factor shows as 0% although the tank has been used. The Load Factor for 2014 is expected to be similar to the Load Factor for 2013.

UNION GAS LIMITED

Answer to Interrogatory from
Northeast Midstream LP

Reference: Exhibit A Tab 1, Page 13, Lines 13-21, Page 14 Lines 1-9

Please specify the expected annual load factor of the Hagar liquefaction unit over the life of the expansion, including the projected number of stop/starts per year.

Response:

Year	Load Factor
2015	16%
2016	40%
2017	62%
2018	71%

This information is available for the first 4 years of the expansion. It is not possible to project the number of starts and stops that will be required.

UNION GAS LIMITED

Answer to Interrogatory from
Northeast Midstream LP

Reference: Exhibit A Tab 1, Page 13, Lines 13-21, Page 14 Lines 1-9

Please provide the historical Mean Time to Failure (MTTF) and Mean Time To Repair (MTTR) figures for the liquefaction equipment over the past 10 years.

Response:

Union does not track this metric at Hagar.

UNION GAS LIMITED

Answer to Interrogatory from
Northeast Midstream LP

Reference: Exhibit A Tab 1, Page 13, Lines 13-21, Page 14 Lines 1-9

Please indicate whether the Mean Time to Failure (MTTF) and Mean Time To Repair (MTTR) figures for the liquefaction equipment is expected to increase over the future life of the project.

Response:

Yes. As equipment is used more often it will need to be repaired more frequently. The increase in O&M outlined in Exhibit A, Tab 1, Table 4 reflects the higher use expected.

UNION GAS LIMITED

Answer to Interrogatory from
Northeast Midstream LP

Reference: Exhibit A Tab 1, Page 13, Lines 13-21, Page 14 Lines 1-9

Please indicate whether the future load factor is expected to compromise reliability or the plant's ability to fulfill its prime function of supplementing system integrity.

Response:

The primary function of Hagar is to support system integrity. The new liquefaction activity will not affect this function.

UNION GAS LIMITED

Answer to Interrogatory from
Northeast Midstream LP

Reference: Exhibit A Tab 1, Page 14-15, Lines 12-22 and 1-6

Please specify to what extent the stated Tank-O-Meter inaccuracy is due to the inherent physical limitations of the equipment or other factors, including but not limited to liquid density caused by boil off and nitrogen rejection.

Response:

The stated Tank-O-Meter level of accuracy is due to the physical limitations of the equipment. Other factors such as density changes are not considered.

UNION GAS LIMITED

Answer to Interrogatory from
Northeast Midstream LP

Reference: Exhibit A Tab 1, Page 14-15, Lines 12-22 and 1-6

Please provide evidence that tank levels have not been higher than indicated given the acknowledgement that the current tank level system is stated within a plus/minus level of accuracy.

Response:

Union errs on the side of caution and as such has predefined a maximum level which takes into account the level of accuracy of the Tank-O-Meter.

UNION GAS LIMITED

Answer to Interrogatory from
Northeast Midstream LP

Reference: Exhibit A Tab 1, Page 14-15, Lines 12-22 and 1-6

Please state whether it is possible that the actual tank levels have historically been higher than indicated due to level measurement inaccuracy, and that more accurate measuring equipment may not provide for the anticipated additional storage space.

Response:

Please see the response to Exhibit B.Northeast.30.

UNION GAS LIMITED

Answer to Interrogatory from
Northeast Midstream LP

Reference: Exhibit A Tab 1, Page 14-15, Lines 12-22 and 1-6

Please confirm that the tank impoundment volume can accommodate the proposed increase in LNG stored.

Response:

The tank impoundment area was designed to accommodate the maximum fill volume of the tank.

UNION GAS LIMITED

Answer to Interrogatory from
Northeast Midstream LP

Reference: Exhibit A Tab 1, Page 14-15, Lines 12-22 and 1-6

Please state whether the combination of higher tank levels and potential for increased LNG density in kg/m3 due to increased ethane and C6+ content present any issues with the tank foundation loading.

Response:

The tank foundation was designed with full loadings considered. When the foundation was designed the LNG had a higher heating value than today.

UNION GAS LIMITED

Answer to Interrogatory from
Northeast Midstream LP

Reference: Exhibit A Tab 1, Page 14-15, Lines 12-22 and 1-6

Please state whether Union uses a travelling density/temperature probe to detect stratification in tank volume density that can lead to a tank roll over. If so, how does the level data collected from that device compare historically to the Tank-O-Meter level data?

Response:

Union does not use a travelling density/temperature probe.

UNION GAS LIMITED

Answer to Interrogatory from
Northeast Midstream LP

Reference: Exhibit A Tab 1, Page 15, Lines 8-13

Please confirm the number of days of liquefaction that 7,000 GJ is capable of storing, with respect to the nominal liquefaction capacity of the plant and the maximum allowable take under the proposed L1 rate.

Response:

The 7,000 GJ is sized to provide balancing between the daily deliveries of gas to the tank and the batch deliveries of LNG out of the tank. It is not meant to provide a defined period of storage.

UNION GAS LIMITED

Answer to Interrogatory from
Northeast Midstream LP

Reference: Exhibit A Tab 1, Page 15, Lines 8-13

Please confirm whether the 7,000 GJ of storage is a hard limit for L1 rate customers, and that Union does not intend to “borrow” storage from the system integrity tank to make interruptible deliveries of LNG.

Response:

Please see the response to Exhibit B.Northeast.39.

UNION GAS LIMITED

Answer to Interrogatory from
Northeast Midstream LP

Reference: Exhibit A Tab 1, Page 15, Lines 8-13

Please identify any scenarios where Union anticipates that interruptible deliveries of LNG will require more than 7,000 GJ of storage.

Response:

Please see the response to Exhibit B.Northeast.39.

UNION GAS LIMITED

Answer to Interrogatory from
Northeast Midstream LP

Reference: Exhibit A Tab 1, Page 15, Lines 8-13

Please indicate the accuracy of the new radar system to measure an additional 7,000 GJ of storage in a 648,000 GJ tank at volume intervals varying from empty to full.

Response:

The current tank level gauge allows accuracy of +/- .97 ft = +/- 7,000 GJ. The new radar measurement gauge will be accurate to +/-.007 ft = +/- 47 GJ. After rounding there will be increased working capacity of 7,000 GJ.

The 7,000 GJ is the stated difference between the two types of measurement. The height of the LNG in the tank will not affect this difference in measurement.

UNION GAS LIMITED

Answer to Interrogatory from
Northeast Midstream LP

Reference: Exhibit A Tab 1, Page 15, Lines 8-13

Please quantify in terms of hours /days the terms "temporary" and "timing differences" in line 13 above.

Response:

As described in Exhibit A, Tab 1, pages 14-15, Union will be increasing the working storage space at Hagar by 7,000 GJ by making a one-time improvement to the measuring equipment at the facility. Union estimates that liquefaction customers will use up to 7,000 GJ of storage space.

Storage will be used to balance timing differences between supplies and dispensing of LNG. The duration could range from hours to as long as weeks, in the case of a maintenance or unscheduled equipment outage.

UNION GAS LIMITED

Answer to Interrogatory from
Northeast Midstream LP

Reference: Exhibit A Tab 1, Page 15 – 16, Lines 16-20 and Line 1

The service is identified as “interruptible” throughout the application, yet utilities typically do not build infrastructure for “interruptible” service. But the L1 Rate Schedule (Tab 2, Schedule 3) indicates that the customer is subject to an annual minimum charge of liquefaction services. This “take-or-pay” feature seems to imply that the L1 rate is actually for “firm” delivery of LNG services for a specified quantity on an annual basis. Please clarify on what basis the L1 rate of $5.096 per GJ is for “interruptible” or “firm” service?

Response:

Union’s proposed Rate L1 liquefaction service is being offered on an interruptible basis. Union does not have firm liquefaction capacity available.

As described at Exhibit A, Tab 1, page 14, excess liquefaction capability exists at Hagar because liquefaction is currently only required to replace LNG volumes vapourized as a result of a system integrity event or regularly occurring boil off. In the event of a system integrity event or during maintenance periods, Union may not be able to provide liquefaction service for the contracted quantities.

Union has proposed an annual minimum volume commitment for the liquefaction service. The minimum annual volume is intended to ensure that Union recovers the incremental project costs from Rate L1 customers.

UNION GAS LIMITED

Answer to Interrogatory from
Northeast Midstream LP

Reference: Exhibit A Tab 1, Page 15 – 16, Lines 16-20 and Line 1

What is the expected contract tenor for L1 service?

