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CANADIAN CRUDE OIL AND NATURAL GAS PRODUCTION AND SUPPLY COSTS OUTLOOK (2016 – 2036)


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CANADIAN CRUDE OIL AND NATURAL GAS PRODUCTION AND SUPPLY COSTS OUTLOOK (2016 – 2036)

Canadian Crude Oil and Natural Gas Production and Supply Costs Outlook
(2016 – 2036)

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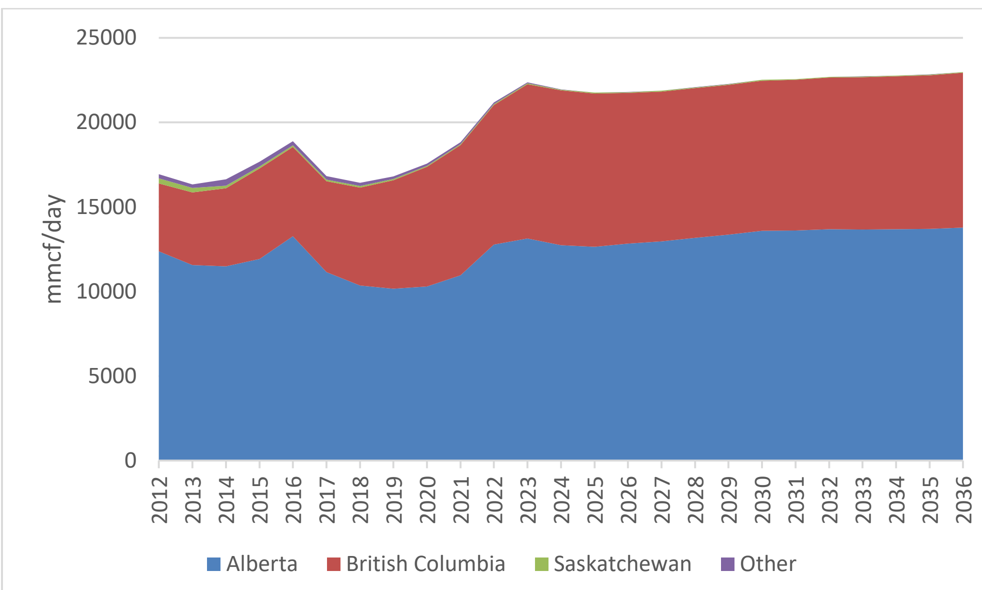
Executive Summary

This study examines the next 20 years of Canada's conventional crude oil and natural gas industries, including production forecasts and supply costs. It includes shale gas, tight gas, coalbed methane, as well as tight and offshore oil production in Canada, and does not include production from oil sands.

Both Canadian natural gas and oil producers have faced challenges with the price declines in both commodities as well as the "shale revolution" that has occurred in the United States. The declines in commodity prices have not only negatively affected the Canadian oil and gas industry and related service sectors, but also the economic growth in Canada.

The shale revolution will transform the US from a net importer to a net exporter of natural gas by 2017. With Canada being the main natural gas exporter to the US, it is no surprise that there are negative consequences for Canadian gas producers. In 2014, Canada was the fifth largest producer of natural gas globally[1] with a volume of 178,290,038 thousand cubic metres[2] (6,427 billion cubic feet, Bcf) over the year, with Alberta representing approximately three-quarters of the country's production. Total natural gas production in Canada from 2012 through 2036 is shown in Figure E.1:

Figure E.1: Total Canadian Natural Gas Production



Source: CERI, NEB, BCOGC, AER, Government of Saskatchewan, PSAC, CAPP

[1] BP website, BP Statistical Review of World Energy June 2015, https://www.bp.com/content/dam/bp/pdf/energy-economics/statistical-review-2015/bp-statistical-review-of-world-energy-2015-full-report.pdf, pp. 22. (Accessed on February 14, 2016)

[2] CAPP Statistical Handbook, May 2016, Table 3.9.

