NAVIGANT

LNG CANADA
Description of Expected Gas Supplies and Requirements over the Requested Licence Term

Prepared for:
LNG Canada Development Inc.

Navigant Consulting, Inc.
35 Iron Point Circle, Suite 225
Folsom, CA 95630
USA

916.631.3200
www.navigant.com

June 30, 2015

Disclaimer: This Report ("Description of Expected Gas Supplies and Requirements over the Requested Licence Term") was prepared by Navigant Consulting, Inc. for the benefit of LNG Canada Development Inc. This work product involves forecasts of future natural gas demand, supply, and prices. Navigant Consulting applied appropriate professional diligence in its preparation, using what it believes to be reasonable assumptions. However, since the report necessarily involves unknowns, no warranty is made, express or implied.

NAVIGANT

Table of Contents

1. Executive Summary 1

2. Introduction 4

2.1 Purpose of the Report 4
2.2 Overview of LNG Canada's Kitimat Project 4

3. Supply and Demand Forecast and Market Assessment 6

3.1 Introduction and Summary of Outlook 6
3.2 Gas Resources 9
3.2.1 Size of the Gas Resource 9
3.2.1.1 Canadian Resources and Resource Life 9
3.2.1.2 Potential Limitations on LNG Export Project Development 15
3.2.1.3 U.S. Resources and Resource Life 15
3.2.1.4 North America Resources and Resource Life 17
3.2.2 Character of Shale Gas Resources 17
3.2.3 Improvements in Hydraulic Fracturing and Horizontal Drilling 18
3.3 Modeling Overview 21
3.4 Macro Assumptions 22
3.4.1 Oil Prices 22
3.4.2 Economic Growth 23
3.5 Supply 23
3.5.1 Background 23
3.5.2 Forecast 25
3.6 Demand 28
3.6.1 Background 28
3.6.2 Forecast 30
3.7 Risks to the Supply and Demand Forecasts 33
3.7.1 Environmental Issues 33
3.7.2 Market Issues 34
3.8 Supply-Demand Balance 34
3.8.1 Base Case 34
3.8.2 Additional Scenario 37
3.9 Inter-Regional Patterns 38
3.10 Market Outlook 40
3.11 Conclusions 41

List of Figures and Tables

Figures:

Figure 1: Relevant Project Region Pipelines 5
Figure 2: North American Shale Gas Basins 7
Figure 3: Montney and Horn River Production History 11
Figure 4: General Map of Western Canada Gas Resource Plays 12
Figure 5: U.S. Potential Gas Committee Gas Resource Estimates 16
Figure 6: Marcellus Production History 17
Figure 7: Henry Hub Price History 19
Figure 8: Eagle Ford Rig Efficiency 20
Figure 9: U.S. Gas Production and Rig Count History 20
Figure 10: WTI Price Assumed in Natural Gas Forecast 23
Figure 11: Historical Canadian Natural Gas Production 24
Figure 12: Canadian Dry Gas Production Forecast Breakout 26
Figure 13: Canadian Shale Gas Production Forecast 27
Figure 14: North American Natural Gas Production Forecast 27
Figure 15: Annual U.S. Natural Gas Production History 28
Figure 16: Canadian Natural Gas Demand Forecast, by Location 31
Figure 17: Canadian Natural Gas Demand Forecast, by Type 32
Figure 18: Alberta Natural Gas Demand Forecast, by Type 32
Figure 19: North American Natural Gas Demand Forecast 33
Figure 20: Canadian Supply-Demand Balance 35
Figure 21: Net Canadian Pipe and LNG Export Forecast—Reference Case 36
Figure 22: North American Supply-Demand Balance 36
Figure 23: Net Canadian Pipe and LNG Export Forecast--Additional Scenario 38
Figure 24: U.S. Northeast Natural Gas Demand by Sourcing Area 39
Figure 25: Natural Gas Price Outlook 40

Tables:

Table 1: Canadian Natural Gas Resource Estimates 10
Table 2: Major Canadian Gas Resource Plays 12
Table 3: Gas Resource Life (to supply domestic demand plus pipeline exports) 13
Table 4: Gas Resource Life (to supply domestic demand only) 14
Table 5: North American Natural Gas Resource Life 17
Table 6: Economic Growth Assumptions 23
Table 7: Average Annual Gas Demand Growth Rates for Key Demand Segments 29
Table 8: Canadian Generation by Fuel Source 30

1. Executive Summary

LNG Canada Development Inc. ("LNG Canada"), on behalf of Shell Canada Energy, Diamond LNG Canada Ltd., Kogas Canada LNG Ltd., and Brion Kitimat LNG Partnership (collectively referred to as "the Participants"), is applying to the National Energy Board ("NEB") for a licence to export natural gas from Canada. LNG Canada is developing a liquefied natural gas ("LNG") export facility (the "Project") near Kitimat, British Columbia. Among other things, the Project will include a natural gas liquefaction facility (the "Facility") and related infrastructure and facilities to enable export of LNG to worldwide markets. Annual maximum LNG exports would be the equivalent to 1,357.8 Bcf of natural gas per year or 3.72 billion cubic feet per day (Bcfd), inclusive of a tolerance allowance.[1] For purposes of this Description of Expected Gas Supplies and Requirements over the Requested Licence Term ("DGSR"), a maximum gross feedstock requirement of 3.97 Bcfd has been assumed, after accounting for fuel losses in liquefaction of 4% and pipeline fuel gas of 2.4%. [2]

This DGSR has been prepared to support LNG Canada's export application and the accompanying Report on the Implications of the proposed export volumes on the ability of Canadians to meet their gas Requirements ("ROI") to satisfy the requirement of "an assessment of the impact of the proposed exportation on Canadian energy and natural gas markets to determine whether Canadians are likely to have difficulty in meeting their energy requirements at fair market prices."[3] The DGSR also finds that the quantity of liquefied natural gas to be exported by LNG Canada "does not exceed the surplus remaining after due allowance has been made for the reasonably foreseeable requirements for use in Canada, having regard to the trends in the discovery of oil or gas in Canada."[4]

Overall natural gas supply growth in North America continues to be robust in the U.S. and Canada. Although Canadian gas shale development started a few years after the prolific developments in the U.S., due to the vast size of the shale gas resource and the high reliability of shale gas production, the supply-demand dynamic has the potential to be more closely 'in balance' for the foreseeable future, even as natural gas demand grows. This is predominantly attributable to the presence of prolific supplies of unconventional gas which can now be produced economically, even at lower commodity price levels.

Not only are entirely new gas resource plays being discovered, and then brought into production, but as additional data from producing gas plays is gathered over time, the resource estimates of those active plays have generally been increased. The large growth in shale gas and tight gas estimates is the reason for the increasingly healthy status of Canadian recoverable gas resources. For example, combining the recent 573 Tcf estimate by the U.S. Energy Information Administration (U.S. E.I.A.)[5] of Canadian shale

---

[1] Navigant notes that this DGSR and our modeling was based on a slightly higher annual maximum than is included in the cover application filed by LNG Canada in connection with its application for a 40-year natural gas export licence. Whereas this DGSR based its analysis on an annual maximum project volume of 1,357.8 Bcf, including tolerance, the application is for a slightly lower annual maximum volume of 1,343.2 Bcf. This difference relates to the unit conversion factors used by LNG Canada to convert tonnes to Bcf in its 2012 export licence application.

[2] I.e., (1,357.8 Bcf/y) / (365 days/year) / 0.96 / .976 = 3.97 Bcf/d

[3] See note 9.

[4] See note 10.

[5] See note 16.

resources with the NEB's most recent reference case non-shale resource estimates totaling 871 Tcf[6] gives a total Canadian endowment of 1,444 Tcf of recoverable resource.

This Canadian resource base is sufficient to supply Canadian domestic demand at today's levels, plus today's net pipeline exports to the U.S., for 260 years, or just Canadian domestic demand for 380 years. Accounting for LNG Canada's requested export volumes as an additional use of Canadian natural gas, as planned by LNG Canada, would only decrease those Canadian resource life estimates to about 205 and 275 years, respectively. Even assuming additional exports of more than 21 Bcfd to allow for all other approved Canadian long-term gas exports, those resource life estimates would still be more than 95 years and almost 110 years, respectively. The overall North American natural gas resource life, based on 2014 North American gas demand levels, comes to 148 years. It is thus Navigant's view that the size of the gas resource in North America is more than adequate to serve all forecast domestic demand in Canada (and the rest of North America), as well as the demand added by LNG Canada's proposed exports, through the study period through 2062.

This DGSR is based on Navigant's latest natural gas market forecast (*North American Natural Gas Market Outlook, Year-End 2014*), as well as Navigant's experience and knowledge of the Canadian and North American natural gas markets, including supply, demand, supply-demand balance, market conditions and evolving natural gas recoverable resource estimates.[7] In developing its gas production forecast, Navigant's basic modeling assumption, based on industry observations, is that natural gas supply will respond dynamically to demand in a reasonably short time—months, not years. The shale gas resource is furthermore adequate to be readily produced more or less on demand in quantities to meet all presently expected gas demand levels if economics and policy are supportive.

Navigant forecasts sustained long-term growth of British Columbia production as a result of the Montney and Horn River development. Navigant forecasts a strong increase for Canadian dry gas production of 57 percent between 2015 and 2062 (from 15.2 to 23.9 Bcfd), driven by the significant increases in British Columbia shale gas production to build on the roughly level Alberta conventional gas production. While Navigant's current outlook for production in Alberta appears lackluster, Navigant expects its outlook to likely improve in the future as new plays and additional markets are developed.

Similar to Canada, total North American shale gas production will add a significant amount of incremental gas supply on top of stagnant conventional production, with a 160 percent increase in shale gas production from 37.9 Bcfd in 2015 to 98.9 Bcfd in 2062 leading to an overall 70 percent increase in total North American production from 91.6 Bcfd in 2015 to 156.0 Bcfd in 2062. At that time, shale gas will account for 63 percent of North American gas production.

Navigant's forecast of Canadian natural gas demand shows an increase from 10.2 Bcfd in 2015 to 19.1 Bcfd in 2062, or 88 percent. The largest increases by Canadian demand category over the forecast period are for industrial use (including oil sands), growing 93 percent from 4.6 Bcfd to 8.9 Bcfd, and for electric

---

[6] See note 23.

[7] This report is based on Navigant's Mid-Year 2014 Outlook. Because prior Navigant reports prepared for export applications to the NEB were based on prior Navigant forecasts, e.g. Navigant's Spring 2013 Outlook (Jordan Cove LNG LP and Oregon LNG Marketing Company LLC), on Navigant's Fall 2013 Outlook (WesPac Midstream LLC and Steelhead LNG Corp.), or on Navigant's Mid-Year 2014 Outlook (GNL Québec), some report results may not be directly comparable.

generation requirements, expanding 355 percent from 0.9 Bcfd to 4.1 Bcfd. North American natural gas demand is forecasted to increase 62 percent.

From a supply-demand balance perspective, the production forecast compared to the demand forecast yields annual levels of net exports from Canada (by pipeline or natural gas liquefaction) that are always sufficient to meet the 3.72 Bcfd export quantity required for the Project, and average 4.4 Bcfd (representing about 21 percent of average production of 20.8 Bcfd). Thus, we project that strong production growth will be able to meet increasing Canadian demand.

Navigant also modeled a scenario that increased the average growth rate in Canadian demand by more than 20%, from 1.4 percent per year to 1.85 percent[8], as well as explicitly accounted for the 3.72 Bcfd export quantity of the Project. The results of this scenario yielded average annual net pipeline exports to the U.S. of 1.7 Bcfd (i.e. production that is surplus to both Canadian demand and LNG exports from Canada).

The rapid growth in shale gas production, coupled with conventional gas production declines, has increased gas-on-gas competition and has already started to cause changes in the traditional gas flow patterns across North America. An indicator of this dynamic is the change in supply patterns to the U.S. Northeast market. With the strong development of the Marcellus play after 2008, a clear displacement of other gas supply sources, including Canadian, to the U.S. Northeast is evident. The Western Canadian Sedimentary Basin's ("WCSB") share of U.S. Northeast supply has dropped by a 16 percent share (a 76 percent reduction) since 2008. Such basin displacement is an example of the competitive pressure WCSB resources now face in the transformed U.S. market against the continually growing U.S. shale gas production.

Navigant's natural gas price outlook reflects reasonable and competitive long-term pricing conditions, with hub prices in Alberta (AECO) expected to average less than $5.85 per MMBtu, and remaining below $6.70 per MMBtu through 2062. Included in this outlook are forecast liquefied natural gas (LNG) export volumes of 9.3 Bcfd from North America, reflecting Navigant's current market view of a range of 8 Bcfd to 10 Bcfd for North America.

In addition to a market characterized by reasonable and competitive prices, we believe the stability of the market will continue to be further enhanced as proportionately more natural gas supply comes from unconventional shale gas. Given the benefits of the shale gas production process (*i.e.* lower exploration risk, improved supply response), increased reliance upon shale gas should help to mitigate the "boom-and-bust" patterns in the industry and lower price volatility. As additional base load natural gas demand represented by LNG exports increases the size of the gas market, this will in turn foster further development of shale gas resources and lead to continuing decreases in market volatility due to the reduced production risk associated with shale gas.

This DGSR provides an outlook for both Canadian and North American natural gas markets characterized by ample, stable supplies and competitive, stable prices. Ultimately, the abundant volume of natural gas supports an assessment that the quantity of natural gas to be exported from Canada by LNG Canada will not threaten the ability of the market to meet the foreseeable requirements of natural gas in Canada, having regard to the trends in discovery of oil and gas in Canada.

---

[8] See footnote 67, infra.

2. Introduction

2.1 *Purpose of the Report*

This DGSR has been prepared to support the application of LNG Canada to the NEB for a licence to export natural gas from Canada. The DGSR supports the accompanying ROI that provides "an assessment of the impact of the proposed exportation on Canadian energy and natural gas markets to determine whether Canadians are likely to have difficulty in meeting their energy requirements at fair market prices."[9] The DGSR also supports a finding that the quantity of natural gas to be exported by LNG Canada "does not exceed the surplus remaining after due allowance has been made for the reasonably foreseeable requirements for use in Canada, having regard to the trends in the discovery of oil or gas in Canada."[10]

2.2 *Overview of LNG Canada's Kitimat Project*

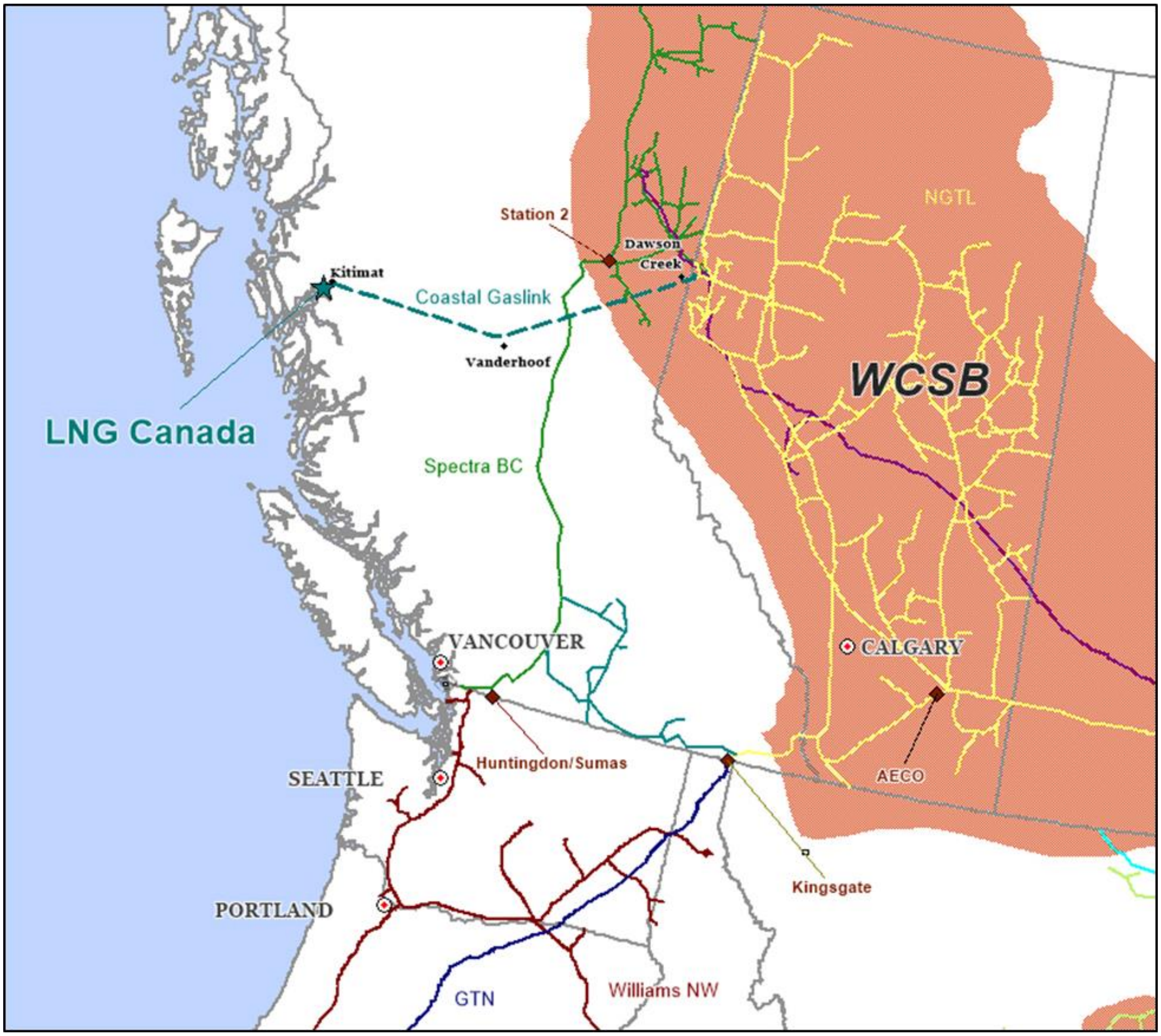
LNG Canada Development Inc. ("LNG Canada") is developing a liquefied natural gas ("LNG") export facility (the "Project") near Kitimat, British Columbia. Among other things, the Project will include a natural gas liquefaction facility (the "Facility") and related infrastructure and facilities to enable export of LNG to worldwide markets. At full build-out, the Facility is expected to include four LNG processing units ("Trains").

