Energy Market Assessment

Short-term Canadian Natural Gas Deliverability 2016-2018

National Energy Board
Office national de l'énergie

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Foreword

The National Energy Board (NEB, or the Board) is an independent, federal, quasi-judicial regulator established to promote safety and security, environmental protection and economic efficiency in the Canadian public interest within the mandate set by Parliament for the regulation of pipelines, energy development and trade. The Board's main responsibilities include regulating:

- the construction, operation and abandonment of pipelines that cross international borders or provincial/territorial boundaries, as well as the associated pipeline tolls and tariffs;
- the construction and operation of international power lines, and designated interprovincial power lines; and
- imports of natural gas and exports of crude oil, natural gas liquids (NGLs), natural gas, refined petroleum products and electricity.

For oil and gas exports, the Board's role is to evaluate whether the oil and natural gas proposed to be exported is surplus to reasonably foreseeable Canadian requirements, having regard to the trends in the discovery of oil or gas in Canada.

If a party wishes to rely on material from this report in any regulatory proceeding before the Board, it may submit the material, just as it may submit any public document. Under these circumstances, the submitting party in effect adopts the material and could be required to answer questions pertaining to its content.

While preparing this report, in addition to conducting its own quantitative analysis, the NEB held a series of informal meetings and discussions with various industry and government stakeholders. The NEB appreciates the information and comments provided and would like to thank all participants for their time and expertise.

This report does not provide an indication about whether any application will be approved or not. The Board will decide on specific applications based on the material in evidence before it at that time.

Overview and Summary

This report provides an outlook of Canadian natural gas deliverability[1] from the beginning of 2016 to the end of 2018. The outlook presents three distinct cases, a Higher Price Case, Mid-Range Price Case, and a Lower Price Case, each of which are based on a set of assumptions.

Since mid-2014, lower commodity prices have effected Canadian producers via reduced revenues, constrained cash flows and significantly reduced gas-targeted drilling. Major cuts to capital expenditures were made in 2015. Producers are wrestling with spending within cash flows and having to remain within bank-imposed debt limits, while continuing drilling operations to help minimize declines in reserves and production. Canadian natural gas deliverability is expected to decline in the near-term as reduced drilling activity and continued U.S. competition further challenge Canadian output. The lower Canadian dollar has resulted in additional complications, although providing a modest boost to revenues because exports to U.S. markets are paid in U.S. currency, it also creates challenges because some equipment and required supplies are purchased from the U.S., and paid for in U.S. dollars. Despite this challenging environment North American producers may continue to find deliverability gains on a per-well basis through high-grading[2].

It is expected that gas prices and Canadian drilling activity in 2016 will remain suppressed because the warmer-than-average winter softened demand and left ample storage volumes that require less production to refill. Multiple pipeline projects flowing gas out of the U.S. Appalachian Basin are scheduled to be operational by 2017-2018 and are expected to further challenge western Canadian gas in key markets. The Canadian liquefied natural gas (LNG) picture remains ambiguous. A 2016-2017 final investment decision (FID) for one or more Canadian LNG export projects could accelerate pre-positioning by producers and result in additional Canadian deliverability over the projection period.

In the Mid-Range Price Case, the Henry Hub price of natural gas would initially fall from \$2.70/MMBtu[3] in 2015 to \$2.50/MMBtu in 2016, climbing thereafter to \$3.00/MMBtu by 2018, while Canadian natural gas deliverability declines slightly from 427 $10^6m^3/d$ (15.1 Bcf/d) in 2015 to 412 $10^6m^3/d$ (14.5 Bcf/d) in 2018. The Higher Price Case would see natural gas prices at \$4.00/MMBtu by 2018, resulting in more drilling and Canadian deliverability increasing to 434 $10^6m^3/d$ (15.3 Bcf/d) by 2018. In a Lower Price Case, prices would remain at, or below \$2.50/MMBtu, and deliverability would decline to 393 $10^6m^3/d$ (13.9 Bcf/d) by 2018. A comparison of the price assumptions for each case can be found in Figure 1.1.