This report examines natural gas production out of each province individually. The "Other" category includes production out of Ontario, New Brunswick, Nova Scotia, the Yukon and Northwest Territories and their values are from the National Energy Board's Energy Future January 2016.[3]

The vast majority of natural gas production will continue to come out of British Columbia and Alberta. Both provinces will see declining natural gas production from 2016 through 2018 while the market adjusts to the reduction in drilling that has happened in the current low price environment. Both provinces will also see an uptick in production leading to Liquefied Natural Gas (LNG) projects, the first of which the Canadian Energy Research Institute (CERI) predicts will come online in 2022. Once production has risen to accommodate the increase in demand that the LNG projects will cause, production remains fairly stable with marginal increases through the remainder of the study period. In 2036, production of natural gas will be slightly above 20 Bcf/day.

Being a global market, the decline in oil prices is more complex than its natural gas counterpart. The North American natural gas market is, for the most part, a continental market, though LNG is changing that fact. However, similar to shale gas, advances in horizontal drilling and multi-stage hydraulic fracturing have been a game-changer for the crude oil market, opening up previously uneconomic and unfeasible areas for production, particularly in the United States.

While high oil prices over the last decade stimulated new sources of global oil supply, North American production has grown the fastest. This heightened global production, in turn, contributed substantially to the lower world prices that materialized in mid-2014. In 2008, the production of shale oil was almost non-existent. Today, the sector produces about 4 million barrels per day (MMbpd) and, before the recent drop in prices, was on track to increase its output to almost 4.8 MMbpd in 2020.[4]

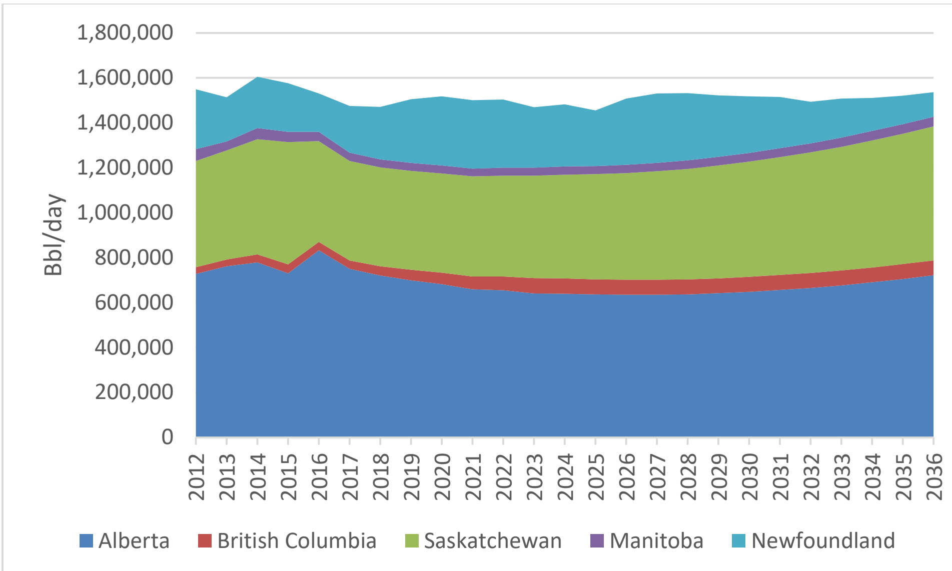
Canadian oil production rose in response to increasing prices. Oil sands production especially grew fivefold between 1993 and 2014, to 2.3 million barrels per day, and now accounts for more than 60 percent of Canada's crude oil production.

Conventional oil production including pentanes plus in 2015 was 1.5 million barrels per day (MMbpd), led by Alberta at 0.7 MMbpd, 0.5 MMbpd from Saskatchewan and 0.2 MMbpd from Newfoundland (offshore).[5] It is important to note that this study does not cover the oil sands, only conventional (including offshore) crude oil production.

[3] National Energy Board, Canada's Energy Future 2016: Energy Supply and Demand Projections to 2040, January 2016, accessed July 2016.
[4] US EIA. *Annual Energy Outlook* 2013, 2014, 2015.
[5] Totals may not add up due to rounding. NEB, Estimated Production of Canadian Crude Oil and Equivalent, https://www.neb-one.gc.ca/nrg/sttstc/crdlndptrlmprdct/stt/stmtdprdctn-eng.html

Figure E.2 shows total conventional crude oil produced in Canada between 2012 and 2036. It does not include production out of the territories, Ontario, New Brunswick or Nova Scotia as these volumes are negligible.