Annual LNG exports would be the equivalent to 1,357.8 Bcf of natural gas per year, or 3.72 Bcfd inclusive of a tolerance allowance. For purposes of this DGSR, a maximum gross feedstock requirement of 3.97 Bcfd has been assumed, after accounting for fuel losses in liquefaction of 4%, and pipeline fuel gas of 2.4%. The Project is tentatively scheduled for start of operations in 2021, but may commence as early as 2019, and operate for a 40-year term. The forecast term in this report, however, extends through 2062 in the event the Project only comes on-line by the end of 2022. A map showing the location of the Project and various gas transmission pipelines in the region appears in Figure 1.

---

[9] See National Energy Board Act Part VI (Oil and Gas) Regulations, Part II, Division I, Section 12 (g).

[10] Section 118 of the NEB Act, as quoted by the Board in its Letter Decision issuing an LNG export licence to LNG Canada Development Inc. on February 4, 2013 (File OF-EI-Gas-GL-L384-2012-01 01), at 3. The Board stated that the quoted passage is what the Board is "legally mandated and authorized to consider" when assessing a gas export licence application.



Source: Navigant / Ventyx

Figure 1: Relevant Project Region Pipelines

Natural gas supply for the Project is expected to be sourced primarily in the Western Canadian Sedimentary Basin ("WCSB"), which is composed principally of resources in British Columbia and Alberta. Natural gas supply for the Project may be accessed in a number of ways, including proprietary natural gas holdings of the Participants, and third party agreements with gas producers, marketers, and aggregators. Third party purchases are expected to be transacted at market hubs that may include, but are not limited to, the NOVA Inventory Transfer ("NIT") virtual trading point through access to the NOVA Gas Transmission Ltd. ("NGTL") System. This system provides the Participants with integrated access to gas production throughout the WCSB.

LNG Canada and the Participants have entered into a commercial arrangement with Coastal GasLink Pipeline, Ltd. ("Coastal GasLink"), a subsidiary of TransCanada PipeLines Limited, whereby Coastal

GasLink will permit, own, build and operate the Coastal GasLink pipeline ("CGL") that will deliver gas from the WCSB to the Project. The CGL is proposed to be a 48-inch diameter and 670-km long natural gas pipeline running from a point or points on the NGTL System infrastructure to the Project with an initial capacity of two to three Bcfd. As discussed in detail throughout this report, gas supplies from the WCSB should be readily available for the Project due to the changing North American gas market dynamics, including gas production growth in the U.S.

3. Supply and Demand Forecast and Market Assessment

3.1 Introduction and Summary of Outlook

In order to evaluate whether the natural gas to be exported by LNG Canada "does not exceed the surplus remaining after due allowance has been made for the reasonably foreseeable requirements for use in Canada, having regard to the trends in the discovery of oil or gas in Canada"[11], Navigant assessed the key factors affecting the current gas markets. This DGSR is based on Navigant's latest natural gas market forecast (*North American Natural Gas Market Outlook, Year-End 2014*), as well as Navigant's experience and knowledge of the Canadian and North American natural gas markets, including supply, demand, supply-demand balance, market conditions and evolving natural gas recoverable resource estimates.

Overall natural gas supply growth in North America continues to be robust in the U.S. and Canada. Although Canadian gas shale development started a few years after the prolific developments in the U.S., due to the vast size of the shale gas resource (discussed in Section 3.2.1) and the high reliability of shale gas production (discussed in Section 3.2.1), the supply-demand dynamic has the potential to be easily balanced for the foreseeable future, even as natural gas demand grows. This is predominantly attributable to the presence of prolific supplies of unconventional gas which can now be produced economically. Unconventional gas includes shale gas, tight sands gas, coal bed methane, and gas produced in association with shale oil. It has been the ramp up of gas shale production that has been the biggest contributor to overall gas supply abundance over the last several years.[12] The geographic scope of the interconnected North American shale gas resource can be seen in the map shown in Figure 2.

[11] This is the "surplus test" contained in Section 118 of the NEB Act.

[12] Navigant first identified the rapidly expanding development of natural gas from shale in 2008, in its groundbreaking report for the American Clean Skies Foundation, *North American Natural Gas Supply Assessment*, July 4, 2008, available at http://www.navigant.com/~/media/WWW/Site/Insights/Energy/NCI_Natural_Gas_Resource_Report.ashx.

Source: U.S. Energy Information Administration based on data from various published studies. Canada and Mexico plays from ARI.
Updated: May 9, 2011

Figure 2: North American Shale Gas Basins

Before the advent of significant shale gas production, the natural gas industry was characterized by “boom and bust” cycles, where periods of investment in production alternated with periods of increased or decreased demand based on the market’s perception of future prices. That perception was driven in part by uncertainty and risk around the process of finding and developing gas supply to meet demand, both for the short and long term. Due to the uncertainty of the exploration process (and at times the availability of capital to fund such discovery), gas supply was sometimes “out of phase” with demand for natural gas by gas-fired electric generating facilities and other users on the demand side, causing prices to rise and fall dramatically. This in itself caused other ramifications impacting the investment cycle for supply, such as investments in the pipeline infrastructure that is required to connect supply and demand. Such large-scale investments as pipelines have also experienced both underutilization and bottlenecks, as a result of uncoordinated cycles of supply and demand investment.

These factors have contributed to natural gas price volatility. The volatility itself affects investment decisions, amplifying the feedback loop of uncertainty. In the end, price volatility has been a major limitation on the more robust expansion of natural gas as a fuel, despite its advantages over other energy forms as an environmentally clean, abundant and affordable energy resource. The dependability of shale gas production as a result of its abundance, as well as its reduced exploration risk as compared to conventional gas resources, creates the potential to improve the alignment between supply and demand, which will in turn tend to lower price volatility. Thus, the vast shale gas resource not only has the potential to support a larger demand level than has yet been seen in North America, but at prices that are less volatile (with the necessary infrastructure capacity).

Navigant's outlook for the North American natural gas market projects a period of relatively less volatile natural gas prices over the long-term. Since the technological breakthrough of hydraulic-fracturing of gas shale through horizontal drilling, production-related activities rather than exploration are now the key factors in supply. The market is not expected to revert to its previous fundamental structure where exploration risk drove at least a portion of the price volatility in the market. In the future with shale gas becoming a larger share of natural gas supply, we expect a commensurate reduction in exploration risk.

Navigant's market view is that U.S. and Canadian domestic supply is abundant to such a degree that it will support domestic market requirements as well as export demand for LNG shipped from North America. The majority of production growth is likely to be driven by unconventional gas development, as opposed to conventional gas, which has been in decline. Plans to develop large known deposits of conventional frontier gas, such as the Mackenzie Pipeline Project in Arctic Canada, have been put in jeopardy, if not shelved completely, due not to any change in the resource itself but to the high cost of those projects relative to unconventional resource development opportunities closer to markets. It should be noted, however, that while production from these frontier sources is not being modeled by Navigant in our current forecasts due to their higher costs and lack of current pipeline connectivity, the gas resources will continue to exist and stand to be available in the future whenever the economics of supply and demand deem their development feasible, perhaps without long-haul pipeline capacity to the Lower 48, but marketed in the form of LNG, for instance. Recent developments in Alaska support this new approach to Northern supply developments.

LNG exports offer the potential for a steady, reliable baseload market which will serve to underpin currently ongoing supply development. The existence of growing U.S. and Canadian domestic and export demand will also tend to support additional supply development, and as a result tend to reduce price volatility as shale gas becomes a larger and larger part of the overall market. With respect to concerns raised that exporting LNG from North America may somehow link domestic gas prices to overseas gas pricing, which has historically been tied to higher-priced oil, Navigant believes it is very unlikely that anticipated exports from North America would lead to significant impacts on prices, much less a linkage to oil prices.[13]

As a result of the large magnitude of North American natural gas resources (as subsequently discussed in this DGSR), indigenous supplies will be sufficient to meet U.S. and Canadian demand. From a regional perspective, several interesting results emerge that highlight not only the feasibility, but also the benefit of the Project. First, Canada will maintain its status as a net exporter of natural gas to the U.S., with the bulk of deliveries exported directly out of Western Canada. This will confirm the feasibility of sourcing the Project's exports from Western Canadian supplies. Second, eastern Canada is forecast to be a regional net importer of U.S. supplies as a result of strong U.S. gas production growth from the Marcellus and Utica gas shales.[14] The benefit to the Project of this regional supply pattern is that the

---

[13] See Section 3.10; see also text accompanying footnotes 61 to 63.

[14] This continues the trend noted by the NEB 1) in its 2013 Energy Briefing Note that flows into Niagara have reversed from levels of 800 MMcfd into the U.S. in the early 2000's to 360 MMcfd into Canada in November 2012. *Canadian Energy Overview 2012, Energy Briefing Note*, NEB, 2013, at 3, and 2) in February 5, 2015 Market Snapshot that imports have averaged 400 MMcfd at Niagara since the reversal at the end of 2012. http://www.neb-one.gc.ca/nrg/ntgrtd/mrkt/snpsht/2015/02-01gsflw-eng.html . NEB's Market Snapshot also noted that TransCanada has stated that the decreases in export flows at Iroquois from relatively constant to highly seasonal beginning in 2009 signal its trending toward becoming a physical import point.

eastern Canadian market imports from the U.S. lessen competitive demand for Western Canadian supplies, enhancing Western Canadian supply availability for LNG Canada exports. The Project provides additional gas demand that is needed to support Western Canadian natural gas development, while further enhancing price stability over the long term. This will benefit the Western Canadian producing sector.

Navigant forecasts market-clearing prices in a sustainable and reasonable long-term range of about $3 to $7 per MMBtu (2014 U.S.$) at both AECO and Westcoast Station 2, with AECO slightly higher over the term. Throughout this DGSR, monetary values are expressed in real (2014) U.S.$, unless otherwise noted. These prices are based on modeling that accounts for a certain level of LNG exports (*i.e.* about 9.3 Bcfd from North America) to reflect expected increased global gas on gas competition. Modeling of higher amounts of LNG exports suggests that the associated price impacts of exports, as well as resulting price levels, will also be moderate.

The pipeline flows between Canada and the U.S., as well as the ability of North American natural gas supply and demand to balance efficiently and effectively, highlight the interconnected, competitive and functional nature of the North American natural gas market.

3.2 Gas Resources

The key driver behind the strong market outlooks for both Canada and North America as a whole is what has come to be known as the "shale revolution", the vast extent of which was first quantified in 2008 by Navigant.[15] While geologists and natural gas production companies had been aware of shale gas resources for years, such resources had been uneconomic to recover. The key factor behind today's robust outlook for the natural gas market is the advent of the shale gas resource, driven by the sheer magnitude of the resource as well as the particular characteristics and efficiencies of the production process. The following sections discuss in more detail the factors underpinning the forecasted increase in gas supply.

3.2.1 Size of the Gas Resource

The importance of the shale revolution would be difficult to exaggerate. Shale gas resources are the primary driver behind the large increases in recoverable resource estimates (as well as the increases in actual production), and warrant the attention they are receiving.

3.2.1.1 Canadian Resources and Resource Life

Before outlining the specifics of the dominant portions of the Canadian natural gas resource base (*i.e.* in Western Canada), it is important to note the clearly stated, progressive and unique policy of the Province of British Columbia in favor of accelerated development of its natural gas resources. The Province's Natural Gas Strategy, released in February 2012 as part of the overall Province Jobs Plan, seeks the diversification of its gas markets, including development of supplies to meet new gas demand in North America. In fact, the Province estimated an increase in gas production from the then-current level of 1.1 Tcf per year to over 3 Tcf per year in 2020. With its natural gas strategies, the Province is clearly planning for a significant growth of its natural gas industry, from upstream production through midstream transportation and processing, to further growth of downstream end-use markets.

[15] See note 12.

NAVIGANT

With regard to the gas resource base, the latest, most comprehensive study of global shale gas resources, including Canada, was released by the U.S. Energy Information Administration ("U.S. E.I.A.") in June 2013.[16] The NEB's latest comprehensive review of Canadian total gas resources appears in its 2013 long-term energy supply and demand projection report, in which it increased its 2011 estimate of Canada's remaining marketable gas resources by 65 percent, from 664 Tcf to 1093 Tcf.[17] A key component of the NEB's changed resource estimate was based on an update specific to the prolific Montney Formation. That update, issued jointly by the NEB and agencies in British Columbia and Alberta in November 2013, raised the Montney resource estimate more than 300 percent, from 108 Tcf in the NEB's 2011 reference case to 449 Tcf.[18] A summary of relevant resource estimates for both Canada as a whole and for Western Canada appears below in Table 1.

Table 1: Canadian Natural Gas Resource Estimates

	Canada			Western Canada			
Natural Gas Recoverable Resource	Tcf	%	Source:	Tcf	%	% of Canada	Source:
Shale	573	40%	2013 U.S. E.I.A.	538	46%	94%	2013 U.S. E.I.A.
Non-Shale (excl. Montney)	422	29%	2013, NEB (Energy Future)	190	16%	45%	2013, NEB (Energy Future)
Montney	449	31%	2013, NEB (Energy Future)	449	38%	100%	2013, NEB (Energy Future)
Total	1,444	100%		1,177	100%		

Table 1 shows that the U.S. E.I.A. Assessment estimates Canadian shale gas recoverable resources at 573 Tcf, with the Western Canada portion being 538 Tcf, or almost 94 percent of the Canadian total[19]. The shale plays included in these estimates include the Horn River Basin (at 133 Tcf), the Liard Basin (at 158 Tcf), the Duvernay (at 113 Tcf) and the Cordova Embayment (at 20 Tcf); the U.S. E.I.A. Assessment estimates do not include any Montney resources, which the study considered to be tight gas. These shale play resource levels constitute about 40 percent of Canadian total gas recoverable resources, or about 46 percent of the total recoverable gas resources in Western Canada.[20] Comparing the NEB's latest analysis, in its Energy Future 2013 report that estimated WCSB marketable shale gas at 222 Tcf, to its 2011 analysis that estimated WCSB marketable shale gas at 90 Tcf, indicates an almost 150-percent increase in estimated WCSB marketable shale gas, highlighting the importance of shale gas in increasing resource estimates. Even more dramatic is the almost 500-percent increase of WCSB shale resources in the U.S. E.I.A. Assessment (*i.e.*, 538 Tcf) compared to the NEB's 2011 shale resource estimate. The other major unconventional gas resource, tight gas, is also an important component of Canada's growing natural gas resource, as discussed below.

---

[16] *World Shale Gas and Shale Oil Resource Assessment*, exhibit to *Technically Recoverable Shale Oil and Shale Gas Resources: An Assessment of 137 Shale Formations in 41 Countries Outside the United States*, U.S. Energy Information Administration, June 2013 (U.S. E.I.A. Assessment).