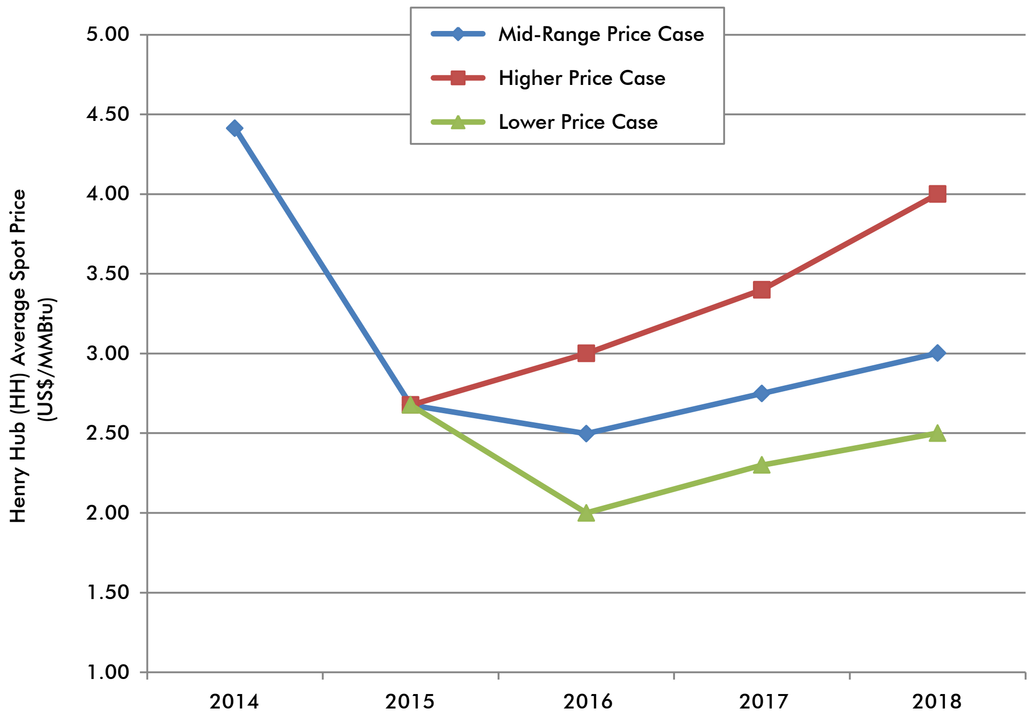
1 Deliverability is the estimated amount of gas supply available from a given area based on historical production and individual well declines, as well as projected activity. Gas production may be less than deliverability due to a number of factors, such as weather-related supply interruptions, and shut-in production due to economic or strategic considerations or insufficient demand.

2 When the amount of investment capital available to industry tightens, producers and service companies attempt to reduce costs while focusing their drilling efforts on the most economic prospects–commonly referred to as 'high-grading'.

3 Unless otherwise specified, North American natural gas prices are quoted at Henry Hub, given in \$US/MMBtu and rounded to the nearest \$0.05. Canadian natural gas prices are quoted as the Alberta Gas Reference Price and are listed in \$C/GJ.

FIGURE 1.1

Historical and Projected Henry Hub Natural Gas Spot Price



The Analysis and Outlook section of this report contain key assumptions for each price case.
The Appendices contain a detailed description of the input assumptions used in projecting deliverability.

Background

The North American Natural Gas Market

North American producers continue to struggle with lower commodity prices. This is resulting in reduced revenues, constrained cash flows, less gas-targeted drilling, and a reduction of oil-derived natural gas production. Reserve write-downs[4] and reduced credit ratings have made it more difficult for some producers to access capital. Consequently, producers are decreasing drilling activity, reducing staff, seeking price concessions from suppliers and pursuing efficiency improvements in order to reduce cost. While the devaluation of the Canadian dollar relative to the U.S. dollar benefits Canadian producers when export sales are paid in U.S. currency, it also disadvantages Canadian producers when purchasing equipment and supplies in U.S. dollars.

Canada

- Canada produced an average of 427 10^6m^3/d (15.1 Bcf/d) of marketable[5] natural gas in 2015, up 2.6 per cent from 2014, remaining well below the 482 10^6m^3/d (17 Bcf/d) peak in 2005.
  - Western Canada is the primary natural gas producing region, contributing 99 per cent of total Canadian natural gas production in 2015. The remainder of Canadian natural gas production is supplied by Nova Scotia, Ontario, and New Brunswick.
- Overall natural gas demand in Canada was up slightly in 2015 at about 269 10^6m^3/d (9.5 Bcf/d) and is expected to see ongoing modest growth as lower gas prices encourage industrial consumption. Rising oil sands production is fueled by natural gas and including gas consumed for cogeneration is now over 88 10^6m^3/d (3.1 Bcf/d). Gradual growth in Canadian electricity demand is being met by a combination of increases in renewable generating capacity (wind, solar and hydro) and from natural gas. Imports of U.S. Marcellus and Utica gas will continue to challenge Canadian gas for markets in central Canada.
- Canada's natural gas exports to the U.S. remained flat in 2015 at about 211 10^6m^3/d (7.4 Bcf/d). Imports of U.S. gas declined moderately in 2015 due to an increase in firm service contracting on Canadian pipelines resulting in Canadian net exports of 158 10^6m^3/d (5.6 Bcf/d) in 2015. This represented about a five percent increase in net exports in 2015, but remained well below the 2007 peak in Canadian exports of 294 10^6m^3/d (10.4 Bcf/d).
- Canadian natural gas exports to the U.S. Midwest continued to decline in 2015 as pipeline reversals and expansions flow more U.S. Marcellus and Utica gas into that market. Part of this decline was made up by increased Canadian gas exports to the western U.S. as higher temperatures increased demand for gas-fired power generation to meet air conditioning demand.

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4 A write-down is a reduction in the estimated or nominal value of an asset.

5 Marketable (sales) gas is gas that has been processed to remove impurities and NGLs and meets specifications for use as an industrial, commercial, or domestic fuel.

