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2014 Natural Gas Market Review
Final Report

Prepared for:
Ontario Energy Board

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1. Executive Summary

This 2014 Natural Gas Market Review Final Report ("Report") was prepared to support the Ontario Energy Board's ("Board") stakeholder consultation on the North American and Ontario natural gas markets, focusing on the factors currently and prospectively impacting Ontario natural gas supply, demand and prices. The Report first examines recent historical (i.e. over the last ten years) factors that have influenced the Ontario natural gas market. The Report then presents a review of recent and emerging trends, as well as Navigant's outlook to 2020, regarding the North American natural gas market in relation to supply; demand; pipeline flows, tolls, and infrastructure; storage infrastructure and services; gas prices and volatility; and environmental and other regulatory developments.

The key driver of the recent North American natural gas market has been the "shale revolution" of abundant natural gas resources contained in prolific continent-wide shale formations now being economically producible through horizontal drilling and hydraulic fracturing. Growth in North American natural gas production since 2008 has been driven by shale gas production, and has ushered in a new environment of abundant and reasonably priced natural gas.

The developing shale production plays have ushered in changes to the traditional market dynamics, with the key Marcellus producing area in the U.S. Appalachian Basin becoming the continent's major supply center and serving demand not only in the U.S. Northeast, but also to the U.S. South, to the Gulf, to the Midwest, and to Eastern Canada. In fact, significant differences from the 2010 Natural Gas Market Review for the OEB center on much higher Marcellus and overall shale production, faster and larger reversals of transport to flows from the U.S. into Canada at Niagara, and much larger prospects for LNG exports.

Key developing trends that directly feed the outlook going forward include 1) the continuing expansion of gas-fired electric generation in the U.S., focusing on abundance and economic and environmental benefits versus coal, and 2) the continuing expansion of the Canadian industrial sector, primarily in the Alberta oilsands. Ontario's growth center for natural gas consumption, as in the U.S., is expected to be from gas-fired electric generation that has some very consequential impact on reducing some of Ontario's primarily nuclear-powered plant fleet and essentially eliminating coal-fired generation in Ontario. Between 2013 and 2025, Ontario gas consumption for electric generation is forecast to increase 288 percent, from 0.3 Bcfd to 1.1 Bcfd, as gas-fired generation moves from 7% to 29% of province generation mix.

Decreased throughput on the TCPL Mainline from Alberta is expected to continue as Marcellus supplies continue to dominate the east. The outlook is for Marcellus supplies to increase from meeting 13 percent of Ontario gas demand in 2013 to 41 percent in 2020, with the Western Canadian Sedimentary Basin declining from meeting 74 percent to 42 percent of Ontario gas demand. Expanded pipeline infrastructure is expected to increase access of markets, including Ontario, to these prolific supplies from the U.S. Marcellus shale and Utica shale basins.

With respect to prices, we project prices at Dawn in the future to more closely follow prices at just above Henry Hub, averaging about $4.90 per MMBtu[1], and reaching $5.68 per MMBtu in 2020. Hub prices in

[1] All prices, unless otherwise noted, are reflected in real (2013) US$.

Alberta (AECO) are projected to be lower than prices at Dawn, averaging less than $4.25 per MMBtu, and remaining below $5.10 per MMBtu through 2020 and be less of a determinant than previously. Our scenario analysis yielded prices that are still in the reasonable and competitive range, with the Low Demand Case prices averaging 7 to 9 percent below the Reference Case averages, and the High Demand Case prices averaging 4 to 5 percent above the Reference Case averages.

2. Introduction

2.1 Overview

At the highest level, the key driver of the North American natural gas market since the last OEB Natural Gas Market Review in 2010, and before that going back even further, has been the "shale revolution", the vast extent of which was first quantified in 2008 by Navigant[2], leading to continued remarkable growth in overall natural gas supply in North America. Due to the vast size of the shale gas resource (discussed in Section 4.1.1.1) and the high reliability of shale gas production (discussed in Section 3.2.2), the supply-demand dynamic has the potential to be 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 growth that has been the biggest contributor to overall gas supply abundance over the last several years. The geographic scope of the interconnected North American shale gas resource can be seen in the map shown in Figure 1.

[2] 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 1: North American Shale Gas Basins

Navigant's outlook included herein is based on Navigant's latest natural gas market forecast (*North American Natural Gas Market Outlook, Mid-Year 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. In certain instances, a discussion going beyond 2020 is included only to provide helpful additional context around the 2020 outlook provided by the Report.

2.2 Navigant North American Market Model and Approach

Before discussing the analysis and outlook proper, a brief introduction to Navigant's gas market modeling is in order. Twice a year, Navigant produces its long-term reference case 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.

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 higher than actually occurs over the forecast period. .

Navigant's modeling is based upon the existing North American pipeline and LNG import terminal infrastructure, augmented by planned expansions that have been publicly announced and that appear likely to be built, including consideration of LNG export terminals. 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 experience and market intelligence for reasonableness.

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 had been announced at the time of our forecasting in mid-2014. 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 large 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.

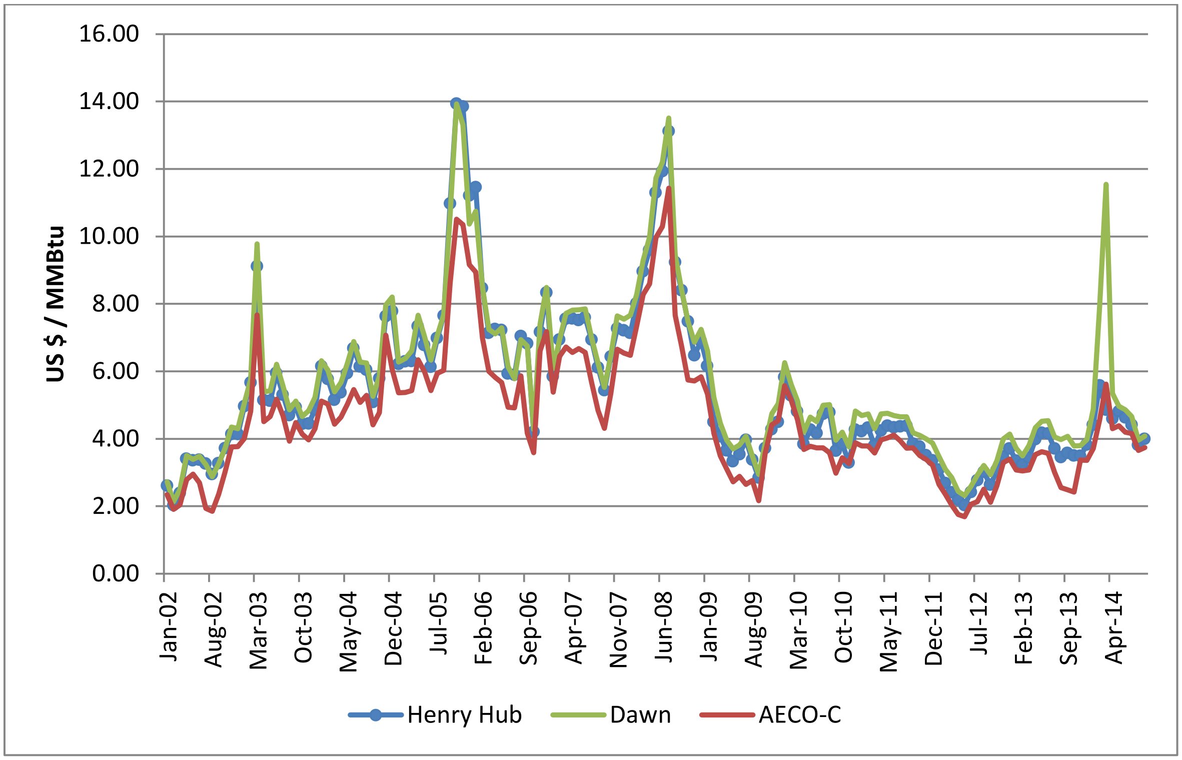
Storage facilities in the Navigant model reflect actual in-service facilities as of mid-2014, as well as a number of announced storage facilities that are judged likely to be in operation in the near future. No unannounced storage facilities were introduced into the model. The inventory, withdrawal, 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 expected should more storage capacity be developed.

3. Recent Influences in the North American and Ontario Gas Markets

3.1 Price Overview

Historical natural gas prices at Henry Hub, Dawn and AECO-C are shown in Figure 2, which indicates market prices tracking in the $6 range before 2008 and in the $4 range after 2008, with several instances of pronounced price spikes in some or all three of these price points. Specifically, there was generally widespread spiking in late 2005 to early 2006 (Hurricanes Katrina and Rita) and 2008 (high global oil prices)[3], and region-specific spiking at Dawn in the winter of 2013/14.

[3] See discussion in Energy Facts: Canadian Energy Pricing Trends 2000-2010, National Energy Board, October 2011, pp. 3-4.



Source: Navigant / Platts

Figure 2: Historical Monthly Natural Gas Prices

With the exception of winter 2013/14 (which is addressed in the companion report by Navigant for the OEB), Dawn prices have tracked Henry Hub, consistent with the interconnected nature of the North American market. Dawn has similarly tracked AECO prices with the exception of winter 2013/14, but with a larger price spread, although Dawn spiked farther above AECO at the time of Hurricanes Katrina and Rita. It should be noted that the only time when Dawn pricing clearly diverged from both Henry Hub and AECO prices was the polar vortex event last winter that affected much but not all of the U.S., which is an indication that the primary driver of prices is the over-arching fact that Ontario is an integral part of the integrated North American natural gas market driven by macro conditions. This observation is consistent with the NEB's view on the natural gas market:

> "Natural gas markets in Canada and the United States operate as single integrated market. Events relating to weather, storage, transportation or infrastructure, however, have a direct impact on markets in many regions of North America."[4]

Regarding volatility, in addition to the generally lower level of prices after 2008, Figure 2 also indicates that the swings in the market prices appear to have somewhat moderated after 2008, which was effectively the beginning of the shale revolution. Before the advent of significant shale gas production, the natural gas industry's history reflected periods of "boom and bust" cycles. Investment in both production and usage seesawed on the market's perception of future prices. That perception was driven in part by uncertainty and risk around the exploration 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

[4] Id, pp. 3-4.

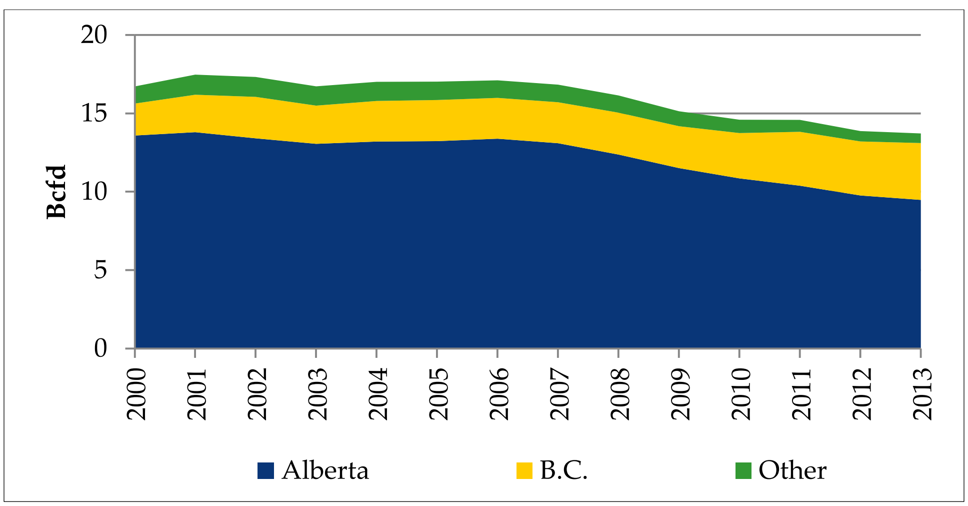
at times the availability of capital to fund any such discovery), gas supply suffered from periods where it was "out of phase" with demand for natural gas by gas-fired electric generating facilities and other users on the demand side, causing prices to rise and fall dramatically. This in itself caused other, second-tier ramifications impacting the investment cycle for supply. For example, the pipeline infrastructure that is required to connect supply and demand is another large-scale investment that at times has suffered from underutilization or has become a bottleneck, as a result of the second order effects 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. Over its history, natural gas' price volatility has been a major limitation on the more robust expansion of the natural gas market. 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 and in turn assist natural gas in gaining market share. 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. While other factors will no doubt also affect volatility, the advent of shale gas has created a new production environment that is substantially different from the past and will likely impact market responses to various events differently than without shale.

3.2 *Supply Source Factors*

3.2.1 Declines in WCSB Production

From a historical perspective, the peak of Canada dry gas production occurred in 2001 at 17.5 Bcfd, as can be seen in Figure 3.[5] 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 13.7 Bcfd in 2013.[6] Alberta contributed to virtually the entire Canadian production decline since 2007.



Source: NEB

Figure 3: Historical Canadian Natural Gas Production

[5] NEB data, http://www.neb-one.gc.ca/nrg/sttstc/ntrlgs/stt/mrktblntrlgsprdctn-eng.html

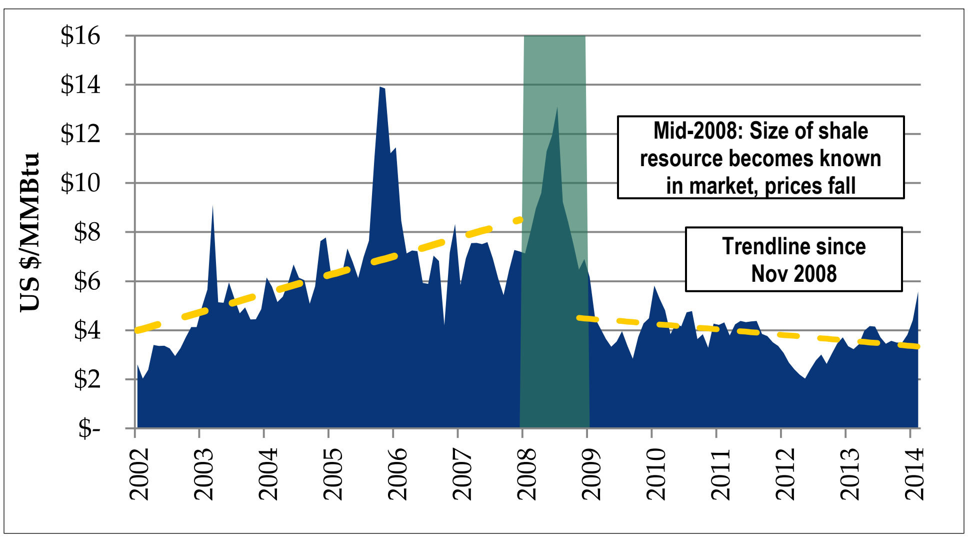
[6] Id.

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 3 Bcfd by the beginning of 2014.[7] Navigant forecasts sustained long-term growth of British Columbia production as a result of the Montney and Horn River development.

In Alberta, gas production peaked around the turn of the century, averaging 5.1 Tcf per year.[8] 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.[9] From 2006 to 2012, Alberta gas drilling activity fell sharply by more than 80 percent.[10] 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."[11]

3.2.2 Shale Boom and Huge Marcellus Production

Natural gas prices increased substantially in the first decade of this century, culminating in significantly higher prices in 2007-2008, as shown in Figure 4. 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, conventional wisdom held that North American gas production would have to be supplemented increasingly by imported LNG owing to domestic North American supply resource decline.



Source: Navigant / Platts

Figure 4: Henry Hub Price History

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[7] *Short-Term Canadian Natural Gas Deliverability, 2013-2015, Appendices*, National Energy Board, May 2013, Table C.1.

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

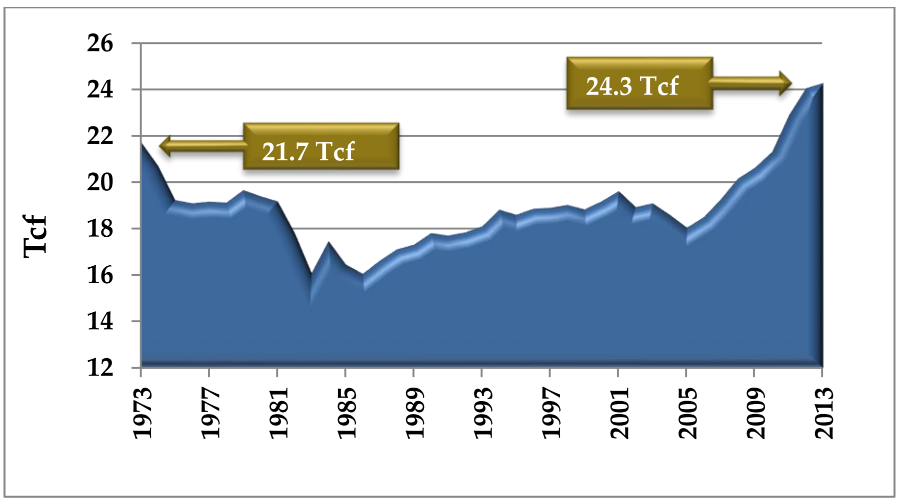
[9] NEB data.

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

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

Far less conspicuously, higher prices also supported the development of horizontal drilling and hydraulic fracturing, existing technologies which were combined together to be continually improved towards dramatically increased drilling and production efficiencies, reduced costs, and improved finding and development economics of the industry. When Navigant released its American Clean Skies natural gas supply assessment in mid-2008, domestic gas production from shale began to overtake imported LNG as the new gas supply of choice in North America. The combination of these technologies was the key to unlocking the potential of the gas shale resource.

Figure 5 clearly shows the dramatic upward trend in gas production seen in the U.S. over the last 5-8 years, corresponding to the start of the shale revolution, 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 over 30 percent over the last seven years has been due to growth in shale gas production, and underlies Navigant's basic modeling assumption in developing its gas production forecast, based on industry observations, that natural gas supply will respond dynamically to demand in a reasonably short time—months, not years.