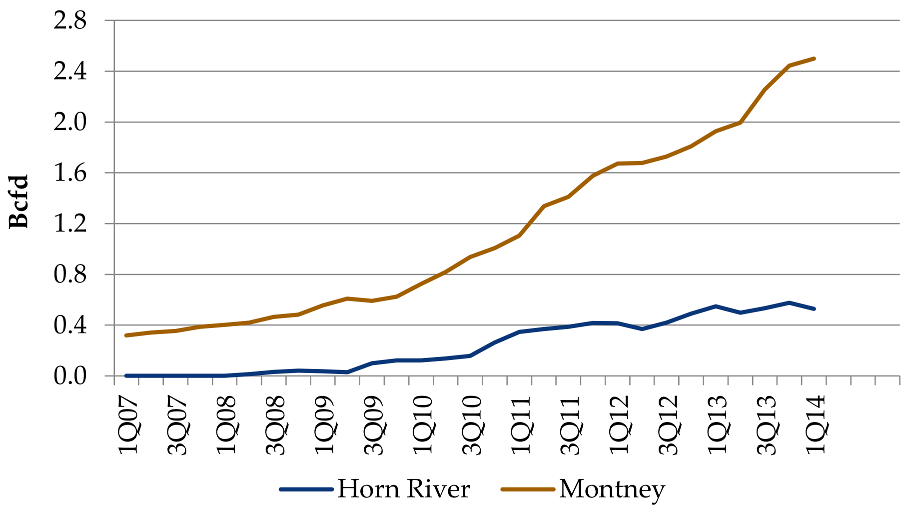
[17] *Canada's Energy Future 2013: Energy Supply and Demand Projections to 2035*, National Energy Board, November 2013. (NEB Energy Future 2013), at Chapter Six; see also *Canada's Energy Future 2011: Energy Supply and Demand Projections to 2035*, National Energy Board, November 2011, (NEB Energy Future 2011), at Table A4.1.

[18] *The Ultimate Potential for Unconventional Petroleum from the Montney Formation of British Columbia and Alberta*, Energy Briefing Note, National Energy Board, B.C. Oil & Gas Commission, Alberta Energy Regulator and B.C. Ministry of Natural Gas Development, November 2013. (NEB Montney 2013). Note that although portions of the Montney Formation are gas shale, the formation as a whole is generally classified as unconventional (but non-shale) due to the variety of its characteristics, including tight gas.

[19] Navigant is using the shale gas resource estimates published in the U.S. E.I.A. Assessment because of the more detailed, disaggregated nature of the estimates.

[20] Based on the sum of U.S. E.I.A. Assessment shale and NEB Energy Futures 2013 non-shale.

The increase in estimates of unconventional resource volumes also shows up on a play-specific basis--not only are entirely new gas resource plays being discovered, and then brought into production, but as additional data from producing gas plays is obtained over time, the resource estimates of those active plays have repeatedly been raised. Figure 3 highlights the increases in play production (*e.g.* the strong increasing production trends in the Montney and Horn River plays in Canada) that help explain increasing resource estimates. Not coincidentally, good examples in Canada of increasing resources would be the B.C./NEB's 2011 estimate of Horn River Basin recoverable shale gas estimates of 78 Tcf (which it did not update in its 2013 estimate) being followed by the 2013 U.S. E.I.A. Assessment estimate of the Horn River of 133 Tcf. Even more pronounced was the NEB's assessment of Montney resources (considered tight gas) increasing by more than 300 percent from 108 Tcf in its 2011 reference case[21] to 449 Tcf in its 2013 Montney assessment[22].



Source: Navigant / LCI Energy Insight

Figure 3: Montney and Horn River Production History

This large growth in shale gas and tight gas estimates is the primary reason for the increasingly healthy view of Canadian recoverable gas resources. For example, combining the recent 573 Tcf estimate in the U.S. E.I.A. Assessment of Canadian shale resources with the NEB's most recent reference case non-shale resource estimates totaling 871 Tcf[23], gives a total Canadian endowment of 1,444 Tcf of recoverable natural gas. For just Western Canada, combining the recent 538 Tcf shale gas estimate in the U.S. E.I.A. Assessment with the NEB's reference case non-shale resource estimates for the WCSB totaling 639 Tcf[24] gives a total Western Canadian endowment of 1,177 Tcf. These total recoverable resource figures, which appear in the total row of Table 1 and are driven by increases in the shale gas estimates (as well as the unconventional Montney estimates), strongly suggest that there is a huge abundance of natural gas to serve Canadian needs for hundreds of years, considerably longer than in the U.S. A summary of the major Canadian gas resource plays that principally make up this supply abundance appears in Table 2.

[21] NEB Energy Future 2011, supra note 17, at Table A4.1.

[22] NEB Montney 2013, supra note 18, at Table 1.

[23] See NEB Energy Future 2013, showing remaining marketable gas resources at 1,093 Tcf, less 222 Tcf of shale gas.

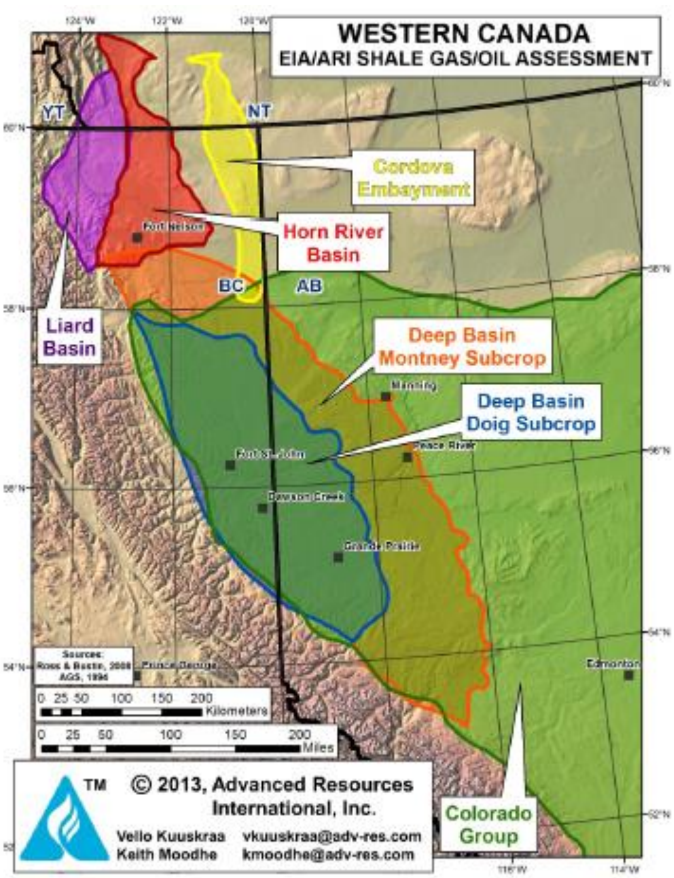
[24] See NEB Energy Future 2013, showing total WCSB remaining marketable gas resources at 861 Tcf, less 222 Tcf of shale gas.

Table 2: Major Canadian Gas Resource Plays

		Horn River Basin	Liard Basin	Cordova Embayment	Montney Formation	Duvernay Formation
Province		B.C.	B.C.	B.C.	B.C./Alberta	Alberta
Gross Area	acres (000)	4,544	2,752	2,746	32,098	32,320
Prospective Area	acres (000)	2,125	2,112	1,280		14,880
Avg. Depth	meters	2,439	3,049	1,829	varies	3,242
Avg. Thickness	meters	160	122	63	100-300	15
Recoverable Gas	Tcf	132	158	20	449	113

Sources: U.S. E.I.A. Assessment at Tables I-2 and I-3, except NEB Montney 2013 for Montney

A map from the U.S. E.I.A. Assessment detailing locations of the Horn River, Liard, Cordova and Montney gas resource plays appears in Figure 4. The Duvernay, not shown, is located generally between Edmonton and Grand Prairie.



Source: U.S. E.I.A. Assessment (see note 16)

Figure 4: General Map of Western Canada Gas Resource Plays

The following tables illustrate the resource life by summarizing Canada's natural gas abundance under a variety of demand assumptions (details of the demand forecast itself are discussed in Section 3.6). Table 3 estimates potential resource life by comparing Canada's recoverable natural gas resource estimates to its estimated 2014 natural gas demand, plus scenarios of assumed exports to account for 1) the Project, 2) the Project, plus currently approved Canadian LNG export licences totaling 21.55 Bcfd, or 3) the Project, plus approved plus applied-for Canadian LNG export licences totaling 47.28 Bcfd.[25] For Table 3, the national demand is assumed to include both Canadian consumption and net pipe shipments out of Canada.[26]

Table 3: Gas Resource Life (to supply domestic demand plus pipeline exports)

	Canada	
	Tcf	Years
Recoverable Resource	1,444	
2014 demand (*)	5.5	260
2014 demand (*), plus 3.97 Bcfd	7.0	206
2014 demand (*), plus 25.52 Bcfd	14.9	97
2014 demand (*), plus 51.25 Bcfd	24.3	60

Notes:

(*) demand is domestic consumption, plus net pipeline shipments out of Canada (see note 26).

- 3.97 Bcfd is the gross feedstock requirement of LNG Canada
- 25.52 Bcfd is LNG Canada feedstock plus 21.55 Bcfd for approved Canadian export licences as of 6/1/2015 (see note 25).
- 51.25 Bcfd is LNG Canada feedstock plus 47.28 Bcfd for approved and applied for Canadian export licences, as of 6/1/2015 (see note 25).

Table 4 is similar, but only includes Canadian consumption in the estimated demand figures.[27]

[25] The additional assumed exports for this resource life calculation are 21.55 Bcfd representing the 12 other approved Canadian project licences (Kitimat LNG (1.3 Bcfd); BC LNG (0.25 Bcfd); (Prince Rupert LNG (2.9 Bcfd); WCC LNG (4 Bcfd); Pacific Northwest LNG (2.7 Bcfd); Woodfibre LNG (0.3 Bcfd); Jordan Cove (1.55 Bcfd); Triton (0.3 Bcfd); OLNG (1.45 Bcfd); Aurora (3.3 Bcfd); Grassy Point (3.1 Bcfd); and WesPac (0.4 Bcfd)), and 47.28 Bcfd representing the approved licences plus the applied for licences (Kitsault (2.7 Bcfd); Goldboro (1.4 Bcfd); Steelhead (4.25 Bcfd); Discovery (2.46 Bcfd); Cedar (0.85 Bcfd); and Orca (3.68 Bcfd); GNL Quebec (1.56 Bcfd); Bear Head (1.88 Bcfd); Canada Stewart (4.1 Bcfd); New Times (1.85 Bcfd); AltaGas (1.0 Bcfd)). The approval of the Discovery LNG project's export application occurred after the preparation of this report. The AC LNG project was not included because, as far as Navigant is aware, it is the only project with associated import volumes greater than its export volumes. Navigant has not included the Stolt LNGaz project in its analysis because of the small volume of the project at 0.08 Bcfd.

[26] 2014 Canadian domestic demand at 10.3 Bcfd (3.76 Tcf/y) plus net pipe shipments to the U.S of 4.9 Bcfd (1.79 Tcf/y), totaling 15.1 Bcfd (5.5 Tcf/y). Estimated by Navigant.

[27] 2014 Canadian domestic demand at 10.3 Bcfd (3.76 Tcf/y), as estimated by Navigant.

Table 4: Gas Resource Life (to supply domestic demand only)

	Canada	
	Tcf	Years
Recoverable Resource	1,444	
2014 demand (**)	3.8	384
2014 demand (**), plus 3.97 Bcfd	5.2	277
2014 demand (**), plus 25.52 Bcfd	13.1	110
2014 demand (**), plus 51.25 Bcfd	22.5	64

Notes:
(**) demand is domestic consumption only (see note 27).
- 3.97 Bcfd is gross feedstock requirement for LNG Canada
- 25.52 Bcfd is LNG Canada feedstock plus 21.55 Bcfd for approved Canadian export licences as of 6/1/2015 (see note 25).
- 51.25 Bcfd is LNG Canada feedstock plus 47.28 Bcfd for approved and applied for Canadian export licences, as of 6/1/2015 (see note 25).

As can be seen in Table 3, which includes some non-Canadian consumption by virtue of the pipe exports to the U.S., there is 260 years' worth (*i.e.*, the resource/production ratio) of natural gas supply for Canada as a whole, based on the current estimate of recoverable resources and the 2014 consumption rate.. After considering an incremental demand equal to 3.97 Bcfd for the Project, the endowment is still over 200 years of supply.

Assuming further incremental volumes of 21.55 Bcfd to supply the 12 other approved Canadian export licences, or alternatively a further 47.28 Bcfd for all approved plus applied for licences at this time, there is still approximately 95 or 60 years of supply, respectively. These levels of LNG export volumes are much higher than what seems remotely conceivable at this time. As discussed below, they certainly represent volumes much in excess of the 2 Bcfd of gross Canadian LNG exports that Navigant's reference forecasts project.[28]

The potential resource life figures increase when only considering Canadian domestic consumption in the estimated demand. As can be seen in Table 4, for Canada as a whole there is over 380 years' of natural gas supply at the 2014 consumption rate and the current estimate of recoverable resources. After considering an incremental demand equal to 3.97 Bcfd for the Project, the endowment is still over 275 years of supply. Assuming further incremental volumes of 21.55 Bcfd to supply the 12 other approved Canadian export licences, or alternatively a further 47.28 Bcfd for approved plus applied for licences, there is still approximately 110 or 65 years' of supply, respectively.

[28] As noted by the International Energy Agency in its latest gas market report, beyond projects currently under construction, "new LNG projects will struggle to get off the ground" due to current low prices. IEA, Medium Term Gas Market Report 2015, Executive Summary, p. 4.

3.2.1.2 Potential Limitations on LNG Export Project Development

It should be noted that Navigant considers the higher volume ranges discussed here for Canadian LNG unlikely. As noted on page 37, the need for additional liquefaction capacity worldwide to meet global LNG demand in 2035 may only be approximately 30 Bcfd, in addition to currently operating and under construction projects. [29] As such, not all of the proposed Canadian liquefaction projects, constituting between 80 and 160 percent of that incremental global demand, will be built. Even without looking at the demand figures, other factors exist which create obstacles to the construction of Canadian liquefaction facilities. For example, building pipelines through challenging terrain, costs for greenfield versus brownfield sites, completion risks, and regulatory and permitting risks all create challenges for project proponents in Canada.

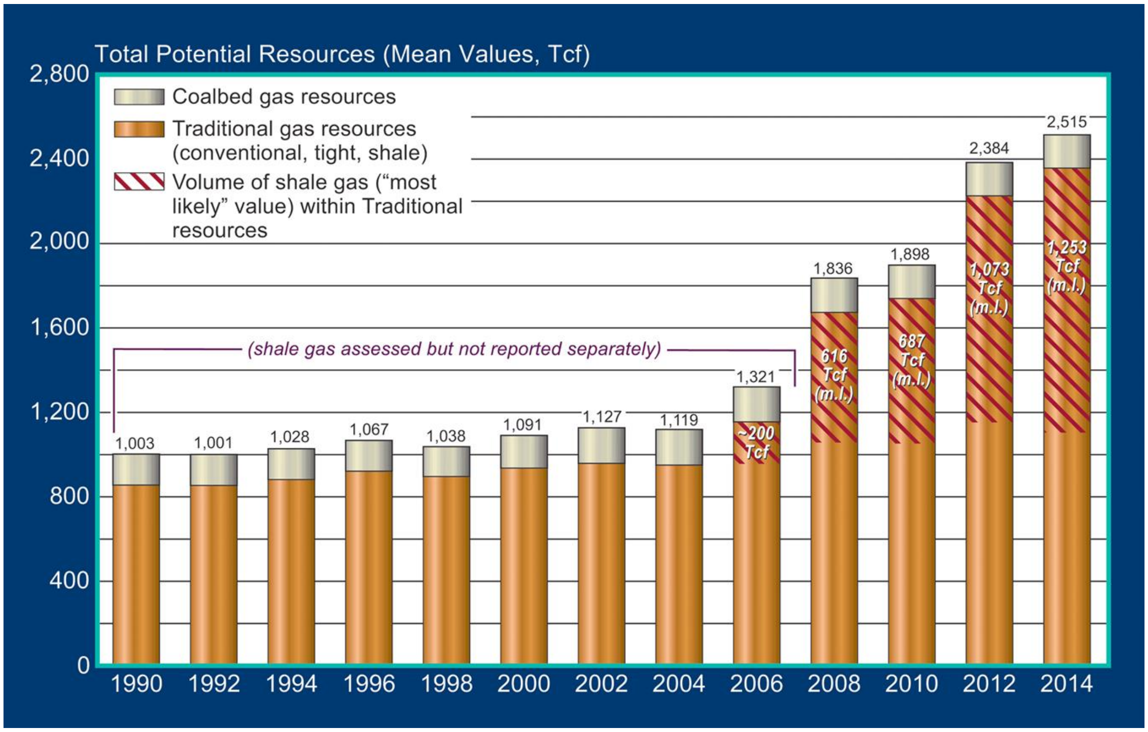
Other risk elements relate to both regional and international market changes affecting natural gas prices, technical challenges, and the actual costs of construction. Other risk factors not directly related to the gas industry, such as changes in the price of oil and other market cycles that could again occur over the long term life of these projects, could result in a lowered competitive outlook for LNG in the global market and more risk facing these large projects for project financing.