Response:

Given the LNG market is at the very early stages of development Union expects the majority of contracts will be for a one to three-year term.

UNION GAS LIMITED

Answer to Interrogatory from
Northeast Midstream LP

Reference: Exhibit A Tab 1, Page 15 – 16, Lines 16-20 and Line 1

What are the renewal rights, if any?

Response:

Please refer to Article 3.2 of the Draft Liquefaction & Dispensing Contract provided in the response to Exhibit B.Northeast.14.

UNION GAS LIMITED

Answer to Interrogatory from
Northeast Midstream LP

Reference: Exhibit A Tab 1, Page 15 – 16, Lines 16-20 and Line 1

Will customers provide and maintain evidence of creditworthiness throughout the term of the L1 service agreement? Where is creditworthiness factored into the rate proposal?

Response:

Please refer to Article 9.3 of the Draft Liquefaction General Terms & Conditions provided in the response to Exhibit B.Northeast.14.

UNION GAS LIMITED

Answer to Interrogatory from
Northeast Midstream LP

Reference: Exhibit A Tab 1, Page 15 – 16, Lines 16-20 and Line 1

What flexibility will customers have in terms of the timing for nomination for service, liquefaction, storage, and dispensing under the proposed L1 rate of $5.096?

Response:

The draft contract documents referred to in Exhibit B.Northeast.14 define the nomination windows for all services under the proposed L1 rate.

UNION GAS LIMITED

Answer to Interrogatory from
Northeast Midstream LP

Reference: Exhibit A Tab 1, Page 15 – 16, Lines 16-20 and Line 1

What is the minimum contracted quantity that will trigger Union to make a final investment decision and build facilities?

Response:

Union will need a minimum commitment, or a very high expectation of completing contracts prior to the in-service date, of at least 50% of the liquefaction capacity available.

UNION GAS LIMITED

Answer to Interrogatory from
Northeast Midstream LP

Reference: Exhibit A Tab 1, Page 15 – 16, Lines 16-20 and Line 1

Please describe the rationale for the price ceiling for short-term "interruptible" service at three-times the proposed rate of $5.096 / GJ. Will the short-term rate have a floor?

Response:

Similar to other regulated services offered by Union, the higher ceiling was established to allow Union to capture market opportunities when the demand for LNG might spike above normal demand levels.

No. The short-term rate will not have a floor.

UNION GAS LIMITED

Answer to Interrogatory from
Northeast Midstream LP

Reference: Exhibit A Tab 1, Page 15 – 16, Lines 16-20 and Line 1

How will Union set the price (i.e., a daily auction mechanism) and will procurement be open access or restricted?

Response:

Union will determine the short term price through an auction process with the existing parties under contract. Access to LNG will be restricted to those parties that have contracted for such service with Union.

UNION GAS LIMITED

Answer to Interrogatory from
Northeast Midstream LP

Reference: Exhibit A Tab 1, Page 15 – 16, Lines 16-20 and Line 1

Please describe any limits to prevent Union from "dumping" short-term LNG volumes into the transportation fuel market at a discount to the L1 proposed rate, and potentially undercutting other suppliers.

Response:

As stated in response to Exhibit B.Northeast.46, the short-term rate will not have a floor. However, as noted in the response to Exhibit B.Northeast.49, Union would not sell short-term liquefaction service at a rate that does not, at a minimum, recover the variable costs associated with the provision of the service. The excess liquefaction available from Hagar is such that Hagar will never be a "dominant" force in a robust and active LNG market, and therefore will never be a "price setter".

UNION GAS LIMITED

Answer to Interrogatory from
Northeast Midstream LP

Reference: Exhibit A Tab 1, Page 15 – 16, Lines 16-20 and Line 1

Please describe how any spot market premiums or losses could impact the rate base.

Response:

For the purposes of this response, Union assumes that the reference to 'spot market premiums or losses' refers to Union's proposal for a maximum interruptible liquefaction rate for short-term (i.e. one year or less) service of $15/GJ.

Union's proposed maximum interruptible liquefaction rate of $15/GJ and any revenue generated from short-term liquefaction activity will not impact rate base. The additions to rate base associated with Union's capital investment of $8.7 million will be based on the actual costs of the constructed facilities when the facilities are deemed to be in-service.

Revenue generated from short-term liquefaction service at a premium (i.e. above the cost-based rate) will contribute to utility earnings, subject to sharing with ratepayers. Union would not sell short-term liquefaction service at a rate that does not, at a minimum, recover the variable costs associated with the provision of the service. Accordingly, Union does not anticipate any 'spot market losses' from the provision of short-term liquefaction service.

UNION GAS LIMITED

Answer to Interrogatory from
Northeast Midstream LP

Reference: Exhibit A Tab 1, Page 18, Lines 14-21

Please state whether liquefaction and dispensing of interruptible LNG volumes will be carried out during periods of tank replenishment to achieve the full level identified for system integrity.

Response:

Yes.

UNION GAS LIMITED

Answer to Interrogatory from
Northeast Midstream LP

Reference: Exhibit A Tab 1, Page 18, Lines 14-21

If the tank volume is less than the maximum volume required to cover system integrity, please state how Union will prioritize demands for liquefaction for system integrity versus requests for interruptible LNG.

Response:

Filling for system integrity will take priority over demands for interruptible LNG. Prioritization of liquefaction at Hagar available for interruptible LNG will be a function of tank level and available days remaining to get to full.

UNION GAS LIMITED

Answer to Interrogatory from
Northeast Midstream LP

Reference: Exhibit A Tab 1, Page 19, Lines 2-19

Please confirm the minimum contract tenor for the proposed L1 Rate.

Response:

The minimum contract term is one year.

UNION GAS LIMITED

Answer to Interrogatory from
Northeast Midstream LP

Reference: Exhibit A Tab 1, Page 19, Lines 2-19

Please confirm the minimum daily quantity on a "take-or-pay" basis.

Response:

There is no minimum daily quantity on a "take or pay" basis. "Take or Pay" language refers only to an annual Minimum quantity that a customer must take (or at least pay for) in a year.

UNION GAS LIMITED

Answer to Interrogatory from
Northeast Midstream LP

Reference: Exhibit A Tab 1, Page 19, Lines 2-19

Please confirm the minimum monthly quantity on a "take-or-pay" basis.

Response:

Please see the response to Exhibit B.Northeast.53.

UNION GAS LIMITED

Answer to Interrogatory from
Northeast Midstream LP

Reference: Exhibit A Tab 1, Page 19, Lines 2-19

Please state whether customers can "bank" LNG deliveries on an inter-monthly basis? (In other words: Can a customer who has been invoiced for one month of service, but not taken delivery of the LNG in that month, take delivery of the LNG it has already paid for in a following month in addition to the following month's quantity?)

Response:

Customers are expected to balance their daily natural gas deliveries and LNG shipments such that the two quantities are equal at the end of any month. There is no provision to carry over LNG inventory from one month to the next. If the customer has been unable to pick up a scheduled LNG delivery e.g. a truck breakdown, then the customer has three days in which to reschedule that delivery. If the customer has reduced their LNG receipts in a month based on their nomination 15 days prior to the start of the month, then that shortfall may be made up in any following month provided that Union has accepted the customer's higher nomination in that following month.

UNION GAS LIMITED

Answer to Interrogatory from
Northeast Midstream LP

Reference: Exhibit A Tab 1, Page 19, Lines 2-19

Please indicate the remedies available to L1 customers in the event that Union cannot meet the Minimum Annual Volume commitment under the L1 rate due to a high utilization of the plant for system integrity purposes, unplanned outages, and the like.

Response:

If for any reason, Union has interrupted the L1 rate service, and that interruption is less than three consecutive business days, and the customer was scheduled to receive an LNG delivery, then the customers' delivery will be rescheduled following the interruption. If the interruption is greater than three consecutive business days and the customer was scheduled to receive an LNG delivery in that time, then the customers' Minimum Annual Commitment and Monthly Dispensing Amount will be prorated accordingly.

UNION GAS LIMITED

Answer to Interrogatory from
Northeast Midstream LP

Reference: Exhibit A Tab 1, Page 20, Lines 2-9

The Hagar plant was placed in service in 1968. Since that time, code requirements for the design, construction and operation of LNG facilities have evolved substantially. The current Hagar plant is grandfathered with respect to current code requirements. In North America, substantive changes to LNG plant equipment or operations have resulted in the plant's operation and design being reviewed against current code requirements. The current code covering LNG facilities is CSA-276-11 Liquefied Natural Gas (LNG) Production, Storage, and Handling. This code requires several design features that may be difficult to implement in the existing plant. There are a wide range of design and operating requirements in the CSA code and implicit in current industry practices that may be costly or even impossible to retrofit to the plant. Please indicate whether Union has filed or intends to file for an amendment to its Environmental Compliance Approval from the Ontario Ministry of the Environment.