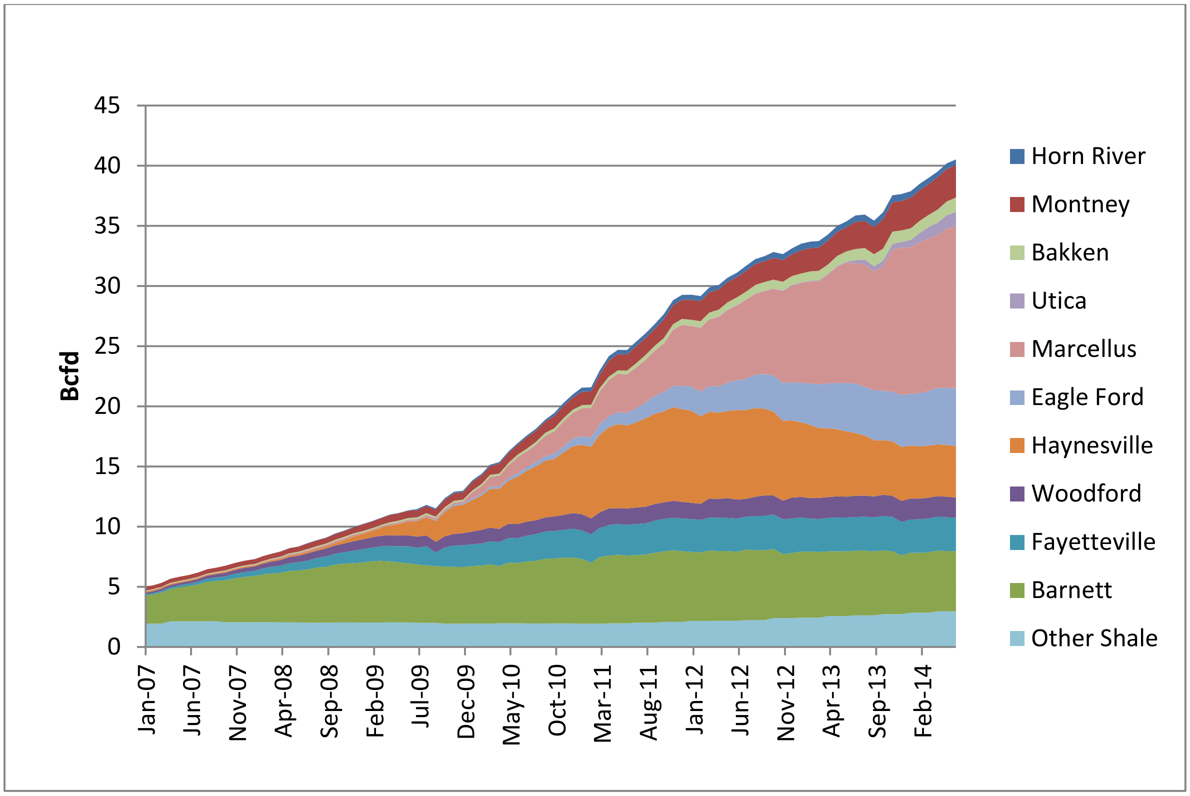
Source: Navigant / U.S. E.I.A.

Figure 5: U.S. Natural Gas Production History

An important point to note is that actual shale gas production growth has been so robust that today it vastly exceeds the amounts estimated to be produced in 2020 in the 2010 Natural Gas Market Review (2010 Review) prepared for the OEB. This has been a common phenomenon for shale gas production forecasts, as with U.S. EIA outlooks with projected volumes at least several years in the future that have often already been reached by the time the forecasts are released. In any event, Figure 6 shows that while the 2010 Review forecasted Marcellus production to increase to 6 Bcfd in 2020[12], actual shale gas production in the Marcellus had already reached 6 Bcfd by May 2012 (and most recently has passed 13 Bcfd). Similarly, total North American shale gas production has reached over 38 Bcfd this year, while the 2010 Review forecast a level of 29 Bcfd in 2020.[13] These are significant findings and market developments for the 2014 Natural Gas Market Review compared to previous reviews.

[12] 2010 Natural Gas Market Review, ICF International, August 20, 2010, p. 63.

[13] Id., p. 52.



Source: Navigant / LCI Energy Insight

Figure 6: North American Wellhead Shale Production

The nature of the shale gas resource – often spread continuously throughout large formations, and often in formations containing liquids or condensates – leads to several favorable production characteristics that bode well not only for producers but for the markets themselves. These characteristics are lower exploration risk, and reliable production often with enhanced returns due to valuable Natural Gas Liquids (NGLs) 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 expensive 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 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 and, in many cases, are in existing gas fields wherein the shale was penetrated regularly but not able to be produced economically from vertically drilled wells, the risk of not finding a producible formation in an unconventional shale gas well previously drilled is much lower compared to conventional gas reservoirs.

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 gas shale. 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 beyond the sheer magnitude of the resource is due to the fact that some shale formations contain both natural gas liquids ("NGL"s) and natural gas[14], which strengthens the economic prospects of gas shale. Natural gas when produced with NGL's, is therefore incented not only by the economics of natural gas itself, but by NGL prices, which generally track higher crude-based oil prices. Oil prices have historically and still currently offer a significant premium to natural gas on a per-MMBtu basis, with oil at $90 per barrel equating to about $15.50 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.

For example, several energy companies including Enbridge, Enterprise Products Partners, Buckeye Partners, Kinder Morgan, and Dominion have recently announced plans to build or enhance NGL gathering and transmission systems in the Marcellus shale formation. The Eagle Ford formation in Texas is being developed as an NGL play as much as a natural gas play. Recently, discoveries in the Utica formation in eastern Ohio have led Chesapeake Energy to state that it is "likely most analogous, but economically superior, to the Eagle Ford."[15] For the Utica, which is in its early stages of development with limited data, the natural gas resource estimates already run up to 111 Tcf[16], compared to 132 Tcf in the Horn River and 113 Tcf in the Duvernay[17], indicating the potential significance of gas resources there.

Similarly, in December 2012, EnCana announced its creation of a joint venture with PetroChina to develop EnCana's extensive liquids-rich Duvernay gas shale acreage in Alberta that it acquired in 2011 to exploit natural gas liquids, which again would lead to additional associated natural gas production in Alberta. Recently, a unit of the Kuwait national oil company moved to acquire a 30 percent interest in Chevron's 330,000-acre holding in the Kaybob area of the Duvernay.[18] Other development in Alberta may also lead to additional production from conventional and unconventional resources. We point this out only to mention the historical significance of Alberta as by far the country's largest producing gas province and the potential some still see in the province, which we share.

[14] And consequently often referred to as "liquids-rich" or "wet gas" resources.

[15] Chesapeake Energy, *October 2011 Investor Presentation*, available at http://www.chk.com/Investors/Documents/Latest_IR_Presentation.pdf

[16] See U.S. E.I.A. Assessment, infra note at Table A-1, Attachment C.

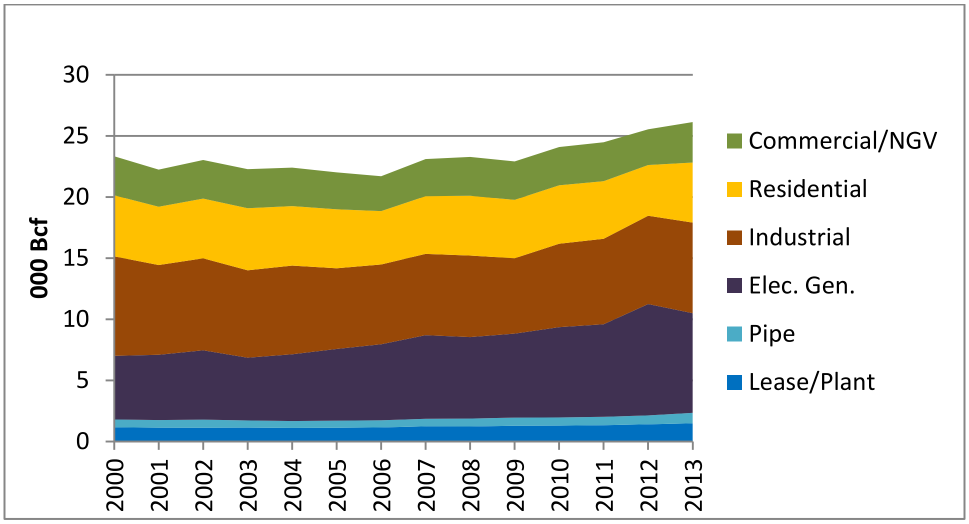
[17] See Table 2, page 22.

[18] Financial Post, October 6, 2014.

3.3 *Sector Gas Demand Factors*

3.3.1 Electric Generation U.S.

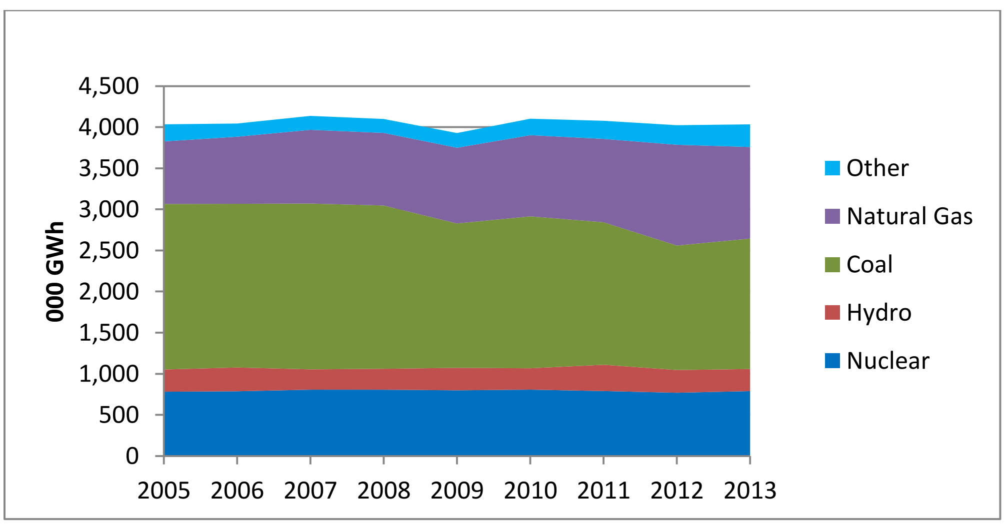
As shown in Figure 7, gas consumption for electric generation has been increasing almost steadily over the last ten years in the U.S., and has been the primary driver of increases in U.S. gas usage over the last five years. Over the same period, the residential, commercial and industrial gas demand sectors have remained relatively level or have even decreased slightly.



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

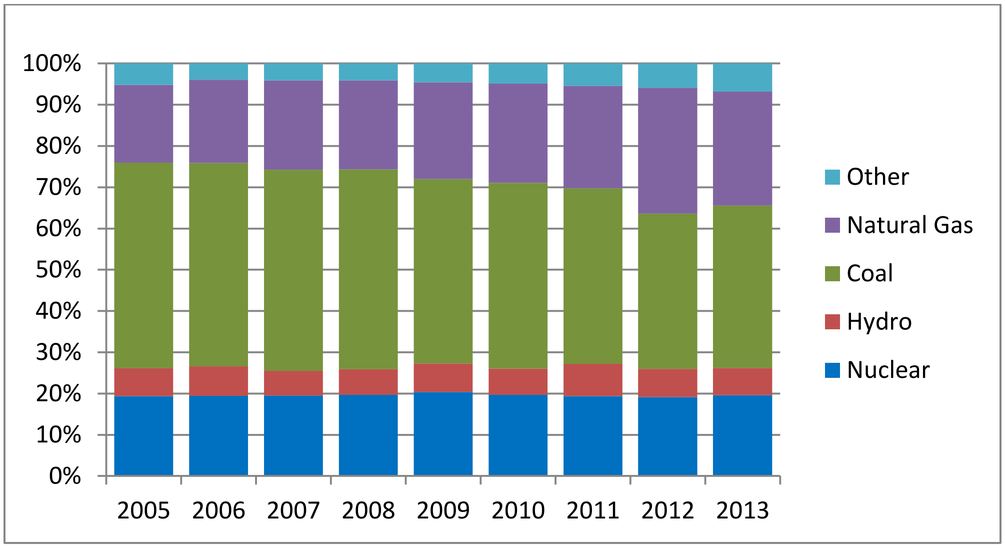
Figure 7: Historical U.S. Natural Gas Demand by Sector

As can be seen in Figure 8, total electric generation in the U.S. has been stable at least since 2005 at about 4,000 TWh. However, the amount of natural gas-fired generation has been almost steadily increasing, as has its percentage share of the generation mix, as shown in Figure 9 (the exception being a drop in 2013 following a dramatic increase in 2012).



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

Figure 8: Historical U.S. Generation by Fuel Source



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

Figure 9: Historical U.S. Generation Mix

There are several main reasons behind the increase in natural gas-fired generation, generally related to natural gas as an alternative to coal-fired generation. One is the economic "coal-to-gas switching" that was especially widespread in 2011 and 2012 when there was a distinct market price advantage for natural gas versus coal, which can be seen in Figure 10 (and which is still reflected in recent forward prices). And again, the driver behind gas' price advantage was the incredible supply abundance, enabled by horizontal drilling and hydraulic fracturing applied to shale gas resources that led to readily available gas supplies becoming available to additional markets.

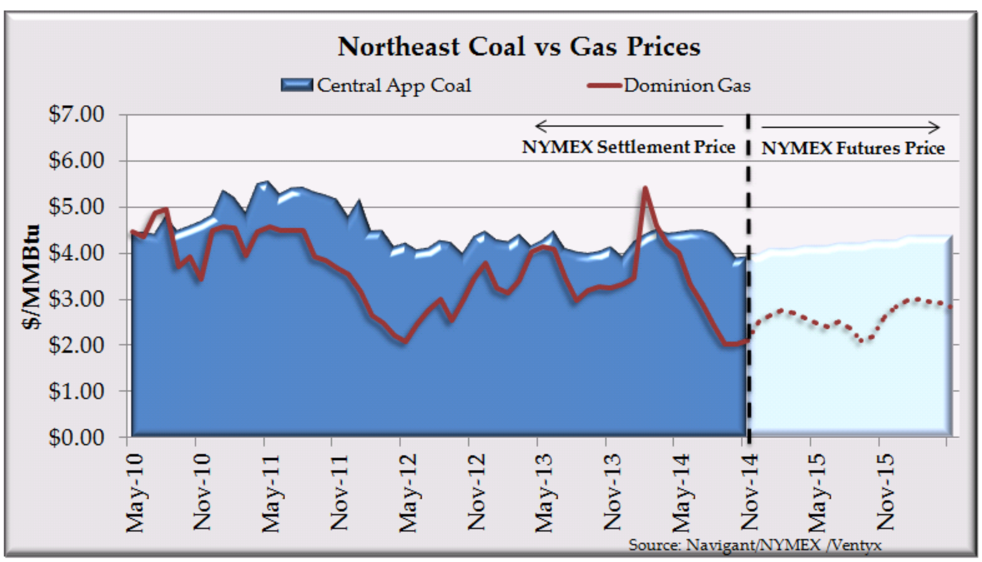


Figure 10: U.S. Northeast Coal vs. Gas Prices (summer 2014)

Another reason for the increase in gas-fired electric generation is the on-going retirement of aging coal-fired electric generation plants. While most coal unit retirements are yet to come (and which will support additional gas demand), there has been an initial set of retirements of aging coal-fired generation plants, as shown in Figure 11. In addition, from a climate change perspective, natural gas has been estimated to have a much lower carbon footprint than coal per MWh of electricity generated (more than 50% lower than coal on a lifecycle basis for baseload generation)[19], another factor certainly in its favor versus coal.

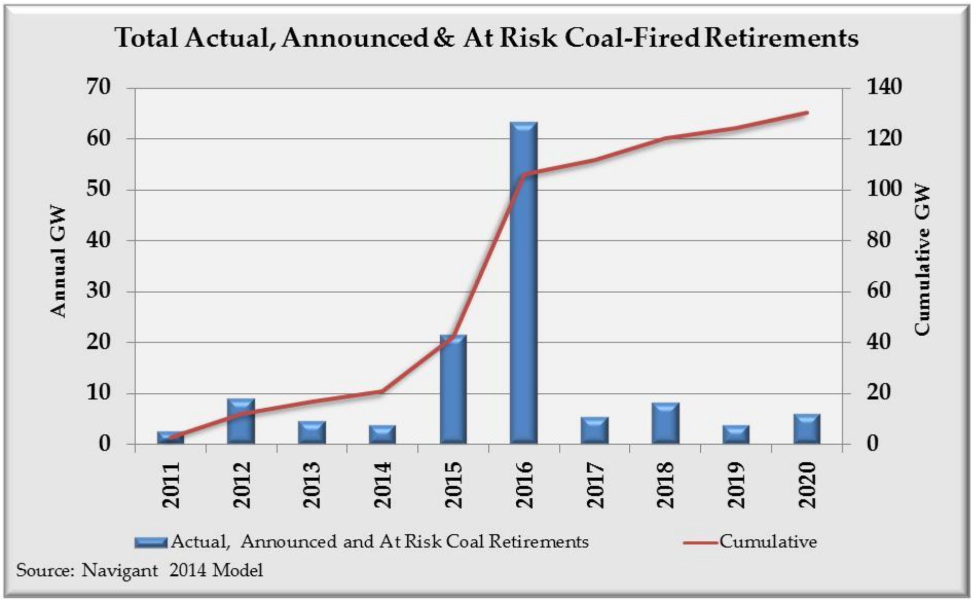
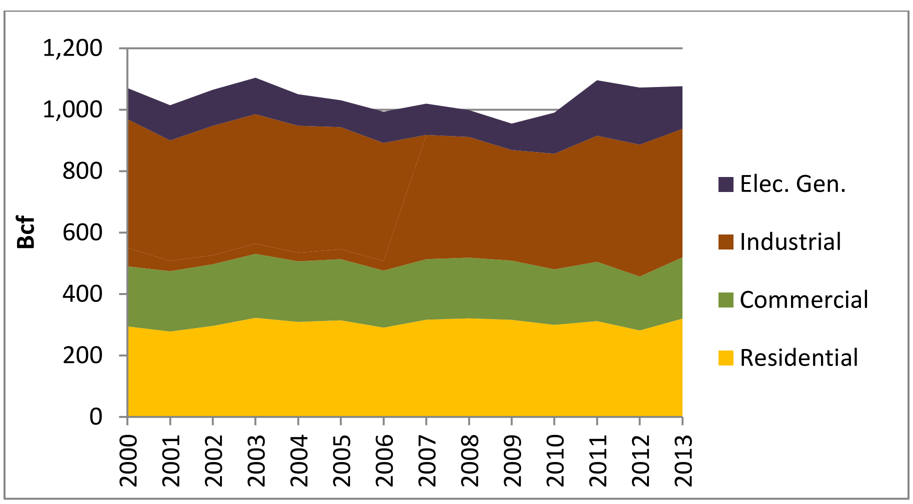


Figure 11: U.S. Coal-Fired Plant Retirements, 2011 - 2020

3.3.2 Electric Generation Ontario

Recent increases in Ontario natural gas-fired electric generation, as shown in Figure 12, have helped to offset stagnant gas consumption levels in the province for residential and commercial (and a marked downward trend in industrial gas consumption), with total Ontario gas demand reaching 1.1 Tcf in 2013.