Figure E.2: Total Canadian Conventional Crude Oil Production



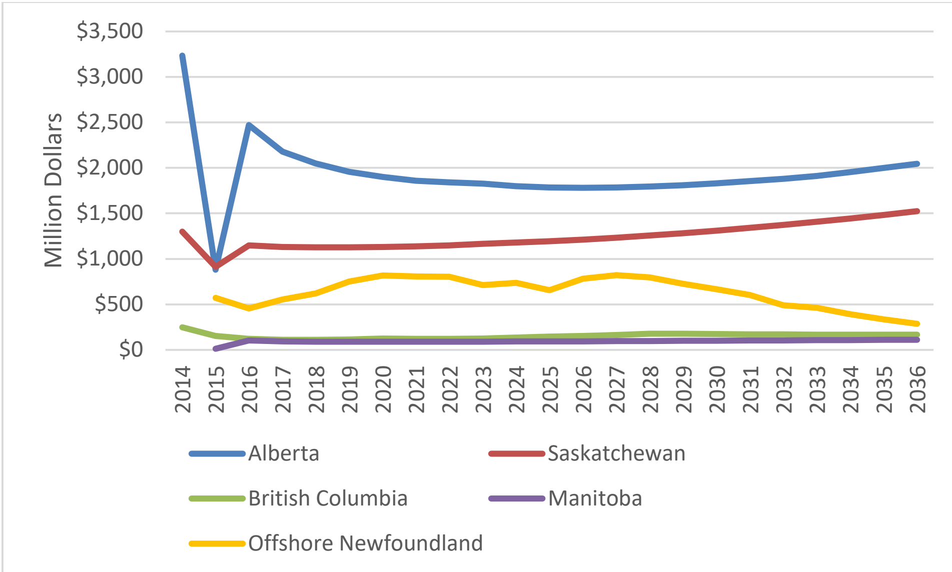
Source: CERI, BCOGC, AER, Government of Saskatchewan, Government of Manitoba, CNLOPB, PSAC, CAPP

As with natural gas, this report examines conventional crude oil production out of each province individually. Production levels are not expected to reach the highs seen in 2014 prior to the decline in oil price. Total production will remain fairly stable through the remainder of the study period, with slight growth in Western Canada being offset by the declines seen in offshore Newfoundland. The growth in crude oil production will be dominated by Saskatchewan as it is expected the province will be focusing on drilling their tight oil formation. In 2036, total conventional crude oil production is just above 1.2 MMbpd.

As part of the supply cost calculations for both oil and gas wells, and relevant to both industry and government, CERI calculates royalty payments for each province, given expected production.

Figure E.3 highlights CERI's estimates of royalty revenues that each province in question could earn throughout the study period. The 2014 values are from the various provincial budgets, while the values for 2015 through 2036 were calculated using the province's royalty calculations and CERI's production forecasts for oil and gas.

Figure E.3: Royalty Revenues by Province



Source: CERI, Governments of Alberta, British Columbia, Saskatchewan, Manitoba and Newfoundland and Labrador

Consistent with production levels, royalty revenues are expected to drop from their highs in 2014. The drastic appearance in the drop in Alberta's royalty revenues can be attributed to the step changes built into the formula according to the price of oil. Alberta's new royalty framework differentiates between oil priced at $30, $50 and $100 per barrel.[6] The province of Saskatchewan also sees reduced revenues from 2014, however not as drastic as in Alberta. After 2016, the revenues are expected to rise continuously through the duration of the study period. The royalties from offshore Newfoundland's oil production are expected to rise as production ramps up due to Hebron's 2017 commissioning, and then ramp down as the projects come to the end of their producing lives.

[6] Department of Energy, Government of Alberta, "Alberta at a Crossroads: Royalty Review Advisory Panel Report", January 2016, accessed June 2016.