Response:

Union Gas has a Certificate of Approval that is filed with the Ministry of the Environment. When new equipment is added the Certificate is amended as required.

UNION GAS LIMITED

Answer to Interrogatory from
Northeast Midstream LP

Reference: Exhibit A Tab 1, Page 20, Lines 2-9

Please indicate whether the expansion or the associated road widening will require an environmental impact assessment, approval from the town/municipality, and/or consultations with local residents.

Response:

Upgrades to the Northern Central Road do not require an environmental impact assessment. The Municipality has defined the scope of road improvements to ensure compliance with applicable road standards. In addition, a public information session was held on November 25, 2013 at the St. Charles Community Centre. This session allowed Union the opportunity to discuss and get feedback from the affected public on project related details. Consultations with affected residents who live along Northern Central Road have been initiated and are on-going.

UNION GAS LIMITED

Answer to Interrogatory from
Northeast Midstream LP

Reference: Exhibit A Tab 1, Page 20, Lines 2-9

Please confirm that the Hagar plant will be in compliance with CSA 276-11 upon completion of the expansion.

Response:

The Hagar facility is grandfathered in respect to the CSA Z276 code. Any new work that is done to the facility will be in compliance with today's codes and standards.

UNION GAS LIMITED

Answer to Interrogatory from
Northeast Midstream LP

Reference: Exhibit A Tab 1, Page 20, Lines 2-9

Please provide design LNG spill scenarios that have been modeled, showing that the resulting gas cloud down to a level of 50% LEL stays on the property along with separation distances.

Response:

The dispersion modelling associated with an LNG spill during a truck loading activity has not yet been completed. It will be completed as part of the detailed design.

UNION GAS LIMITED

Answer to Interrogatory from
Northeast Midstream LP

Reference: Exhibit A Tab 1, Page 20, Lines 2-9

Please provide design fire scenarios that have been modeled, showing that thermal radiation heat flux rates at the property line fall within specified limits.

Response:

The thermal radiation heat flux analysis of the proposed truck loading facility will be completed as part of the TSSA Variance application.

UNION GAS LIMITED

Answer to Interrogatory from
Northeast Midstream LP

Reference: Exhibit A Tab 1, Page 20, Lines 2-9

Please provide a Quantitative Risk Analysis that has been developed and/or submitted for approval to the TSSA.

Response:

Union is currently in discussion with the TSSA and has yet to develop and submit a revised Quantitative Risk Assessment for TSSA approval. TSSA has identified a 3-stage approval process. Stage 1 completion is required prior to construction.

UNION GAS LIMITED

Answer to Interrogatory from
Northeast Midstream LP

Reference: Exhibit A Tab 1, Page 20, Lines 2-9

Please indicate whether the capital cost of the plant modifications and rate calculation include an allowance for each of these additional requirements.

Response:

Please refer to Exhibit A, Tab 1, p. 20 for a description of the proposed $8.7 million capital investment at the Hagar facility. This investment is required to facilitate the dispensing of LNG into tanker trucks.

Union is assuming the “additional requirements” cited above refer to Northeast Midstream’s interrogatory questions 58 to 62 (Exhibit B.Northeast.58 to Exhibit B.Northeast.62). With respect to the road upgrade, the one-time cost of $500,000 is O&M and was factored into the rate calculation. The costs of the remaining requirements: compliance with CSA 276-11; design spill scenarios; design fire scenarios; and, Quantitative Risk Analysis were included in the capital cost estimate and ultimately the rate calculation.

UNION GAS LIMITED

Answer to Interrogatory from
Northeast Midstream LP

Reference: Exhibit A Tab 1, Page 20, Lines 2-9

Would these additional requirements influence how the current functional asset allocation is structured, particularly land costs attributable to code imposed separation distances?

Response:

The “additional requirements” as cited in the response to Exhibit B.Northeast.63 have no influence on how the current functional asset allocation is structured. The incremental facilities are being constructed on Union Gas property and represent a small addition relative to the existing Hagar site.

UNION GAS LIMITED

Answer to Interrogatory from
Northeast Midstream LP

Reference: Exhibit A Tab 1, Page 21, Lines 2-6

Please indicate whether the O&M budget includes additional human, financial, physical, and knowledge resources that are required to execute an aggressive market growth business strategy to supply LNG services versus a utility business strategy of operating gas infrastructure.

Response:

The O&M budget presented is strictly for the Operation and Maintenance of the Hagar facility. Additional resources required to market LNG are not included. Union will use existing Sales personnel to market LNG services from Hagar. No incremental marketing staff are required.

UNION GAS LIMITED

Answer to Interrogatory from
Northeast Midstream LP

Reference: Exhibit A Tab 1, Page 21, Lines 2-6

Please indicate how the O&M budget takes into account the cost of increasing the load capacity of the liquefaction equipment.

Response:

The O&M budget is tied directly to the liquefaction forecast. As the number of days for liquefaction increases so too does the O&M budget.

UNION GAS LIMITED

Answer to Interrogatory from
Northeast Midstream LP

Reference: Exhibit A, Tab 2; Exhibit A Tab 2, Schedules 1-6 and Exhibit A, Tab 2, Attachment A

Northeast Midstream retained Crowe Soberman to analyse the applicant's cost allocation and rate design as set out in the above noted Exhibits. Crowe Soberman prepared a report dated July 17, 2014 (the "Crowe Soberman Report"). The following interrogatories are based upon the Crowe Soberman Report and where indicated refer to the Crowe Soberman Report. The Crowe Soberman report is attached as Schedule 1 to Northeast Midstream's interrogatories.

Please confirm that the Board-Approved 2013 revenue requirement for the Hagar facility would be equivalent to $8.223/GJ, assuming a liquefaction volume of 751,950 GJ per year (648,000 GJ per year for system integrity and 104,000 GJ per year for "boil-off")?

Response:

The Crowe Soberman Report (dated July 17, 2014) attached as a schedule to the Northeast Midstream interrogatories and referenced in various interrogatories has not been submitted as evidence in this proceeding and remains untested as to its assertions or conclusions. As such, responses given by the applicant in respect of the interrogatories referencing the report should not be taken as an acceptance of the report as evidence in this proceeding or of the degree to which the report should be relied upon. The responses are given without prejudice to Union's right to object to or make submissions at a later time as to whether the report' admissible or whether it is authoritative.

Confirmed. Based on the 2013 Board-approved Hagar revenue requirement of $6.183 million (including $1.085 million in compressor fuel costs) and assumed annual liquefaction demands for system integrity and boil off of 751,950 GJ, the per unit cost would be $8.223/GJ.

UNION GAS LIMITED

Answer to Interrogatory from
Northeast Midstream LP

Reference: Exhibit A, Tab 2; Exhibit A Tab 2, Schedules 1-6 and Exhibit A, Tab 2, Attachment A

Northeast Midstream retained Crowe Soberman to analyse the applicant's cost allocation and rate design as set out in the above noted Exhibits. Crowe Soberman prepared a report dated July 17, 2014 (the "Crowe Soberman Report"). The following interrogatories are based upon the Crowe Soberman Report and where indicated refer to the Crowe Soberman Report. The Crowe Soberman report is attached as Schedule 1 to Northeast Midstream's interrogatories.

Please confirm that the costs (other than compressor fuel) assigned to "Variable Costs" are based on the "boil-off" replacement of 104,000 GJ per year only.

Response:

The Crowe Soberman Report (dated July 17, 2014) attached as a schedule to the Northeast Midstream interrogatories and referenced in various interrogatories has not been submitted as evidence in this proceeding and remains untested as to its assertions or conclusions. As such, responses given by the applicant in respect of the interrogatories referencing the report should not be taken as an acceptance of the report as evidence in this proceeding or of the degree to which the report should be relied upon. The responses are given without prejudice to Union's right to object to or make submissions at a later time as to whether the report' admissible or whether it is authoritative.

Confirmed.

UNION GAS LIMITED

Answer to Interrogatory from
Northeast Midstream LP

Reference: Exhibit A, Tab 2; Exhibit A Tab 2, Schedules 1-6 and Exhibit A, Tab 2, Attachment A

Northeast Midstream retained Crowe Soberman to analyse the applicant's cost allocation and rate design as set out in the above noted Exhibits. Crowe Soberman prepared a report dated July 17, 2014 (the "Crowe Soberman Report"). The following interrogatories are based upon the Crowe Soberman Report and where indicated refer to the Crowe Soberman Report. The Crowe Soberman report is attached as Schedule 1 to Northeast Midstream's interrogatories.