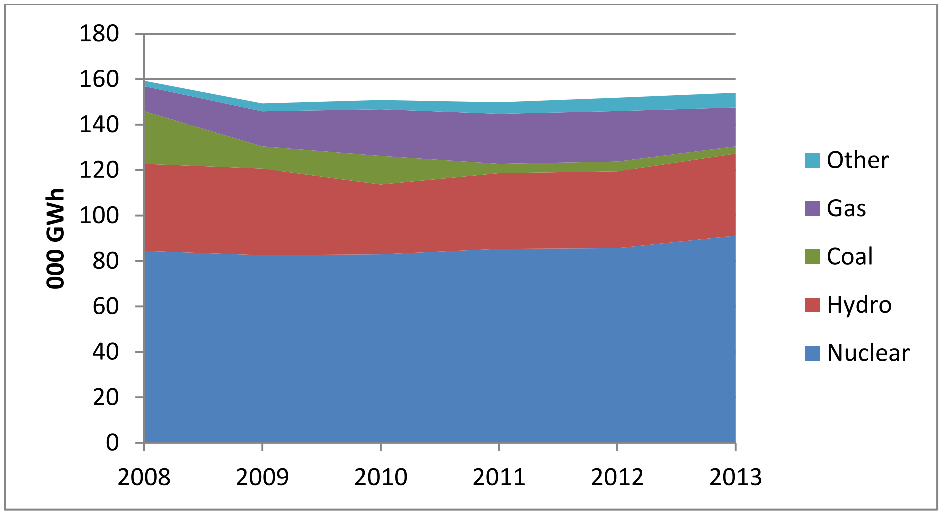


Source: Navigant / StatsCan

Figure 12: Historical Ontario Natural Gas Demand by Sector

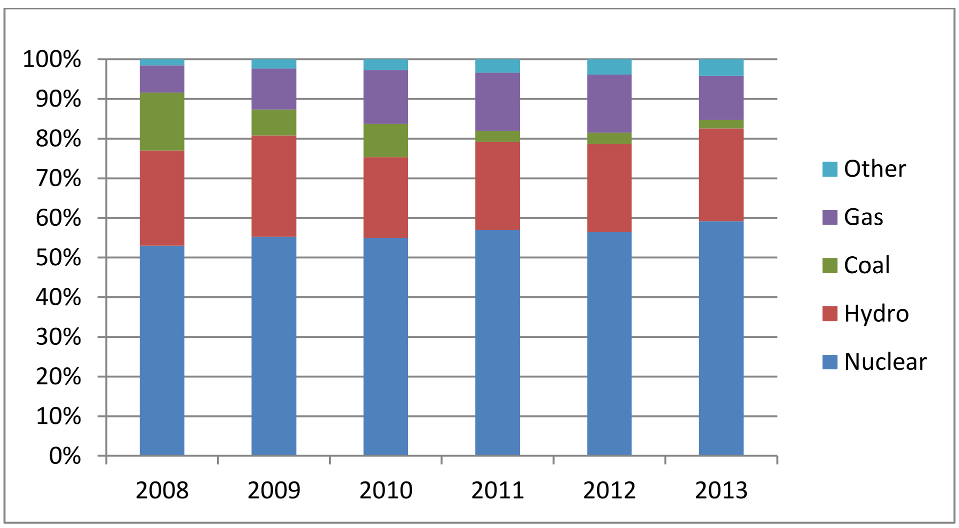
[19] See *LCA and the U.S. Natural Gas Resource*, James Littlefield, U.S. Department of Energy, National Energy Technology Laboratory, December 16, 2013, slide 3.

Also similar to the U.S., Ontario's increase in natural-gas fired generation coincided with a continuing phase-down of coal-fired generation. At the same time, nuclear generating capacity has retained its market dominant position in Ontario. This is a somewhat unique aspect of the Ontario electric generation market compared to most other markets in North America. The trends in Ontario's electric generation mix can be seen in Figure 13 and Figure 14.



Source: Navigant / IESO

Figure 13: Historical Ontario Generation by Source

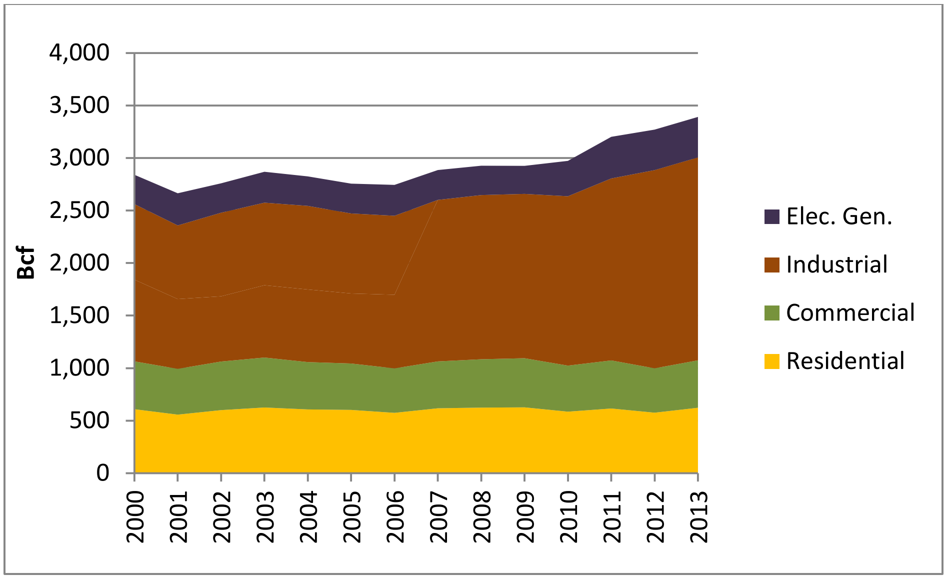


Source: Navigant / IESO

Figure 14: Historical Ontario Generation Mix

3.3.3 Canadian Industrial Demand

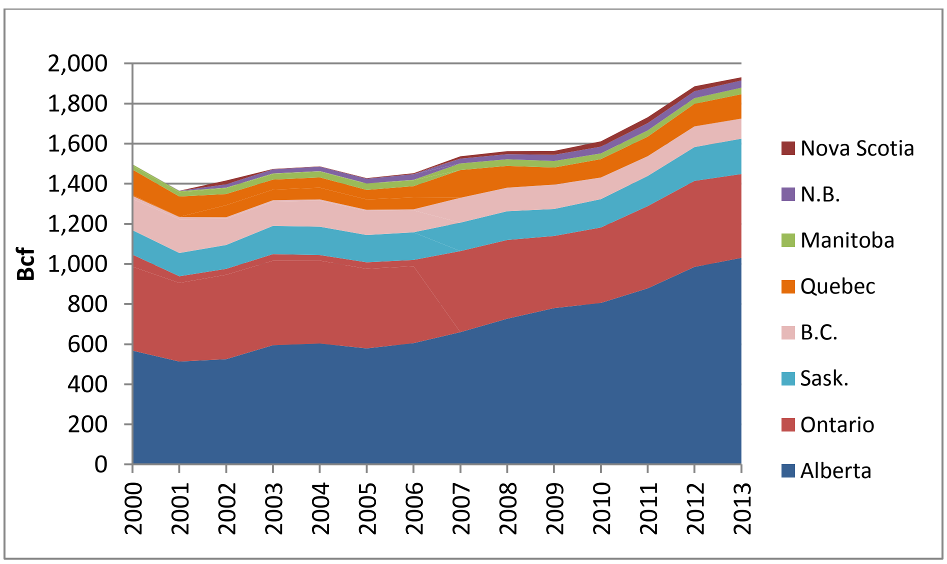
As shown in Figure 15, Canadian gas consumption has been increasing since 2006, reaching 3.4 Tcf in 2013. Those increases, and particularly over the last four years, have been largely driven by increases in industrial gas usage, which reached 1.9 Tcf in 2013.



Source: Navigant / StatsCan

Figure 15: Historical Canadian Natural Gas Demand by Sector

As shown in Figure 16, Canada's industrial gas demand increases have been almost entirely the result of sharp increases in Alberta's industrial demand, which in turn has been driven by increases in oil sands gas usage. The impact on Ontario of the recent Alberta demand increases, together with the decreasing competitiveness of Alberta gas due to long and expensive transportation to markets in the U.S. that can also be served with Marcellus supplies, has been a decline in Western Canadian supply, which has helped drive the decreases in TransCanada PipeLine (TCPL) flows as discussed in Section 3.4.1.

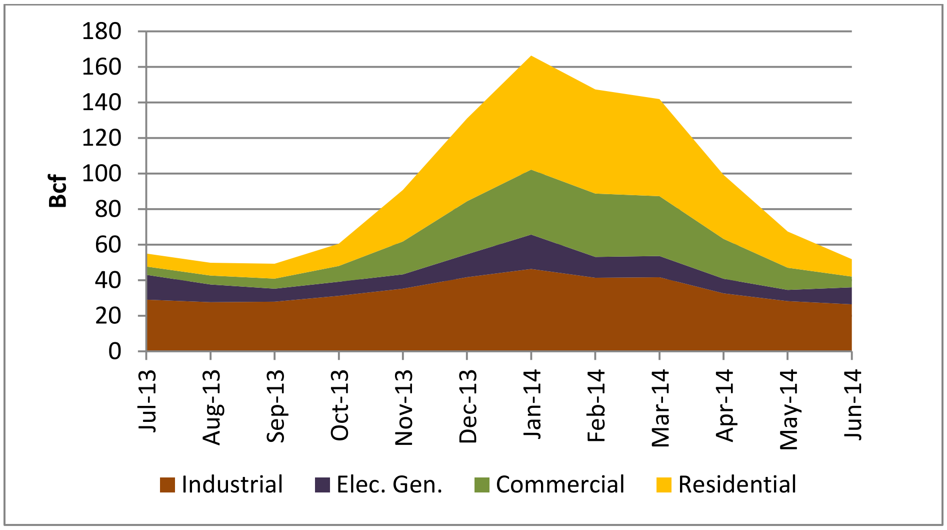


Source: Navigant / StatsCan

Figure 16: Historical Canadian Industrial Gas Demand

3.3.4 Ontario Consumption Patterns

As shown in Figure 17, Ontario's annual consumption pattern clearly makes it a winter-peaking gas consuming region. As expected, residential and commercial demands are the most peaky, and industrial appears to be the least. Electric generation increases in both winter and summer.



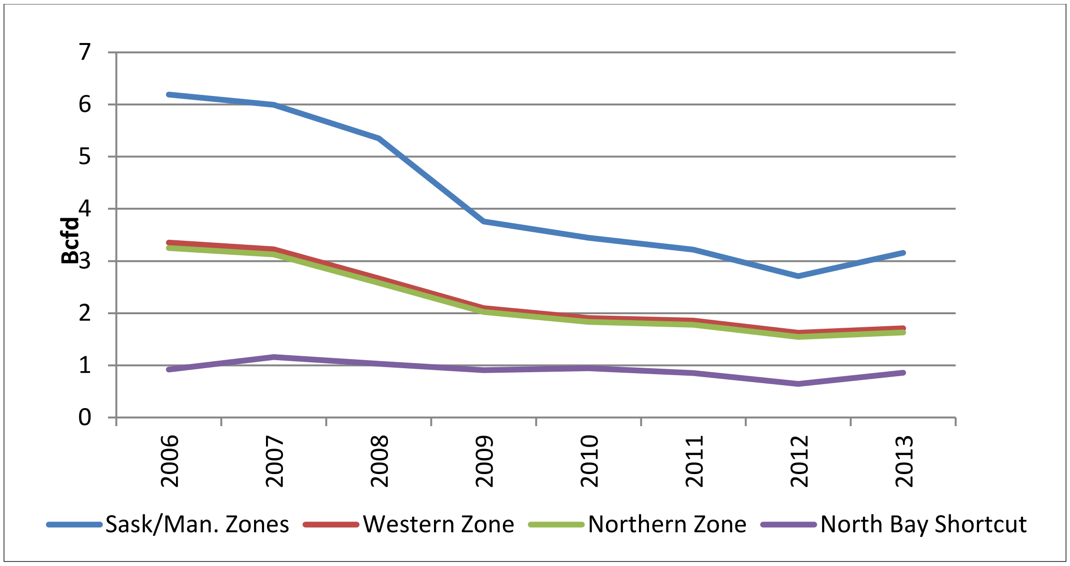
Source: Navigant / StatsCan

Figure 17: 2013/2014 Ontario Monthly Natural Gas Demand by Sector

3.4 Pipeline and Storage Infrastructure Factors

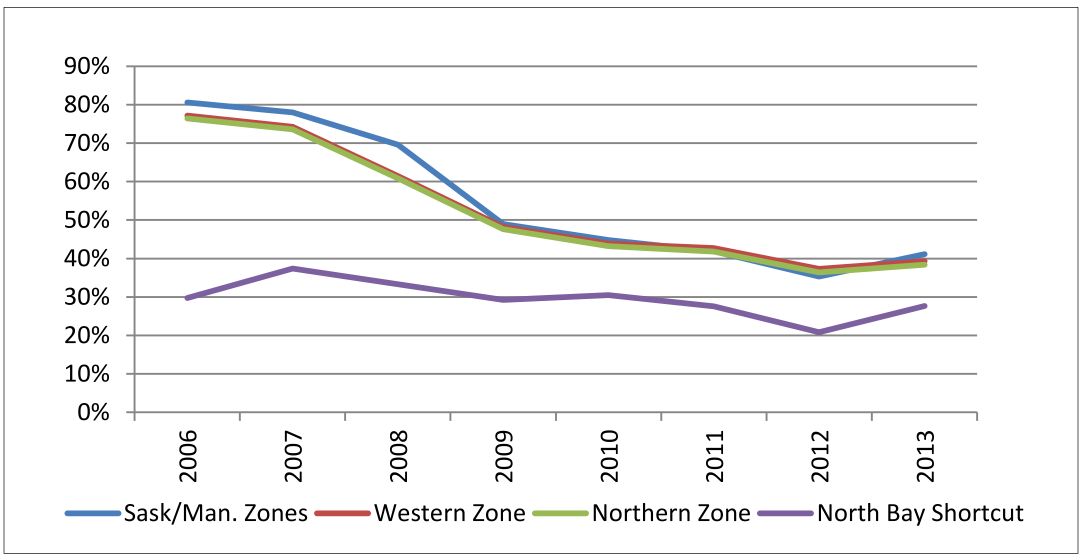
3.4.1 TCPL Throughput Declines

Coincident with the expansion of shale gas production in the U.S. that accelerated dramatically about 2008, as well as with the decline in production in Alberta, flows on the TransCanada Mainline began a noticeable drop off, particularly in the Saskatchewan and Manitoba Zones of the Mainline. As can be seen in Figure 18, there has been about a 50% reduction in those Mainline flows over the six years from 2006 to 2012, from about 6 Bcfd to about 3 Bcfd. On a percent utilization basis, as shown in Figure 19, the reduction was from about 80% utilization to about 40% utilization (versus a capacity of about 7.7 Bcfd), leaving unused capacity of about 4.7 Bcfd in those zones. Flow trends for the other portions of the Mainline are also reflected in Figure 18 and Figure 19. For the major Ontario portions of the Mainline (i.e. the Western and Northern Zones), there was similarly a reduction in volumes and utilization of about 50%. Flows dropped from about 3.25 Bcfd to about 1.6 Bcfd, while utilization dropped from about 75% to about 35% (versus capacity of about 4.3 Bcfd), leaving unused capacity of about 2.7 Bcfd. In the North Bay Shortcut section of the Mainline Eastern Zone, there was a less dramatic drop in volumes, although utilization is even lower at about 20-30% (versus capacity of about 3.1 Bcfd), leaving unused capacity of over 2 Bcfd.



Source: Historical data provided within RBAC GPCM dataset

Figure 18: Historical TCPL Mainline Throughput Volumes



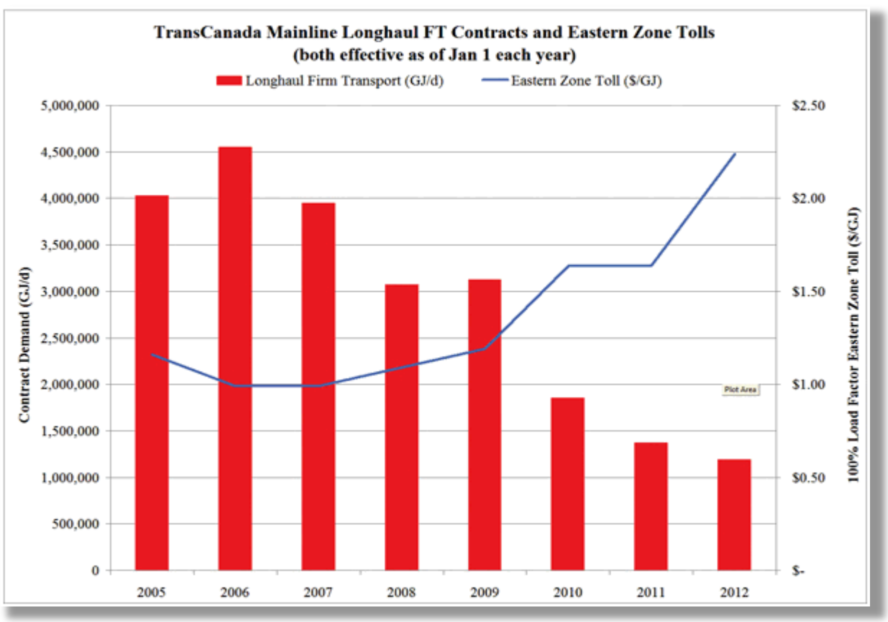
Source: Historical data provided within RBAC GPCM dataset

Figure 19: Historical TCPL Mainline Utilization

3.4.2 TCPL Rate Restructuring

The declines in TCPL Mainline throughput described in Section 3.4.1, above, created unprecedented difficulties for TCPL's revenue recovery. To compensate for declining volumes, TransCanada's Mainline rates increased steeply, further impacting the Mainline's competitiveness in a worsening spiral. In September 2011, TransCanada filed with the NEB for a rate restructuring of the Mainline (RH-003-2011 proceeding). While many aspects of the restructuring proposal were denied by the Board, the ultimate decision in March 2013 fixed tolls on a multi-year period (through 2017) at C$1.42/GJ from Empress to Dawn, a substantial decrease from the interim rates that would have prevailed, at C2.58/GJ. Other parts of the NEB decision gave TransCanada pricing discretion on interruptible and short-term products, allowing TransCanada to incentivize shippers to contract for long-term firm capacity. In fact, TransCanada stated, in its December 2013 Application for Approval of Mainline 2013-2030 Settlement, that it has recovered greater-than-forecast revenues on the Mainline, primarily through increased contracting for firm services. On November 28, 2014, the NEB approved the proposed Mainline Settlement for rates effective 2015-2020, raising long-haul tolls from those approved in the Mainline Restructuring decision by 18 percent (and short-haul tolls by 52 percent).