These risks and uncertainties represent impediments to the development of LNG projects in Canada. In addition, U.S. LNG projects appear to be on a schedule to commence exports in advance of Canadian projects. This will likely impact whether certain projects in Canada are able to mobilize to meet global demand in time.

3.2.1.3 U.S. Resources and Resource Life

There is a similar impact of the shale revolution on U.S. resource estimates, where the Potential Gas Committee's resource estimates have shown the shale gas portion of potential recoverable resources growing from about 15 percent in 2006 (or about 200 Tcf) to about 50 percent in 2014 (or to 1,253 Tcf), as shown in Figure 5. The increase in the shale gas resource estimate since 2006 exceeds 525 percent. Combining the shale gas resource estimate with non-shale gas estimate yields total potential resource growth of 90 percent from 2006 (at 1,321 Tcf) to 2014 (at 2,515 Tcf). Accounting for proved reserves of 338 Tcf as well, the current total U.S. recoverable resource figure rises to 2,853 Tcf.[30] At the 2014 U.S. gas consumption rate[31], this resource endowment equals almost 110 years' of U.S. natural gas supply.

[29] See text accompanying footnotes 64 to 66 regarding potential LNG export levels.
[30] See 4/8/15 Press Release, "Potential Gas Committee Reports Increase in Magnitude of U.S. Natural Gas Resource Base," Table 2.
[31] 72.3 Bcfd (26.4 Tcf/y), as estimated by Navigant



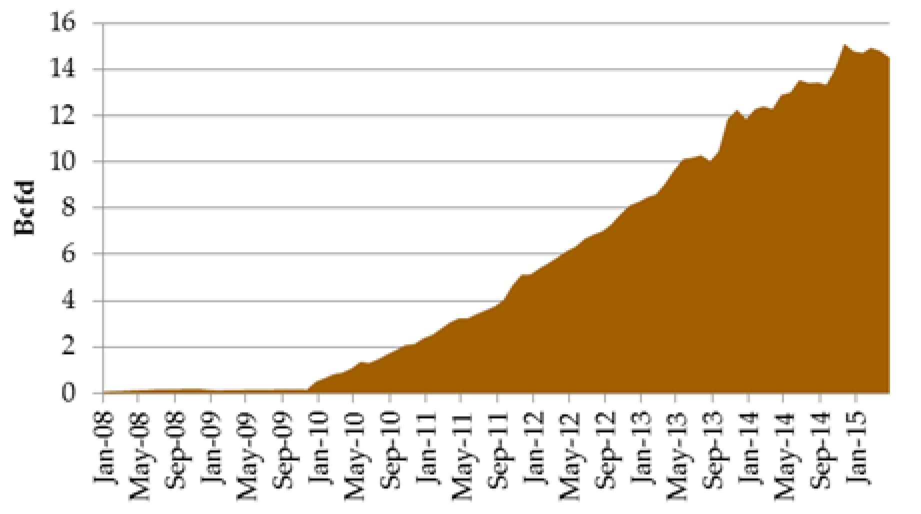
Source: U.S. Potential Gas Committee (see note 30)

Figure 5: U.S. Potential Gas Committee Gas Resource Estimates

In the last three to four years, the increases in the U.S. shale gas estimates are notable. In 2011, estimates included 521 Tcf (Rice University), 650 Tcf (MIT), and 687 Tcf (Potential Gas Committee)[32]. More recent and larger estimates include 840 Tcf (International Energy Agency), 1,073 (Potential Gas Committee), and 1,161 Tcf (U.S. E.I.A. Assessment).[33] The increase between the average levels of these two sets of estimates (that are only one to two years apart) is 65 percent. Most recently, the Potential Gas Committee's 2015 assessment represented a 17 percent increase to its 2013 assessment, showing that resource estimates have continued to increase.

As in the case for Canada, play-specific resource estimates are an important part of increasing estimates. In the U.S., estimates for the Marcellus play, for example, have risen from 50 Tcf in 2008[34] to close to 400 Tcf as more well data became available[35]. Figure 6 highlights the increases in Marcellus production that help explain its increasing resource estimates.

[32] *The Rice World Gas Trade Model: Development of a Reference Case*, Kenneth B. Medlock III, James A Baker III Institute for Public Policy, Rice University, May 9, 2011, slide 17; *The Future of Natural Gas*, Ernest J. Moniz, et al, Massachusetts Institute of Technology, June 2011, Chapter 1, p.7; Potential Gas Committee Press Release, "Potential Gas Committee Reports Substantial Increase in Magnitude of U.S. Natural Gas Resource Base", April 27, 2011.
[33] *Golden Rules for a Golden Age of Gas*, International Energy Agency, Special Report, May 29, 2012, Table 3.1; Potential Gas Committee Press Release, "Potential Gas Committee Reports Significant Increase in Magnitude of U.S. Natural Gas Resource Base", April 9, 2013; *World Shale Gas and Shale Oil Resource Assessment*, exhibit to *Technically Recoverable Shale Oil and Shale Gas Resources: An Assessment of 137 Shale Formations in 41 Countries Outside the United States*, U.S. Energy Information Administration, June 2013.
[34] *Marcellus Shale Play's Vast Resource Potential Creating Stir in Appalachia*, American Oil & Gas Reporter, T. Engelder and G. Lash, May 2008.
[35] See e.g. U.S. E.I.A. Assessment, supra note 16, at Attachment C, Table A-1.



Source: Navigant / PointLogic

Figure 6: Marcellus Production History

3.2.1.4 North America Resources and Resource Life

Including the estimated natural gas resources and domestic demand of Mexico with those of Canada and the U.S. leads to a North American resource life estimate of 148 years. Resource life estimates are summarized in Table 5.

Table 5: North American Natural Gas Resource Life

	Natural Gas Resource Conventional (Tcf)	Unconvent'l (Tcf)	Total (Tcf)	Demand (Tcf)	Resource Life (Years)
Canada	422	1,022	1,444	3.8	384
U.S.	1,442	1,411	2,853	26.4	108
Mexico	-	545	545	2.5	222
North America	1,864	2,978	4,842	32.6	148
Sources: U.S. E.I.A. Assessment; NEB Energy Future 2013; Navigant forecast; Potential Gas Committee					

As indicated by all of the above, the gas resource base in North America is extremely large. It is Navigant's view that the gas resource base in North America is more than adequate to serve the composite total of all forecast domestic demand in Canada and the U.S. through the study period to 2062, as well as the demand added by LNG Canada's proposed exports.

3.2.2 Character of Shale Gas Resources

The nature of the shale gas resource – often spread continuously throughout large formations, also containing liquids or condensates – leads to several favorable production characteristics that bode well for both producers and the markets. These characteristics are lower exploration risk, and reliable production often with enhanced returns due to NGL co-products such as ethane, propane and pentanes. The result of these benefits will be a more stable, less volatile market, as well as plentiful supply.

The shale gas resource has a generally lower-risk profile when compared to conventional gas supply that reinforces its future growth potential. Finding economically producible amounts of conventional gas has historically been challenging due largely to geologic risk. Conventional gas is usually trapped in porous rock formations, typically sandstone, under an impermeable layer of cap rock, and is produced by drilling through the cap into the porous formation. Despite advances in technology, finding and producing conventional gas involves a significant degree of geologic risk, with the possibility that a well will be a dry hole or will produce at very low volumes that do not allow the well to be economic.

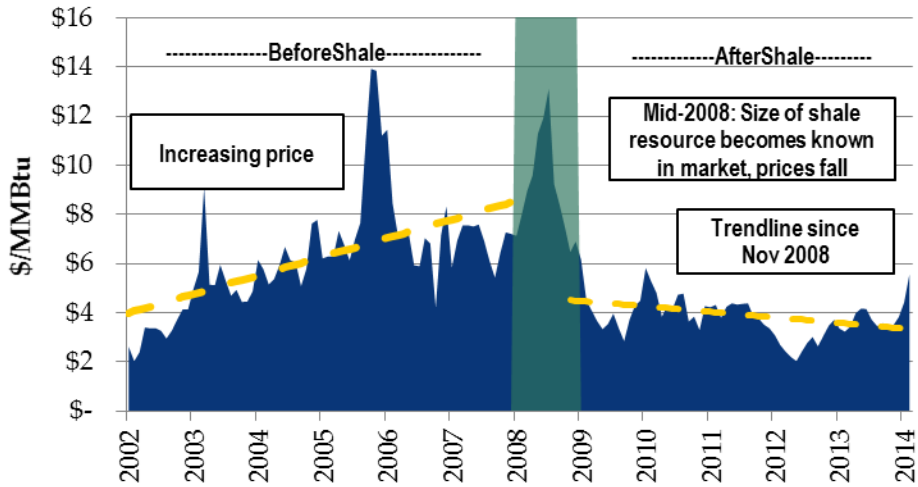
Gas in a shale formation is contained in the source rock itself. It does not accumulate in pockets under cap rock, but tends to be distributed in relatively consistent quantities over great volumes of the shale. The most advanced gas shale drilling techniques allow a single well-pad to be used to drill multiple horizontal wells into a given formation, with each bore producing gas. Since the shale formations can be dozens or even hundreds of miles long and often several hundred feet thick, the risk of not finding a producible formation is much lower compared to some types of conventional gas structures.

Consequently, in unconventional shale gas, exploration risk is significantly reduced. Resource plays have become much more certain to be produced in commercial quantities. The reliability of discovery and production has led shale gas development to be likened more to a manufacturing process rather than an exploration process with its attendant risk. This ability to control the production of gas by managing the drilling and production process potentially allows supplies to be produced in concert with market demand requirements and economic circumstances, thus moving towards lessening the occurrence of boom-and-bust cycles that have characterized the gas supply industry prior to shale gas. If demand is growing, additional zones and/or shale wells can be drilled and fractured to meet that demand and to mitigate the initial production decline rates from earlier wells. If demand subsides, drilling rates can be reduced or discontinued completely in response to the negative market signal.

An additional benefit of shale gas resources is that some shale formations contain both natural gas liquids ("NGL"s) and natural gas (*i.e.* "liquids-rich" or "wet gas" resources), which strengthens the economic prospects of shale gas. Since NGLs can be produced when natural gas is produced, and therefore gas production can be incented not only by the economics of natural gas itself, but by NGL prices, which generally track crude oil prices. Oil prices have historically and still currently offer a premium to natural gas on a per-MMBtu basis, with oil at $90 per barrel equating to about $15.50 per MMBtu, and even oil at $60 per barrel representing $10 per MMBtu, compared to gas prices that are about $5.00 per MMBtu. The point here is that even when the target is higher priced oil or liquids, natural gas is being found and produced.

3.2.3 Improvements in Hydraulic Fracturing and Horizontal Drilling

Natural gas prices increased substantially in the first decade of this century, culminating in significantly higher prices in 2007-2008, as shown in Figure 7. These increasing prices induced a boom in LNG import facility construction in the late 1990s and 2000s, which was very conspicuous due to the size of the facilities. As late as 2008, it was fully expected that North American gas production would have to be supplemented increasingly by imported LNG owing to domestic North American supply resource decline.



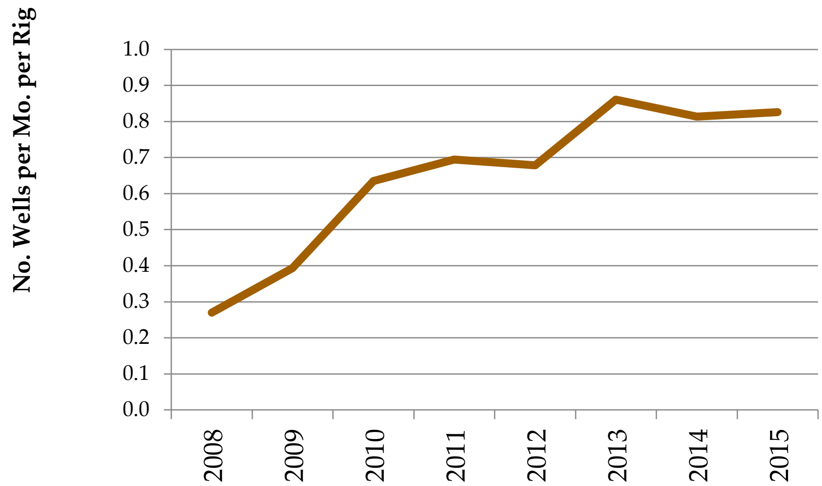
Source: Navigant / NYMEX

Figure 7: Henry Hub Price History

High prices also supported the development of horizontal drilling and hydraulic fracturing. These technologies were combined to dramatically increase drilling and production efficiencies, reduce costs, and improve finding and development economics of the industry. In mid-2008, domestic gas production from shale began to overtake imported LNG as the new gas supply of choice in North America. The evolution of the combined cost-effective technologies was the key to unlocking the potential of the gas shale resource.

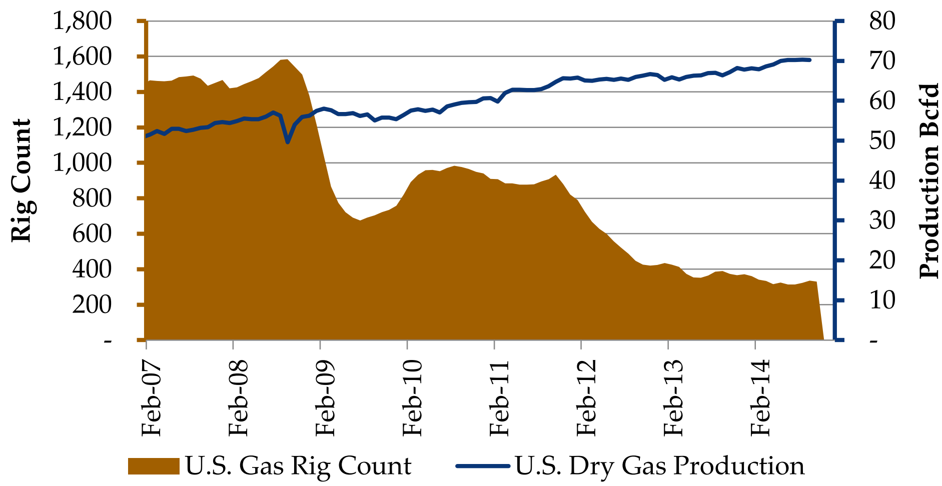
Shale gas production efficiency has continued to improve over time in both Canada and the U.S. The efficiencies in drilling and production can be clearly seen by looking at metrics examined in an article by Navigant.[36] For example, drilling rig efficiency, as measured by the number of wells that are drilled by a rig in a month or year, has been marked by generally steady increases. Figure **8** shows that in the Eagle Ford play in Texas, the average rig drilled three wells per year in 2008, but 10 wells per year in 2015. Such efficiencies have helped to allow total U.S. natural gas production to increase even as natural gas rig counts have decreased by about 75 percent since 2008, from 1,600 rigs down to less than 250, as can be seen in Figure 9. An additional factor behind the phenomenon is the production of gas "associated" with the production of oil, which has been increasing as producers have been switching from gas-directed to oil-directed drilling. However, over the last few months, oil-directed drilling has been impacted by lower oil prices and the eventual outcome on "associated" gas is to be determined.

[36] See *So, where's the drop-off in U.S. gas production?*, Bob Gibb, Navigant NG Market Notes, July 2013, at 2.



Sources: Navigant / PointLogic

Figure 8: Eagle Ford Rig Efficiency



Source: Baker Hughes, U.S. E.I.A.

Figure 9: U.S. Gas Production and Rig Count History

The overall trend has been for drilling and completion costs to decline as producers gain knowledge of the geology, develop efficiencies and leverage investments in upstream drilling and completion activities across greater volumes of gas. For example, most shale gas plays appear to be economic today within the $2.00 to $5.00 per MMBtu range, which appears to have decreased somewhat from earlier analyses indicating a predominant range from about $3.00 to $5.00 per MMBtu.[37] Improvements continue in other

[37] See Range Resources, Company Presentation, April 28, 2015, citing Credit Suisse breakeven analysis as of Feb. 2015, at slide 15, and Keyera Corp. company presentation 5/17/12, citing Peters & Co. breakeven analysis as of Jan.

aspects of hydraulic fracturing technology, and recent initiatives taken by producers seem to address some of the more contentious issues, such as water use. "Waterless fracking" is an area in early deployment that can achieve fracking of gas shale by using compounds other than water, such as liquefied propane gas[38], cold compressed natural gas[39], or high pressure nitrogen.[40] Besides reducing issues related to water use, waterless fracking can also increase well yields.[41] These and other efforts to continue to improve water management will enhance the ability of shale operations to expand in both Canada and the U.S. in the future.