United States

- U.S. natural gas production has increased steadily since 2005 and averaged 2 103 $10^6 m^3/d$ (74.2 Bcf/d)[6] in 2015. This represents an increase of 5.3 per cent year-over-year and a 50 per cent increase over production of 1 401 $10^6 m^3/d$ (49.5 Bcf/d) in 2005.
    - Natural gas produced in the U.S. is increasingly derived from tight and shale formations and is serving a growing share of U.S. demand, in turn reducing the need for Canadian natural gas imports.
- The U.S. expects only modest growth in natural gas demand. Only the power generation sector has shown robust demand as lower gas prices have allowed gas-fired power plants to maintain higher utilization rates beyond the typical summer period of air-conditioning loads. In addition, a number of coal plant retirements and increases in requirements for gas-fired generation as a backup for intermittent wind and solar capacity are adding to gas demand. In 2015, U.S. natural gas demand was 2 129 $10^6 m^3/d$ (75.2 Bcf/d), an increase of three per cent over the prior year.
- The U.S. shipped its first LNG cargo export in February 2016. By the end of 2018, the U.S. is expected to have operational[7] liquefaction capacity of 241 $10^6 m^3/d$ (8.5 Bcf/d) which is equivalent to about 11 per cent of 2015 U.S. natural gas production.
- Mexico is becoming an increasingly important outlet for excess U.S. natural gas supply. The amount of gas moving southward to meet growing Mexican demand represents volumes not available to compete with Canadian gas in other regions of the U.S. and Canadian market.

Mexico

- Mexican natural gas production decreased slightly between 2006 and 2015 to about 114 $10^6 m^3/d$ (4 Bcf/d)[8]. Although Mexico may turn out to have sizeable resources of shale gas, its development lags behind the U.S. and Canada. Shale gas production is unlikely to expand rapidly in the short-term.
- Mexican demand for natural gas is expected to increase significantly in the mid to long term due to the planned construction of dozens of natural gas-fired power plants. In 2015 Mexico imported 82 $10^6 m^3/d$ (2.9 Bcf/d) of natural gas from the U.S.[9]. It is expected that Mexico will continue to rely on imports to meet incremental demand for natural gas.
- As additional pipeline infrastructure is added, imports from the U.S. are expected to satisfy an increasing portion of Mexican demand and potentially displace some imports of higher cost LNG from other countries. Mexican natural gas imports from the U.S. are expected to increase to 142 $10^6 m^3/d$ (5 Bcf/d) by 2020[10].

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6 EIA estimate of U.S. Lower 48 dry natural gas production.

7 EIA Natural Gas Weekly Update April 15, 2015.

8 PIRA Energy Group.

9 Energy Information Administration, U.S. Natural Gas Pipeline Exports to Mexico.

10 Energy Information Association: Mexico International Analysis.

Current Trends in Supply and Demand

The North American natural gas market continues to be oversupplied. Storage inventories in the U.S. began 2016 above historical averages due to a warmer than usual winter. Strong U.S. gas production, ample inventories and reduced heating demand are expected to keep the market amply supplied and could keep price soft for most of 2016.

- Cyclical imbalances of supply and demand are typical of the North American natural gas market. Demand often varies because of weather, changes to economic growth, and infrastructure constraints.
    - A typical cycle occurs as follows: during periods of increased demand, prices increase to ration supply and direct it toward the markets that value it most. Higher prices also provide incentives to develop and produce the next most costly natural gas resources which can cause deliverability to exceed demand, subsequently depressing prices. Lower prices discourage production of high cost supply sources but at the same time also foster demand. As demand grows, prices begin to rise again and the cycle repeats itself.
- Natural gas prices have been on a downward trend since early 2014 and oil prices dropped sharply in mid-2014 which subsequently reduced demand for drilling rigs and well-servicing equipment across the oil and gas sector. Producers and service companies have since lowered costs, improved operational efficiencies, and achieved higher levels of production per-well by high-grading.
    - Producers significantly reduced costs in 2015, some reporting cost reductions between 25 and 50 per cent.
    - Although producers will continue to look for further savings in 2016, it is unlikely future cost reductions will be of the same magnitude as those achieved in prior years as the majority of cost savings have likely already been obtained.
- Modern drilling technologies, such as multi-stage hydraulic fracturing and multi-well pads, are now used extensively, improving the size and economics of the Canadian and U.S. natural gas resource base while boosting deliverability.
- It may take years for new major markets to develop for natural gas. Natural gas has largely displaced competing fuels in traditional space-heating markets in Canada and the U.S. already.
    - Proposed LNG export facilities represent a large potential increase in gas demand. Long lead times to obtain approvals, establishing overseas markets, and the construction of facilities are factors that slow down the development of these projects. Currently, none of the proposed Canadian LNG projects with approved export licenses have announced a FID, although one project has issued a conditional FID.
    - Other potential sources of major demand growth could require years or decades to develop to meaningful scale. Examples include growth of the North American petrochemical industry, additional upgrading of bitumen in Alberta, and widespread use of compressed natural gas or LNG for transportation.
- The U.S. has a large inventory of wells that have been drilled but not completed. This allows producers to avoid selling into the market at lower prices, while taking advantage of lower drilling and service costs available because of reduced activity. These wells can be completed later when prices rise, which could rapidly increase supply, stifling large price increases.