Figure 20 depicts the recent Mainline contract demand and long-haul tolls. Although shippers' costs continue to be higher compared to historic lows, the Mainline decisions appear to provide certainty and protection of consumers for the time being. The difficulty, however, over the long term is the fact that the price spread on average between AECO and Dawn, Ontario fails to cover pipeline tariff costs, even at the new reduced tariff rate of C$1.42/GJ (or C$1.68/GJ when increased for the Mainline Settlement). For instance, the summer (April-October) 2014 spread between AECO and Dawn averaged C$$0.48/GJ. In calendar year 2013, the spread averaged C$0.97/GJ. At these prices, holding pipeline capacity is not an economic proposition and is a disincentive to holding TCPL Mainline system capacity. This no doubt also contributes to the decreased utilization on the TCPL Mainline system, as outlined earlier in Section 3.4.1.



Source: TransCanada

Figure 20: TCPL Mainline Contract Demand and Tolls

3.4.3 Storage

Between Canada and the U.S., the two countries have approximately 5 Tcf of working gas storage capacity. Working gas storage is total gas storage capacity less base or 'cushion' gas that remains in the storage reservoir and therefore is not usable capacity. About 1.5 Tcf of the working gas capacity is in the U.S. producing' region, close to the Gulf of Mexico, and as such not as directly significant to the U.S. Northeast and Eastern Canadian markets. U.S. storage capacity of approximately 3.9 Tcf is located in the Eastern Region (2.2 Tcf) and in the West Region (0.5 Tcf). For comparison, other regions around the globe all have important but lesser storage volumes than North America, with storage capacity in North

America that vastly exceeds the combined capacity in the rest of the world. Western Europe, for instance, has storage capacity of just over 2 Tcf, and the large Asian demand region has effectively no existing storage in operation currently. Storage capacity therefore distinguishes the North American gas market.

In Canada, the country has about 0.7 Bcf of total working gas storage capacity; about 450 Bcf in Western Canada and about 245 Bcf in Eastern Canada, located primarily in Southern Ontario.[20] A small amount of effective storage exists in New Brunswick and is associated with the LNG storage facility at Canaport LNG terminal near Saint John. Of the storage in Southern Ontario, Union Gas, a division of Spectra Energy, lists their Dawn Hub storage facility at 155 Bcf, therefore making up almost 65% of the Southern Ontario storage capacity and representing the largest underground storage facility in Canada.

In Canada, with a winter seasonal peaking load profile driven by the heat sensitive commercial and residential utility market, storage is used to support the market by allowing additional supply purchases in the summer for injection into storage to be withdrawn over the course of the winter. In providing for such market support, storage acts as a market cushion against market volume and price shocks while contributing to supply reliability.

3.5 Regulatory Changes

3.5.1 TransCanada Energy East Project

TransCanada Pipeline, owner of the key 'mainline' pipeline system reaching across Canada from the Alberta border to Eastern Canada, has submitted an application to the National Energy Board of Canada to convert a portion of the pipeline from a gas line to oil. The project, known as Energy East, has been submitted by Energy East Pipeline Ltd., a wholly-owned partner of TransCanada Oil Pipelines, a limited partner of TransCanada. The project will involve the conversion of 3,000 km of the existing natural gas line and the construction of 1,460 km of new pipeline across various sections of Ontario, Quebec and New Brunswick and is being proposed as an entire project subject to NEB regulation.

The project is projected to cost $11.3 Billion, with the Ontario section accounting for roughly $380 million. At the end of the project, should it occur, the pipeline will have a capacity of about 1.1 million Barrels per day. Deliveries are planned to begin in late 2017.

As evidenced by the decreasing utilization of the TCPL Mainline pipeline system partially as result of the decreased levels of production in Alberta over the last five to ten years, it is Navigant's further expectation that production will continue to drop over the long term to 2035. Supported by this market view, it is Navigant's expectation that the TCPL Mainline conversion will likely have minimal impact upon Ontario gas consumer. This expectation is based upon the fact that Ontario as well as Eastern Canadian demand more generally is already being met without dependence on the Mainline capacity to be converted. This also serves to shape our view that future gas demand growth in Ontario will be met primarily from gas coming into Ontario from U.S. gas supplies in the Marcellus and Utica basins.

3.5.2 TransCanada Pipelines Limited Toll Restructuring Proposal.

By the NEB's decision on RH-003-2011 issued in March 2013, the NEB rejected TCPL's proposal to restructure the Mainline system rate structure and instead approved fixed, multiyear rates for five years

[20] Canadian Gas Association, http://www.cga.ca/wp-content/uploads/2014/11/CGA_bulletin_Storage_EN.pdf, Page 3

at $1.42 per gigajoule from Alberta to southwestern Ontario on the Mainline system. These rates were subsequently raised by the Mainline Settlement approved in RH-001-2014, as discussed in Section 3.4.2.

The full impact of the NEB's decision is still to be determined but to some degree the impact has been at least muted by market forces that have had market prices 'non-supportive' of even the reduced tariffs as contained in the NEB's Toll Restructuring decision. The lack of market support is the result of the price spread between Alberta and southwestern Ontario generally being lower that the Mainline tariff rate and making the restructured transportation service non-economic for shippers to hold capacity.

For more discussion on the TCPL Rate Restructuring Proposal, see Section 3.4.2.

4. Emerging Trends and Outlook for North American Natural Gas Market

4.1 Supply Source

4.1.1 Continued Shale Boom

While the shale revolution has been well underway since production figures began their increase in 2008, the boom has continued to gather strength. Evidence of that acceleration can be found not only in the production increases, but also in increasing resource estimates and production efficiency, discussed below.

4.1.1.1 Resource Estimates

The importance of the shale revolution would be difficult to exaggerate. Shale resources are almost totally behind the large increases in recoverable resource estimates (as well as the increases in actual production). 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.[21] 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.[22] A key component of the NEB's changed resource estimate was based on an update specific to the prolific Montney Formation, that was issued jointly by the NEB with agencies in British Columbia and Alberta in November 2013, that raised the Montney resource estimate more than 300 percent, from 108 Tcf in the NEB's 2011 reference case to 449 Tcf.[23] A summary of relevant resource estimates for both Canada as a whole and for Western Canada appears below in Table 1.

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[21] *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).

[22] *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.

[23] *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

Table 1: Canadian Natural Gas Resource Estimates

Natural Gas Recoverable Resource	Canada			Western Canada			
	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[24]. 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.[25] 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.

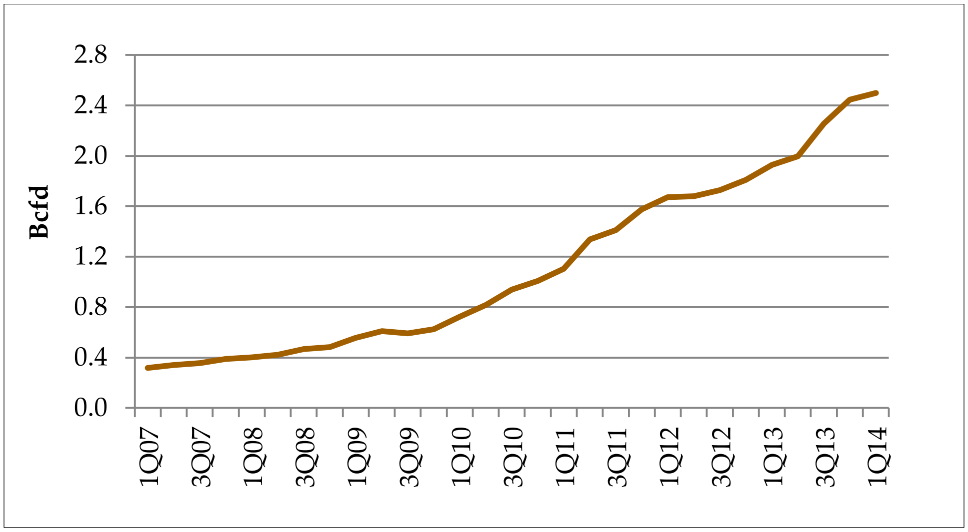
The increase in estimates of unconventional resource volumes also shows up on a play-specific basis, which is an additional aspect of why such dramatic increases are occurring -- not only are entirely new gas resource plays being discovered, and then brought into production, but as additional data from producing gas plays is obtained over time, the resource estimates of those active plays have generally ended up being raised in an on-going series of increases. Figure 21 highlights the increases in play production (*e.g.* the strong increasing production trends in the Montney play in Canada) that help explain increasing resource estimates. Not coincidentally, a good example in Canada of increasing resources would be the NEB's increased estimates of Montney resources in its 2013 Montney assessment[26].

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.

[24] 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.

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

[26] See supra note 22 and accompanying text.



Source: Navigant / LCI Energy Insight

Figure 21: Montney 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[27] 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[28] 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 simply a huge abundance of natural gas to serve Canadian needs for hundreds of years, actually a considerably longer resource life than in the U.S. A summary of the major Canadian gas resource plays that primarily make up this supply abundance appears in Table 2.

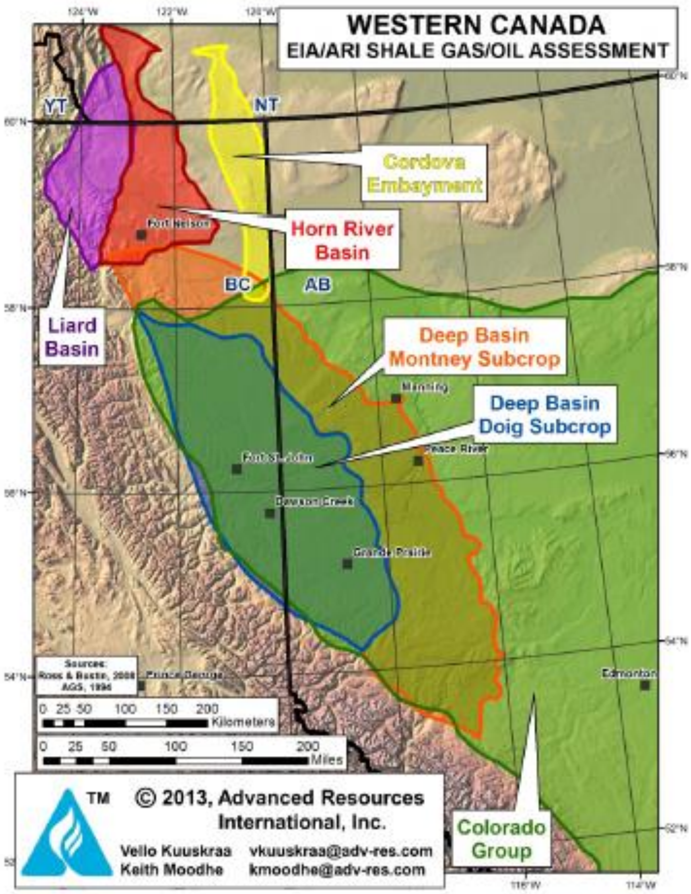
Table 2: Major Canadian Gas Resource Plays

		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

[27] See NEB Energy Future 2013, showing remaining marketable gas resources at 1,093 Tcf, less 222 Tcf of shale gas.
[28] See NEB Energy Future 2013, showing total WCSB remaining marketable gas resources at 861 Tcf, less 222 Tcf of shale gas.

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 22. The Duvernay, not shown, is located generally between Edmonton and Grand Prairie.



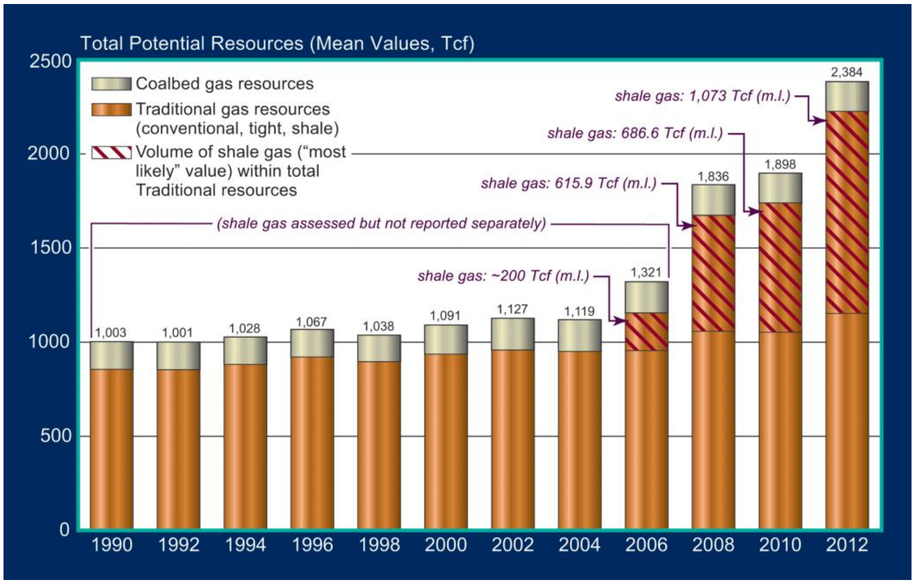
Source: U.S. E.I.A. Assessment

Figure 22: General Map of Western Canada Resource Plays

There is a similar impact of the shale revolution on U.S. resource estimates, where the Potential Gas Committee/Colorado School of Mine'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 45 percent in 2012 (or to 1,073 Tcf), as shown in Figure 23. The increase in the shale gas estimate itself since 2006 comes to over 430 percent. Combining the shale gas resource estimate with non-shale gas estimate yields total potential resources that show an 80 percent increase from 2006 (at 1,321 Tcf) to 2012 (at 2,384 Tcf). Accounting for proved reserves of 305 Tcf as well, the current total U.S. recoverable resource figure rises to 2,689 Tcf.[29] At the 2013 U.S. gas consumption rate[30], this resource endowment equals over 100 years' of U.S. natural gas supply.

[29] See 4/19/13 Press Release, "Potential Gas Committee Reports Significant Increase in Magnitude of U.S. Natural Gas Resource Base," Table 2.

[30] 71.6 Bcfd (26.1 Tcf/y), as forecasted by Navigant



Source: Potential Gas Committee

Figure 23: U.S. Potential Gas Committee Gas Resource Estimates

Even looking at just the last several 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)[31]. 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).[32] The average increase between these two sets of estimates that are only one to two years apart is 65 percent. That is how rapidly the resource estimates have continued to be ramping upwards.

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[33] to close to 400 Tcf today as more well data became available[34]. Figure 24 highlights the increases in Marcellus production that help explain its increasing resource estimates.

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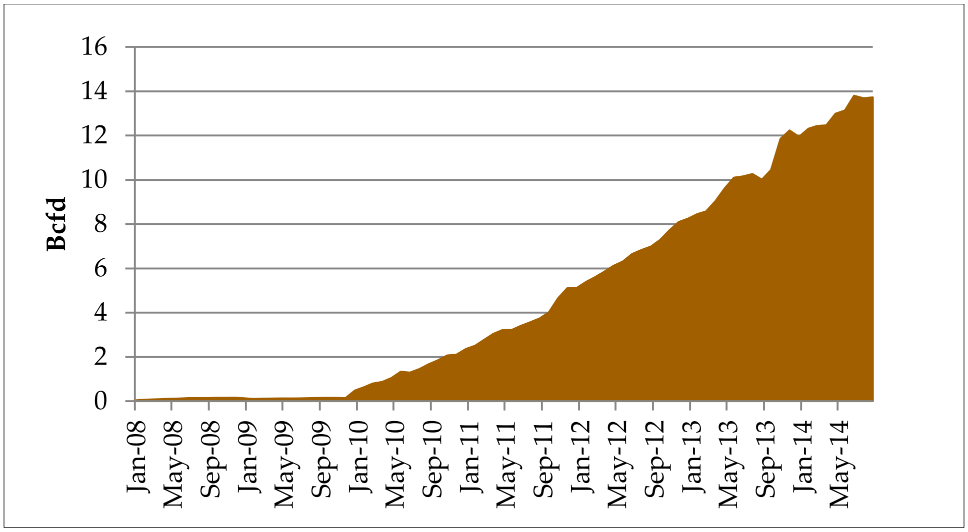
[31] *The Rice World Gas Trade Model: Development of a Reference Case*, Kenneth B. Medlock III, James A Baker III Institute for Public Policy, Rice University, May 9, 2011, slide 17; *The Future of Natural Gas*, Ernest J. Moniz, et al, Massachusetts Institute of Technology, June 2011, Chapter 1, p.7; Potential Gas Committee Press Release, "Potential Gas Committee Reports Substantial Increase in Magnitude of U.S. Natural Gas Resource Base", April 27, 2011.

[32]*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.

[33] *Marcellus Shale Play's Vast Resource Potential Creating Stir in Appalachia*, American Oil & Gas Reporter, T. Engelder and G. Lash, May 2008.

[34] See e.g. U.S. E.I.A. Assessment, supra note 21, at Attachment C, Table A-1.



Source: Navigant / LCI Energy Insight

Figure 24: Marcellus Production History

Including the estimated natural gas resources and domestic demand of Mexico, along with that of Canada and the U.S., leads to a North American resource life estimate of 146 years. Resource life estimates are summarized in Table 3.