Union has assigned $842,000 of a total of $1,463,000 in fixed O&M to storage. Please comment on the reasonableness of assigning $842,000 of a total $1,463,000 in fixed O&M to storage, which is an inherently passive activity, when liquefaction is typically the most labour and maintenance intensive activity at an LNG plant.

Response:

The Crowe Soberman Report (dated July 17, 2014) attached as a schedule to the Northeast Midstream interrogatories and referenced in various interrogatories has not been submitted as evidence in this proceeding and remains untested as to its assertions or conclusions. As such, responses given by the applicant in respect of the interrogatories referencing the report should not be taken as an acceptance of the report as evidence in this proceeding or of the degree to which the report should be relied upon. The responses are given without prejudice to Union's right to object to or make submissions at a later time as to whether the report' admissible or whether it is authoritative.

The allocation of $0.842 million of the total $1.463 million in fixed O&M costs to the storage function is reasonable. Fixed O&M costs do not vary based on the level of liquefaction, storage or vapourization activity at the Hagar facility.

Union's proposed allocation of fixed O&M costs is in proportion to net plant. As the fixed O&M costs support the assets that provide the liquefaction, storage or vapourization functions it is appropriate to allocate these costs in a manner consistent with the allocation of net plant. This approach best reflects cost causality.

UNION GAS LIMITED

Answer to Interrogatory from
Northeast Midstream LP

Reference: Exhibit A, Tab 2; Exhibit A Tab 2, Schedules 1-6 and Exhibit A, Tab 2, Attachment A

Northeast Midstream retained Crowe Soberman to analyse the applicant's cost allocation and rate design as set out in the above noted Exhibits. Crowe Soberman prepared a report dated July 17, 2014 (the "Crowe Soberman Report"). The following interrogatories are based upon the Crowe Soberman Report and where indicated refer to the Crowe Soberman Report. The Crowe Soberman report is attached as Schedule 1 to Northeast Midstream's interrogatories.

Please comment on the following observation in the Crowe Soberman Report on Page 5 concerning different time periods assigned to depreciation and revenue requirement in the Union application:

"We do note that there are some observations, which may be made regarding the data on Appendix B, and/or regarding the calculation of the average costs and revenue requirement. Thus, for example, it appears that the plant investment is assumed to have been made for approximately 4 months of 2015, while depreciation is included for 6 months of 2015. However, subsequently, the revenue requirement is considered over 4 complete years, and the average liquefaction volume (of 415,520 GJ) is also calculated over 4 complete years."

Response:

The Crowe Soberman Report (dated July 17, 2014) attached as a schedule to the Northeast Midstream interrogatories and referenced in various interrogatories has not been submitted as evidence in this proceeding and remains untested as to its assertions or conclusions. As such, responses given by the applicant in respect of the interrogatories referencing the report should not be taken as an acceptance of the report as evidence in this proceeding or of the degree to which the report should be relied upon. The responses are given without prejudice to Union's right to object to or make submissions at a later time as to whether the report' admissible or whether it is authoritative.

The different timing assumptions for depreciation expense and the revenue requirement in 2015 associated with Union's capital investment are appropriate.

The project in-service date is September 2015 and accordingly, the revenue requirement calculation is based on the project being in-service for four months in 2015. From an accounting perspective, depreciation expense in 2015 is calculated using the half year rule or the equivalent of six months. This is consistent with Union's accounting treatment for all capital projects.

UNION GAS LIMITED

Answer to Interrogatory from
Northeast Midstream LP

Reference: Exhibit A, Tab 2; Exhibit A Tab 2, Schedules 1-6 and Exhibit A, Tab 2, Attachment A

Northeast Midstream retained Crowe Soberman to analyse the applicant's cost allocation and rate design as set out in the above noted Exhibits. Crowe Soberman prepared a report dated July 17, 2014 (the "Crowe Soberman Report"). The following interrogatories are based upon the Crowe Soberman Report and where indicated refer to the Crowe Soberman Report. The Crowe Soberman report is attached as Schedule 1 to Northeast Midstream's interrogatories.

Please comment on the following observation in the Crowe Soberman Report on Page 5, and explain why the average cost of compressor fuel is $1.44 per GJ of LNG produced for system integrity and only $0.73 per GJ of LNG produced for interruptible LNG service:

"We also note that the assumed compressor fuel average annual cost is $303,000 for average liquefaction of 415,520GJ per annum. By comparison, from Appendix A, it appears that (for 2013) the compressor fuel cost was estimated to be $1,085,000 for (apparently) average liquefaction of 751,950 GJ. We do not have sufficient information to explain the (relatively) lower compressor fuel cost reflected on Appendix B."

Response:

The Crowe Soberman Report (dated July 17, 2014) attached as a schedule to the Northeast Midstream interrogatories and referenced in various interrogatories has not been submitted as evidence in this proceeding and remains untested as to its assertions or conclusions. As such, responses given by the applicant in respect of the interrogatories referencing the report should not be taken as an acceptance of the report as evidence in this proceeding or of the degree to which the report should be relied upon. The responses are given without prejudice to Union's right to object to or make submissions at a later time as to whether the report' admissible or whether it is authoritative.

Union does not agree that the 2013 Board-approved average cost of compressor fuel for liquefaction is $1.44 per GJ.

Union's 2013 Board-approved costs include a total of $1.085 million in compressor fuel requirements, of which approximately $0.464 million are related to liquefaction, $0.520 million are to recover gas lost to boil-off and the remaining costs are forecasted for compressor fuel required for vapourization and distribution activities.

Subsequent to Union's 2013 rebasing proceeding, Union invested in an additional boil off compressor at the Hagar facility that uses electricity to return the boiled-off gas to Union's system. As a result of this investment, there are no additional costs to replace the gas lost to boil off for the Rate L1 service.

Please see Table 1 for a comparison of the 2013 Board-approved Hagar compressor fuel costs and the forecasted Rate L1 compressor fuel costs for liquefaction activity.

Table 1
2013 Board-Approved vs. Rate L1 Compressor Fuel

Line No.	Particulars	2013 Board-Approved	Rate L1
		(a)	(b)
1	Total Compressor Fuel ($000's)	1,085	303
2	Boil Off Gas (1)	520	-
3	Other Compressor Fuel (2)	101	-
4	Liquefaction Compressor Fuel (line 1 - line 2 - line 3)	464	303
5	Liquefaction Activity (GJ)	648,000	415,520
6	Liquefaction Compressor Fuel Unit Cost	0.72	0.73

Notes:
(1) Boil-off gas not recovered prior to installation of second boil off compressor.
(2) Other compressor fuel requirements, including vapourization and distribution.

The Rate L1 compressor fuel unit cost is nearly identical to the 2013 Board-approved compressor fuel unit cost. The small difference between the cost per unit is due to different cost of gas assumptions. Union's 2013 Board-approved compressor fuel was based on the July 2012 QRAM cost of gas and the Rate L1 compressor fuel was based on the July 2014 QRAM cost of gas.

UNION GAS LIMITED

Answer to Interrogatory from
Northeast Midstream LP

Reference: Exhibit A, Tab 2; Exhibit A Tab 2, Schedules 1-6 and Exhibit A, Tab 2, Attachment A

Northeast Midstream retained Crowe Soberman to analyse the applicant's cost allocation and rate design as set out in the above noted Exhibits. Crowe Soberman prepared a report dated July 17, 2014 (the "Crowe Soberman Report"). The following interrogatories are based upon the Crowe Soberman Report and where indicated refer to the Crowe Soberman Report. The Crowe Soberman report is attached as Schedule 1 to Northeast Midstream's interrogatories.

Please state whether Section 1 "Original Plant Operation" and Section 2 "Proposed Plant Expansion" in Appendix C of the Crowe Soberman Report is a fair and reasonable summary of the revenue requirement following the proposed expansion described in the Application by Union Gas.

Response:

The Crowe Soberman Report (dated July 17, 2014) attached as a schedule to the Northeast Midstream interrogatories and referenced in various interrogatories has not been submitted as evidence in this proceeding and remains untested as to its assertions or conclusions. As such, responses given by the applicant in respect of the interrogatories referencing the report should not be taken as an acceptance of the report as evidence in this proceeding or of the degree to which the report should be relied upon. The responses are given without prejudice to Union's right to object to or make submissions at a later time as to whether the report' admissible or whether it is authoritative.