Future Uncertainties

Trends in future Canadian and U.S. deliverability will likely follow a pattern similar to previous cycles, but several factors make it difficult to anticipate the duration and extent of the current cycle:

- Many small and mid-sized Canadian oil and gas producers could have difficulty accessing capital, which not only challenges drilling operations, but also increases the chance of bankruptcy or acquisition of smaller producers by larger, more financially stable companies.
    - In lieu of debt financing, producers and service companies in the U.S. and Canada are utilizing private equity[11] investment. This may provide the capital required by smaller and mid-sized producers to continue operations. Currently, there is more private equity investment activity in the U.S. than in Canada.
    - As commodity prices remain depressed, an increase in merger and acquisitions (M&A) is expected. In order to obtain the best deal possible, investors typically wait to see evidence of prices bottoming out before investing. Anticipation of even lower prices partially explains why Canada has yet to see an increase in M&A activity. In 2015, year-over-year M&A activity in the Canadian oil and gas sector fell by almost half, from $41 billion in 2014 to $21 billion[12].
    - The extraction of NGLs[13] (which are priced in relation to crude oil) from natural gas production represents an additional source of producer revenue. As natural gas prices declined after 2008 and crude oil prices continued to rise, the increasing value of the NGLs from some natural gas wells could exceed the value of the natural gas produced. This promoted NGL-targeted drilling and resulted in additional natural gas deliverability based on the value of the NGLs rather than the natural gas. Eventually rising NGL deliverability began creating excess supplies of ethane, propane, and butane in Canada and the U.S. Excess NGL volumes coupled with declining crude oil prices since 2014 have decreased the supplemental revenues generated from NGL-targeted activity and slowed the development of this source of natural gas deliverability.
    - Heavier NGLs such as condensate have higher value in western Canada because they are used to dilute bitumen for pipeline transport. It is possible that condensate-rich gas plays could see sustained drilling activity in western Canada.
- Shale gas resources such as the Marcellus and Utica are close to markets in central Canada, the U.S. northeast, and the U.S. Midwest. Gas from this area has significantly displaced Canadian exports to the North East U.S. market because proximity presents a cost advantage relative to shipping in Western Canada Sedimentary Basin (WCSB) gas.
    - By 2018, newly constructed pipelines in the Marcellus and Utica region could add additional 88 $10^6m^3/d$ (3.1 Bcf/d) import capacity into Canadian markets and 156 $10^6m^3/d$ (5.5 Bcf/d) into the U.S. Midwest. This additional capacity could displace some of the supply provided by the WCSB in these markets.
    - Since July 2015 production from the Marcellus shale has been slowly declining as companies wait for higher prices and new pipeline infrastructure. Production from the Utica however, is increasing and has largely offset Marcellus production declines, continuing to challenge Canadian market share.

11 Private equity investment generally refers to capital invested by individuals or funds into private (non-publically traded) companies, or into publically traded companies with the intention of taking them private.

12 Evaluate Energy – CanOils M&A database.

13 NGLs are liquid hydrocarbons including ethane, propane, butanes, and pentanes plus. Natural gas containing commercial amounts of NGLs is known as NGL-rich, liquids-rich or wet gas. Dry natural gas contains little or no NGLs.

- Producers are testing gas resources in western Canada that could support proposed LNG exports, potentially increasing drilling in the area. A FID to proceed with a Canadian LNG export project in 2016-2018 could accelerate this activity within the time period assessed in this report.
- The Nova Scotia Deep Panuke project was expected to offset declining output from the Sable Offshore Energy Project. Deep Panuke is now operating seasonally, producing in winter when demand is greater. Increasing amounts of water are being produced with natural gas at Deep Panuke, and this could shorten the project's lifetime.
- The Alberta Government recently reviewed and updated its oil and gas royalties program. The new royalty framework, which comes into effect for wells drilled in 2017, favors efficiency and may create benefits for some producers. The new royalty framework recommends that existing royalties remain in effect for 10 years on investments already made, and royalty changes should only be implemented on new wells[14].
- The lower price of natural gas alongside a change in environmental regulations is encouraging the switch from coal to gas for power generation in the U.S. Coal-to-gas switching for power generation would create additional demand for natural gas. To date, the majority of coal plant retirements have been aging units, not heavily utilized. In the U.S., the extent to which the displacement of modern efficient coal plants equipped with emissions controls by gas plants would depend on the price competitiveness of gas compared to coal. The timing of further displacement in power generation will depend on mandated timelines in government legislation, demand for power generation, and relative prices of gas and coal.

14 Alberta At A Crossroads: Royalty Review Advisory Panel Report – January 2016.

Analysis and Outlook

Canadian natural gas drilling activity decreased significantly in 2015 (Table 3.1) due to lower prices, major slashes to capital expenditures, and a difficult economic environment. Drilling costs are expected to continue declining slightly throughout 2016, as producers find remaining efficiencies. Increased deliverability from the U.S. continues to depress gas prices, rendering some western Canadian natural gas prospects uneconomic to pursue.

Three price cases for Canadian natural gas deliverability are examined in this report. These cases differ primarily in terms of Canadian and U.S. natural gas prices and the rate at which Canadian gas is backed out of key markets by lower cost U.S. supply. The Appendices contain a detailed description of the assumptions used for projecting deliverability.

A summary of the key assumptions used in the cases and their respective deliverability results are shown in Table 3.1.