Chapter 1: Introduction

Background

These are challenging times for Canadian natural gas and oil producers. Both commodities have experienced price declines. The price of oil has declined substantially from mid-2014, from a WTI market price of US$105 per barrel ($/bbl) in June 2014, down to a low point of US$30/bbl in February 2016, before rebounding and settling at US$47/bbl in May 2016.[7] The price of natural gas has also declined considerably. As of May 2016, the average monthly spot price at Henry Hub is US$1.92 per million British thermal units (MMBtu). In looking at the past decade, this is down from a high of US$13.31 per MMBtu in July of 2008, and more recently US$8.15 per MMBtu in February of 2014. [8] Similarly, the AECO-C price of natural gas – the Canadian benchmark price of natural gas – in May 2016 is US$1.07 per MMBtu, down from US$2.21 per MMBtu in May 2015 and down from C$10.24 per MMBtu in May 2008.[9] It is prudent to use the same month/season when comparing natural gas prices, due to strong seasonality or cyclical nature of Canadian drilling rig activity. Drilling plunges due to spring thaw and drilling crews move their equipment to avoid environmental damage. It is important to note that all subsequent analysis in this study related to natural gas utilizes AECO-C prices.

The declines in commodity prices have not only negatively affected the Canadian oil and gas industry and related service sectors, but also the economic growth in Canada as well. While analysts debate to what degree Canada's economic growth has been affected, there is little doubt that the crude oil and natural gas industries are central to Canada's energy industry and are significant contributors to Canada's economy. In 2015, Statistics Canada reported that Canada's energy sector contributed almost 20 percent to the country's GDP, down from 28.6 percent in 2014 and 30.7 percent in 2013.[10]

The North American natural gas and oil markets have both been transformed by the emergence of the so-called 'shale revolution'. Advances in horizontal drilling, 3-D seismic technology and hydraulic fracturing have enabled gas and oil production growth from basins that were once thought uneconomic, particularly in the United States.

[7] US Energy Information Administration, Crude Oil, WTI Spot Price FOB, Monthly, June 29, 2016, http://www.eia.gov/dnav/pet/hist/LeafHandler.ashx?n=pet&s=rwtc&f=m

[8] US Energy Information Administration, Natural Gas, Henry Hub Natural Gas Spot Price July 20, 2016 http://www.eia.gov/dnav/ng/hist/rngwhhdd.htm

[9] Platt's Daily Price Guide & CERI Commodity Report – Natural Gas

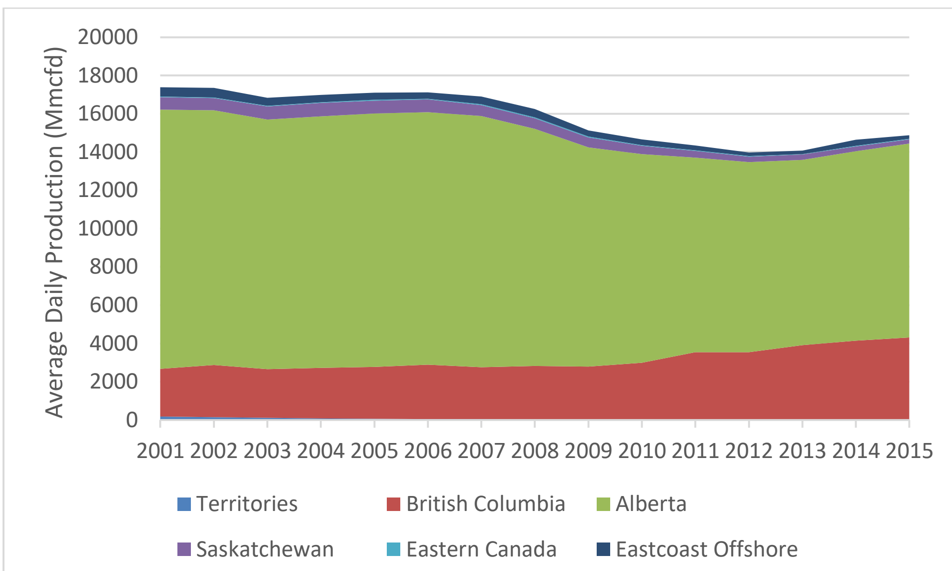
[10] Statistics Canada, Gross domestic product (GDP) at basic process, by North American Industry Classification System (NAICS), provinces and territories, CANSIM table 379-0028, accessed August 2016.