No, Section 1 "Original Plant Operation" in Appendix C is not a fair and reasonable summary of the revenue requirement described in Union's application by Union.

Section 1 "Original Plant Operation" in Appendix C shows a liquefaction cost adjustment of $800,000. This is incorrect, as Union did not allocate 2013 Board-approved costs to the proposed liquefaction service.

Union has proposed a cost allocation methodology that functionalizes 2013 Board-approved costs to liquefaction, storage and vapourization. Union used the functionalized liquefaction and storage costs to determine the Rate L1 contribution towards the recovery of existing liquefaction and storage costs.

Union's proposed rate design determines the Rate L1 contribution towards existing liquefaction and storage costs based on the allocated 2013 Board-approved costs and system integrity liquefaction demands. As shown at Exhibit A, Tab 2, Schedule 6, the average unit rate for liquefaction $2.324/GJ and $3.573/GJ for storage.

Union adjusted the average liquefaction unit rate based on 167 days per year of liquefaction service provided to Rate L1 customers or the equivalent of 46 percent. This adjustment results in a Rate L1 contribution towards existing liquefaction costs of $1.062 per GJ, as provided at Exhibit A, Tab 2, Schedule 6, line 5.

Union adjusted the average storage unit rate based on 7,000 GJ of storage space capacity utilized by liquefaction customers of the total Hagar storage space of 648,000 GJ or the equivalent of 1.1%. This adjustment results in a Rate L1 contribution towards existing storage costs of $0.0386 per GJ, as provided at Exhibit A, Tab 2, Schedule 6, line 15.

Section 2 "Proposed Plant Expansion" in Appendix C is generally a fair and reasonable summary with minor corrections.

The $0.016 million allocated to storage is not an incremental revenue requirement. It is revenue generated by the contribution towards existing storage costs.

Union's proposed liquefaction rate of $5.096/GJ includes liquefaction costs of $4.576/GJ (Exhibit A, Tab 2, Schedule 6, line 9). Section 2 in Appendix C shows a required revenue per unit of $4.617/GJ.

UNION GAS LIMITED

Answer to Interrogatory from
Northeast Midstream LP

Reference: Exhibit A, Tab 2; Exhibit A Tab 2, Schedules 1-6 and Exhibit A, Tab 2, Attachment A

Northeast Midstream retained Crowe Soberman to analyse the applicant's cost allocation and rate design as set out in the above noted Exhibits. Crowe Soberman prepared a report dated July 17, 2014 (the "Crowe Soberman Report"). The following interrogatories are based upon the Crowe Soberman Report and where indicated refer to the Crowe Soberman Report. The Crowe Soberman report is attached as Schedule 1 to Northeast Midstream's interrogatories.

Following the proposed expansion, please confirm that required revenue for system integrity operation would be $7.159/GJ, while the required revenue for supplying interruptible LNG under the proposed L1 rate would be $4.617/GJ (system integrity rate is before removing a nominal amount for storage costs transferred to new business).

Response:

The Crowe Soberman Report (dated July 17, 2014) attached as a schedule to the Northeast Midstream interrogatories and referenced in various interrogatories has not been submitted as evidence in this proceeding and remains untested as to its assertions or conclusions. As such, responses given by the applicant in respect of the interrogatories referencing the report should not be taken as an acceptance of the report as evidence in this proceeding or of the degree to which the report should be relied upon. The responses are given without prejudice to Union's right to object to or make submissions at a later time as to whether the report' admissible or whether it is authoritative.

Please see the response to Exhibit B.Northeast.72.

UNION GAS LIMITED

Answer to Interrogatory from
Northeast Midstream LP

Reference: Exhibit A, Tab 2; Exhibit A Tab 2, Schedules 1-6 and Exhibit A, Tab 2, Attachment A

Northeast Midstream retained Crowe Soberman to analyse the applicant's cost allocation and rate design as set out in the above noted Exhibits. Crowe Soberman prepared a report dated July 17, 2014 (the "Crowe Soberman Report"). The following interrogatories are based upon the Crowe Soberman Report and where indicated refer to the Crowe Soberman Report. The Crowe Soberman report is attached as Schedule 1 to Northeast Midstream's interrogatories.

Please indicate whether you agree with the following observation in the Crowe Soberman Report on Page 6:

"Notwithstanding the above, we have identified an apparent error in the Union Gas calculations, and we have shown a revised calculation on Appendix C. When Union Gas pro-rate their calculated pre-expansion liquefaction rate (of $2.325/GJ) to 167 days, they do not take into account the fact that the LNG commercial business envisages average production of 415,520 GJ, while the calculated pre-expansion liquefaction rate is based on an annual volume of 751,950 GJ."

Response:

The Crowe Soberman Report (dated July 17, 2014) attached as a schedule to the Northeast Midstream interrogatories and referenced in various interrogatories has not been submitted as evidence in this proceeding and remains untested as to its assertions or conclusions. As such, responses given by the applicant in respect of the interrogatories referencing the report should not be taken as an acceptance of the report as evidence in this proceeding or of the degree to which the report should be relied upon. The responses are given without prejudice to Union's right to object to or make submissions at a later time as to whether the report' admissible or whether it is authoritative.

Union does not agree with the observation in the Crowe Soberman Report on Page 6. Union has not made an error in the calculation of the Rate L1 contribution towards existing liquefaction costs.

As described in the response to Exhibit B.Northeast.72. Union has calculated a liquefaction unit rate based on its proposed functionalization of 2013 Board-approved costs to liquefaction. The

2013 Board-approved costs assume liquefaction activity of 751,950 GJ per year for system integrity purposes.

Accordingly, it is appropriate to determine the contribution that the proposed liquefaction rate should make to the recovery of 2013 Board-approved liquefaction costs based on the liquefaction activity that underpinned the determination of those costs.

UNION GAS LIMITED

Answer to Interrogatory from
Northeast Midstream LP

Reference: Exhibit A, Tab 2; Exhibit A Tab 2, Schedules 1-6 and Exhibit A, Tab 2, Attachment A

Northeast Midstream retained Crowe Soberman to analyse the applicant's cost allocation and rate design as set out in the above noted Exhibits. Crowe Soberman prepared a report dated July 17, 2014 (the "Crowe Soberman Report"). The following interrogatories are based upon the Crowe Soberman Report and where indicated refer to the Crowe Soberman Report. The Crowe Soberman report is attached as Schedule 1 to Northeast Midstream's interrogatories.

Please confirm that a portion of the liquefaction annual revenue requirement should be allocated to the LNG commercial business (calculated on Appendix C of the Crowe Soberman Report to be $800,000 and based on 167/365 days of the pre-expansion liquefaction revenue requirement of $1,748,000).

Response:

The Crowe Soberman Report (dated July 17, 2014) attached as a schedule to the Northeast Midstream interrogatories and referenced in various interrogatories has not been submitted as evidence in this proceeding and remains untested as to its assertions or conclusions. As such, responses given by the applicant in respect of the interrogatories referencing the report should not be taken as an acceptance of the report as evidence in this proceeding or of the degree to which the report should be relied upon. The responses are given without prejudice to Union's right to object to or make submissions at a later time as to whether the report' admissible or whether it is authoritative.

Not confirmed.

Union's cost allocation proposal to functionalize 2013 Board-approved Hagar costs between the liquefaction, storage and vapourization functions is not intended to functionalize these costs to the proposed liquefaction service directly. Union's proposal is intended to determine 2013 Board-approved liquefaction costs and then calculate a unit cost based on the system integrity demands of 751,950 GJ per year that underpin the costs.

Union's rate design ensures that the proposed liquefaction service provides a contribution to the recovery of functionalized liquefaction costs based on the forecasted liquefaction activity and the number of days of flow.

Union is forecasting average liquefaction activity of 415,520 GJ per year. Accordingly, the liquefaction service will contribute $441,000 per year (415,520 GJ x $1.062/GJ) towards the recovery of 2013 Board-approved liquefaction costs.

Please also see the response to Exhibit B.Northeast.72.

UNION GAS LIMITED

Answer to Interrogatory from
Northeast Midstream LP

Reference: Exhibit A, Tab 2; Exhibit A Tab 2, Schedules 1-6 and Exhibit A, Tab 2, Attachment A

Northeast Midstream retained Crowe Soberman to analyse the applicant's cost allocation and rate design as set out in the above noted Exhibits. Crowe Soberman prepared a report dated July 17, 2014 (the "Crowe Soberman Report"). The following interrogatories are based upon the Crowe Soberman Report and where indicated refer to the Crowe Soberman Report. The Crowe Soberman report is attached as Schedule 1 to Northeast Midstream's interrogatories.