3.3 Modeling Overview

Twice a year, Navigant produces a long-term forecast of monthly natural gas prices, demand, and supply for North America. The forecast incorporates Navigant's extensive work on North American unconventional gas supply, including the rapidly growing gas shale supply resources. It projects natural gas forward prices and monthly basis differentials at more than 90 market points, and pipeline flows throughout the entire North American gas pipeline grid. Navigant's modeling uses a proprietary, in-house version of RBAC Inc.'s GPCM, a competitive, partial-equilibrium model that balances supply and demand while accounting for the costs and capacity of transport and storage. Since the current projections go only through 2035, Navigant extended the outlook in order to produce a monthly forecast through 2062 for purposes of this LNG Canada supply and demand assessment.

Throughout the outlook term, gas volumes (by state, province or region), imports and exports (including gas by pipeline and LNG by terminal), storage, sectoral gas demand, and prices are modeled on a monthly basis. Annual averages are generally presented for the purposes of this DGSR.

All North American supply in Navigant's modeling comes from currently established basins. The forecasts assume no new gas supply basins beyond those already identified as of mid-2014. This should be regarded as a conservative assumption, given the steady rate at which new shale resources have been identified over the past few years and the history of increasing estimates of the North American natural gas resource base. The impact of these conservative assumptions is that Navigant's price forecast is more likely to be overstated than understated versus the prices that ultimately occur.

Navigant's modeling is based upon the existing North American pipeline and LNG import terminal infrastructure (as well as Cheniere's under-construction Sabine Pass export terminal); augmented by certain planned expansions that have been publicly announced and have begun moving through the development process. Pipelines are modeled to have sufficient capacity to move gas from supply sources to demand centers. Some local expansions have been assumed and built into the model in future years to relieve expected bottlenecks. In these cases, supply has been vetted against Navigant's industry

---

2012 at slide 14. "Economic" referred to the breakeven gas price for production operations to yield rates of return of 10 percent (2012 analysis) or 15 percent (2015 analysis).

[38] Calgary's GasFrac developed a process that uses gelled propane rather than water as fracking fluid. www.gasfrac.com.

[39] Expansion Energy's VRTG process uses cryogenically processed natural gas from nearby wells or from the targeting formation itself as the fracturing medium, virtually eliminating chemical additives no longer needed to mitigate the impacts of water, according to www.expansion-energy.com.

[40] Baker Hughes' VaporFrac fracturing fluid is produced by pumping ultra-lightweight proppant slurry directly into a high-pressure nitrogen or carbon dioxide stream, nearly eliminating liquids disposal, according to www.bakerhughes.com.

[41] The German chemical company Linde AG reports that use of its technology to add nitrogen or carbon dioxide to the fracking mix reduces water requirements and increases gas yields. Linde Technology #1.12, The Linde Group, 2012, at p.22.

experience and market intelligence for reasonableness. For LNG export capacity, Navigant incorporates regional liquefaction capacity assumptions based on its assessment of regional project development status and market conditions.

In general, no publicly unannounced infrastructure projects have been introduced into the model. This means that no new infrastructure has been incorporated into the model post-2014, except as it directly supports the modeled export projects or had been announced at the time of our forecasting in mid-2014. This is a highly conservative assumption in that it is likely that some measure of new pipeline capacity will be constructed to support the ongoing development of the gas supply resource and the accompanying demand between 2014 and 2050, thereby facilitating supply and further moderating prices. In the absence of specific information, Navigant limits its infrastructure expansion to those instances where an existing pipeline has become constrained as determined by the model. The remedy consists of adding sufficient capacity to relieve the constraint only. The impact of these conservative assumptions is that Navigant's price forecast is more likely to be overstated than understated versus the prices that ultimately occur.

Some proposed pipeline projects have been excluded from Navigant's modeling, most notably the Mackenzie Pipeline in northern Canada, which we believe to be uneconomic to construct at this time, and for the duration of the study period, and faces other challenges. On the other hand, several large regional pipelines are assumed to be operational soon in other parts of the U.S., such as the Nexus Pipeline by 2017, which will help deliver Utica Shale gas from Ohio to Michigan and Ontario. The Nexus Pipeline project capacity is captured in the modeling.

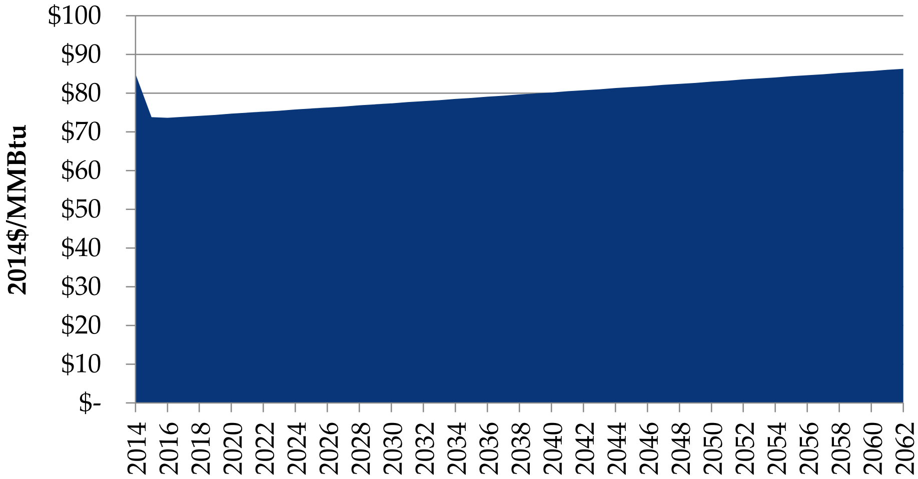
Storage facilities in the Navigant model reflect actual in-service facilities as of mid-2014, as well as a number of announced storage facilities that are judged likely to be in operation in the near future. No unannounced storage facilities were introduced into the model. The inventory, withdrawal, and injection capacities of storage facilities are based on the most recent information available, and are not adjusted in future years. Assuming no new storage facilities beyond those announced and judged likely to be built is a highly conservative assumption that in turn produces a gas forecast that is higher than prices that would be expected should more storage capacity than assumed actually be developed.

These highly conservative assumptions that limit future new pipeline and storage tend to put moderate upward pressure on prices as supply and demand grow, especially in the later years of the forecast.

3.4 Macro Assumptions

3.4.1 Oil Prices

Figure 10 shows the prices of West Texas Intermediate ("WTI") crude oil assumed in the model. The price of oil is assumed to escalate in a constant manner beginning in 2015. Prior to 2015, Navigant uses an average of settlement prices in the NYMEX WTI futures contract to establish a forward projection. The price of WTI in 2015 is $74 per barrel and $86 per barrel in 2062 (2014$).



Source: Navigant Year-End 2014 Outlook

Figure 10: WTI Price Assumed in Natural Gas Forecast

3.4.2 Economic Growth

Navigant uses gross domestic product ("GDP") figures from the U.S. Congressional Budget Office's Budget and Economic Outlook of February 2015 for the U.S. economic growth assumptions. To extend the outlook beyond the last year, the final year GDP of 2.0 percent is continued to the end of the forecast period. Table 6 shows these economic growth assumptions.

Table 6: Economic Growth Assumptions

2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025-2062
3.19%	3.50%	3.01%	2.41%	2.30%	2.26%	2.20%	2.15%	2.09%	2.01%	2.0%

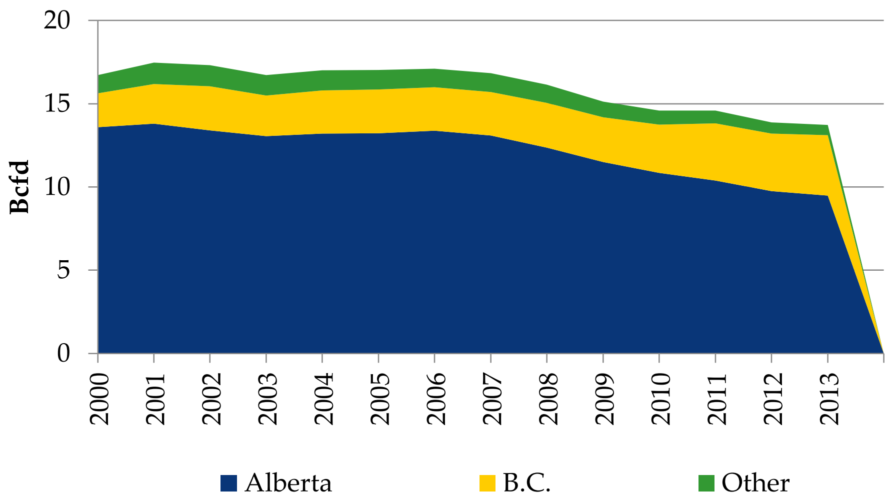
3.5 *Supply*

3.5.1 Background

From a historical perspective, the peak of Canada dry gas production occurred in 2001 at 17.5 Bcfd, as can be seen in Figure 11.[42] Since then, Canadian production gradually fell off to an average rate of 16.9 Bcfd in 2007, and continued the trend afterwards, dropping more steeply to 13.9 Bcfd in 2012.[43] Alberta contributed to virtually the entire production decline since 2007.

[42] NEB data.

[43] Id.



Source: NEB

Figure 11: Historical Canadian Natural Gas Production

Since 2002, total production in British Columbia was stagnant through 2009. During this period, the reserves inventory was rebuilt to a level that could support growth for a substantial period of time. Meanwhile, Horn River and Montney, the two large unconventional shale and tight sands plays, began to develop. Production began to rapidly increase in the second half of 2010, growing to 4 Bcfd by the end of 2014, as is indicated by Figure 3. Navigant forecasts sustained long-term growth of British Columbia production as a result of the Montney and Horn River development, which will be positively impacted by the prospect of a new gas market such as offered by the Project.

In Alberta, gas production peaked around the turn of the century, averaging 5.1 Tcf per year.[44] Between 2002 and 2007, annual production in the province slowly dropped to 4.8 Tcf, then fell more steeply to 3.5 Tcf in 2013, before slightly rebounding in 2014.[45] From 2006 to 2012, Alberta gas drilling activity fell sharply by more than 80 percent.[46] As noted by the NEB in its recent Energy Briefing Note, "[g]as prices were not high enough for companies to cover costs except for a few plays in Western Canada."[47] Looking into the future, Navigant has forecast continued stagnation of non-associated gas production in Alberta, driven by lower prices in the Alberta basin resulting from competitive supplies, and general diminished economics. Coal bed methane will play a role in slowing down the production decline. Despite the recent trend, it should be remembered that the magnitude of natural gas production in Alberta is still by far the largest in Canada, and will continue to be until 2025. Further, as noted, Navigant anticipates that the outlook for Alberta may improve as prospective unconventional plays start to produce gas and are brought into our forecast, particularly as new demands such as LNG Canada help to expand the opportunity for ongoing supply development.

---

[44] *Canada's Energy Future: Energy Supply and Demand Projections to 2035*, National Energy Board, November 2011, at Table A4.2.

[45] NEB data.

[46] See TransCanada presentation "Western Canada Winter 2012-2013 Gas Supply Update", slide 10 on wells drilled.

[47] *Canadian Energy Overview 2012, Energy Briefing Note*, NEB, 2013, at 3.

Navigant forecasts a continuation of the recent rebound of Canada gas production as a result of several factors, including growing British Columbia shale gas production, as well as associated gas production from oil production in Alberta and Saskatchewan. In total, gas production increases originate primarily from Western Canada.

In developing its gas production forecast, Navigant's basic modeling assumption, based on industry observations, is that natural gas supply will respond dynamically to demand in a reasonably short time—months, not years. The shale gas resource is furthermore so large that it can be readily produced more or less on demand in sufficient quantities to meet all presently expected gas demand levels if economics and policy are supportive.

3.5.2 Forecast

As indicated in Figure 12, Navigant forecasts a strong increase for Canadian dry gas production of 57 percent between 2015 and 2062 (from 15.2 to 23.9 Bcfd), driven by the significant increases in British Columbia shale gas production that build on the roughly level conventional natural gas production in Alberta. Navigant forecasts B.C. shale gas production to increase 344 percent between 2015 and 2062 (a 3.2 percent compound annual growth rate), increasing from 2.7 Bcfd (18 percent of total national production) to 12.0 Bcfd (50 percent of total national production). Alberta production, on the other hand, is forecast to decrease about five percent over the same period, from 9.4 Bcfd (62 percent of total national production) to 8.9 Bcfd (37 percent of total national production).

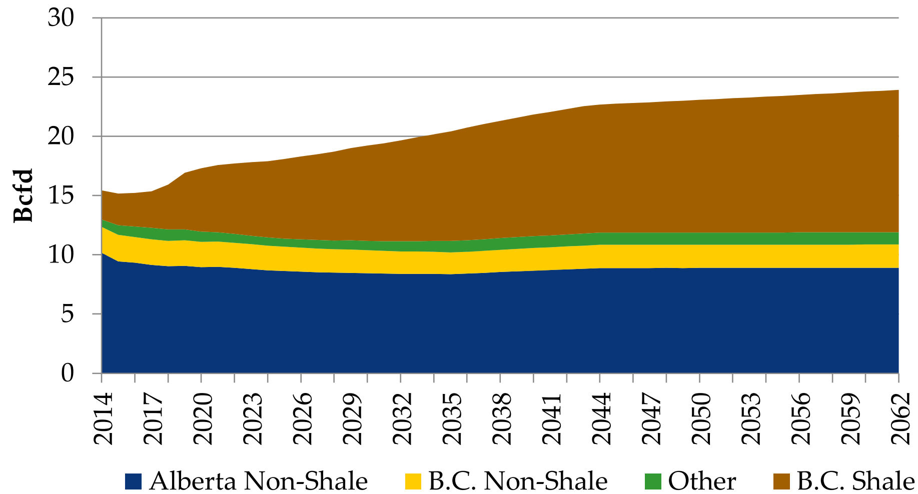
It should be noted that because of the conservative approach used by Navigant in its treatment of shale play development, modeled market clearing volumes are likely on the low side. Specifically, Navigant does not recognize prospective shale plays for purposes of modeling supply until a play is actually producing natural gas. Given the pattern of development and production in shale plays, it is likely that additional plays will be developed, and that supply curves in existing plays will be pushed out in recognition of increased production activity. With the large unconventional resource endowments estimated in Alberta, such as the Duvernay's 113 Tcf of recoverable natural gas estimated in the U.S. E.I.A. Assessment[48], or the Montney's 2,133 Tcf of gas-in-place estimated by the province's Energy Resources Conservation Board[49] (now, the Alberta Energy Regulator), Alberta should be favorably positioned for a ramping up of unconventional production, especially given its strong existing infrastructure base of pipelines and processing capacity. Also important in driving the production forecast is the demand forecast, since equilibrium levels are determined by the interplay of supply and demand. It should be remembered that an increase in the assumed LNG exports beyond those assumed by Navigant (*i.e.* 2 Bcfd from Canada, and 9.3 Bcfd from North America overall) would result in a higher production forecast than reflected in Figure 12.

While Navigant's production outlook in Alberta currently appears lackluster, Navigant expects its future outlooks to likely be higher as new plays and additional markets are developed and impact the modeling assumptions. In comparison, British Columbia has already started to show strong potential for future growth, as noted in Section 3.5.1, with the forecast continuation of the trend shown in Figure 12.

---

[48] See discussion on page 10, supra, of the U.S. E.I.A. Assessment.

[49] See *Summary of Alberta's Shale and Siltstone-Hosted Hydrocarbon Potential*, Energy Resources Conservation Board, October 2012, at p.xi, reporting the median estimate of Montney resource endowment (gas-in-place) in Alberta of 2,133 Tcf, 4.8 times the amount of its 443 Tcf estimate for the Duvernay gas-in-place.