Natural Gas

In terms of natural gas, the effects are staggering, transforming the US from a net importer to a net exporter of natural gas as soon as 2017. With Canada being the main natural gas exporter to the US, it is no surprise that there are negative consequences for Canadian gas producers.

Canada was estimated to have 1,087 trillion cubic feet (Tcf) of marketable natural gas resources remaining as of the end of 2014,[11] with just under 80 percent of this concentrated in the Western Canadian Sedimentary Basin (WCSB), a large area that extends from northern British Columbia eastward through Alberta, southern Saskatchewan and into Manitoba, and from the Yukon and Northwest Territories in the north to the US border in the south. In 2014, Canada was the fifth largest producer of natural gas globally[12] with a volume of 178,290,038 thousand cubic metres[13] (6,427 billion cubic feet, Bcf) over the year, with Alberta representing approximately three-quarters of the country's production. Canada's average daily production, by year and by region, between 2001 and 2015 is shown in Figure 1.1.

Figure 1.1: Canadian Marketed Natural Gas Production



Source: CAPP[14]

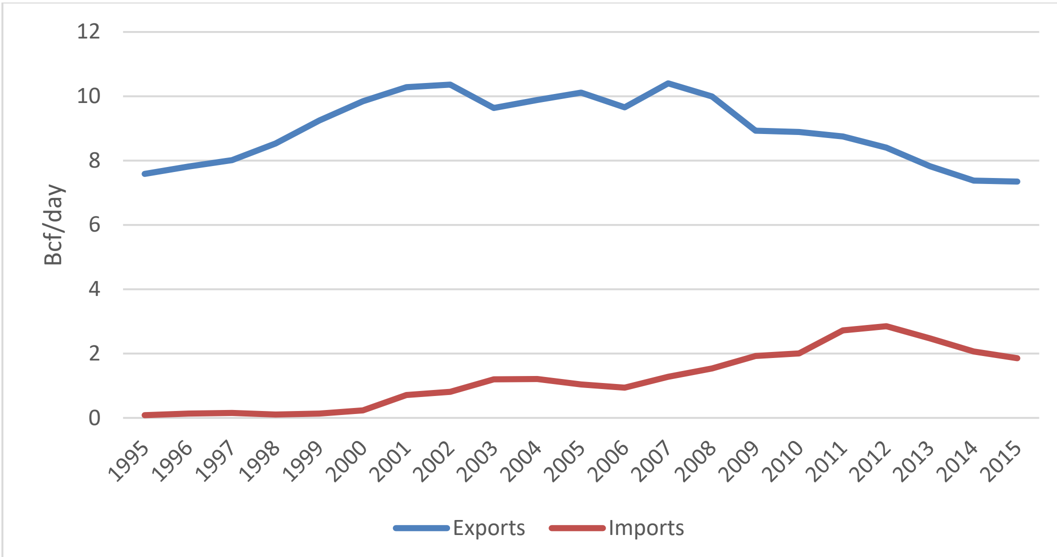
However, despite these high levels of production and reserves, transportation infrastructure and economics dictates that Canada also imports natural gas from the United States, particularly in Eastern Canada. While historically Canada's exports to the United States vastly exceeded its

[11] NEB, "Canada's Energy Future 2016" , http://www.neb-one.gc.ca/nrg/ntgrtd/ftr/2016/index-eng.html#fn78
[12] BP website, BP Statistical Review of World Energy June 2015, https://www.bp.com/content/dam/bp/pdf/energy-economics/statistical-review-2015/bp-statistical-review-of-world-energy-2015-full-report.pdf, pp. 22. (Accessed on February 14, 2016)
[13] CAPP Statistical Handbook, May 2016, Table 3.9.
[14] CAPP Statistical Handbook, May 2016, Table 3.10.

imports from the United States, this gap is shrinking due to unprecedented growth in US shale gas production, led by the Marcellus Shale.

The shrinking gap between exports from and imports to Canada is illustrated in Figure 1.2.