TABLE 3.1

Pricing Overview and Deliverability Results

		Mid-Range Price Case			Higher Price Case			Lower Price Case		
	2015	**2016**	**2017**	**2018**	**2016**	**2017**	**2018**	**2016**	**2017**	**2018**
Henry Hub (HH) Average Spot Price (US$/MMBtu)	$2.68 [a]	$2.50	$2.75	$3.00	$3.00	$3.40	$4.00	$2.00	$2.30	$2.50
Alberta Gas Reference Price (C$/GJ)	$2.57 [b]	$2.70	$3.00	$3.25	$3.25	$3.70	$4.10	$2.15	$2.40	$2.60
Natural Gas Drilling Expense ($ Millions)	2 052	2 031	2 198	2 441	2 317	2 807	3 323	1 622	1 754	1 854
Natural Gas Intent Drill Days	20 412	21 249	22 965	24 234	23 614	27 875	31 366	17 424	18 817	19 847
Natural Gas Intent Wells	814	848	919	971	943	1 115	1 257	696	753	795
Canadian Deliverability ($10^6m^3/d$)	427	425	418	412	428	430	434	420	406	393
Canadian Deliverability (Bcf/d)	15.1	15.0	14.8	14.5	15.1	15.2	15.3	14.8	14.3	13.9

[a] GLJ Publications - average of daily market prices.
[b] GLJ Publications.

For this analysis, the Board divides natural gas production in western Canada into conventional, coalbed methane (CBM), and shale gas, with tight gas included as a sub-category of conventional production. Due to large regional differences in geological and production characteristics, the Board further subdivides these categories into smaller geographic areas, or regions, which have similar characteristics for production decline analysis. Within each region, groupings of the producing formations are made on a geological basis. Details on the characterization of the resources are available in Appendix B. Canadian natural gas production outside of western Canada includes:

- Onshore production from New Brunswick and Ontario, which is declining as minimal future drilling activity is expected over the projection period.
- Nova Scotia production from the offshore Sable Island project and Deep Panuke.

Shale gas potential exists in Quebec, New Brunswick, and Nova Scotia, however, provincial policies currently prohibit hydraulic fracturing which is required for shale gas development. It is assumed these policies do not change over the projection period. Natural gas production from the Mackenzie Delta and elsewhere along the Mackenzie Corridor in the Northwest Territories ceased in 2015 on account of lower prices rendering production uneconomic.

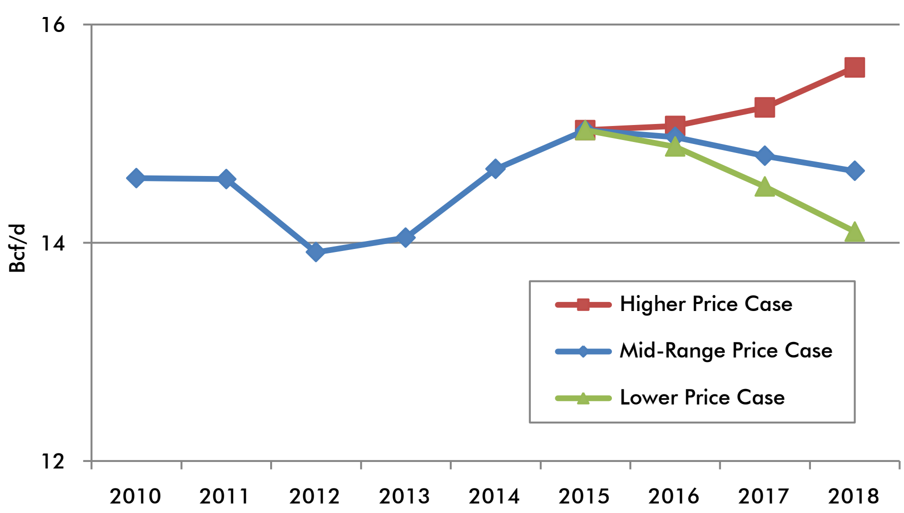
Deliverability Outlooks

- The three price cases cover a range of market conditions: In the Mid-Range Price Case, Canadian gas struggles to maintain market share as low cost U.S. natural gas sources back Canadian supply out of central Canada and the U.S. Midwest market. Deliverability remains relatively flat in 2016 and declines through 2018. By the end of 2018 deliverability declines as newly drilled wells are unable to replace declining production from older wells.
- In the Higher Price Case, U.S. production from the Marcellus and Utica region is needed to support increasing Mexican exports, increasing U.S. LNG exports, additional gas-fired power generation and petrochemical industry requirements, and to offset declines in U.S. natural gas produced from oil wells. These factors increase the opportunity for Canadian gas to flow into key markets. Strong economic growth and U.S. LNG projects finishing ahead of schedule contribute to increased demand over the period. As a result, Canadian deliverability rises throughout the projection period.
- In the Lower Price Case, lower cost Marcellus and Utica shale gas resources further increase their market share in central Canada and the U.S. Midwest, facilitated by new pipeline capacity. Displaced U.S. Rockies supply creates challenges for Canadian gas to access markets on the U.S. West Coast. U.S. LNG exports increase more gradually resulting in increased U.S. gas surplus. Consequently, western Canadian natural gas is further challenged and squeezed out of key markets. Lower prices and reduced market opportunities result in steadily decreasing deliverability over the projection period.

A comparison of the three Canadian natural gas deliverability outlooks to 2018 is shown in Figure 3.1.

FIGURE 3.1

Historical and Projected Natural Gas Deliverability



The levels of drilling activity that support these deliverability estimates are the result of capital investment assumptions and estimated drilling costs. Comparisons of natural gas drilling activity in the three cases in terms of drill days and gas-intent wells drilled are shown in Figure 3.2 and Figure 3.3, respectively.