Table 3: 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	3.7	392
U.S.	1,458	1,231	2,689	26.1	103
Mexico	-	545	545	2.3	242
North America	1,880	2,798	4,678	32.1	146
Sources: U.S. E.I.A. Assessment; NEB Energy Future 2013; Navigant forecast; Potential Gas Committee					

4.1.1.2 Production Efficiency

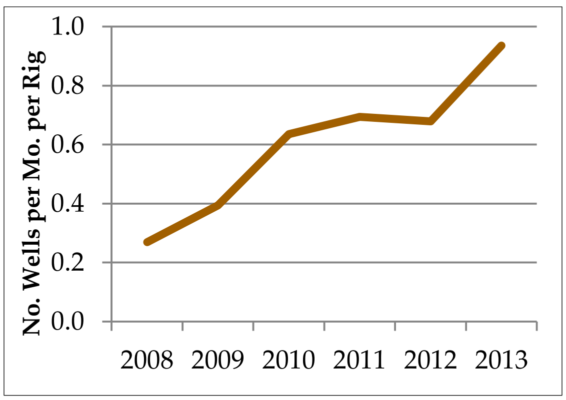
Shale gas production efficiency has continued to improve over time in both Canada and the U.S. As reported by the Province of Alberta, in some locations, 16 wells can be drilled on the same pad, which helps decrease downtime from rig moves.[35] The lengths of horizontal runs, once limited to several hundred feet, can now reach up to 3,000 meters.[36] The number of fracture zones reportedly has increased from four to up to 24 or more in some instances.[37] The efficiencies in drilling and production can be

[35] See "Improved Productivity in the Development of Unconventional Gas", Technical Study for Productivity Alberta, May 2012, at 10.

[36] Id.

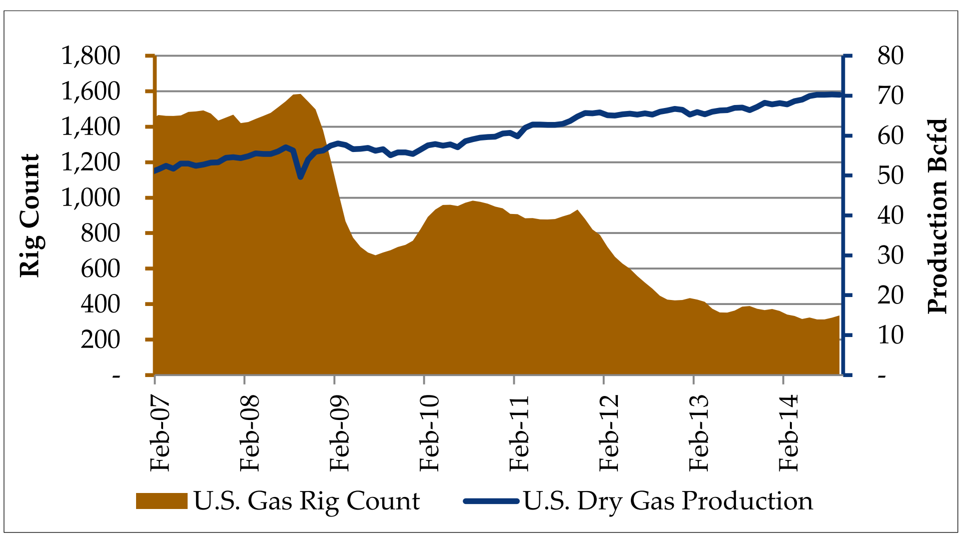
[37] "Magnum Hunter pushes Eagle Ford completions with longer laterals, greater frac stages", Oil & Gas Financial Journal, December 1, 2011.

clearly seen by looking at metrics examined in a recent article by Navigant.[38] 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 25 shows that in the Eagle Ford play in Texas, the average rig drilled three wells per year in 2008, but 11 wells per year in 2013. 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 400, as can be seen in Figure 26. 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. While recent declines in global oil prices may have an impact on levels of oil-directed drilling, any effects on production of associated gas should be countered by the presence of readily available dry gas resources in already drilled wells.



Source: Navigant / LCI Energy Insight

Figure 25: Eagle Ford Rig Efficiency



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

Figure 26: U.S. Gas Production and Rig Count History

While the cost of producing commercial quantities of gas does vary from play to play, and even within a play, the overall trend has been for drilling and completion costs to decline as producers gain knowledge

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

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.[39]

Improvements continue in other aspects of hydraulic fracturing technology, and recent initiatives taken by producers seem to address some of the more contentious issues, such as water use. For example, Range Resources is pioneering the use of recycled flowback water, and by October 2009 was successfully recycling 100 percent of water used in its core operating area in southwestern Pennsylvania. Range estimates that 60 percent of Marcellus shale operators are recycling some portion of flowback water, noting that such efforts can save significant amounts of money by reducing the need for treatment, trucking, sourcing, and disposal activities.[40] It has been reported that Apache is recycling 100 percent of its produced water in the Permian Basin, Chesapeake is reusing nearly 100% of its produced water in the Marcellus region, and Anadarko and Shell are buying effluent water from local municipalities.[41] "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[42], cold compressed natural gas[43], or high pressure nitrogen.[44] Besides reducing issues related to water use, waterless fracking can also increase well yields.[45]

These and other efforts to continue to improve water management will tend to enhance the ability of shale operations to expand in both Canada and the U.S. in the future.

4.1.2 Outlook for Supply

Navigant forecasts a 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

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[39] See Keyera Corp. company presentation 9/23/13 (available at https://www.keyera.com/titanweb/keyera/webcms.nsf/AllDoc/6E64209AB560271887257BEF005A93B9/$File/September%202013%20corporate%20profile_%20sept%2020.pdf), citing Peters & Co. breakeven analysis as of Jan. 2013 at slide 24, and Keyera Corp. company presentation 5/17/12, citing Peters & Co. breakeven analysis as of Jan. 2012 at slide 14. "Economic" referred to the breakeven gas price for production operations to yield internal rates of return of 10 percent.

[40] "Range Answers Questions on Hydraulic Fracturing Process ," Range Resources, http://www.rangeresources.com/Media-Centre/Featured-Stories/Range-Answers-Questions-on-Hydraulic-Fracturing-Pr.aspx. Accessed April 10, 2014.

[41] *Hydraulic Fracturing & Water Stress: Water Demand by the Numbers*, Report by Ceres, January 2014, p. 12.

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

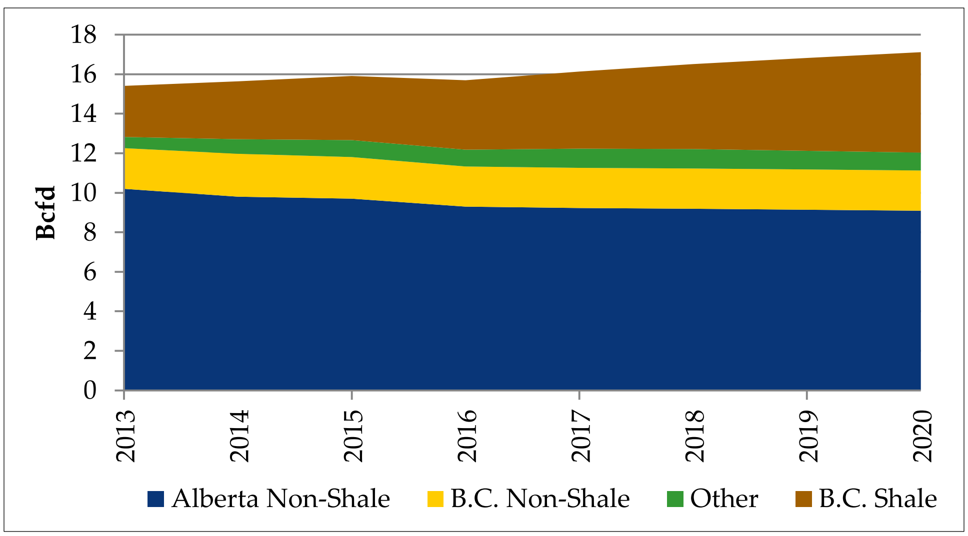
[43] Expansion Energy's VRTG process uses cryogenically processed natural gas from nearby wells or from the target formation itself as the fracturing medium, virtually eliminating chemical additives no longer needed to mitigate the impacts of water, according to www.expansion-energy.com.

[44] 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.

[45] 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.

Alberta and Saskatchewan. 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, Navigant anticipates that the outlook for Alberta may improve as prospective unconventional plays start to produce gas and are brought into our forecast. 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[46], or the Montney's 2,133 Tcf of gas-in-place estimated by the province's Energy Resources Conservation Board[47], Alberta should be favorably positioned for a ramping up of unconventional production, especially given its strong existing infrastructure base of pipelines and processing capacity. In total, gas production increases in Canada are driven by increases in production from Western Canada.

More specifically, as indicated in Figure 27, Navigant forecasts an increase for Canadian dry gas production of 11 percent between 2013 and 2020 (from 15.4 to 17.1 Bcfd), driven by increases in British Columbia shale gas production that build on smaller decreases in conventional natural gas production in Alberta. Navigant forecasts B.C. shale gas production to increase 96 percent between 2013 and 2020, increasing from 2.6 Bcfd (17 percent of total national production) to 5.1 Bcfd (30 percent of total national production). Alberta production, on the other hand, is forecast to decrease about 11 percent over the same period, from 10.2 Bcfd (66 percent of total national production) to 9.1 Bcfd (53 percent of total national production).



Source: Navigant Mid-Year 2014 Outlook

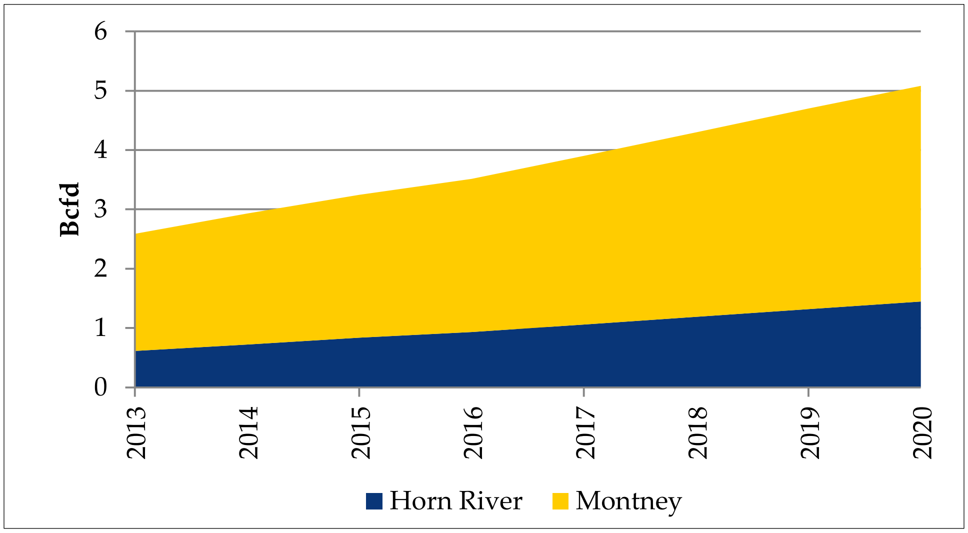
Figure 27: Canadian Dry Gas Production Forecast Breakout

The modest conventional production occurring in B.C. is forecast to hold steady at about 2.0 Bcfd, dropping from 13% of national production in 2013 to 12% in 2020. Production in the balance of Canada (outside of B.C. and Alberta) is forecast to slightly increase, though it will still be only about 5.3 percent

[46] See discussion on page 21, supra, of the U.S. E.I.A. Assessment.

[47] 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.

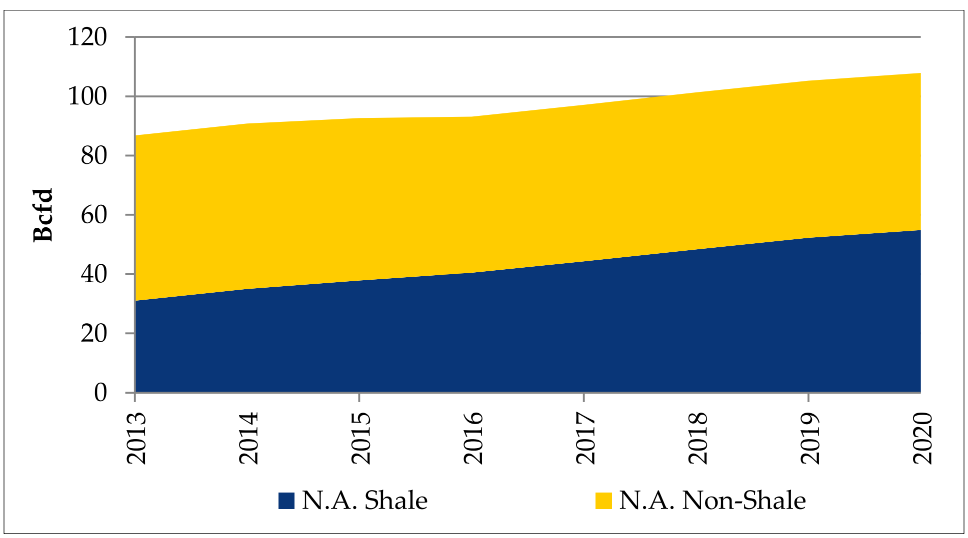
of total national production in 2020. Navigant's B.C. shale forecast is based on the existing Horn River and Montney plays, whose forecast production is shown in Figure 28.



Source: Navigant Mid-Year 2014 Outlook

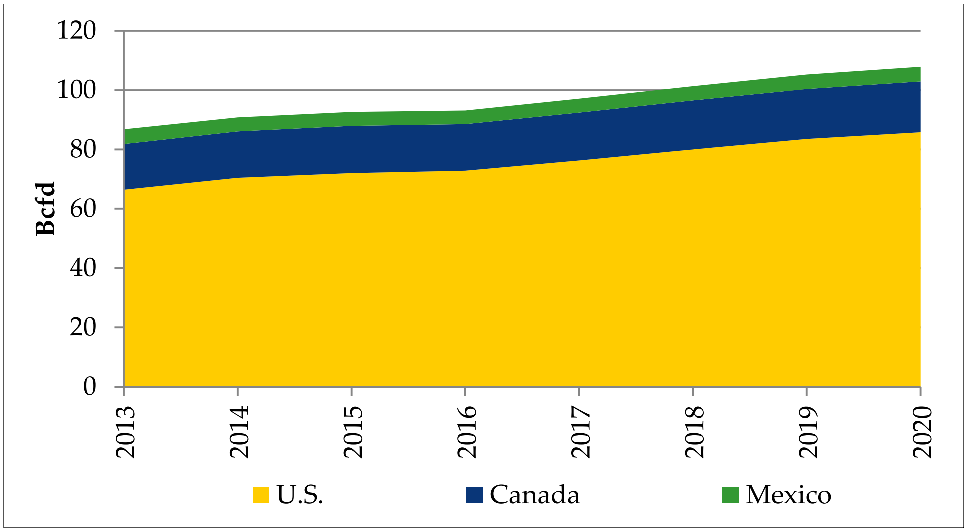
Figure 28: Canadian Shale Gas Production Forecast

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 29 highlights the 77 percent increase in North American shale gas production from 31.0 Bcfd in 2013 to 54.9 Bcfd in 2020, leading to an overall 24 percent increase in total North American production from 86.8 Bcfd in 2013 to 107.9 Bcfd in 2020, at which point shale gas will account for 51 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. A country-level forecast for North American production is shown in Figure 30.



Source: Navigant Mid-Year 2014 Outlook

Figure 29: North American Natural Gas Production Forecast by Type



Source: Navigant Mid-Year 2014 Outlook

Figure 30: North American Natural Gas Production Forecast by Country

4.2 *Sector Gas Demands*

4.2.1 Electric Generation Sector

The recent trends toward gas-fired electric generation are expected to continue as coal-fired generation becomes less and less attractive given environmental policies and regulations that either mandate a move away from coal, or make its use uneconomic. In addition, the push for renewables will continue the need for additional gas-fired generation to help electrically integrate new renewables. Another important factor impacting Ontario's generation mix will be changes to the nuclear power plant fleet as older units are set aside for refurbishment. 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 licensed *PROMOD* software model, but 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[48], 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. **Table** 4 shows the trends in fuel source estimated by POM for Ontario and Canadian power generation, through 2025. The forecast is for the gas-fired generation portion in Canada to triple by 2025 to 18%, and the gas-fired portion of Ontario generation to increase four-fold by 2025 to 29%. We are showing the mix to 2025, beyond the 2020 outlook period, because Ontario gas-fired generation reflects only a partial ramp-up to 12% by 2020. The increase in gas-fired generation comes at the expense of nuclear generation, which drops from 59% to 38% in 2025 in Ontario and from 18% to 11% in Canada. Coal-fired

[48] 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.

generation as a percent of Canadian generation is forecast to drop to less than half of the gas-fired percentage, while in Ontario coal-fired generation is forecast to be completely eliminated. In both Canada and Ontario, hydro generation remains relatively stable, in the mid-50% range and at 24%, respectively. It should be noted that while the electric generation sector is an emerging sector that will become more important over time, it currently represents a relatively small portion of total gas demand in Ontario and in Canada.

Table 4: Ontario and Canada Generation Mix by Fuel

	Generation Mix by Fuel				
	Ontario			Canada	
Fuel	2014	2020	2025	2014	2025
Gas	7%	12%	29%	6%	18%
Coal	1%	0%	0%	11%	8%
Oil	0%	0%	0%	0%	0%
Nuclear	59%	52%	38%	18%	11%
Hydro	24%	25%	24%	58%	54%
Wind	6%	8%	7%	5%	8%
Solar	0%	0%	0%	0%	0%
Biomass	2%	2%	2%	2%	1%

Source: Navigant POM model

4.2.2 LNG Exports

A significant emerging trend is the expectation for Canadian and U.S. exports of liquefied natural gas (LNG). In the wake of dramatically increasing gas production, lower gas prices, and improved economic potential for LNG exports, many project developers have joined the fray in the last several years. Our count currently comes to about 37 Bcfd for 17 Canadian projects and 39 Bcfd for 26 U.S. projects. Navigant's assumed level of ultimate North American LNG exports is currently 8 to 10 Bcfd, with 9.3 Bcfd in our reference case for the 2014 Mid-Year Outlook. Since the current environment of supply abundance creates the potential for an unbalanced market that could potentially lead to stagnation of gas asset development, 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.

An important point to note is that this 2014 Natural Gas Market Review estimates North American LNG exports at about 7.5 Bcfd in 2020, on the way to an ultimate level of 9.3 Bcfd by 2023. [49] This forecast is in contrast to the much smaller figure of 0.8 Bcfd estimated in the 2010 Review.[50] Similarly, the 2010 Review forecast North American LNG imports to increase to 3.7 Bcfd in 2020,[51] as opposed to the continuation of the modest current imports of less than one Bcfd assumed in this 2014 Review.

[49] Navigant's scenario analysis, discussed in Section 4.4.2, includes modifications for an extra 1.2 Bcfd of East Coast LNG exports, as well as both earlier and later project on-line dates.