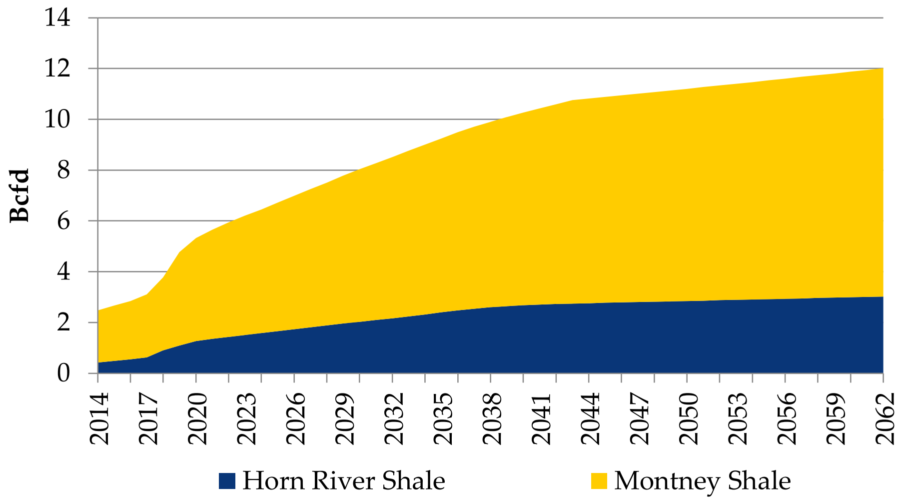
Source: Navigant Year-End 2014 Outlook

Figure 12: Canadian Dry Gas Production Forecast Breakout

The modest conventional production occurring in B.C. is forecast to hold steady at about 2.0 Bcfd, dropping from 15% of national production in 2015 to 8% in 2062. Production in the balance of Canada (outside of B.C. and Alberta) is forecast to slightly increase, though it will still be only about 4.4 percent of total national production in 2062.

As evident in Figure 12, the growth in B.C. shale gas production is forecast to build on the somewhat stabilized conventional natural gas production in both Alberta and B.C.[50] Navigant's B.C. shale forecast is based on the existing Horn River and Montney plays, whose forecast production is shown in Figure 13.

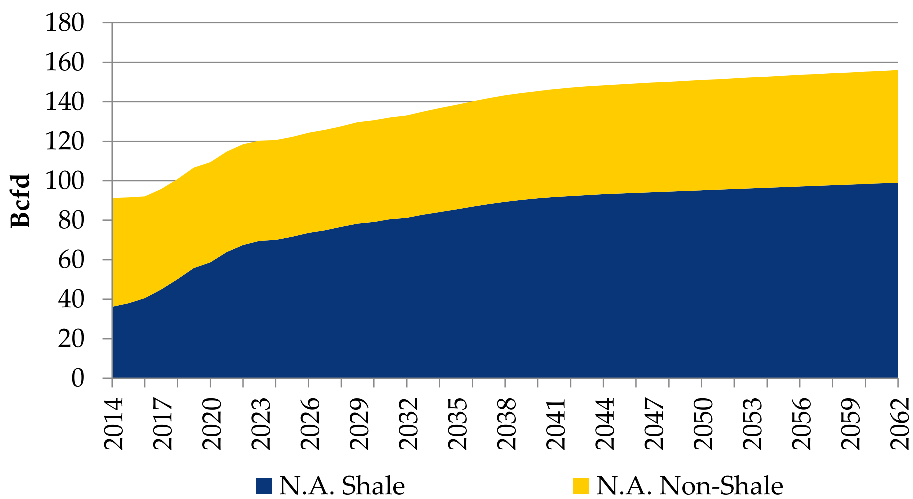
[50] Navigant's modeling does not currently include forecast shale production from Alberta, as Alberta shale plays, such as the Duvernay, are only prospective. However, forecasts of Alberta shale production have been produced by others, such as EnCana. An EnCana presentation (*The Future of Canadian Natural Gas and Natural Gas Liquids*, May 8, 2012, p.19) includes a chart of forecast WCSB natural gas production showing the Duvernay reaching about 2.5 Bcfd, from zero at the time of the presentation, by 2025.



Source: Navigant Year-End 2014 Outlook

Figure 13: Canadian Shale Gas Production Forecast

Similar to Canada, total North American shale gas production will add a significant amount of incremental gas supply on top of stagnant to slightly declining conventional production. Figure 14 highlights the 160 percent increase in North American shale gas production from 37.9 Bcfd in 2015 to 98.9 Bcfd in 2062, leading to an overall 70 percent increase in total North American production from 91.6 Bcfd in 2015 to 156.0 Bcfd in 2062, at which point shale gas will account for 63 percent of North American gas production. As with the likely future increase in forecast Canadian production due to the development of Alberta unconventional resources, the North American forecast will likely increase further as other basins yet to be discovered are developed and begin producing associated gas or unassociated gas.

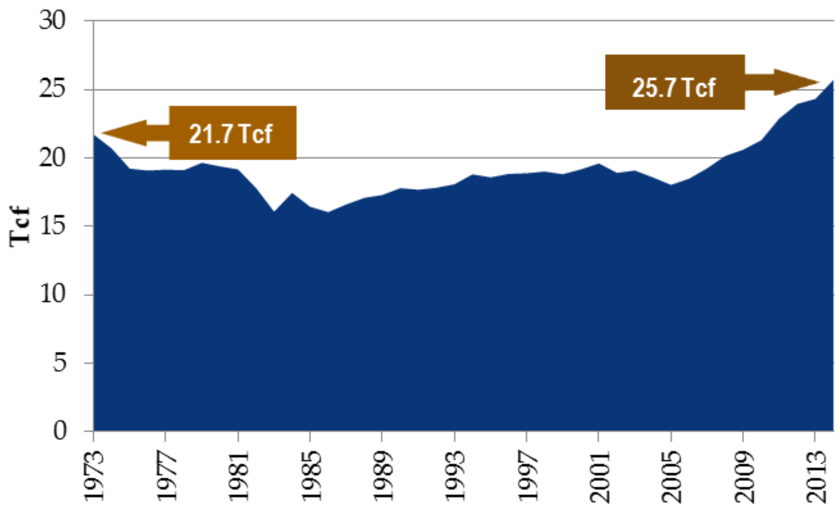


Source: Navigant Year-End 2014 Outlook

Figure 14: North American Natural Gas Production Forecast

The strong forecast trajectories of increases in gas production, for both Canada and North America, are consistent with the trend already seen over the last 5-8 years in the U.S., corresponding to the start of the shale revolution. Figure 15 shows the impact of the shale revolution on gas production, with total U.S. natural gas production now at all-time high levels that finally surpassed prior highs from 40 years ago. The steep increase in actual production of 39 percent over the last eight years has been due to growth in shale gas production, and underlies Navigant's basic modeling assumption in developing its gas production forecast that natural gas supply will respond dynamically to demand in a reasonably short time—months, not years.

.



Source: Navigant / U.S. E.I.A.

Figure 15: Annual U.S. Natural Gas Production History

3.6 Demand

3.6.1 Background

Navigant's forecast of natural gas demand in Canada and North America extends out through 2062. The demand outlook is developed for individual sectors, including residential, commercial, industrial, power generation and others (vehicles, pipeline fuels, etc.). LNG exports are not included within any categories of demand discussed here.

Table 7 shows assumed growth rates for key segments of Canadian natural gas demand. Total Canadian demand growth is driven by growth in electric generation gas consumption at 3.2 percent per year and industrial growth at 1.4 percent per year. On the other hand, commercial and residential demand grows at only 0.4 percent per year. These rates result in a moderate growth rate in total Canadian domestic natural gas demand at 1.4 percent per year over the forecast period.[51] The most significant gas-consuming province is Alberta, where the underlying demand forecasts include strong growth of electric generation gas consumption at 3.1 percent per year, industrial growth (including oil sands) at 2.0 percent

[51] We are aware that the NEB requested sensitivity analyses of 20 percent higher demand growth rates from other applicants. See discussion on page 37.

per year, and residential and commercial growth at 0.4 percent per year. Navigant expects the relationship between Alberta's oil sands and natural gas developments to strengthen in the future, with bitumen producers significantly increasing their natural gas consumption in order to fuel their rising output. Alberta's overall gas demand growth rate is 1.6 percent per year.

Table 7: Average Annual Gas Demand Growth Rates for Key Demand Segments

Demand Segment	Avg. Annual Growth Rate
Canada-Electric Generation	3.2%
Canada-Industrial	1.4%
Canada-Residential/Commercial	0.4%
Canada-Total	1.4%
Alberta-Electric Generation	3.1%
Alberta-Industrial	2.0%
Alberta-Residential/Commercial	0.4%
Alberta-Total	1.6%

Source: Navigant

Forecasts of residential and commercial demand are derived from gas price, weather and provincial customer counts or GDP. The weather assumptions used to build the demand curves in GPCM are based on 30-year average weather from 1981 through 2010.

To estimate natural gas demand for power generation, Navigant utilizes its internal modeling tools to generate the forecast, based on outlooks for electricity sales and generation in Canada. Navigant's proprietary Portfolio Optimization Model ("POM") is a capacity expansion model suitable for risk analysis that incorporates the same generation base, electric demand and other assumptions that are utilized in Navigant's electric market model reference cases using the licenced *PROMOD* software model. POM is a linear program that dynamically solves for the multi-decade planning horizon to simulate economic investment decisions and power plant dispatch on a zonal basis subject to capital costs, reserve margin planning requirements, renewable portfolio standards, fuel costs, fixed and variable O&M costs, emissions allowance costs, and zonal transmission interface limits. It includes a multi-regional representation of the North American electric system with constraints on inter-zonal transmission, and has every individual generating unit specified allowing for state-by-state reporting of generation data.

POM also allows for incorporation of such issues as the relative attractiveness of gas-fired generation to facilitate the reliable integration of the large amounts of new renewable generation from wind and photovoltaics into the electric supply mix[52], the relatively favorable GHG impact of gas-fired generation, and the recent trend in coal-to-gas fuel "switching" for power generation. These considerations all generally lead to increases in the use of gas-fired generation in North America.

---

[52] For the support of wind and solar generation, dispatchable gas-fired generation is ideal to "shape" the output profile of power supplies by following load variations, as well as to "firm" or support the intermittency of both these forms of renewable electric generation by providing available peaking capacity. For 'shaping' purposes for the development of the emerging wind industry, natural gas looks to be critical to wind industry development.

Table 8 shows the trends in fuel source estimated by POM for Canadian power generation, through 2035. The forecast is for the gas-fired generation portion in Canada to triple by 2025, with a 250 percent increase by 2035, more than doubling coal generation by 2025 and exceeding it by a factor of seven by 2035.

Table 8: Canadian Generation by Fuel Source

Fuel	2015	2025	2035
Gas	6%	18%	22%
Coal	10%	7%	3%
Oil	0%	0%	0%
Nuclear	17%	11%	11%
Hydro	59%	55%	51%
Wind	6%	7%	10%
Solar	0%	0%	1%
Biomass	2%	1%	1%

Source: Navigant

Low gas prices, environmental regulations, and reduced nuclear and coal generation are forecast to cause strong growth in gas demand for power generation in Canada. Over the years 2015 to 2035, total gas generation increases more than four times to 155,000 GWh from 32,000 GWh.[53] Overall installed capacity of combined cycle units nearly doubles while capacity of combustion turbine units nearly triples. Gas consumption rises to about a quarter of Canadian generation. The combined cycle units provide the vast majority of the generation as the capacity factors of existing units increases dramatically combined with the doubling of installed capacity. The combustion turbine units generally provide support for non-dispatchable renewables.

The abundance of reliable and economic supply options is a key supply-side factor enabling steadily growing gas demand. With the advent of significant shale gas resources, end-use infrastructure and pipeline project developers can be assured that gas will be available to meet growing market demand. Further, the prospect of steadily growing and reliable supply portends relatively low price volatility. Because of the manufacturing-type profile of shale gas production, production rates can be better matched to demand growth. Lower price volatility, like supply growth, is supportive of long-life end-use infrastructure development and pipeline and mid-stream processing projects to meet increasing demand.

3.6.2 Forecast

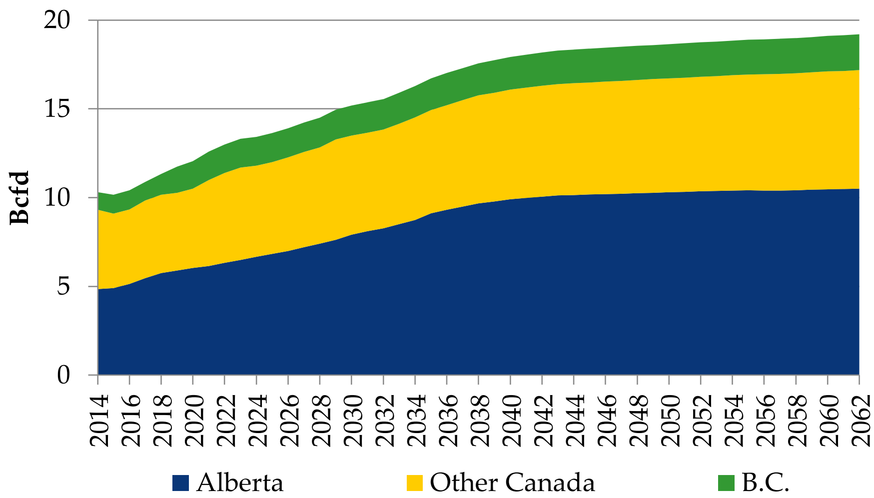
As indicated in Figure 16, Navigant's forecast of Canadian natural gas demand shows a strong increase from 10.2 Bcfd in 2015 to 19.2 Bcfd in 2062, an increase of 88 percent. Comparing Navigant's forecast through 2035 to the NEB's latest forecast (2013 vintage, extending only through 2035) shows a 64 percent increase (from 10.2 to 16.7 Bcfd) for Navigant versus the NEB's 50 percent increase (from 10.4 to 15.5 Bcfd)[54]. In the context of a surplus gas assessment (discussed in Section 3.8), Navigant's higher demand

---

[53] Breakdowns from POM end at 2035. Thereafter, Navigant's gas modeling assumptions for power generation use trend analysis rather than power modeling.

[54] NEB Energy Future 2013, supra note 17.

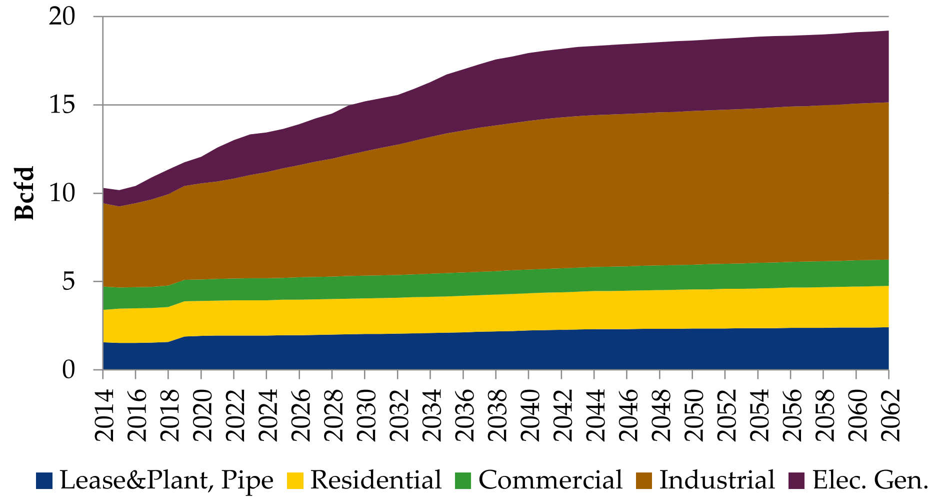
forecast would lead to a more conservative surplus assessment than would the NEB's demand forecast. The largest provincial increase in Navigant's forecast occurs for Alberta, where total demand increases 114 percent from 4.9 Bcfd (48 percent of total national demand) to 10.5 Bcfd (55 percent of total national demand) in 2062.



Source: Navigant Year-End 2014 Outlook

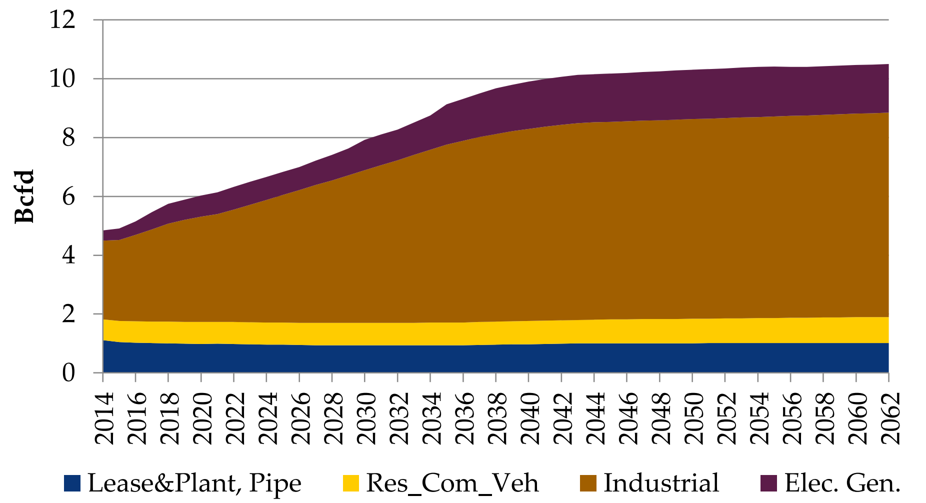
Figure 16: Canadian Natural Gas Demand Forecast, by Location

The largest increases by Canadian demand category over the forecast period are for industrial use (including oil sands), increasing 93 percent from 4.6 Bcfd to 8.9 Bcfd, and for electric generation requirements, increasing 355 percent from 0.9 Bcfd to 4.1 Bcfd, as shown in Figure 17. Alberta represents the bulk of growth in these categories, which are detailed in Figure 18. In Alberta, industrial demand is forecast to increase 150 percent from 2.8 Bcfd (60 percent of Canadian industrial demand and 57 percent of total Alberta demand) to 7.0 Bcfd (78 percent of Canadian industrial demand and 67 percent of total Alberta demand). For electric generation requirements, Alberta gas demand is forecast to increase 325 percent from 0.4 Bcfd (42 percent of Canadian electric generation requirements and 8 percent of total Alberta demand) to 1.7 Bcfd (41 percent of Canadian electric generation requirements and 16 percent of total Alberta demand). How regional demand plays out in the overall Canadian supply-demand balance is discussed in Section 3.9.