Please confirm that the required revenue for the LNG commercial business should increase from \$4.617/GJ to \$5.478/GJ after correcting for the error identified in IR 74 above.

Response:

The Crowe Soberman Report (dated July 17, 2014) attached as a schedule to the Northeast Midstream interrogatories and referenced in various interrogatories has not been submitted as evidence in this proceeding and remains untested as to its assertions or conclusions. As such, responses given by the applicant in respect of the interrogatories referencing the report should not be taken as an acceptance of the report as evidence in this proceeding or of the degree to which the report should be relied upon. The responses are given without prejudice to Union's right to object to or make submissions at a later time as to whether the report' admissible or whether it is authoritative.

Not confirmed. Please see the responses to Exhibits B.Northeast.72 - 75.

UNION GAS LIMITED

Answer to Interrogatory from
Northeast Midstream LP

Reference: Exhibit A, Tab 2; Exhibit A Tab 2, Schedules 1-6 and Exhibit A, Tab 2, Attachment A

Northeast Midstream retained Crowe Soberman to analyse the applicant's cost allocation and rate design as set out in the above noted Exhibits. Crowe Soberman prepared a report dated July 17, 2014 (the "Crowe Soberman Report"). The following interrogatories are based upon the Crowe Soberman Report and where indicated refer to the Crowe Soberman Report. The Crowe Soberman report is attached as Schedule 1 to Northeast Midstream's interrogatories.

Please comment on the following observation in the Crowe Soberman Report on Page 6:

"We note that the calculated number of days required for the LNG commercial business (averaging 167 days) is based on (stated) assumed plant liquefaction capacity of 3,186 GJ/day. If one assumed operation of the plant for (say) 300 days per annum, this would result in annual liquefaction capacity of 955,800 GJ per annum. This raises some concern regarding the capacity of the plant to both (i) produce 415,520GJ for LNG commercial business customers, and (ii) recycle inventory and replace "boil-off" at the production rate of 751,950GJ per annum (the foregoing amounts total 1,167,470 GJ per annum)."

Response:

The Crowe Soberman Report (dated July 17, 2014) attached as a schedule to the Northeast Midstream interrogatories and referenced in various interrogatories has not been submitted as evidence in this proceeding and remains untested as to its assertions or conclusions. As such, responses given by the applicant in respect of the interrogatories referencing the report should not be taken as an acceptance of the report as evidence in this proceeding or of the degree to which the report should be relied upon. The responses are given without prejudice to Union's right to object to or make submissions at a later time as to whether the report' admissible or whether it is authoritative.

Union agrees with this observation. Union does not have sufficient liquefaction capacity to provide both 415,520 GJ per year of liquefaction service and liquefy 751,950 GJ per year for system integrity purposes should the LNG tank be emptied for a system integrity event. As a result, Union can only provide Rate L1 liquefaction service on an interruptible basis, as proposed.

As described at Exhibit A, Tab 1, page 14, excess liquefaction capacity exists at Hagar because liquefaction is currently only required to replace LNG vapourized as a result of a system integrity event or regularly occurring boil off. This means that the excess liquefaction capability available for Rate L1 customers exists only on an interruptible basis throughout the year and the service would be interrupted should there be a system integrity event that requires the use of the Hagar facility.

UNION GAS LIMITED

Answer to Interrogatory from
Northeast Midstream LP

Reference: Exhibit A, Tab 2; Exhibit A Tab 2, Schedules 1-6 and Exhibit A, Tab 2, Attachment A

Northeast Midstream retained Crowe Soberman to analyse the applicant's cost allocation and rate design as set out in the above noted Exhibits. Crowe Soberman prepared a report dated July 17, 2014 (the "Crowe Soberman Report"). The following interrogatories are based upon the Crowe Soberman Report and where indicated refer to the Crowe Soberman Report. The Crowe Soberman report is attached as Schedule 1 to Northeast Midstream's interrogatories.

Please provide the actual liquefaction and vaporization quantities over the past 10 years, showing both the quantities of LNG vapourized for system integrity and the quantities lost to "boil-off".

Response:

This information is available for the past 5 years.

Year	Boil Off, GJ	System Integrity Vapourization, GJ
2009	104,823	0
2010	115,958	0
2011	114,422	19,390
2012	104,055	0
2013	50,492	40,125
2014	62,202	35,325

Year	Liquefaction, GJ
2009	104,823
2010	115,958
2011	133,812
2012	104,055
2013	90,616
2014 (YTD)	0

UNION GAS LIMITED

Answer to Interrogatory from
Northeast Midstream LP

Reference: Exhibit A, Tab 2; Exhibit A Tab 2, Schedules 1-6 and Exhibit A, Tab 2, Attachment A

Northeast Midstream retained Crowe Soberman to analyse the applicant's cost allocation and rate design as set out in the above noted Exhibits. Crowe Soberman prepared a report dated July 17, 2014 (the "Crowe Soberman Report"). The following interrogatories are based upon the Crowe Soberman Report and where indicated refer to the Crowe Soberman Report. The Crowe Soberman report is attached as Schedule 1 to Northeast Midstream's interrogatories.

Please comment whether it is fair and reasonable to adjust the annual liquefaction capacity for system integrity from 751,950GJ to 425,000GJ (including LNG for vaporization and "boil-off").

Response:

No, it is not reasonable. Union is required to ensure that the entire 0.6 PJ of system integrity volume and replacement of boil-off can be cycled in any given year. The annual liquefaction capacity required is 751,950 GJ.

UNION GAS LIMITED

Answer to Interrogatory from
Northeast Midstream LP

Reference: Exhibit A, Tab 2; Exhibit A Tab 2, Schedules 1-6 and Exhibit A, Tab 2, Attachment A

Northeast Midstream retained Crowe Soberman to analyse the applicant's cost allocation and rate design as set out in the above noted Exhibits. Crowe Soberman prepared a report dated July 17, 2014 (the "Crowe Soberman Report"). The following interrogatories are based upon the Crowe Soberman Report and where indicated refer to the Crowe Soberman Report. The Crowe Soberman report is attached as Schedule 1 to Northeast Midstream's interrogatories.

Please indicate whether it is fair and reasonable to assume that 20% of the storage cost should be allocated to LNG commercial customers, since the anticipated L1 volume is 678,000 GJ in 2018 and the actual storage is 648,000 GJ.

Response:

No, it is not fair and reasonable to assume that 20% of the storage costs should be allocated to liquefaction customers. Liquefaction customers should be allocated storage costs based on the amount of storage space they will utilize, not the level of liquefaction activity.

As described in Exhibit A, Tab 1, pages 14-15, Union will be increasing the working storage space at Hagar by 7,000 GJ by making a one-time improvement to the measuring equipment at the facility. Union estimates that liquefaction customers will use up to 7,000 GJ of storage space. Union has allocated 1.1% of storage costs to liquefaction customers based on their expected usage of 7,000 GJ (or 1.1%) of Union's total storage capacity of 648,000 GJ.

UNION GAS LIMITED

Answer to Interrogatory from
Northeast Midstream LP

Reference: Exhibit A, Tab 2; Exhibit A Tab 2, Schedules 1-6 and Exhibit A, Tab 2, Attachment A

Northeast Midstream retained Crowe Soberman to analyse the applicant's cost allocation and rate design as set out in the above noted Exhibits. Crowe Soberman prepared a report dated July 17, 2014 (the "Crowe Soberman Report"). The following interrogatories are based upon the Crowe Soberman Report and where indicated refer to the Crowe Soberman Report. The Crowe Soberman report is attached as Schedule 1 to Northeast Midstream's interrogatories.

Please indicate whether Crowe Soberman's revised calculation, which results in required revenue for the LNG commercial business of $6.885/GJ (before considering distribution costs), is a reasonable basis for determination of the LNG commercial business revenue requirement based on the information available.

Response:

The Crowe Soberman Report (dated July 17, 2014) attached as a schedule to the Northeast Midstream interrogatories and referenced in various interrogatories has not been submitted as evidence in this proceeding and remains untested as to its assertions or conclusions. As such, responses given by the applicant in respect of the interrogatories referencing the report should not be taken as an acceptance of the report as evidence in this proceeding or of the degree to which the report should be relied upon. The responses are given without prejudice to Union's right to object to or make submissions at a later time as to whether the report' admissible or whether it is authoritative.