FIGURE 3.2

Natural Gas-Intent Drilling Days

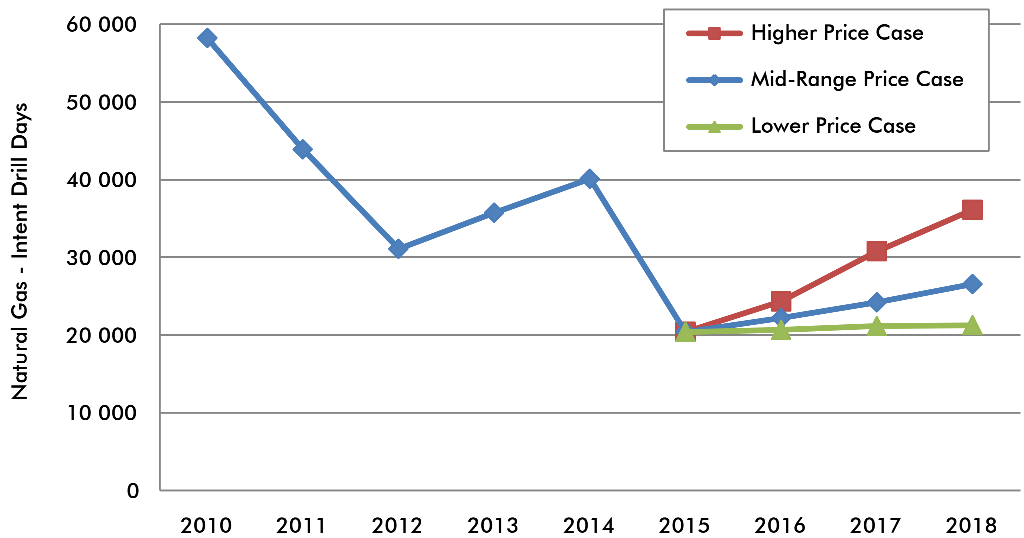
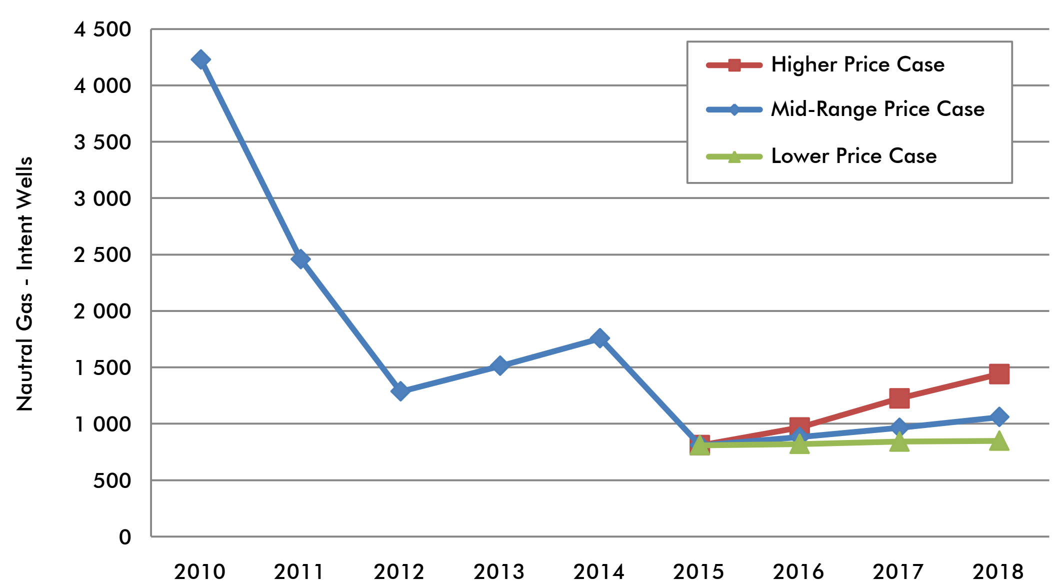


FIGURE 3.3

Natural Gas-Intent Wells



Mid-Range Price Case

Throughout the projection period the Mid-Range Price Case assumes moderate economic growth, weather conditions in line with seasonal averages, continued modest growth in Canadian and U.S. natural gas demand, and on-time completions of U.S. LNG facilities and pipeline infrastructure. Following the warmer-than-average winter of 2015-2016 the North American market remains oversupplied in 2016, both in terms of NGLs and marketable natural gas, resulting in slimmer margins for producers. Following major cuts in 2015, capital expenditures increase slightly over the projection period as pricing conditions improve; however, U.S. natural gas continues to back Canadian supplies out of markets in central Canada and the U.S. Midwest. The outlook for Canadian LNG remains ambiguous with no FID's made before 2017. In spite of additional drilling, Canadian deliverability declines over the projection, as newly drilled wells are unable to fully replace declining production from older wells.

Deliverability Results

In the Mid-Range Price Case, Canadian natural gas deliverability continues to be well above Canadian demand.[15] Canadian deliverability remains relatively flat in 2016 and falls throughout 2017 and 2018 as declines from older wells outpace drilling and production from new wells. Tight gas activity increases over the projection with 700 tight gas wells drilled in western Canada in 2018, including 411 in the Montney tight gas play. The Duvernay Shale play continues to see the most Canadian shale gas activity with 35 wells drilled in 2018. A summary of the Mid-Range Price Case is available in Table 3.2.