Figure 1.2: Natural Gas Exports from/Imports to Canada



Source: NEB[15]

While this is positive for the US gas producing regions, this growth has impacted North American natural gas flows and has certainly impacted western Canadian gas producers, displacing Canadian gas. Lower cost Marcellus gas is closer to markets in eastern Canada, the US Northeast and US Midwest, giving it cost advantages over Western Canadian gas. Marcellus shale gas has already significantly displaced Canadian exports from the US Northeast market and gained additional pipeline access to the US Midwest beginning in 2016.[16] The US imported 2,636 Bcf of natural gas in 2014 from Canada, down from 2,787 Bcf in 2013 and down from the five-year average of 3,096 Bcf.[17] US imports peaked in 2007 at 3,837 Bcf and have been in decline since with a brief respite in 2010.[18] An increasing amount of Marcellus gas is also flowing into central and eastern Canada displacing some demand that was previously satisfied by western Canadian production.

Another important component affecting the price of natural gas in the short term is the level of natural gas inventories, providing a vital component of the North American natural gas transmission and distribution system. While mainline gas transmission lines provide the crucial

[15] National Energy Board, Commodity Statistics, accessed August 2016.

[16] EIA. http://www.eia.gov/todayinenergy/detail.cfm?id=24732. Accessed on March 31, 2016.

[17] US Energy Information Administration website, Natural Gas, US Natural Gas Imports & Exports 2014, May 11, 2015, https://www.eia.gov/naturalgas/importsexports/annual/ (Accessed on February 14, 2016)

[18] US Energy Information Administration website, Natural Gas, US Natural Gas Pipeline Imports, Annual, http://www.eia.gov/dnav/ng/hist/n9102us2a.htm (Accessed on February 14, 2016)

link between producing area and marketplace, underground gas storage facilities help maintain the North American natural gas transmission and distribution system's reliability and its capability to transport gas supplies efficiently and without interruption. Natural gas storage facilities are essential to balance the dramatic divergence between the seasonal and daily variability of gas consumption and the inflexibility of gas production in North America. Residential and commercial end users use natural gas for space and heating needs during winter months and space and cooling during the summer months. Storage inventories mitigate the severity of spikes and drops in demand usually associated with weather.

With working gas storage levels in the US and Canada at near-record highs, the North American gas market continues to be oversupplied, further exacerbating uncertainty for Canadian natural gas producers. In Canada, total storage levels at end-June were 672 Bcf, higher than 468 Bcf at end-June 2015 and 202 Bcf higher than the five-year average.[19] Increased levels of natural gas production, along with the warm temperatures of the 2015/2016 winters have led to high natural gas storage levels. Likewise, according to the Energy Information Agency (EIA), US working natural gas totaled 3,140 Bcf as of the week ending June 24, 2016, higher than 2,529 Bcf at the same time last year and 611 Bcf higher than the five-year average.[20]

Crude Oil

Being a global market, the decline in oil prices is more complex than its natural gas counterpart. The North American natural gas market is, for the most part, a continental market, though Liquefied Natural Gas (LNG) is changing that fact. However, similar to shale gas, advances in horizontal drilling and multi-stage hydraulic fracturing have been a game-changer for the crude oil market, opening up previously uneconomic and unfeasible areas for production. It is important to note that this phenomenon was predominant for the US shale oil reserves; Canadian shale and tight oil production has not seen the same growth.

The technologies pioneered in East Texas' Barnett Shale were quickly utilized in basins across North America, unlocking new gas resources. Natural gas prices began to fall in mid-2008, due to increased natural gas production. As prices dwindled, producers started to focus on either producing "wet" natural gas (i.e., liquid-rich natural gas or gas containing natural gas liquids) or crude oil. Utilizing the same advances in technology that fueled the shale gas boom, exploration and production companies (E&Ps) turned their attention to oil-bearing shales (shale oil) or tight oil plays. The impact of the 'shale revolution' on tight oil, similar to its natural gas counterpart, has been nothing short of astonishing.

In Canada, tight oil plays in the WCSB include the Cardium, the Viking formation, the Slave Point and the most prolific, the Bakken Shale. While the latter is located primarily in Montana and North Dakota, it also extends into Saskatchewan and the southwestern corner of Manitoba.