Crowe Soberman's revised calculation is not a reasonable determination of the Rate L1 revenue requirement. The calculation of $6.885/GJ assumes adjusted system integrity liquefaction volumes of 425,000 GJ and a 20% allocation of storage costs. As described in the responses to Exhibits B.Northeast.79 and B.Northeast.80, Union does not agree with either of these assumptions.

UNION GAS LIMITED

Answer to Interrogatory from
Northeast Midstream LP

Reference: Exhibit A, Tab 2; Exhibit A Tab 2, Schedules 1-6 and Exhibit A, Tab 2, Attachment A

Northeast Midstream retained Crowe Soberman to analyse the applicant's cost allocation and rate design as set out in the above noted Exhibits. Crowe Soberman prepared a report dated July 17, 2014 (the "Crowe Soberman Report"). The following interrogatories are based upon the Crowe Soberman Report and where indicated refer to the Crowe Soberman Report. The Crowe Soberman report is attached as Schedule 1 to Northeast Midstream's interrogatories.

Please comment on the Crowe Soberman view that it is more reasonable to allocate costs (or plant) which cannot be directly assigned after the proposed expansion, rather than before.

Response:

The Crowe Soberman Report (dated July 17, 2014) attached as a schedule to the Northeast Midstream interrogatories and referenced in various interrogatories has not been submitted as evidence in this proceeding and remains untested as to its assertions or conclusions. As such, responses given by the applicant in respect of the interrogatories referencing the report should not be taken as an acceptance of the report as evidence in this proceeding or of the degree to which the report should be relied upon. The responses are given without prejudice to Union's right to object to or make submissions at a later time as to whether the report' admissible or whether it is authoritative.

Union does not agree that it is more reasonable to allocate costs (or plant) which cannot be directly assigned after the proposed expansion.

The proposed rate design for Rate L1 provides a contribution towards existing 2013 Board-approved Hagar costs and recovers all incremental costs associated with the project. This rate design is appropriate in the absence of a cost of service proceeding and is consistent with other services Union developed during the 2008-2012 IRM term, such as the rate design for the C1 Dawn to Dawn-TCPL firm transportation rate approved by the Board in EB-2010-0207.

At rebasing, Union will complete a fully allocated cost allocation study which includes the liquefaction costs and Rate L1 service. Union has provided a fully allocated cost analysis for 2018 for illustrative purposes. The assumptions and results of this analysis are provided at Exhibit B.CME.5 a).

UNION GAS LIMITED

Answer to Interrogatory from
Northeast Midstream LP

Reference: Exhibit A, Tab 2; Exhibit A Tab 2, Schedules 1-6 and Exhibit A, Tab 2, Attachment A

Northeast Midstream retained Crowe Soberman to analyse the applicant's cost allocation and rate design as set out in the above noted Exhibits. Crowe Soberman prepared a report dated July 17, 2014 (the "Crowe Soberman Report"). The following interrogatories are based upon the Crowe Soberman Report and where indicated refer to the Crowe Soberman Report. The Crowe Soberman report is attached as Schedule 1 to Northeast Midstream's interrogatories.

Is it correct that Union Gas and KPMG have allocated the costs of liquefaction, vapourization and storage to the new LNG business before considering the proposed plant expansion that is necessitated by the new LNG business?

Response:

The Crowe Soberman Report (dated July 17, 2014) attached as a schedule to the Northeast Midstream interrogatories and referenced in various interrogatories has not been submitted as evidence in this proceeding and remains untested as to its assertions or conclusions. As such, responses given by the applicant in respect of the interrogatories referencing the report should not be taken as an acceptance of the report as evidence in this proceeding or of the degree to which the report should be relied upon. The responses are given without prejudice to Union's right to object to or make submissions at a later time as to whether the report' admissible or whether it is authoritative.

Yes. Please see the response to Exhibit B.Northeast.82.

UNION GAS LIMITED

Answer to Interrogatory from
Northeast Midstream LP

Reference: Exhibit A, Tab 2; Exhibit A Tab 2, Schedules 1-6 and Exhibit A, Tab 2, Attachment A

Northeast Midstream retained Crowe Soberman to analyse the applicant's cost allocation and rate design as set out in the above noted Exhibits. Crowe Soberman prepared a report dated July 17, 2014 (the "Crowe Soberman Report"). The following interrogatories are based upon the Crowe Soberman Report and where indicated refer to the Crowe Soberman Report. The Crowe Soberman report is attached as Schedule 1 to Northeast Midstream's interrogatories.

Please provide the cost allocation for liquefaction, vapourization and storage taking into account the proposed plant expansion that is necessitated by the launch of the new LNG business.

Response:

The Crowe Soberman Report (dated July 17, 2014) attached as a schedule to the Northeast Midstream interrogatories and referenced in various interrogatories has not been submitted as evidence in this proceeding and remains untested as to its assertions or conclusions. As such, responses given by the applicant in respect of the interrogatories referencing the report should not be taken as an acceptance of the report as evidence in this proceeding or of the degree to which the report should be relied upon. The responses are given without prejudice to Union's right to object to or make submissions at a later time as to whether the report' admissible or whether it is authoritative.

Please see the response to Exhibit B.CME.5 a).

UNION GAS LIMITED

Answer to Interrogatory from
Northeast Midstream LP

Reference: Exhibit A, Tab 2; Exhibit A Tab 2, Schedules 1-6 and Exhibit A, Tab 2, Attachment A

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Is it KPMG's expert opinion that allocating costs after taking into account the proposed plant expansion is a more reasonable apportionment of costs than allocating costs prior to the consideration of the proposed plant expansion?

Response:

This response was prepared by KPMG.

KPMG's mandate was to develop an approach to allocating 2013 Board Approved costs for the Hagar facility amongst the functions of liquefaction, storage and vapourization. The objective of this allocation was to support Union's development of an interruptible liquefaction service rate.

It was not within KPMG's scope of work to determine an appropriate approach to allocating the costs associated with new activities and assets introduced to support the LNG dispensing business. Given our scope of work, we have therefore not examined approaches to allocating these costs in detail. Our opinion on the appropriate approach to allocating such costs will depend on the purpose of the cost allocation exercise and on the relationship of LNG dispensing activities to existing Hagar operations as represented by 2013 Board Approved costs.

Although approaches to allocating the costs associated with LNG dispensing were not within our scope of work, we can offer some observations. These are summarized below.

A notable feature of the approach proposed by Crowe Soberman is that the proportion of existing common costs allocated to storage and vapourization will vary with changes in the capital costs of the incremental facilities added solely to service the new LNG dispensing business. As these new facilities do not affect the nature of existing operations, this outcome appears at odds with the desire for a stable and defensible approach for allocating the costs of the existing Hagar operations among functions.

Another feature of the Crowe Soberman method that can result in distorted outcomes is that it uses net asset value as the way to assign weights to business lines with widely different asset ages. This results in a large and likely disproportionate weight being given to the LNG dispensing business since its assets are new and hence will have limited accumulated amortization. The existing integrated Hagar plant, in contrast, is much older and hence has a much lower relative net book value. The resulting high weighting given to the LNG business in no way reflects the relative operational significance of the different processes. The use of net book value as a method of weighting the shares of functions within the existing Hagar facility was reasonable because this plant was built on an integrated basis many years ago. Although newer individual assets have been added over time, they are not disproportionately associated with one function versus another.

In light of the above considerations, the approach proposed by Crowe Soberman is not appropriate in the circumstances.

UNION GAS LIMITED

Answer to Interrogatory from
Northeast Midstream LP

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Under the cost allocation approach adopted by Union Gas and KPMG, it appears that the new LNG business is being effectively cross-subsidized and existing natural gas customers are failing to share fully in the benefits of the efficiencies arising from the plant expansion. Please comment.

Response:

The Crowe Soberman Report (dated July 17, 2014) attached as a schedule to the Northeast Midstream interrogatories and referenced in various interrogatories has not been submitted as evidence in this proceeding and remains untested as to its assertions or conclusions. As such, responses given by the applicant in respect of the interrogatories referencing the report should not be taken as an acceptance of the report as evidence in this proceeding or of the degree to which the report should be relied upon. The responses are given without prejudice to Union's right to object to or make submissions at a later time as to whether the report' admissible or whether it is authoritative.

Union does not agree that its cost allocation and rate design proposal results in the new LNG business being cross-subsidized.

The proposed rate design for Rate L1 provides a contribution towards the recovery of existing 2013 Board-approved Hagar costs and recovers all incremental costs associated with the project. This rate design is appropriate in the absence of a cost of service proceeding and is consistent with other services developed during Union's 2008-2012 IRM term, such as the rate design for the C1 Dawn to Dawn-TCPL firm transportation rate approved by the Board in EB-2010-0207.