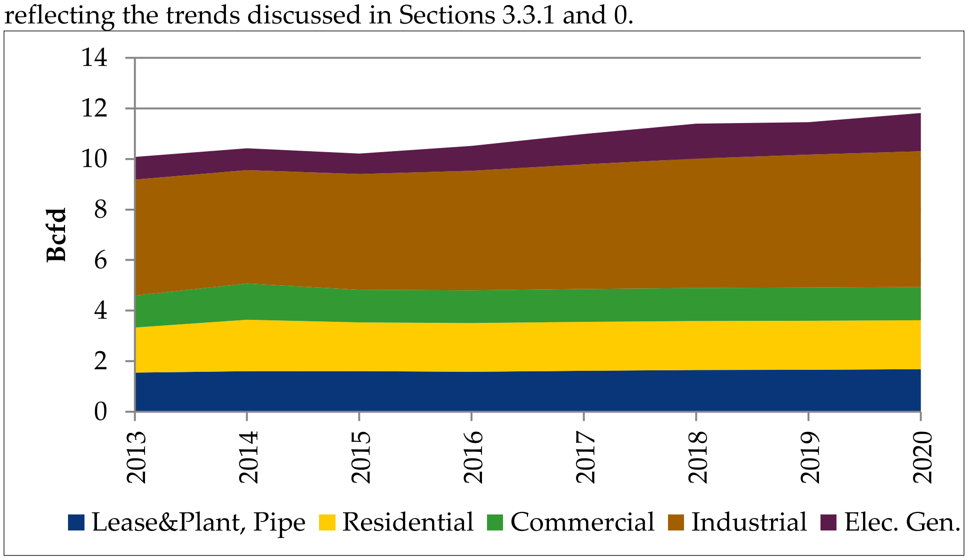
[50] See 2010 Natural Gas Market Review, supra note 12, p. 52.

[51] Id.

It is important also 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 2030 estimates global LNG exports at about 70 Bcfd in 2030[52], while global liquefaction capacity in 2030 of current (operational plus under construction) projects is estimated at about 50 Bcfd.[53] Grossing up demand for a 90 percent utilization factor (to 78 Bcfd) means new liquefaction capacity of about 28 Bcfd would be needed worldwide by 2030, based on these projections. Even if a full 50 percent of new global capacity were to be located in North America, which is highly unlikely, that would be 14 Bcfd, which is less than 20% of all project capacity approved and applied for in North America[54]. To us, this indicates that most LNG liquefaction projects currently being proposed in North America will not be built.

4.2.3 Outlook for Demand

As indicated in Figure 31, Navigant's forecast of Canadian natural gas demand shows an increase from 10.1 Bcfd in 2013 to 11.8 Bcfd in 2020, an increase of 17 percent. The largest increases by Canadian demand category are for industrial use (including oil sands), increasing 17 percent from 4.6 Bcfd to 5.4 Bcfd, followed by electric generation requirements, increasing 67 percent from 0.9 Bcfd to 1.5 Bcfd, reflecting the trends discussed in Sections 3.3.1 and 0.



Source: Navigant Mid-Year 2014 Outlook

Figure 31: Canadian Natural Gas Demand Forecast by Sector

Looking at the province-level outlooks reveals the general increasing trend in Alberta (for industrial usage), as well as a more distinct increase in Ontario in the 2021-2023 period (with the chart extended from 2020 to 2025 for this purpose).

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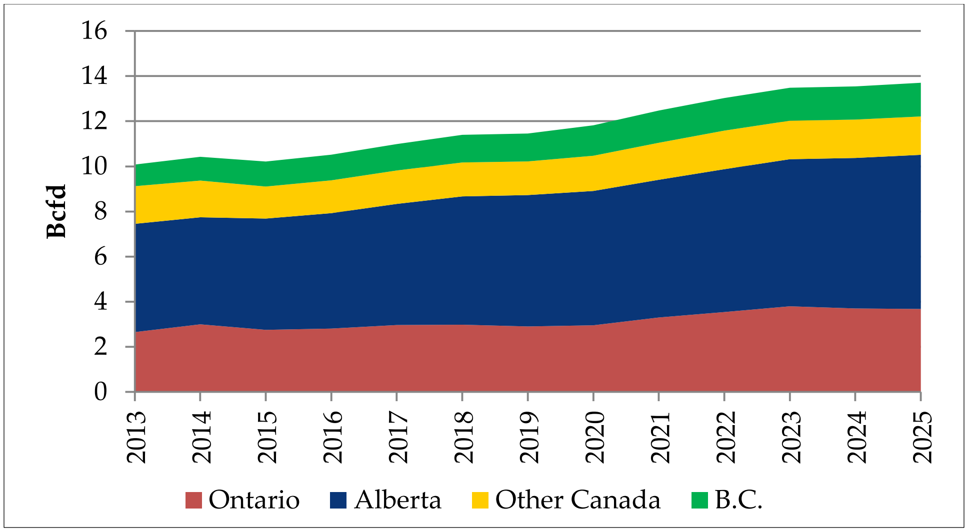
[52] *BP Energy Outlook 2030*, January 2013, slide 22 ("Gas trade and market integration").

[53] *Global LNG: Now, Never, or Later?* Canadian Energy Research Institute, Study No. 131, January 2013, Figure 2.2.

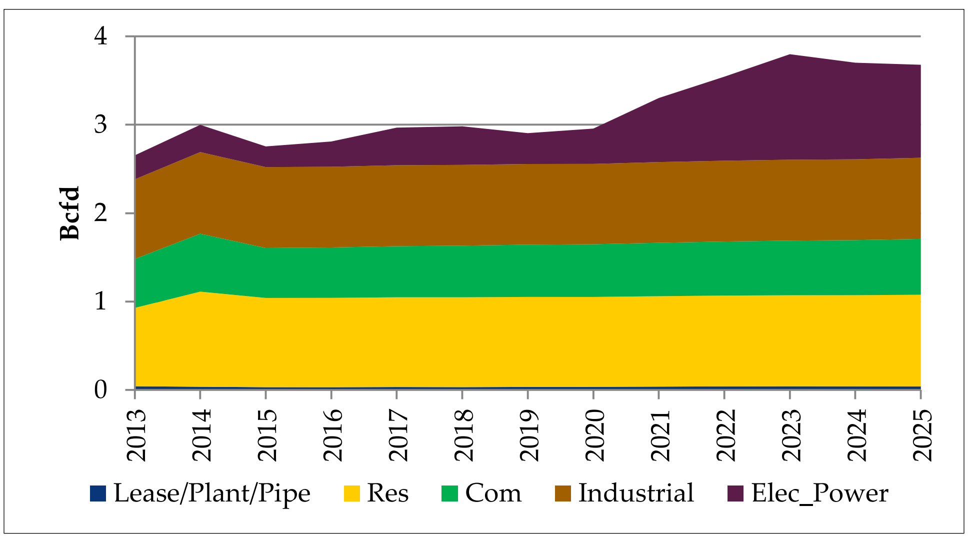
[54] Estimated capacity is about 37 Bcfd for 17 Canadian projects and about 39 Bcfd for 26 U.S. projects.



Source: Navigant Mid-Year 2014 Outlook

Figure 32: Canadian Natural Gas Demand Forecast by Province

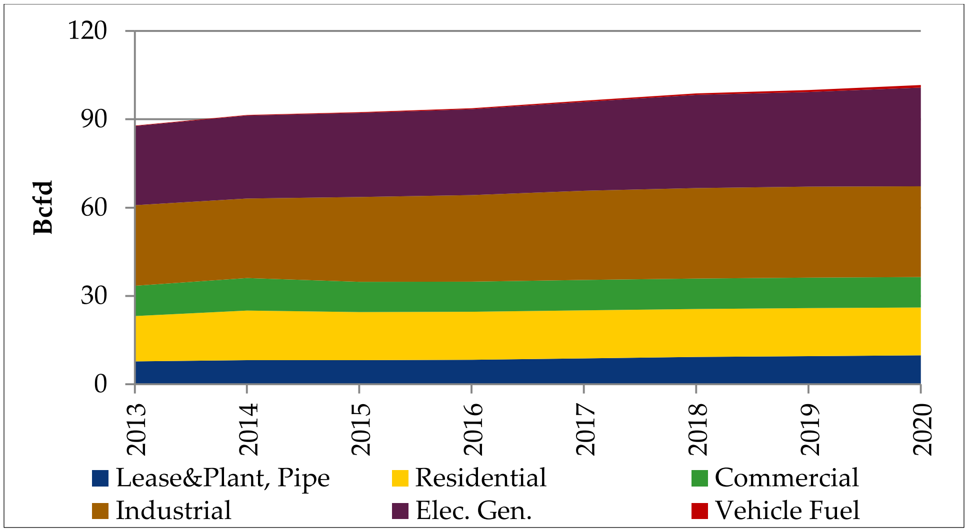
By review beyond the 2020 outlook, the nature of the Ontario demand increase can be seen to be due to forecast electric generation growth, increasing electric generation gas from 0.3 Bcfd in 2013 to 1.1 Bcfd in 2025, an increase of 288 percent.



Source: Navigant Mid-Year 2014 Outlook

Figure 33: Ontario Natural Gas Demand Forecast by Sector

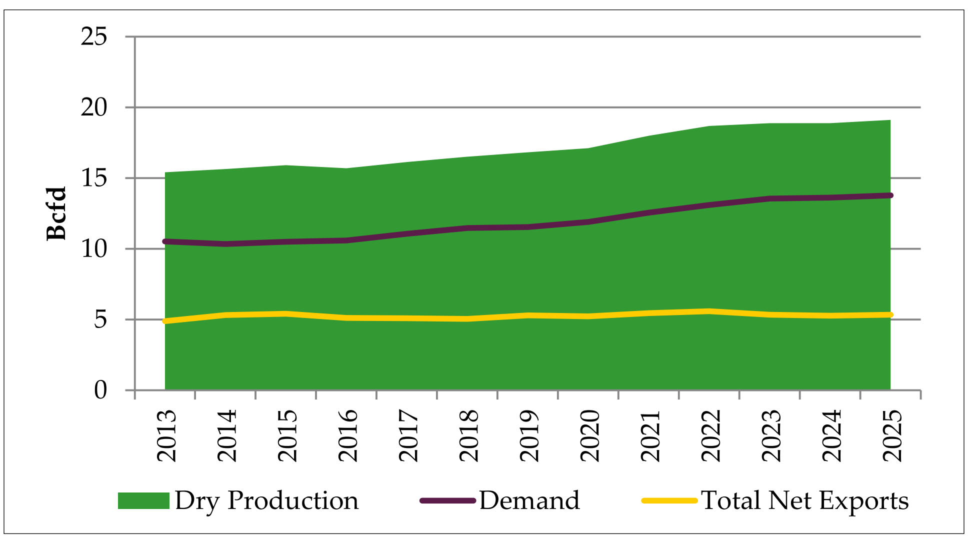
North American natural gas demand is forecast to increase 16 percent, from 87.9 Bcfd in 2013 to 101.6 Bcfd in 2020, as shown in Figure 34.



Source: Navigant Mid-Year 2014 Outlook

Figure 34: North American Natural Gas Demand Forecast by Sector

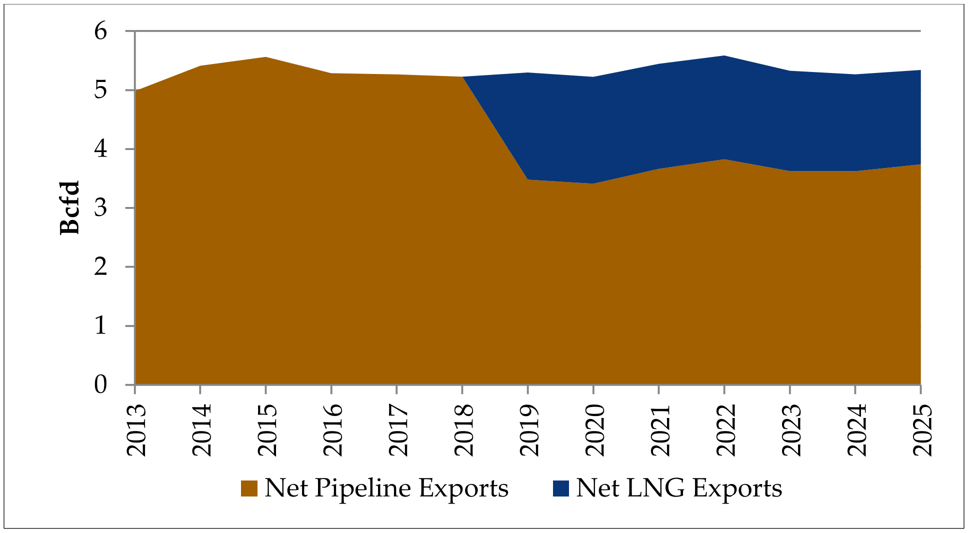
The forecast of total Canadian dry gas production is shown in Figure 35 along with total domestic Canadian natural gas demand. As can be seen, the production forecast compared to the demand forecast yields a stable to increasing level of net exports (by pipeline or LNG liquefaction), at over 5 Bcfd (representing an average of about 30 percent of national production). Thus, strong production growth is clearly able to meet increasing Canadian demand.



Source: Navigant Mid-Year 2014 Outlook

Figure 35: Canadian Supply-Demand Balance

The components of net total exports are shown in Figure 36. 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. 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.



Source: Navigant Mid-Year 2014 Outlook

Figure 36: Net Canadian Pipe and LNG Export Forecast

4.3 Pipeline and Storage

4.3.1 Inter-regional Pipeline Flows

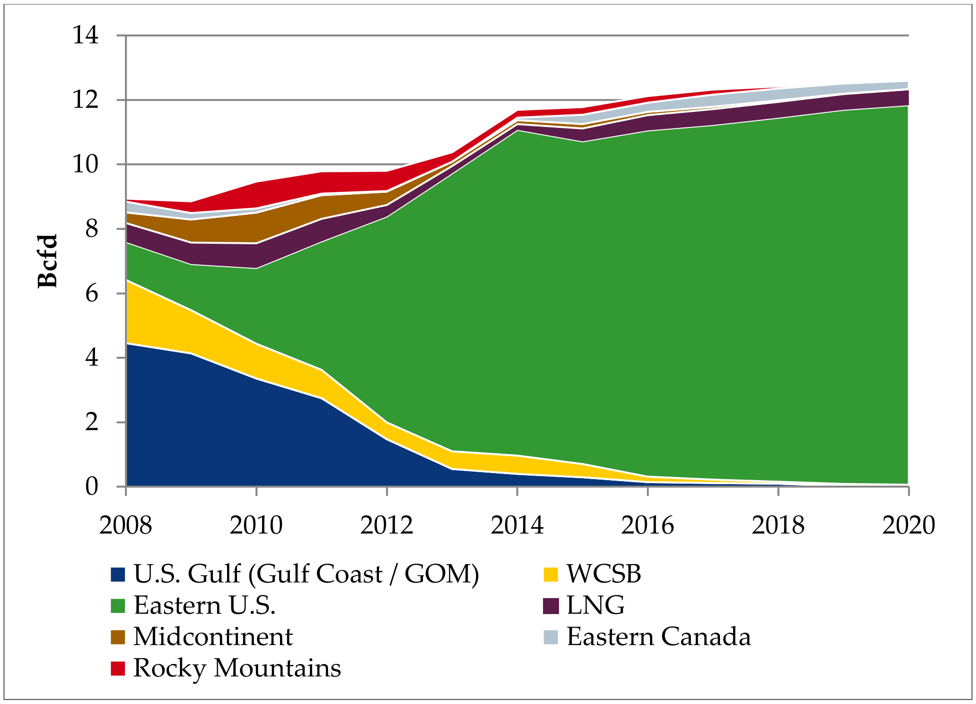
4.3.1.1 Displacement by: Marcellus in the U.S. Northeast

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.[55] An indicator of this dynamic is the change in supply patterns to the U.S. Northeast market, as can be seen in Figure 37. With the strong development of the Marcellus play after 2008, a clear displacement of other gas supply sources to the U.S. 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 44 percent share (an 89 percent reduction) and a 16 percent share (a 76 percent reduction), respectively, since 2008.[56] 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. The NEB recently 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[57], and has led to increasing imports into Canada from the U.S.[58]

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

[56] Gulf share dropped from 49 percent to 5 percent; WCSB share dropped from 21 percent to 5 percent.

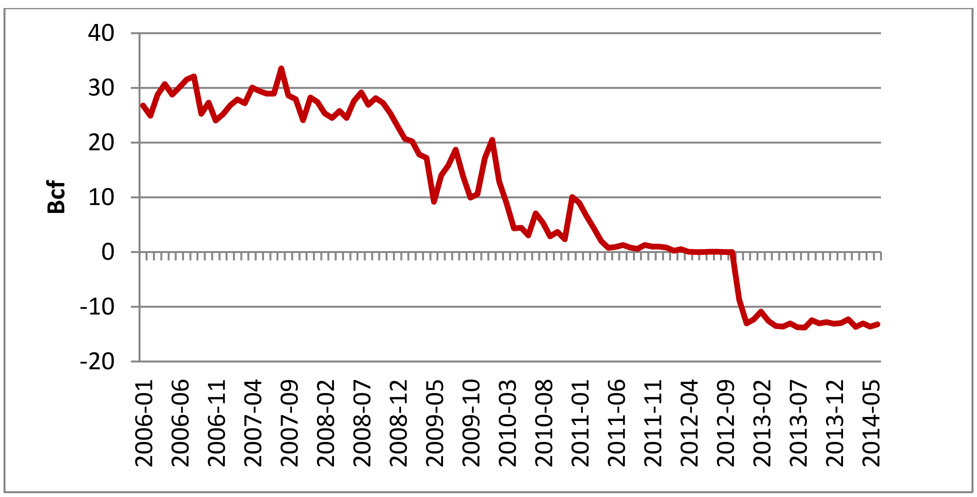
NEB Energy Future 2013 at 15.