Source: Navigant Year-End 2014 Outlook

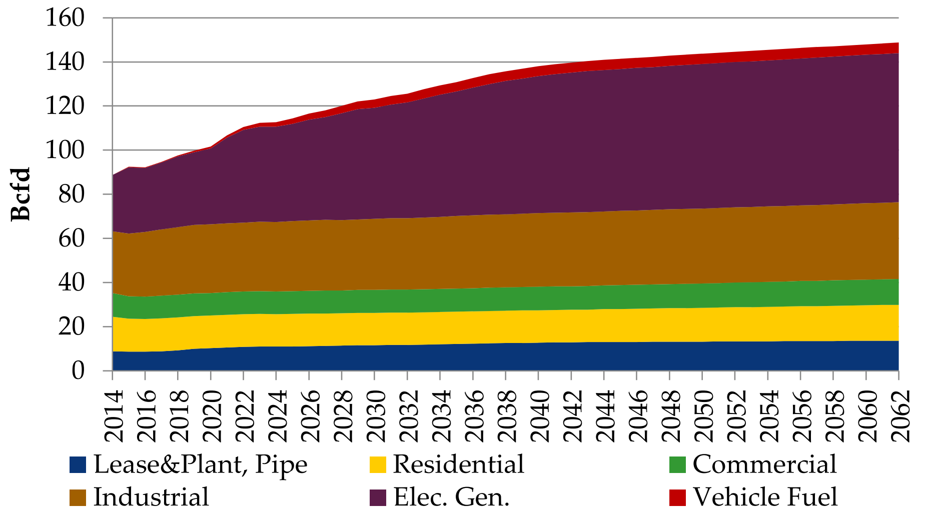
Figure 17: Canadian Natural Gas Demand Forecast, by Type



Source: Navigant Year-End 2014 Outlook

Figure 18: Alberta Natural Gas Demand Forecast, by Type

North American natural gas demand is forecast to increase 62 percent, as shown in Figure 19.



Source: Navigant Year-End 2014 Outlook

Figure 19: North American Natural Gas Demand Forecast

3.7 Risks to the Supply and Demand Forecasts

While the gas supply outlook is strong, and Navigant expects that production will have the capacity to grow, there are risks in the development of the resource that could impact the outlook.

3.7.1 Environmental Issues

Hydraulic fracturing of shale formations to produce gas (or oil) has become a topic of discussion inside and outside the industry. Concern has been raised over its possible environmental impact resulting from water use, water well contamination, and water and chemical disposal techniques. However, the industry has taken positive steps to address the issue of potential water contamination. For example, *FracFocus.ca*, a voluntary registry for disclosing hydraulic fracturing chemicals, has been formed. B.C and Alberta require the disclosure of hydraulic fracturing chemicals on *FracFocus.ca*. Also, the NEB announced its own planned requirement for NEB-regulated companies to participate in the FracFocus.ca website.[55] The Canadian Association of Petroleum Producers has adopted Canada-wide operating guidelines for hydraulic fracturing designed to improve water management and fluids reporting.[56] While some jurisdictions have placed moratoria on fracking (*e.g.* New York state), such action would appear unlikely in B.C and Alberta, where policy, history and economics favor development.

The area of greenhouse gas emissions is a potential risk factor on natural gas demand, although it appears that a regulatory approach has been implemented, aimed specifically at providing regulatory certainty.[57] Current Canadian regulations call for new performance standards for coal-fired power

---

[55] See November 27, 2013 NEB press release, “National Energy Board to Join Fracfocus.ca”, announcing plans to request NEB-regulated companies, i.e. those involved in oil and gas exploration and activities on certain frontier lands and offshore areas not covered by federal/provincial management agreements, to disclose information on hydraulic fracturing practices and fluids on the Fracfocus.ca website within 30 days of completion of operations.

[56] Canadian Association of Petroleum Producers, Press Release, January 30, 2012.

[57] See Environment Canada website, “Questions and Answers: Reduction of Carbon Dioxide Emissions from Coal-Fired Generation of Electricity Regulations”.

plants that are either new or at the end of their useful life (generally 50 years), effective July 1, 2015. The regulations call for a performance standard at 420 tons per GWh, the emissions intensity of high efficiency natural gas combined cycle technology, and are aimed at a "permanent transition towards lower or non-emitting types of generation such as high-efficiency natural gas and renewable energy."[58] The emissions profile of natural gas provides a clear advantage versus other fossil fuel, including coal. The increasing displacement of coal use by natural gas will be a positive development for the environment and will likely lead to increased gas development.

3.7.2 Market Issues

The current environment of supply abundance creates the potential for an unbalanced market that could potentially lead to stagnation of gas asset development. However, LNG exports can be an important contributor to the long-term sustainability of the gas market by contributing to demand levels that will incent important production and distribution investments. LNG exports might even overtake fuel switching from coal plant retirements as the primary incremental natural gas demand for balancing current oversupply conditions.

More specifically, Western Canadian gas development, and hence projected Canadian natural gas production, could be at risk in the event sufficient incremental natural gas demand does not develop. This is primarily due to the competitiveness of U.S. shale gas supplies, especially in the burgeoning Marcellus, capturing larger shares of the U.S. market, which is discussed in more detail in Section 3.9. The new demands sought by the B.C. and Alberta governments, discussed in Section 3.2.1.1 of the Report, are thus key in supporting the further development of the Canadian natural gas industry.

Other factors that could impact the assumptions or outlook include potential shortages of the skilled labour necessary to build and operate natural gas facilities, which could increase costs and slow development. Uncertainties in the ultimate trajectory of oil sands development and gas-fired power generation development create uncertainties in the associated demands for natural gas, just as uncertainties in well productivity create uncertainties on the supply side. As an upside, it has generally been the case that resource discovery continues, and that new plays, currently undiscovered or uneconomic, will enter the supply portfolio. To the extent infrastructure becomes a limiting factor, it could delay development, although fundamentals should be expected to drive appropriate infrastructure investment. Finally, the outcome of U.S. LNG export project approval and development could impact the market by affecting demand. At this time, however, it appears the U.S. DOE and FERC are moving forward with final site and export approvals. FERC has recently issued final site approval of four additional projects beyond the under-construction Sabine Pass project, and DOE has issued a final export authorization for each of them.[59]

3.8 *Supply-Demand Balance*

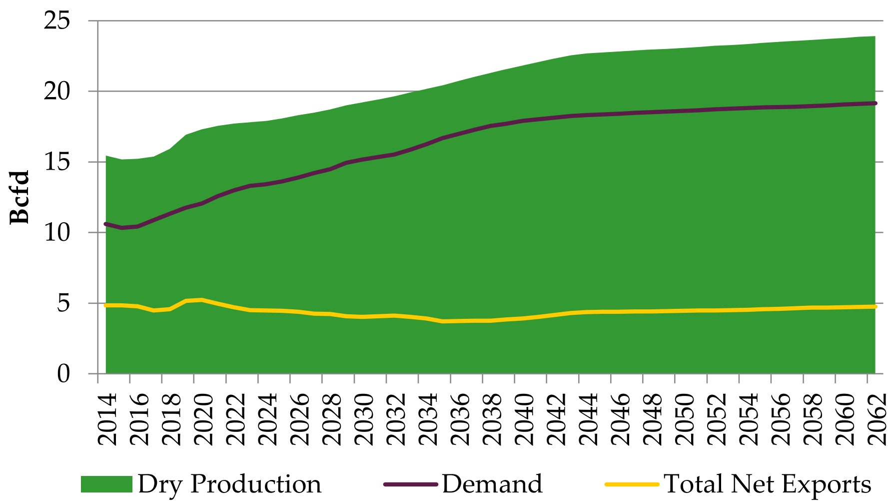
3.8.1 Base Case

The forecast of total Canadian dry gas production (already introduced in Section 2.5, above) is shown in Figure 20 along with total domestic Canadian natural gas demand. As can be seen, the production

[58] Id.

[59] Freeport LNG Expansion, Dominion Cove Point LNG, Cameron LNG, and Corpus Christi Liquefaction.

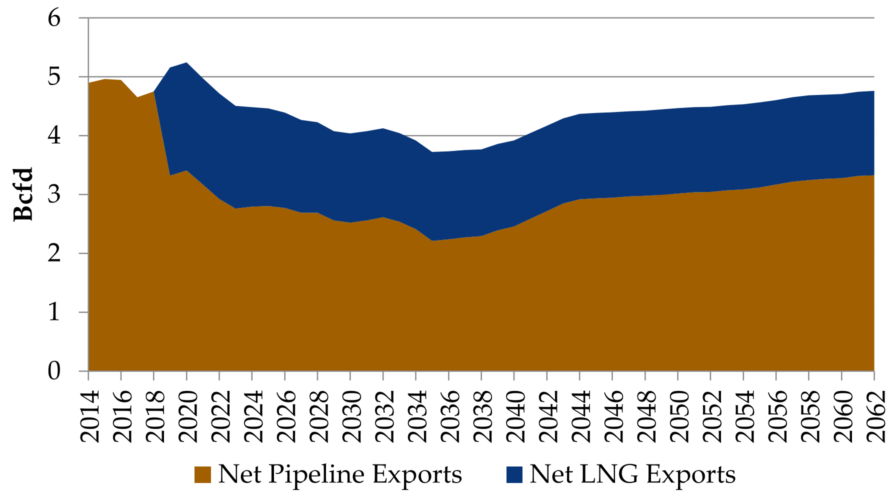
forecast compared to the demand forecast yields a relatively stable range of net exports (by pipeline or LNG liquefaction) over the term of the forecast at between about 4 Bcfd and 5 Bcfd, averaging 4.4 Bcfd (representing an average of about 21 percent of national production). Thus, strong production growth is clearly able to meet increasing Canadian demand. Also, the annual average levels of net exports from Canada are sufficient to meet the 3.72 Bcfd export quantity applied for by the Project throughout the forecast term. As noted in Section 3.7.2, fostering the strong production forecast would actually benefit from expansion of demand (beyond levels assumed in Navigant's modeling). In fact, additional assumed LNG exports will help facilitate the development of additional resource plays as described in Section 3.5.2 (*e.g.* Alberta unconventional resources), leading to production beyond that currently reflected in Navigant's modeling.



Source: Navigant Year-End 2014 Outlook

Figure 20: Canadian Supply-Demand Balance

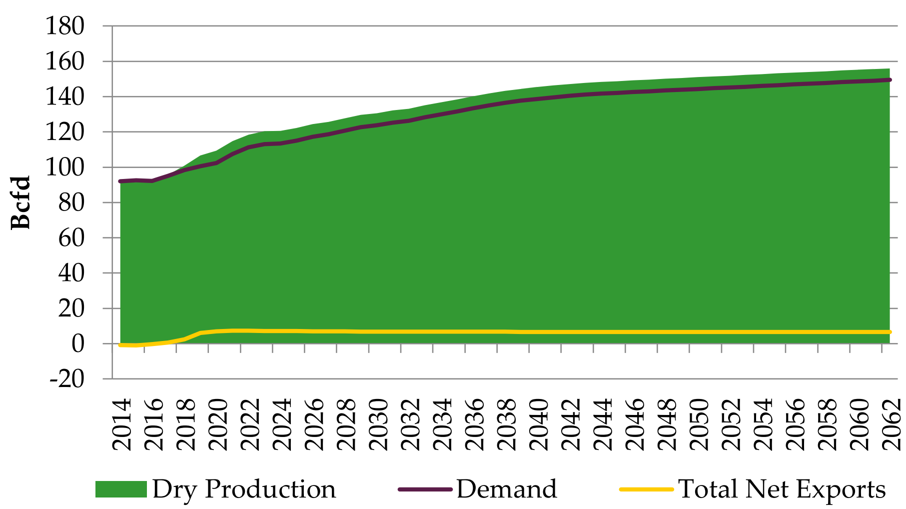
The components of net total exports are shown in Figure 21. Net pipe exports to the U.S. initially diminish as Canadian LNG exports ramp up and deliveries into the U.S. decline, but then start an increasing path to over 3.0 Bcfd for more than the last ten years of the forecast. The positive (and increasing) level in the net pipe exports indicates the proper functioning of the North American integrated market, as well as the "surplus" nature of Canadian supplies. In fact, Figure 21 indicates that additional Canadian demand (reflected by the level of forecast net pipe exports from Canada, which could be alternatively used to meet additional Canadian demand) could be accommodated without even increasing Canadian natural gas production beyond the reference case. In 2062, the 3.3 Bcfd of net pipe exports represents such an additional increment of demand beyond the reference case, which itself already includes net LNG exports from Canada of 1.4 Bcfd.



Source: Navigant Year-End 2014 Outlook

Figure 21: Net Canadian Pipe and LNG Export Forecast—Reference Case

With respect to the North American supply-demand balance, Figure 22 shows that supply is sufficient to meet demand, as well as some exports. The assumed level of ultimate LNG exports in Navigant's Mid-Year 2014 Outlook was about 9.3 Bcfd from North America. Based on the gas resource endowments and supply curves characterizing the North American market, higher volumes of LNG exports are capable of being cleared through the market, as shown by various studies examining the impacts of LNG exports, described below.



Source: Navigant Year-End 2014 Outlook

Figure 22: North American Supply-Demand Balance

For example, the U.S. Energy Information Administration's Annual Energy Outlook 2015 includes U.S. LNG exports of 9.3 Bcfd by 2030 (versus Navigant's 7.3 Bcfd of U.S. LNG exports), with Henry Hub prices in 2030 at $6.60 per MMbtu.[60] In addition, in the LNG export study commissioned by the U.S. D.O.E. and released in December 2012 ("NERA Report"), which examined North American gas pricing impacts in a variety of scenarios of export levels and other assumptions, included a scenario assuming high shale EUR[61] plus international supply and demand shocks with no explicit constraint on LNG exports. This scenario resulted in LNG exports ranging between about 11.5 Bcfd and 23 Bcfd (averaging 17.4 Bcfd), with wellhead prices remaining under $6.00 per MMBtu for the entire forecast period through 2035.[62] We mention this not because we believe exports will reach those levels, but to illustrate that much higher levels of exports than those assumed by Navigant have been modeled without indications of market dysfunction or disruption or indeed excessively high prices.[63]

It is important to recognize that North American LNG exports will occur within a global marketplace, with a supply-demand balance that accounts for international competition. Consequently, it should be expected that only some portion of incremental international LNG liquefaction capacity will be built in North America, and consequently that only some portion of proposed North American facilities will be built. Looking at potential North American LNG export facilities relative to the anticipated growth of the global LNG market illustrates this point. BP's Energy Outlook 2035 estimates global LNG exports at about 78 Bcfd in 2035[64], while Navigant estimates global liquefaction capacity in 2035 of current (operational plus under construction) projects at about 61 Bcfd.[65] Grossing up demand for a 90 percent utilization factor (to 87 Bcfd) means new liquefaction capacity of about 26 Bcfd would be needed worldwide by 2035, based on these projections. Even if all new global capacity were to be located in North America, a virtual impossibility, that would still be less than 30% of all project capacity approved and applied for in North America[66]. Therefore, it is safe to assume that most LNG liquefaction projects currently being proposed in North America will not be built.

3.8.2 Additional Scenario

As noted in footnote 51, we are aware of the NEB's requests to other applicants for sensitivity analyses representing approximately 20 percent higher Canadian demand growth rates. In order to evaluate such a "plus 20 percent" sensitivity, and to specifically incorporate the Project into the modeling, Navigant performed an additional modeling scenario to reflect: 1) average annual Canadian demand growth 1.85, which is actually 29 percent greater than the 1.4 percent average annual growth rate in the reference

---

[60] U.S. Energy Information Administration, Annual Energy Outlook 2015, p. 22 and Table A13.

[61] EUR stands for Expected Ultimate Recovery, a measure of well production levels.