TABLE 3.2

Mid-Range Price Case Summary and Results

	Alberta Gas Reference Price	Gas Intent Drill Days	Gas Intent Wells	Average Deliverability	
	C$/GJ			$10^6m^3/d$	Bcf/d
2015	$2.57[a]	20 412	814	427 [b]	15.1
2016	$2.69	21 249	848	425	15.0
2017	$2.97	22 965	919	418	14.8
2018	$3.25	24 234	971	412	14.5

[a] GLJ Publications.
[b] Annual average of NEB reported provincial production, where available.

Implications

Canadian and U.S. gas markets have been well supplied at historically moderate prices for the past few years. A warmer-than-average winter and elevated storage levels going into 2016 keep prices depressed in the short term. Markets could tighten from reduced capital expenditures, drilling reductions, rising natural gas demand from improved integration of the Mexican market or U.S. LNG projects coming online ahead of schedule.

15 Projections of Canadian demand for natural gas are available in Appendix E.

Higher Price Case

The Higher Price Case assumes a larger recovery for Canadian natural gas deliverability because of higher gas demand from a combination of various factors including: stronger economic growth in the U.S. and Canada, weather that is cooler in the winter and warmer in the summer than average to increase space heating and cooling demand, increased Mexican demand that draws more U.S. gas southward, and U.S. LNG facilities being completed ahead of schedule and heavily utilized. Increased demand boosts prices and results in less displacement of Canadian gas by U.S. supplies. Despite rising natural gas prices, it is assumed that power generators prefer natural gas over coal in specific markets, potentially to meet stricter environmental regulations or to better match variations in the electricity demand profile. It is also assumed that the U.S. petrochemical industry completes a major expansion and increases its use of natural gas and NGLs. Accordingly, Canadian producers are able to obtain capital more easily while continuing to focus drilling efforts on highly productive prospects. A FID in 2016-2017 to proceed with a Canadian LNG export project would accelerate pre-positioning by producers and result in additional Canadian deliverability over the projection period.

Deliverability Results

Canadian natural gas deliverability grows continuously over the projection in the Higher Price Case, increasing from 427 10^6m^3/d (15.1 Bcf/d) in 2015 to 434 10^6m^3/d (15.3 Bcf/d) by 2018. Tight gas production is still the primary source of new production growing from 221 10^6m^3/d (7.8 Bcf/d) in 2015 to 253 10^6m^3/d (8.9 Bcf/d) in 2018. A summary of the Higher Price Case is available in Table 3.3.

TABLE 3.3

Higher Price Case Summary and Results

	Alberta Gas Reference Price	Gas Intent Drill Days	Gas Intent Wells	Average Deliverability	
	C$/GJ			10^6m^3/d	Bcf/d
2015	$2.57 [a]	20,412	814	427 [b]	15.1
2016	$3.24	23,614	943	428	15.1
2017	$3.67	27,875	1,115	430	15.2
2018	$4.13	31,366	1,257	434	15.3

[a] GLJ Publications.

[b] Annual average of NEB reported provincial production, where available.

Implications

Higher prices, increased demand, and improved competitiveness of Canadian gas relative to the U.S. keep deliverability increasing over the projection period. Capital expenditures increase steadily and the supply overhang experienced in the North American market over the past few years diminishes slightly, as harsh weather and U.S. LNG facilities finishing ahead of schedule increase demand and drilling takes place to meet it.

Lower Price Case

In the Lower Price Case, demand for Canadian and U.S. natural gas is assumed to decrease because of warmer winters and cooler summers than average to decrease space heating and cooling demand coupled with more modest economic growth. Other factors include less growth in U.S. exports to Mexico due to slower Mexican demand growth and higher Mexican LNG imports, U.S. LNG facilities not being utilized to maximum capacity, and strong production growth out of the Marcellus and Utica which further displaces Canadian supply. Lower prices reduce revenues, resulting in less capital dedicated to drilling. Canadian producers continue to experience difficulty obtaining debt financing, while private equity investment would occur almost exclusively in the U.S. Canadian natural gas deliverability would remain more than adequate to meet domestic demand. The Lower Price case would also assume no FIDs for Canadian LNG projects are made during the 2016-2018 period.

Deliverability Results

Canadian natural gas deliverability declines in 2016 to 420 $10^6m^3/d$ (14.8 Bcf/d) and falls significantly thereafter reaching 393 $10^6m^3/d$ (13.9 Bcf/d) by 2018. Lower natural gas prices further reduce investment in the sector. A summary of the Lower Price Case is available in Table 3.4.

TABLE 3.4

Lower Price Case Summary and Results

	Alberta Gas Reference Price	Gas Intent Drill Days	Gas Intent Wells	Average Deliverability	
	C$/GJ			$10^6m^3/d$	Bcf/d
2015	$2.57 [a]	20 412	814	427 [b]	15.1
2016	$2.16	17 424	696	420	14.8
2017	$2.42	18 817	753	406	14.3
2018	$2.58	19 847	795	393	13.9

[a] GLJ Publications.

[b] Annual average of NEB reported provincial production, where available.