Source: Navigant Mid-Year 2014 Outlook

Figure 37: U.S. Northeast Natural Gas Demand by Sourcing Area

As traditional Northeast gas supplies have been displaced, there have been related changes in pipeline flows. For example, the diminishing exports of WCSB supplies to serve U.S. Northeast demand, coupled with the availability of Marcellus supplies, have led to a virtual reversal of flows between Ontario and the U.S. at Niagara. As shown in Figure 38, as of late 2012, Niagara has been a net import point, with monthly net exports reaching up to 14 Bcf. This development far exceeds the estimate in the 2010 Review for net Niagara flows into Canada that was forecast to be about 0.3 Bcf per month.[59]



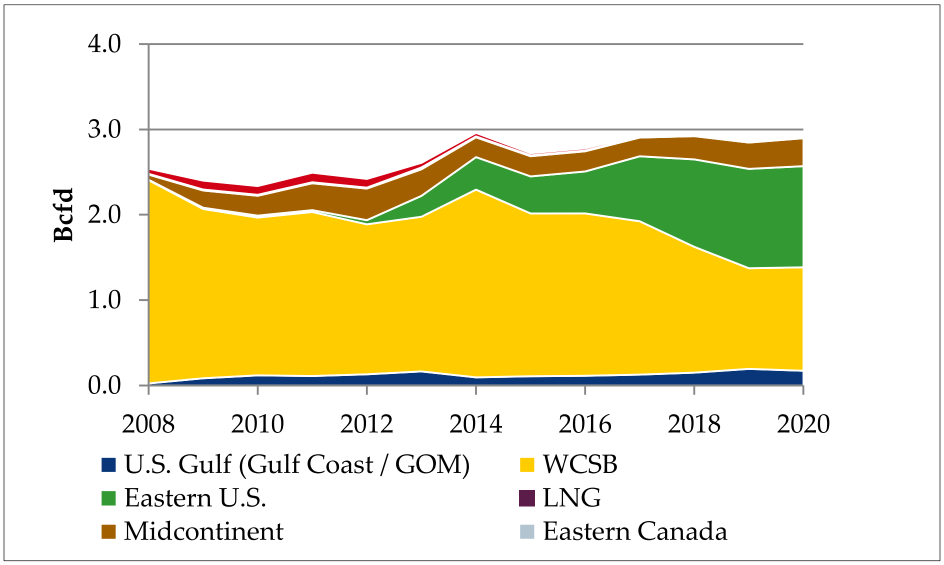
Source: NEB

Figure 38: Net Monthly Natural Gas Exports from Canada at Niagara

[59] See 2010 Natural Gas Market Review, supra note 12, p. 63.

4.3.1.2 Outlook for Interregional Flows

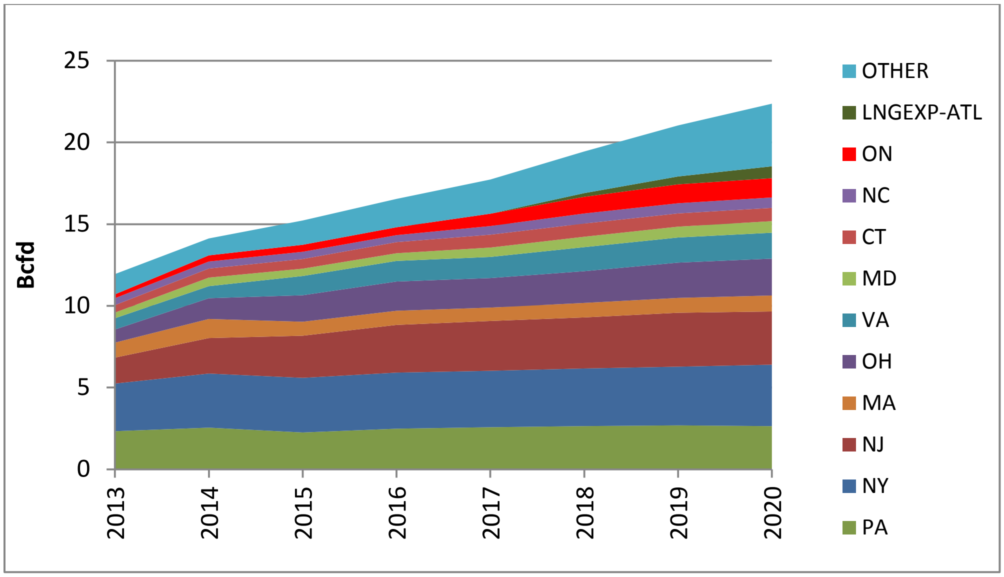
The projected pattern of interregional dynamics for meeting Ontario gas demand is consistent with the trend for meeting U.S. Northeast demand shown in Figure 37 (displacement of WCSB supplies by Marcellus supplies), but starting later. As shown in Figure 39, Navigant estimates that between 2014 and 2020, the percentage of Ontario demand met by WCSB supplies will drop from 74% to 42%, while the percentage met by Marcellus supplies will increase from 13% to 41%.



Source: Navigant Mid-Year 2014 Outlook

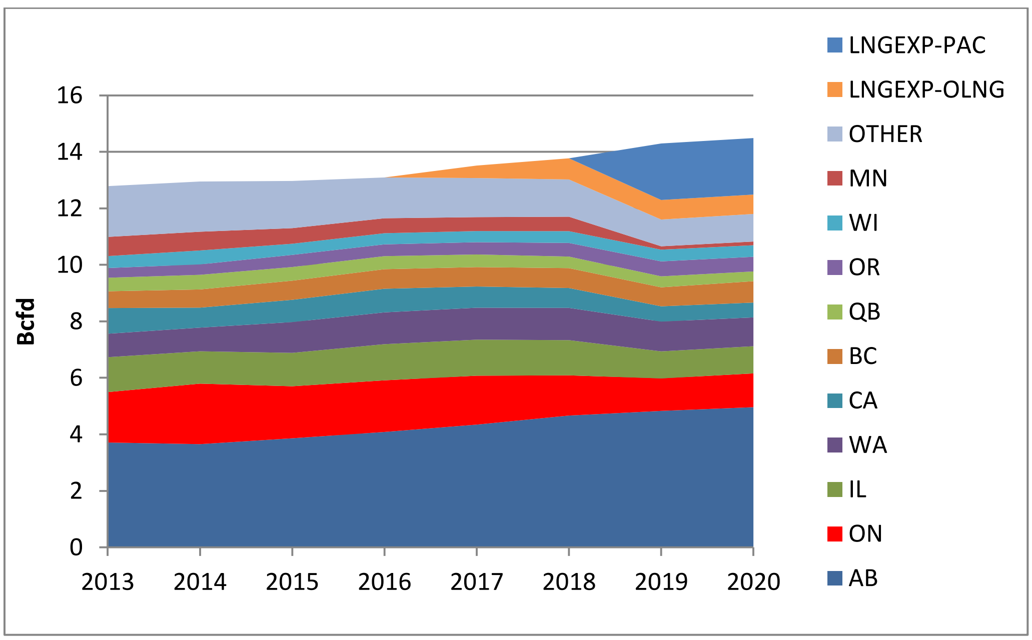
Figure 39: Ontario Natural Gas Demand By Sourcing Area

Figure 40 and Figure 41 show the forecast allocation by the market of Marcellus and Western Canadian gas supplies to various demand regions. These forecast destinations for gas supplies are another way to show the impact of changing interregional dynamics on Ontario, with its Marcellus supplies increasing and its Western Canadian supplies decreasing. An interesting aspect to note is the relatively small proportion of the Marcellus that is actually destined for the Ontario market. In other words, there is a lot more gas being produced that could potentially be redirected. A similar if slightly less obvious situation applies to the relative proportion of the Western Canadian supplies that are used to serve Ontario.



Source: Navigant Mid-Year 2014 Outlook

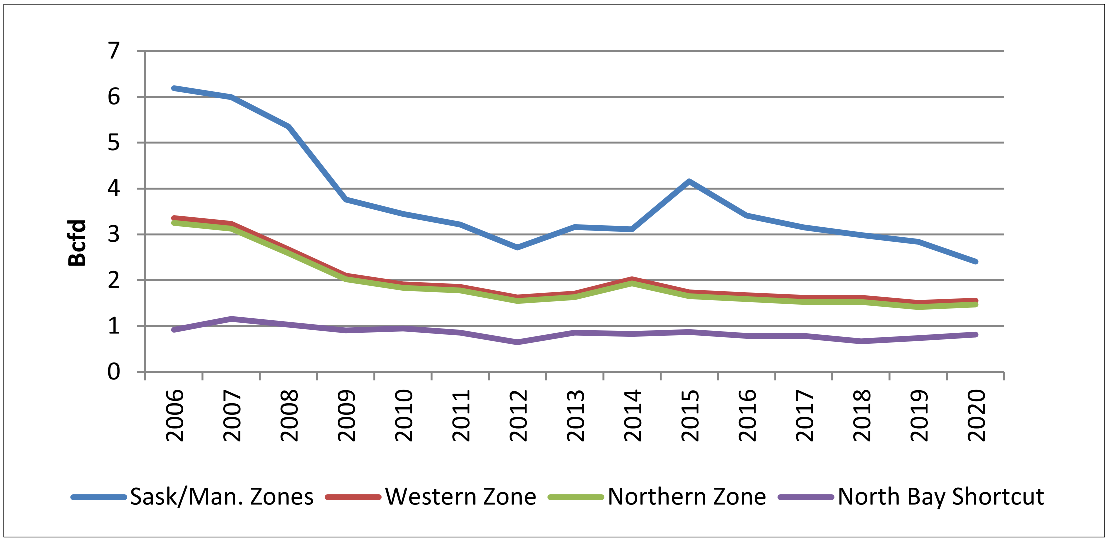
Figure 40: Destinations for Marcellus Gas Supply



Source: Navigant Mid-Year 2014 Outlook

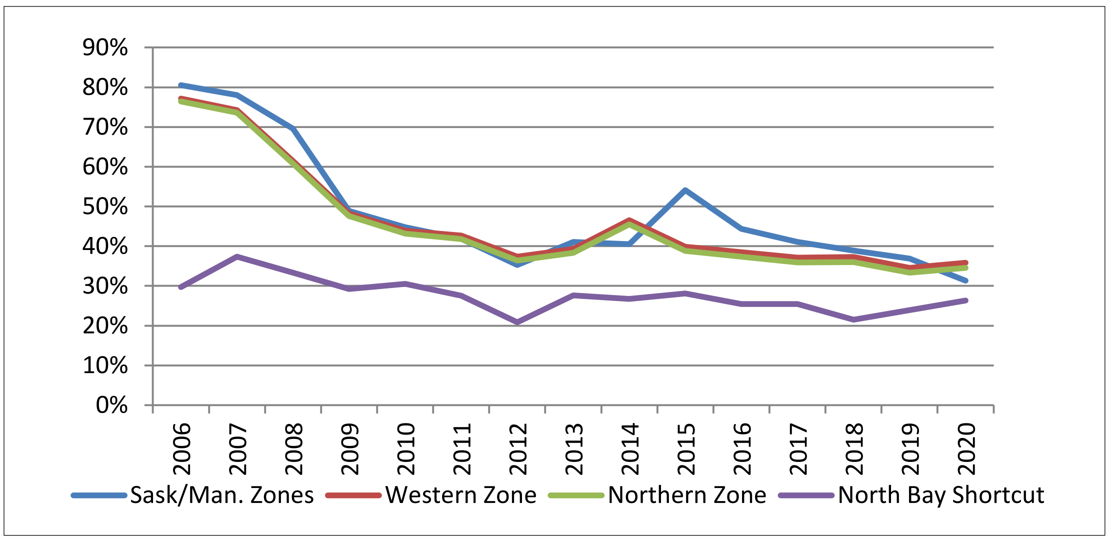
Figure 41: Destinations for Alberta and B.C. Gas Supply

Consistent with the continued decrease in expected usage of Western Canadian natural gas in Ontario, Navigant's forecast projects continued diminished utilization levels of the TCPL Mainline. As shown in Figure 42, flows are projected to generally be 3.5 Bcfd or less in the Prairie Segment zones, 2 Bcfd or less in the Western and Northern Zones in Ontario, and 0.8 Bcfd of less on the North Bay Shortcut in the Eastern Zone. These levels leave projected unused capacity of about 4.2 Bcfd, 2.3 Bcfd, and 2.3 Bcfd, respectively. These forecasts reflect utilization levels of generally in the range of 35% to 45% for the Saskatchewan and Manitoba zones and the Western and Northern Zones in Ontario, and 20% to 30% for the North Bay Shortcut, as shown in Figure 43.



Source: Navigant Mid-Year 2014 Outlook

Figure 42: Historical and Forecast TCPL Mainline Throughput



Source: Navigant Mid-Year 2014 Outlook

Figure 43: Historical and Forecast TCPL Mainline Utilization

4.3.2 Pipeline Infrastructure

4.3.2.1 TCPL Mainline—Energy East Conversion

Navigant's reference case does not include the conversion of TCPL capacity from gas to oil service for the proposed Energy East project. Navigant's forecast of projected continued capacity surplus on the Mainline, in excess of the Energy East pipeline conversion capacity, seems to suggest that the project would not impair the Ontario natural gas market by restricting expected flows of Alberta and Western Canadian natural gas to Ontario. In addition, if Energy East moves forward, we could foresee a circumstance where other natural gas pipeline projects being developed to serve the area would be incented to move their projects forward if they viewed their competitive prospects as having been improved by the reduction of other natural gas transport capacity into eastern Canada resulting from

Energy East's Mainline conversion. But to properly assess the impact of the Energy East project, Navigant has included the decommissioning of a portion of the TCPL Mainline via the Energy East project in its modeled scenario analysis, discussed in Section 4.4.2.

4.3.2.2 New Pipes to Move Marcellus/Utica Gas to Markets and to Serve Potential Eastern Canadian LNG Exports

Infrastructure developments occurring in the U.S. Northeast are further evidence of the new interregional dynamics. 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), and Tennessee Gas Pipeline's Niagara Expansion (158 MMcfd).[60] 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), Algonquin's Atlantic Bridge (500 MMcfd) and Incremental Market (342 Bcfd) projects, National Fuel Supply's Northern Access project (350 MMcfd), and Tennessee Gas Pipeline's Northeast Energy Direct project (1.2 Bcfd). To assess scenarios with more or less assumed pipeline connectivity to new U.S. supplies, Navigant modified certain infrastructure assumptions in its scenario analysis discussed in Section 4.4.2.

4.3.3 Storage Infrastructure

Storage plays an important role in balancing North American natural gas supply and demand and helping to assure reliable gas delivery for consumers. As was seen in the winter of 2013-14 just past, storage played a very important role in keeping natural gas prices in check (even though the extent of the weather contributed to historically high prices in some areas), but more importantly providing for supply assurance to be able to offset short term peak demand requirements as a result of the extreme temperatures experienced over vast regional areas last winter.

As natural gas demand continues to grow in Ontario, storage will play an increasingly important role in assuring that increasing dispatchable non-base load gas electric generation capacity will be assured of reliable gas supply. Fortunate for Ontario, the province as we mentioned in Section 3.4.1 already contains significant storage capacity and with the Dawn storage facility is home to the largest gas storage facility in Canada. Gas Prices, Basis, and Volatility

4.4 Gas Prices, Basis and Volatility

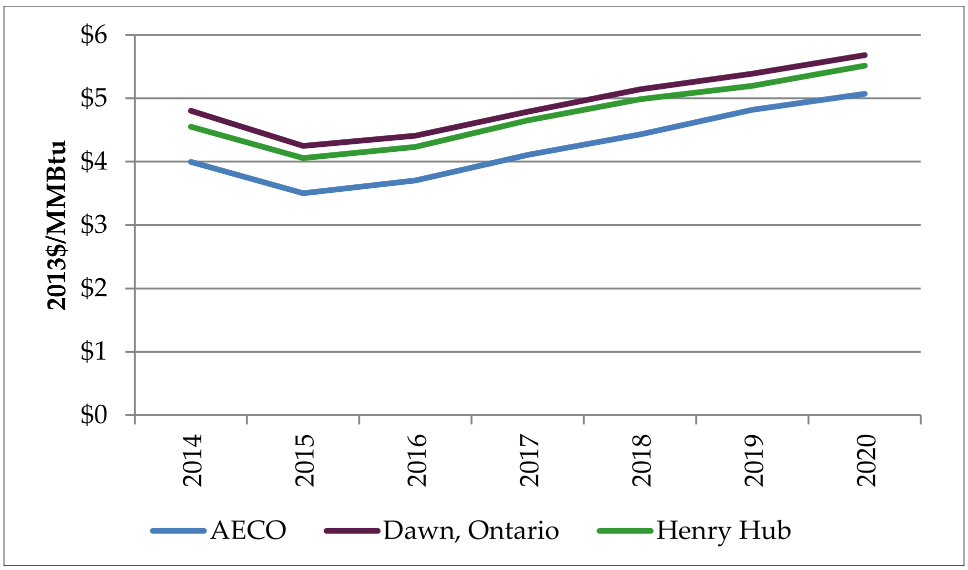
4.4.1 Outlook for Prices

Navigant's outlook for the North American natural gas market projects reasonable and competitive pricing conditions and a period of relatively less volatile natural gas prices. As the result of the key technological breakthrough of hydraulic-fracturing of gas shale through horizontal drilling, production-related activities rather than exploration are now the key factors in supply, and the market is not expected to revert to its previous fundamental structure where exploration risk drove at least a portion

[60] 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 12/17/13 press release announcing binding precedent agreement with Seneca for Niagara Expansion capacity.

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.

As shown in Figure 44, Henry Hub prices through 2020 are forecast to average about $4.75 per MMBtu, topping out at $5.51per MMBtu in 2020. Hub prices in Alberta (AECO) are projected to be lower, averaging less than $4.25 per MMBtu, and remaining below $5.10 per MMBtu through 2020. Prices at Dawn are projected to track price trends just above Henry Hub, averaging about $4.90 per MMBtu, and reaching $5.68 per MMBtu in 2020. Included in this outlook are LNG export volumes growing to about 7.5 Bcfd from North America in 2020 to account for expected increasing global gas on gas competition, and reflecting a partial ramp-up of Navigant's current market view of a range of 8 Bcfd to 10 Bcfd for long-term North American LNG exports.



Source: Navigant Mid-Year 2014 Outlook

Figure 44: Natural Gas Price Outlook

4.4.2 Outlook Scenarios

To provide a range of price outlooks around the reference case forecast, Navigant undertook several scenarios that incorporated a variety of modifications to assumptions of particular interest. The scenarios have been designated "high demand case" and "low demand case", and are outlined in Table 5.