[62] *Macroeconomic Impacts of LNG Exports from the United States*, NERA Economic Consulting, December 2012, at 156.

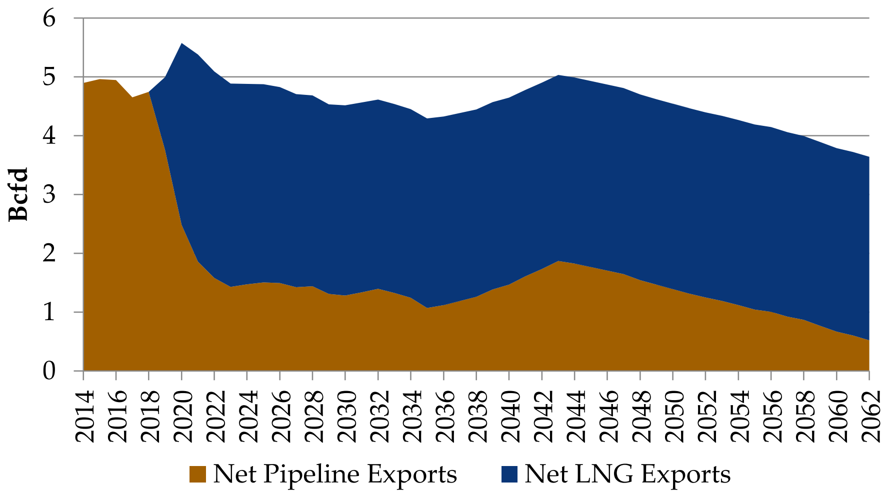
[63] Indeed, an update of the NERA Report, commissioned by Cheniere Energy, Inc. and released February 20, 2014, reinforces the results of the D.O.E.-commissioned NERA Report, finding that the U.S. could export more LNG at lower prices than originally estimated. In fact, a similar scenario of high resource assumptions plus international supply and demand shocks resulted in LNG exports ranging from 18 to 53 Bcfd (averaging 35 Bcfd), with wellhead prices remaining under $4.50 per MMBtu for the entire forecast period through 2038. *Updated Macroeconomic Impacts of LNG Exports from the United States*, NERA Economic Consulting, February 20, 2014, at 12 and 208.

[64] *BP Energy Outlook 2035* (February 2015), slides 51 and 58. Estimated gas consumption in 2035 at 490 Bcfd, with LNG share of gas consumption at about 16% in 2035, yielding estimated LNG demand in 2035 of about 78 Bcfd.

[65] Based on 307.1 mtpa of existing capacity and 158.0 mtpa of under-construction capacity, using an assumed conversion of 7.6 mtpa per Bcfd.

[66] Estimated capacity is about 48 Bcfd for 22 Canadian projects and about 47 Bcfd for 28 U.S. projects.

case[67], and 2) assumed gross LNG exports from Canada reaching 3.72 Bcfd (up from 2 Bcfd), reflecting the export quantities sought by LNG Canada for the Project. With the increased demand growth rates, total Canadian natural gas demand in 2062 increased from 19.2 Bcfd in the reference case to 23.1 Bcfd. The supply-demand balance that resulted from this scenario is shown in Figure 23, and yields annual average levels of net pipeline exports to the U.S. (i.e. production that is surplus to both Canadian demand and LNG exports from Canada) of 1.7 Bcfd, with positive figures every year. These results indicate the surplus nature of Canadian natural gas supply even in the scenario of "plus 20 percent" demand growth rates, and with the assumption of LNG exports in the quantity sought by the Project.



Source: Navigant Additional Scenario

Figure 23: Net Canadian Pipe and LNG Export Forecast--Additional Scenario

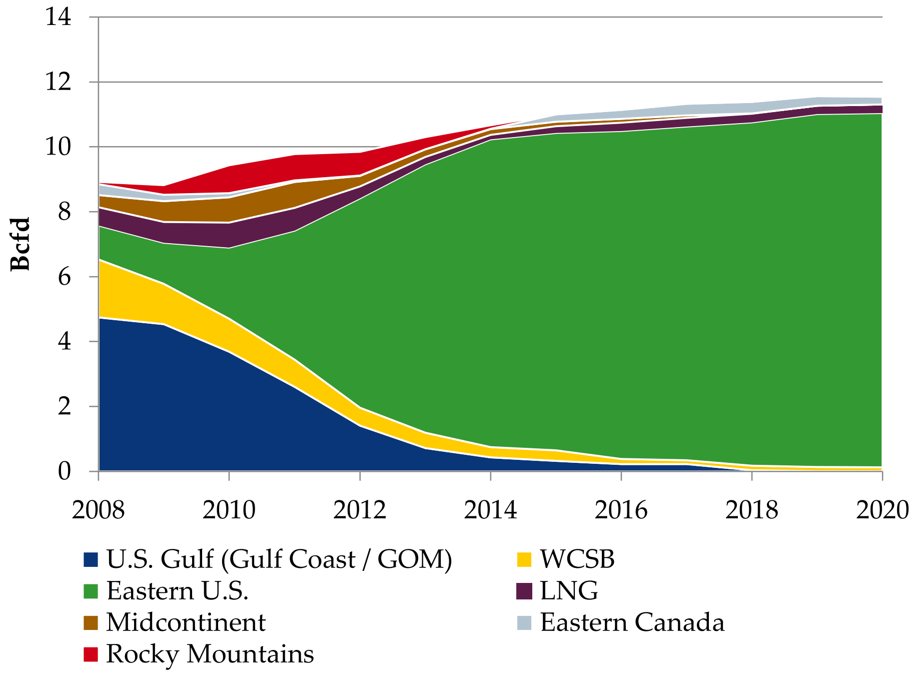
3.9 Inter-Regional Patterns

The rapid growth in shale gas production, coupled with conventional gas production declines, has increased gas-on-gas competition and has already started to cause changes in the traditional gas flow patterns across North America.[68] An indicator of this dynamic is the change in supply patterns to the U.S. Northeast market, as can be seen in Figure 24. With the strong development of the Marcellus play after 2008, a clear displacement of other gas supply sources to the Northeast is evident. Particularly hard hit have been the U.S. Gulf region and the Western Canadian Sedimentary Basin, whose shares have dropped by a 49 percent share (a 92 percent reduction) and a 17 percent share (an 85 percent reduction), respectively, since 2008.[69] Navigant forecasts both production regions to continue to decline in shipments to the Northeast. Such basin displacement is an example of the competitive pressure WCSB resources face from U.S. plays that have geographic and infrastructure advantages.

[67] Increasing the Canadian demand growth rate by a given percentage involves an iterative modeling process. In order to ensure meeting the objectives of a "plus 20 percent" scenario, the modeling results actually represent a 29 percent increase in the base case average growth rate for total Canadian demand.

[68] See e.g. *Shifting Gas Flows*, NG Market Notes, Navigant Consulting, September 2013.

[69] Gulf share dropped from 53 percent to 4 percent; WCSB share dropped from 20 percent to 3 percent.



Source: Navigant Year-End 2014 Outlook

Figure 24: U.S. Northeast Natural Gas Demand by Sourcing Area

The NEB noted the new market dynamics in Energy Future 2013, referencing that increasing production in the Marcellus has reduced the need for Canadian exports to the U.S. Northeast; a market traditionally served in part by WCSB gas[70], and has led to increasing imports into Canada from the U.S.[71] LNG Canada plans to capitalize on this displacement of Canadian gas from traditional U.S. and Canadian markets by using Canadian gas as its LNG feedstock.

These changes are evidenced by infrastructure developments occurring in the U.S. Northeast. For example, at least three major pipeline expansions or extensions to move U.S. gas into eastern Canada have entered the execution phase of development: Spectra's Nexus Pipeline (2 Bcfd), Energy Trading Partners' Rover Pipeline (3.25 Bcfd, with 1.3 Bcfd to Dawn fully subscribed), Tennessee Gas Pipeline's Niagara Expansion (158 MMcfd), and Algonquin's Atlantic Bridge (500 MMcfd) and Incremental Market (342 Bcfd) projects.[72] In addition, numerous other projects to serve U.S. Northeast markets with Appalachian Basin U.S. gas are in various stages of development, including: Williams Companies' Constitution Pipeline (650 MMcfd), National Fuel Supply's Northern Access project (350 MMcfd), and Tennessee Gas Pipeline's Northeast Energy Direct project (1.2 Bcfd).

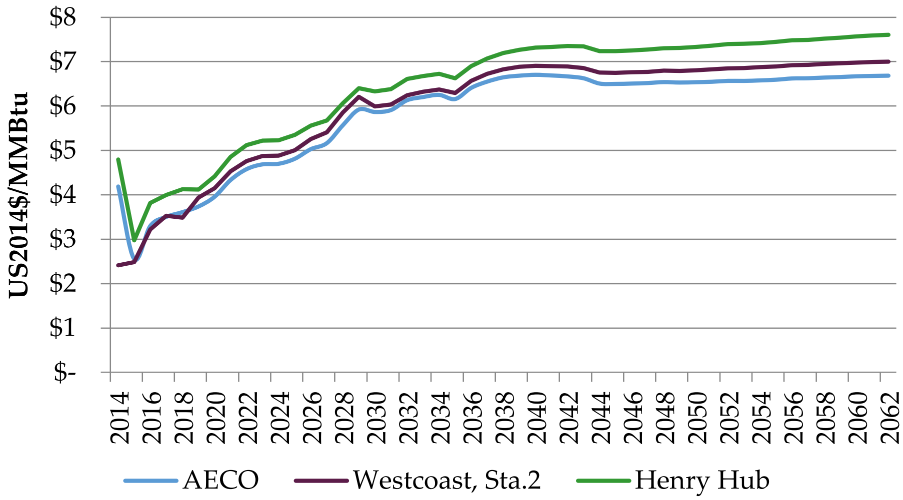
[70] NEB Energy Future 2013 at note 17.

[71] Id. at note 54.

[72] See Spectra Energy 8/6/14 earnings release, p. 2, reporting that Nexus Pipeline moved into execution in Q2 of 2014; Energy Transfer Partner's 8/7/14 10-Q filing, p. 34, reporting that their Board approved construction of Rover Pipeline; Tennessee Gas Pipeline 1/28/15 company presentation "Natural Gas Pipelines", slide 13; Spectra 5/6/15 company presentation "Supplemental Information Appendix", slide 25.

3.10 *Market Outlook*

Navigant's natural gas price outlook reflects reasonable and competitive long-term pricing conditions. As shown in Figure 25 , Henry Hub prices over the forecast term average less than $6.50 per MMBtu over the term through 2062, and remain under $7.60 per MMBtu until 2062[73]. Hub prices in Alberta (AECO) are even lower, averaging less than $5.85 per MMBtu, and remaining at or below $6.70 per MMBtu through 2062. Included in this outlook are LNG export volumes of 9.3 Bcfd from North America to account for expected increasing global gas on gas competition, and reflects Navigant's current market view of a range of 8 Bcfd to 10 Bcfd for North America.



Source: Navigant Year-End 2014 Outlook

Figure 25: Natural Gas Price Outlook

Other significant aspects of Navigant's outlook include the following:

- In addition to a market characterized by reasonable and competitive prices, we believe the stability of the market will continue to be further enhanced as more natural gas supply is sourced from shale gas. Given the benefits of the shale gas production process (*i.e.* lower exploration risk, improved supply response), increased shale gas should help to mitigate the "boom-and-bust" patterns in the industry and help lower volatility. The additional stable natural gas demand represented by LNG exports will increase the size of the gas market, which will foster further development of shale gas resources and lead to continuing decreases in market volatility due to the decreased production risk associated with the shale gas "manufacturing model". We foresee shale gas making up over 60 percent of North American production by 2062.

- This stabilizing impact of increased shale gas production will be strengthened even further by the integrated nature of the Canadian and U.S. regions within the North American natural gas market, which will continue. Specifically, the interconnectedness of both the physical systems (*e.g.* pipelines and storage) and the economic systems (*e.g.* supply contracts and trading activity) helps to optimize market efficiency by allowing market forces to operate on the largest possible scale. Resource development, including that of Canadian unconventional resources, will be incented according to the economics of North American supply and demand factors.

---

[73] As noted in Section 3.1, all prices, unless otherwise noted, are reflected in real (2014) U.S.$.

- Besides the beneficial market dynamics resulting from the character of shale gas and the interconnected nature of the North American gas market, the sheer abundance of natural gas available to meet Canadian and North American demands remains a key aspect of Navigant's market outlook. Several aspects of that abundance are particularly relevant to LNG Canada. First is the surplus nature of the Canadian supply-demand balance (discussed in Section 3.8). Second is the potential displacement of additional demand for Canadian gas in the U.S. due to the expected presence of surplus natural gas in the Rockies. This changing dynamic will be due to increases in Marcellus Shale production, displacing some use of Canadian gas in the U.S. Northeast, as well as in eastern Canada. In addition, Marcellus production will displace some regional uses of Rockies supplies, and thus increase supplies in the Rockies and westward. For example, Navigant's modeling shows decreasing flows over time of Rockies natural gas to the east and increasing flows to the west. As additional infrastructure is put in place to allow access to Marcellus supplies, this trend will only be strengthened. The overall result of these factors is that there should be very large Canadian gas supply resources available to serve incremental Canadian demand. This same result of abundant natural gas would also apply with respect to the scenario of a 20 percent increase (actually 29 percent, as modeled) in the demand growth rate, as requested by the NEB in Information Requests to other applicants, described in Section 3.8.

3.11 Conclusions

1. The primary results of this DGSR concern the strong outlook for both Canadian and North American natural gas markets characterized by ample, stable supplies and competitive, stable prices.

2. The key driver of this outlook is the abundance of the natural gas resource due to the shale revolution. For North America as a whole, currently estimated recoverable gas resources are sufficient to meet 148 years of annual North American natural gas demand at today's consumption levels. The key drivers of this overall 148-year resource life are the large resource lives of over one hundred years in the U.S. and over 380 years in Canada, as presented in Section 3.2.1 and summarized in Table 5.

3. Even under the most conservative (and virtually impossible) assumptions herein, where all approved and applied-for Canadian LNG projects (totaling over 45 Bcfd) are assumed to go forward and current net pipe exports of 4.9 Bcfd are also added to the total Canadian demand total, the Canadian natural gas resource would still have a life of 60 years.

4. The plentiful Canadian resource base, together with the highly integrated North American natural gas market, should ensure sufficient supplies to meet Canadian natural gas demands at competitive prices. Navigant's outlook is for reasonable long-term prices, remaining under $7.60 per MMBtu at Henry Hub through 2062, with Canadian prices lower. Navigant forecasts Alberta (AECO) hub prices to average less than $5.85 per MMBtu, and to remain at or below $6.70 per MMBtu through 2062, based on modeling that includes assumed North American LNG exports of 9.3 Bcfd.

5. Not only is North America forecast to be a net exporter of natural gas, but Navigant also forecasts Canada to continue to be a net exporter of natural gas. In the base case, net pipeline exports to the U.S. are forecast to be 3.3 Bcfd in 2062, in addition to net LNG exports of 1.4 Bcfd. Such a circumstance indicates the surplus nature of Canadian natural gas supplies, notwithstanding the

relatively strong growth in Canadian gas demand (exceeding NEB forecasts by almost 8 percent in 2035) forecast by Navigant. In the additional scenario for increased Canadian demand plus 3.72 of LNG exports, net pipeline exports to the U.S. still average 1.7 Bcfd, and are positive every year for the term of the licence.

6. Because of the integrated nature of the North American natural gas market, shale gas production growth has led to increased gas-on-gas competition that has already started to cause changes in traditional gas flow patterns across North America. An example is the displacement of Canadian natural gas supplies from traditional markets in the U.S. Northeast. Expected further displacements should increase the availability of Western Canadian gas in Canada, to the benefit of LNG Canada as a buyer. In turn, LNG Canada's demand will benefit Canadian producers as sellers in need of new markets.

7. Ultimately, as a result of the significant volumes of natural gas available, as well as the rapid supply responses and diminished production risk attributable to the "manufacturing model" of shale gas production, Navigant believes that the quantity of natural gas to be exported from Canada by LNG Canada does not exceed the surplus remaining after allowance for the reasonably foreseeable requirements for use in Canada, having regard to the trends in discovery of oil and gas in Canada.

8. These conclusions are consistent with those of the Navigant analyses supporting other export licence applications to the NEB, about which the Board has stated, for example, the following:

> "The Board further accepts WPMV's analysis of Canadian demand and, given the size of Canadian natural gas resources and the integrated and well-functioning nature of the North American gas market, concludes that Canadian gas requirements will be met." [74]

[74] NEB Letter Decision dated May 7, 2015, granting the export licence application of WesPac Midstream – Vancouver LLC. See also NEB Letter Decision dated February 20, 2014, granting the export licence application of Jordan Cove LNG Marketing, LP.