Implications

Canadian natural gas consumers would benefit from lower natural gas prices in the short term.
This case shows the greatest decline in natural gas deliverability which results in intensified competition from U.S. sources of natural gas, as well as a significant reduction in drilling and other gas-related service activities.

Key Differences from Previous Projection

The key difference from the previous deliverability projection, *Short-term Canadian Natural Gas Deliverability Outlook 2015-2017*[16], has been the announcement of major cuts to capital expenditures because of sustained lower commodity prices. Drilling activity in 2015 was significantly lower than the previous year as a result. The warmer-than-average winter of 2015-2016 also reduced natural gas heating demand, keeping storage levels above average going into spring and keeping prices soft.

Commodity prices have been lower for longer than was assumed in the 2015-2017 projection. Producers are adjusting by slashing capital expenditures and operating within available cash flows. In addition to tighter capital constraints, reduced producer creditworthiness has increased the difficulty of obtaining capital. Lower NGL prices due to oversupply are expected to reduce the amount of drilling for liquids-rich natural gas, while low oil prices are expected to reduce oil drilling. Altogether, this has significantly reduced demand in the service sector. Throughout 2015 producers worked with service companies to lower service costs and improve capital efficiency on a per-well basis. Although further improvements are possible, it is unlikely they will be of the same magnitude as in 2014-2015.

The Alberta Reference Price in 2015 was $2.57/GJ, below the $2.85/GJ projected in the 2015-2017 Mid-range Price Case and well below the $3.00/GJ projected in the 2015-2017 Higher Price Case. However, actual production averaged 427 10^6m^3/d (15.1 Bcf/d) in 2015, which was near the Higher Price Case projection of 429 10^6m^3/d (15.1 Bcf/d). Actual production was higher than anticipated in the 2015-17 Mid-range Price Case projection due to improved drilling efficiency and improved initial production from some newly drilled wells.

16 Short-term Canadian Natural Gas Deliverability Outlook 2015-2017.

Recent Issues and Current Trends

Factors that will influence future Canadian natural gas deliverability include:

- The development of a Canadian LNG export market. Canada's LNG future remains uncertain. A FID could increase Canadian natural gas deliverability though the construction of facilities would only occur beyond the projection period. It is likely that a significant portion of natural gas exported as LNG will be produced from corporate reserves devoted to the project. Prior to LNG export project completion, these gas resources will need to be proven by additional drilling and testing, and the resultant production would be sold into the North American market.
- The price spreads between natural gas, oil and NGL. The developing NGL glut and subsequent decrease in NGL prices, along with lower oil prices, may result in reduced NGL and oil-targeted drilling, which produces natural gas as a byproduct. It is possible that reduced gas production from these sources would help to balance markets.
- Coordinated production efforts as a result of acquisitions and the consolidation of smaller North American producers by major companies. Moreover, economies of scale could be achieved by integrating supply chains of major companies, further reducing costs.
- The rate at which Canadian natural gas is displaced from markets in central Canada and the U.S. Additional pipeline capacity from the Marcellus and Utica to the U.S. Midwest will be a key factor affecting markets which have been past supporters of Canadian natural gas.
- The potential for increased future deliverability from the Montney despite lower gas prices. NGL-rich gas from the Montney is some of the lowest cost gas in North America and can be competitive with Marcellus gas in certain markets depending on relative transportation costs and foreign exchange rates.
- Improved economics of North American natural gas production. Technological advancements, efficiency gains, and improved data analytics in drilling and hydraulic fracturing operations have improved production capacity of North American natural gas. Inputs including labour and materials have seen cost rollbacks in response to lower activity levels. Depending on the individual producer, improvements in these economic factors may contribute to increased deliverability.
- The development of oil sands. Natural gas is used as a major fuel source to provide energy for Canadian oil sands projects. Oil sands projects under construction and scheduled to begin production between 2016 and 2018 are generally considered sufficiently advanced to be completed despite lower oil prices. Projects in early stages of planning or development may be postponed until global oil markets become more supportive.
- The pace of coal to gas switching for electricity generation in key markets of Canada and the U.S. This has the potential to increase demand for WCSB natural gas and subsequently increase Canadian deliverability.

LIST OF ACRONYMS

CBM	coalbed methane
EIA	Energy Information Administration
FID	Financial Investment Decision
HH	Henry Hub (U.S. Natural Gas Reference Price)
LNG	liquefied natural gas
NEB	National Energy Board
NGLs	natural gas liquids
USD	United States dollar
WCSB	Western Canada Sedimentary Basin

Units

m^3	= cubic metres
MMcf	= million cubic feet
Bcf	= billion cubic feet
m^3/d	= cubic metres per day
$10^6m^3/d$	= million cubic metres per day
MMcf/d	= million cubic feet per day
Bcf/d	= billion cubic feet per day
GJ	= gigajoule
MMBtu	= million British Thermal Units

Common Natural Gas Conversion Factors

1 million m^3 (@ 101.325 kPaa and 15° C) = 35.3 MMcf (@ 14.73 psia and 60° F)
1 GJ (Gigajoule) = .95 Mcf (thousand cubic feet) = .95 MMBtu = .95 decatherms

Price Notation

North American natural gas prices are quoted at Henry Hub and given in $US/MMBtu.

Canadian natural gas prices are quoted as the Alberta Gas Reference Price and are listed in $C/GJ.