Table 5: Summary of Scenario Analysis Assumptions

Assumption	Reference Case	Low Demand Case	High Demand Case
Mainline Settlement (RH-001-2014)	Rate Increase Not Included (*)	Rate Increase Included	Rate Increase Included
Energy East Conversion	Excluded	Excluded	Included
East Coast LNG Exports--Volumes	0.8 Bcfd by 2020	0.8 Bcfd by 2020	2.0 Bcfd By 2020
West Coast Canada LNG Exports--Timing	2019 online	2020 online	2018 online
West Coast US LNG Export--Timing	2017 Online	2018 online	2017 Online

Alberta Oil Sands Gas Demand	1.9 Bcfd in 2016	20% below base starting in 2016	20% above base starting in 2016
Marcellus to Dawn Pipelines	Includes Nexus path at 1 Bcfd; Includes Niagara path at 0.3 to 1.0 Bcfd	1) Expanded Nexus path (with Vector connector) by Incremental 1 Bcfd; 2) Expanded Niagara path (National Fuels to Tenn to Niagara to Dawn) by 0.7 Bcfd	Removed Nexus pipeline
Appalachian Production	Includes 22.4 Bcfd of Appalachian production in 2020	Up about 13% by 2020 with new pipeline capacity	No change from Base Case
(*) A Modified Reference Case adding just the Mainline Settlement rate increase was also performed, and resulted in no price impacts			

The assumptions contained in the Reference Case with respect to the variables subject to scenario modifications have been discussed earlier in the report, and are summarized in the Reference Case column. The modifications applied in the High Demand Case and Low Demand Case are discussed below. The forecast price impacts are summarized in Section 4.4.2.3 We also note at this point that Navigant investigated the impacts of the transport toll changes as called for in the Mainline Settlement[61], and found forecast prices to have remained within two to three cents of the Reference Case.

4.4.2.1 High Demand Case

The High Demand Case contains a blend of modifications favoring increased or accelerated demand, as well as a smaller expansion of pipeline infrastructure compared to the Reference Case. Increases in demand are manifested by increasing assumed East Coast LNG exports from 0.8 Bcfd to 2.0 Bcfd by 2020, a healthy increase that should be met from U.S. Appalachian Basin supplies for which eastern Canada will also compete. The High Demand Case also accelerates by one year assumed start-up of West Coast of Canada LNG exports, from 2019 to 2018. Alberta oil sands natural gas demand is assumed to be 20 percent higher than in the Reference Case, starting 2016.

On the infrastructure side, the High Demand Case includes the conversion of Mainline gas transportation capacity to oil transportation per TransCanada's Energy East project application, as well as exclusion of the Nexus pipeline that is intended to allow Utica and Marcellus supplies to be moved to the Midwest and to Dawn (via the Vector pipeline).

Finally, the toll increase called for in the Mainline Settlement was also included.

4.4.2.2 Low Demand Case

The Low Demand Case contains a blend of modifications favoring decreased or delayed demand, as well as a larger expansion of pipeline infrastructure compared to the Reference Case. Decreases in demand

[61] For purposes of investigating the Mainline Settlement, Navigant raised tolls from 2015 through 2020 as follows: firm service with Eastern Ontario Triangle receipt points, 52% increase; firm service with receipt points outside the EOT, and delivery points in the EOT, 18% increase; all other Mainline firm services, 12% increase. Per TransCanada Application for Approval of Mainline 2013-2030 Settlement, December 2013, p. 68.

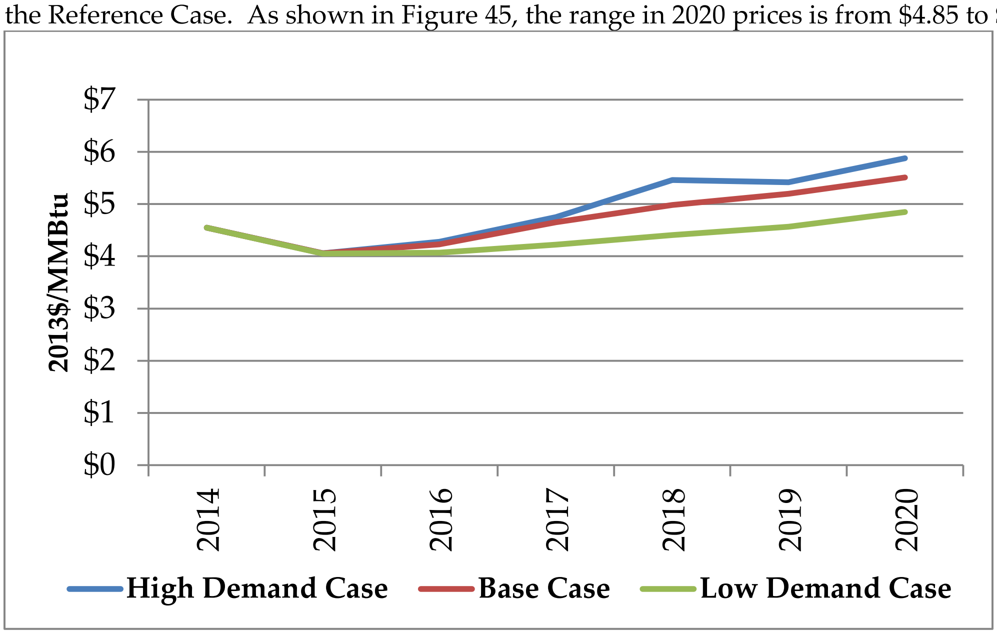
are manifested by delaying by one year assumed start-up of U.S West Coast and Canadian West Coast LNG exports, from 2017 to 2018, and from 2019 to 2020, respectively. Alberta oil sands natural gas demand is assumed to be 20 percent lower than in the Reference Case, starting 2016.

On the infrastructure side, the High Demand Case does not include the conversion of Mainline gas transportation capacity to oil transportation for TransCanada's Energy East project, as the High Demand Case does. The Low Demand Case increases the capacity of both the Nexus pipeline (by an extra 1.0 Bcfd) and the Niagara path for Marcellus gas (by an extra 700 MMcfd). To complement this increased pipeline capacity, Appalachian Basin production is allowed to increase by about 13 percent by 2020.

Finally, like the High Demand Case, the toll increase called for in the Mainline Settlement was also included.

4.4.2.3 Scenario Price Comparisons

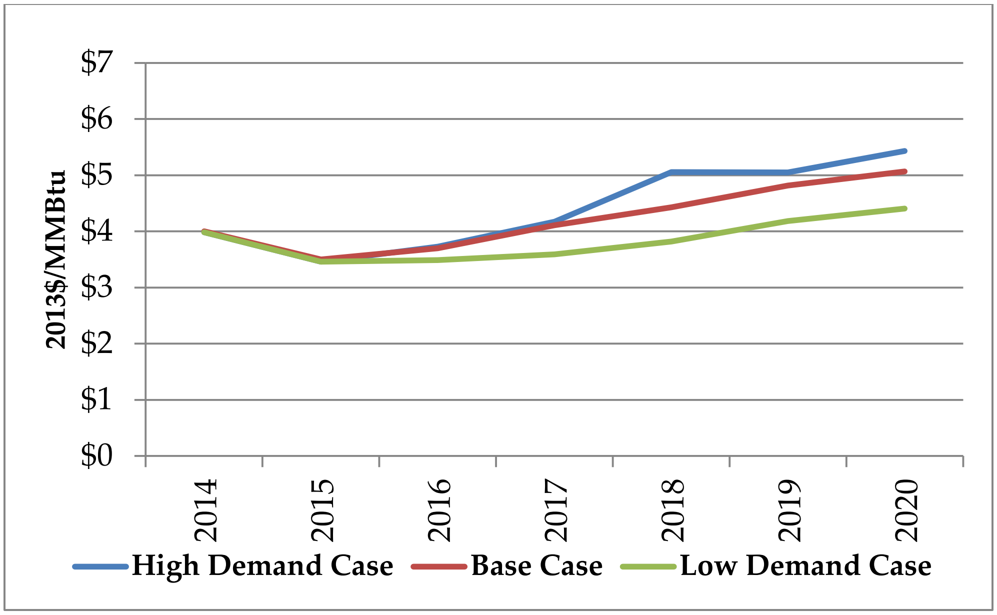
The impacts of the modeled scenarios on Reference Case forecast prices are relatively minor, with the Low Demand Case forecasts averaging between 7 and 9 percent below the Reference Case average for 2014-2020, and the High Demand Case forecasts averaging between 4 and 5 percent above the Reference Case average. Like the Reference Case, then, the scenarios also result in reasonable and competitive pricing conditions. Specifically, Henry Hub prices through 2020 are forecast to average $4.39 per MMbtu in the Low Demand Case and $4.91 per MMBtu in the High Demand Case, versus $4.74 per MMBtu in the Reference Case. As shown in Figure 45, the range in 2020 prices is from $4.85 to $5.88 per MMBtu.



Source: Navigant

Figure 45: Scenario Price Comparison--Henry Hub

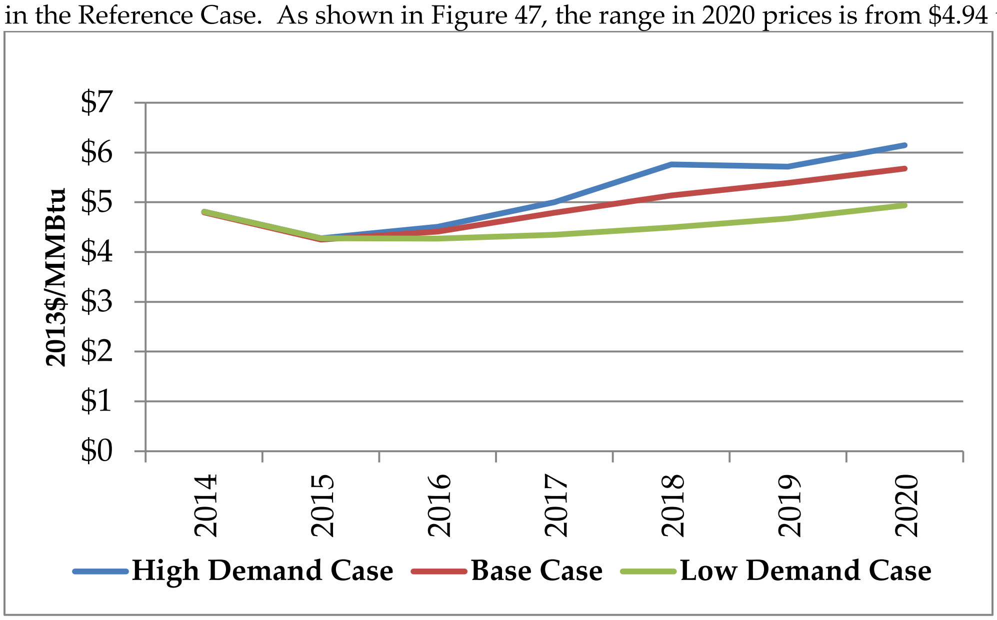
Hub prices in Alberta (AECO) are projected to be lower, with averages ranging from $3.85 per MMBtu in the Low Demand Case to $4.41 per MMBtu in the High Demand Case, versus $4.23 per MMBtu in the Reference Case. As shown in Figure 46, the range in 2020 prices is from $4.40 to $5.43 per MMBtu.



Source: Navigant

Figure 46: Scenario Price Comparison--AECO

Prices at Dawn are projected to track price trends just above Henry Hub, with averages ranging from $4.55 per MMBtu in the Low Demand Case to $5.17 in the High Demand Case, versus $4.92 per MMBtu in the Reference Case. As shown in Figure 47, the range in 2020 prices is from $4.94 to $6.15 per MMBtu.



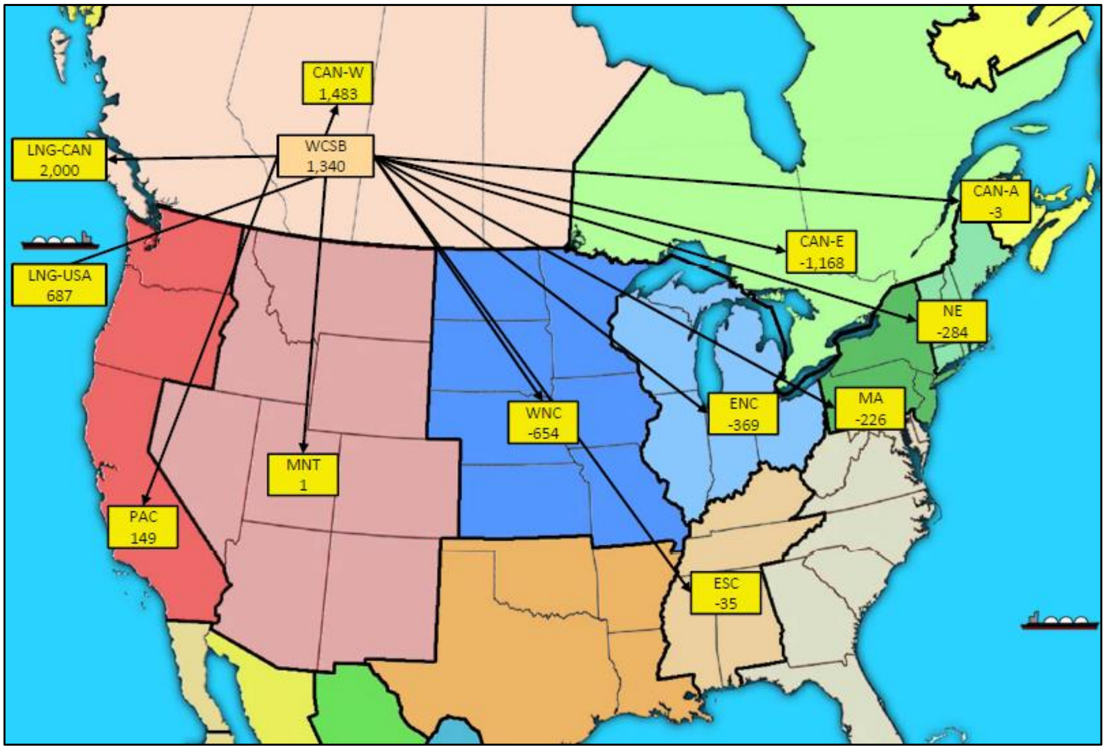
Source: Navigant

Figure 47: Scenario Price Comparison--Dawn

5. Matters for Board Consideration

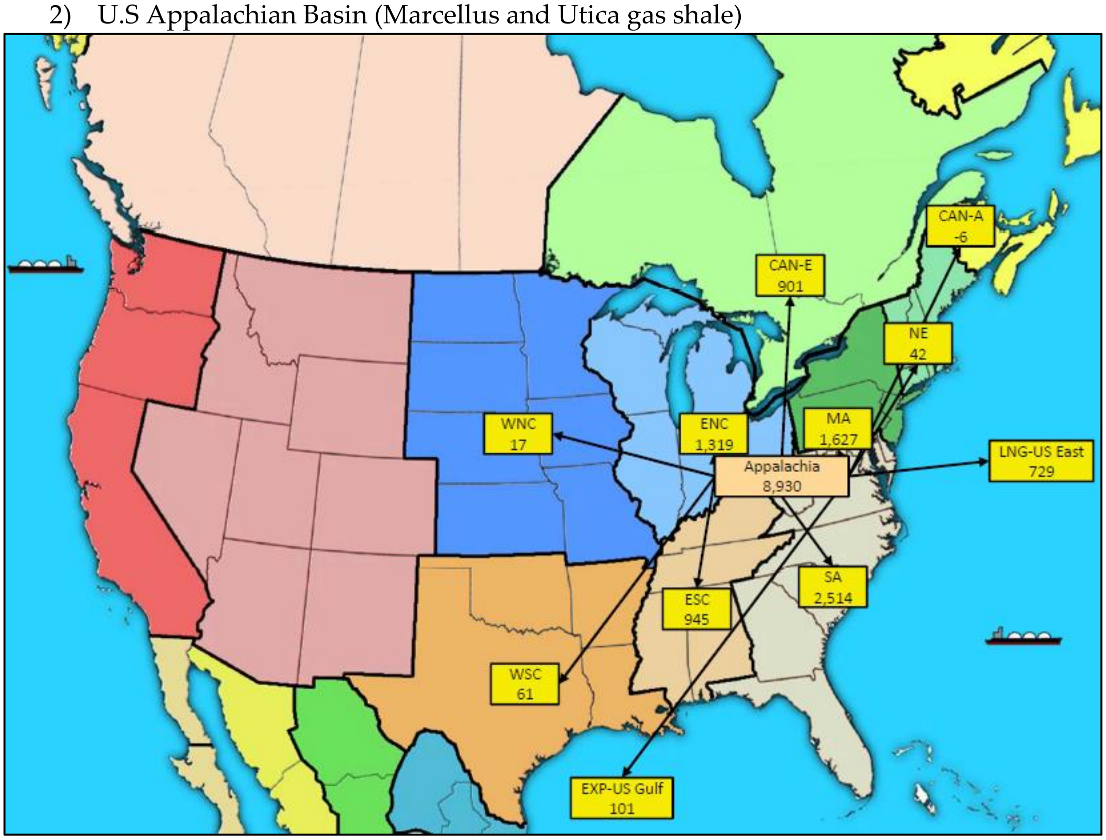
A tale of two supply basins. Changing expected Natural Gas Flow patterns 2014-2020.

1) Western Canadian Sedimentary Basin



Source: GPCM/Navigant

2) U.S Appalachian Basin (Marcellus and Utica gas shale)



Source: GPCM/Navigant

As a key market driver for the forecast period 2014- 2020 in the 2014 Natural Gas Market Review, Navigant has developed two natural gas flow charts above that depict key 'changes' in gas flow patterns between 2014 and 2020. Focusing upon the Western Canadian Sedimentary Basin and the U.S Appalachian basin, the main findings highlighted in the charts and covered more extensively in the report are:

- A shift in North American gas supply has occurred and will continue over the next six years with a marked decline in Canadian sourced gas price flows from Alberta to the 'East' including both the Ontario and U.S. Northeast as to the Midcontinent – Chicago area markets. Over this same period, Western Canadian supply shows an increase in flows to Western markets including California and for LNG exports in Western Canada and in the U..S. (Oregon).
- Over the same forecast period, Navigant forecasts Appalachian basin including the Marcellus gas shale basin will continue to exhibit production increases with steadily increasing gas supply being delivered to the Eastern US seaboard, to the US southeast region, to mid-western markets across Ohio, to the Gulf region through Ohio and into the Eastern Canadian including Ontario markets.
- At the same time, growing production in other areas such as in the Gulf Coast region will mostly stay in the region to meet increasing local demand growth including LNG exports from Texas and Louisiana and potentially other Gulf states.
- Growing Rocky Mountain production will mostly flow to the West coast and to West Texas.