The service will also result in better utilization of Hagar. This better utilization will benefit

Union's existing customers over the 2014-2018 IRM term by contributing to regulated earnings subject to sharing. On rebasing, the revenue from these services will form part of regulated revenue for ratemaking, which should reduce rates for existing customers.

UNION GAS LIMITED

Answer to Interrogatory from
Northeast Midstream LP

Reference: Exhibit A, Tab 2; Exhibit A Tab 2, Schedules 1-6 and Exhibit A, Tab 2, Attachment A

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Please provide the revenue requirement for the LNG business on a cost allocation basis that takes into account the proposed plant expansion.

Response:

The Crowe Soberman Report (dated July 17, 2014) attached as a schedule to the Northeast Midstream interrogatories and referenced in various interrogatories has not been submitted as evidence in this proceeding and remains untested as to its assertions or conclusions. As such, responses given by the applicant in respect of the interrogatories referencing the report should not be taken as an acceptance of the report as evidence in this proceeding or of the degree to which the report should be relied upon. The responses are given without prejudice to Union's right to object to or make submissions at a later time as to whether the report' admissible or whether it is authoritative.

Please see the response to Exhibit B.CME.5 a).

UNION GAS LIMITED

Answer to Interrogatory from
Northeast Midstream LP

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Please provide the revenue requirement for the new LNG business in a scenario where there is no one time per annum recycling of LNG inventory of 648,000 GJ.

Response:

The Crowe Soberman Report (dated July 17, 2014) attached as a schedule to the Northeast Midstream interrogatories and referenced in various interrogatories has not been submitted as evidence in this proceeding and remains untested as to its assertions or conclusions. As such, responses given by the applicant in respect of the interrogatories referencing the report should not be taken as an acceptance of the report as evidence in this proceeding or of the degree to which the report should be relied upon. The responses are given without prejudice to Union's right to object to or make submissions at a later time as to whether the report' admissible or whether it is authoritative.

Union would not adjust the revenue requirement allocated to the proposed liquefaction service to account for a system integrity event that requires the cycling of the LNG tank.

The variable costs for system integrity would change depending on the system integrity cycling assumptions; however, these costs are directly assigned to system integrity and would not impact the Rate L1 contribution to the recovery of existing costs or revenue requirement.

UNION GAS LIMITED

Answer to Interrogatory from
Northeast Midstream LP

Reference: Exhibit A, Tab 2; Exhibit A Tab 2, Schedules 1-6 and Exhibit A, Tab 2, Attachment A

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Please provide all underlying assumptions to support the projection of assumed capacity of 3,186 GJ per day.

Response:

Union assumed a liquefaction capacity of 3 mmcf. The 3 mmcf represents the design of the Hagar plant. For evidence purposes, Union converted the 3 mmcf to GJ using a heat value of 37.51 (2013 Board-approved Union North heat value), as shown below:

$$3 \text{ mmcf X } 28.31685\ 10^3 m^3 \text{ X } 37.51 = 3{,}186 \text{ GJ}$$

UNION GAS LIMITED

Answer to Interrogatory from
Northeast Midstream LP

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What percentage of storage costs did Union Gas and/or KPMG allocate to the new LNG business?

Response:

The Crowe Soberman Report (dated July 17, 2014) attached as a schedule to the Northeast Midstream interrogatories and referenced in various interrogatories has not been submitted as evidence in this proceeding and remains untested as to its assertions or conclusions. As such, responses given by the applicant in respect of the interrogatories referencing the report should not be taken as an acceptance of the report as evidence in this proceeding or of the degree to which the report should be relied upon. The responses are given without prejudice to Union's right to object to or make submissions at a later time as to whether the report' admissible or whether it is authoritative.

Union allocated 1.1% of the total Hagar storage costs to the Rate L1 liquefaction service. This allocation is based on Union's forecast that liquefaction customers will utilize up to 7,000 GJ of Union's total Hagar storage capacity of 648,000 GJ.

UNION GAS LIMITED

Answer to Interrogatory from
Northeast Midstream LP

Reference: Exhibit A, Tab 2; Exhibit A Tab 2, Schedules 1-6 and Exhibit A, Tab 2, Attachment A

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As the existing gross plant is valued at $22.8 million, of which $8.2 million is assigned to pre-expansion liquefaction (see Appendix A of the Crowe Soberman Report), and as the proposed expansion reflects further capital investment of $8.7 million, please state whether it is reasonable to suggest that the incremental capital costs alone to provide the L1 service represents approximately 28% of the total post-expansion gross plant (before considering the use of the existing liquefaction facility by the new business).

Response:

The Crowe Soberman Report (dated July 17, 2014) attached as a schedule to the Northeast Midstream interrogatories and referenced in various interrogatories has not been submitted as evidence in this proceeding and remains untested as to its assertions or conclusions. As such, responses given by the applicant in respect of the interrogatories referencing the report should not be taken as an acceptance of the report as evidence in this proceeding or of the degree to which the report should be relied upon. The responses are given without prejudice to Union's right to object to or make submissions at a later time as to whether the report' admissible or whether it is authoritative.

Yes. It is reasonable to state that the capital investment of $8.7 million represents 28% of the total Hagar gross plant post-expansion ($8.7 million / ($8.7million + $22.8 million)).

UNION GAS LIMITED

Answer to Interrogatory from
Northeast Midstream LP

Reference: Exhibit A, Tab 2; Exhibit A Tab 2, Schedules 1-6 and Exhibit A, Tab 2, Attachment A

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Please comment on whether the ex-post method proposed by Crowe Soberman, which yields the L1 rate of $8.894/GJ, would apportion costs for the new expanded operation in a more equitable manner, and prevents existing natural gas customers from effectively subsidizing L1 customers.

Response:

The Crowe Soberman Report (dated July 17, 2014) attached as a schedule to the Northeast Midstream interrogatories and referenced in various interrogatories has not been submitted as evidence in this proceeding and remains untested as to its assertions or conclusions. As such, responses given by the applicant in respect of the interrogatories referencing the report should not be taken as an acceptance of the report as evidence in this proceeding or of the degree to which the report should be relied upon. The responses are given without prejudice to Union's right to object to or make submissions at a later time as to whether the report' admissible or whether it is authoritative.

As described in response to Exhibit B.Northeast.82, Union does not agree that it is more reasonable to allocate costs (or plant) which cannot be directly assigned after the proposed expansion.

Union also does not agree that existing natural gas customers are subsidizing Rate L1 customers. Rate L1 is providing a contribution towards the recovery of existing costs and is recovering all incremental costs associated with providing the proposed liquefaction service.

UNION GAS LIMITED

Answer to Interrogatory from
Northeast Midstream LP

Reference: Exhibit A, Tab 2; Exhibit A Tab 2, Schedules 1-6 and Exhibit A, Tab 2, Attachment A

Northeast Midstream retained Crowe Soberman to analyse the applicant's cost allocation and rate design as set out in the above noted Exhibits. Crowe Soberman prepared a report dated July 17, 2014 (the "Crowe Soberman Report"). The following interrogatories are based upon the Crowe Soberman Report and where indicated refer to the Crowe Soberman Report. The Crowe Soberman report is attached as Schedule 1 to Northeast Midstream's interrogatories.

Assuming it is reasonable that 20% of the storage cost should be allocated to LNG commercial customers and the ex-post method for cost allocation is equitable for existing customers, do you agree that the revised calculation for the L1 rate is $10.642/GJ as set out in Appendix F of the Crowe Soberman Report.

Response:

The Crowe Soberman Report (dated July 17, 2014) attached as a schedule to the Northeast Midstream interrogatories and referenced in various interrogatories has not been submitted as evidence in this proceeding and remains untested as to its assertions or conclusions. As such, responses given by the applicant in respect of the interrogatories referencing the report should not be taken as an acceptance of the report as evidence in this proceeding or of the degree to which the report should be relied upon. The responses are given without prejudice to Union's right to object to or make submissions at a later time as to whether the report' admissible or whether it is authoritative.

Union does not agree with the revised calculation for Rate L1 as set out in Appendix F.

As described in the response to Exhibit B.Northeast.79 and Exhibit B.Northeast.80, it is not reasonable to assume system integrity liquefaction capacity of 425,000 GJ or to allocate 20% of the storage costs to Rate L1.

Further, as described in the response to Exhibit B.Northeast.82, Union does not agree it is more reasonable to allocate costs (or plant) which cannot be directly assigned after the proposed expansion, as presented in Appendix F.