[19] Platt's Natural Gas Daily & CERI Commodity Report – Natural Gas

[20] US Energy Information Administration, Weekly Working Gas in Underground Storage (for week ending June 24, 2016), http://www.eia.gov/dnav/ng/ng_stor_wkly_s1_w.htm

Without a doubt, advances in technology have bolstered Canadian conventional oil reserves, making up approximately ten percent of remaining ultimate potential; the remaining 90 percent are bitumen resources located in the oil sands in Alberta. Estimated remaining ultimate potential of conventional oil resources in northern Canada are estimated at 10.2 billion barrels, followed by the WCSB at 7.7 billion barrels, eastern Canada at 3.1 billion barrels and other at 1.2 billion barrels.[21] Altogether, Canada was estimated to have a remaining ultimate potential of 330 billion barrels as of the end of 2014,[22] with an estimated 170.8 billion barrels of remaining established reserves, of which 97 percent, or 166.3 billion barrels, is in oil sands. The remainder is made up of the WCSB at 3.1 billion barrels and eastern Canada at 1.4 billion barrels.[23]

High oil prices over the last decade have stimulated new sources of oil supply around the world. Unconventional sources of oil (including US shale oil, Canadian bitumen, deep water offshore, and other high-cost sources) have grown rapidly. New supply has also come on stream from countries in the Middle East (including Iraq, Iran and Libya).

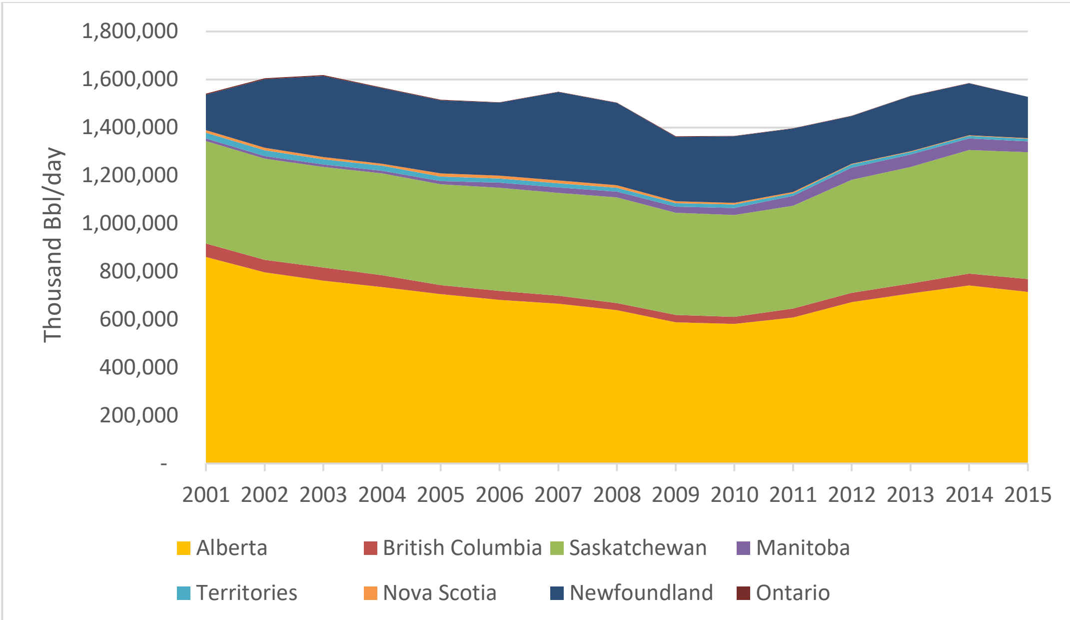
North American production has grown the fastest, and this has contributed substantially to the lower world prices that materialized in mid-2014. In 2008, the production of shale oil was almost non-existent. Today, the sector produces about 4 million barrels per day and, before the recent drop in prices, was on track to increase its output to almost 4.8 million barrels per day in 2020.[24]

Canadian oil production also rose in response to increasing prices. Oil sands production especially grew fivefold between 1993 and 2014, to 2.3 million barrels per day, and now accounts for more than 60 percent of Canada's crude oil production.

Conventional oil production including pentanes plus in 2015 was 1.5 million barrels per day (MMbpd), led by Alberta at 0.7 MMbpd, 0.5 MMbpd from Saskatchewan and 0.2 MMbpd from Newfoundland (offshore).[25] It is important to note that this study does not cover the oil sands, only conventional (including offshore) crude oil production. Conventional crude oil production from 2001 to 2015 is shown in Figure 1.3

[21] NEB, "Canada's Energy Future 2016", http://www.neb-one.gc.ca/nrg/ntgrtd/ftr/2016/index-eng.html#fn78
[22] ibid
[23] ibid
[24] US EIA. *Annual Energy Outlook* 2013, 2014, 2015.
[25] Totals may not add up due to rounding. NEB, Estimated Production of Canadian Crude Oil and Equivalent, https://www.neb-one.gc.ca/nrg/sttstc/crdlndptrlmprdct/stt/stmtdprdctn-eng.html

Figure 1.3: Canadian Conventional Crude Oil Production (Light, C5+/Condensate, Heavy)



Source: NEB[26]

Canadian oil and natural gas producers are undoubtedly facing challenges, which highlights the fact that while both Canadian and the US E&Ps are utilizing the same technologies, geographical proximity to consuming markets and cost structures are different. As such, this study is a timely analysis of the supply costs and production outlook in Canada for oil and natural gas producers.

Report Structure

This study provides an outlook of production for crude oil and natural gas as well as production supply costs for new development. This study includes shale gas, tight gas, coalbed methane, as well as tight and offshore oil production in Canada, and does not include production from oil sands.

From the oil perspective, it is an update and expansion of two studies undertaken by CERI: Study 135: "Conventional Oil Supply Costs in Western Canada," June 2013 and Study 150: "Western Canada Crude Oil Forecasts and Impacts (2015-2035)," July 2015. The former analyzed the average oil supply cost of new oil wells drilled in Alberta, British Columbia and Saskatchewan, providing an indication of economic viability of oil production in each study area. The latter, on the other hand, investigated the production potential in western Canada, as well as calculated the economic impacts associated with the aforementioned drilling and future production forecast for Alberta, British Columbia and Saskatchewan.

[26] National Energy Board, Estimated Production of Canadian Crude Oil and Equivalent, accessed July 2016, https://www.neb-one.gc.ca/nrg/sttstc/crdlndptrlmprdct/stt/stmtdprdctn-eng.html

From the natural gas perspective, this study is an update of the recently released Study 158: "Canadian Natural Gas Market Review," June 2016 and from Study 136: "Conventional Natural Gas Supply Costs in Western Canada," June 2013.

While updating the previously mentioned studies, this study, however, expands the supply costs and production forecast to include British Columbia, Alberta, Saskatchewan, Manitoba and offshore Newfoundland. Despite the fact the vast majority of oil and gas is produced in the WCSB, it is important to include Newfoundland and Labrador and its significant resource potential. While Quebec has shale gas and tight oil potential within its Utica Shale – lying in the St. Lawrence Lowlands between Quebec City and Montreal – Quebec is not included in this study; well economics and regulatory issues, including a moratorium on fracking, will likely limit production for the study period.

This study is divided into four chapters, with Chapter 1 providing a background, as well as defining the scope of the project.

Chapter 2 discusses the Western Canadian Sedimentary Basin (WCSB) and the province of Newfoundland and Labrador's supply costs and production forecasts. It is subsequently divided into two parts: oil and natural gas. Both sections are further sub-divided by province.

Chapter 3 gives a national summary of oil and natural gas production and Chapter 4 provides the conclusions.

Appendix A provides the methodologies for supply cost calculations and the production forecast and Appendix B includes the maps of provinces where active drilling is taking place.

Chapter 2: Canadian Oil and Gas Supply Costs and Production – Provincial Outlook

This chapter examines the crude oil and natural gas production forecast and associated supply costs within the Western Canadian Sedimentary Basin by province (British Columbia, Alberta, Saskatchewan and Manitoba) as well as for the province of Newfoundland and Labrador, between the years of 2016 and 2036. This analysis covers crude, shale and tight oil activity, and conventional marketable natural gas, coalbed methane, shale gas and the associated natural gas liquids, using vertical and horizontal wells. Oil production out of Alberta's oil sands is not included and can be found separately in CERI's upcoming Annual Oil Sands Update.

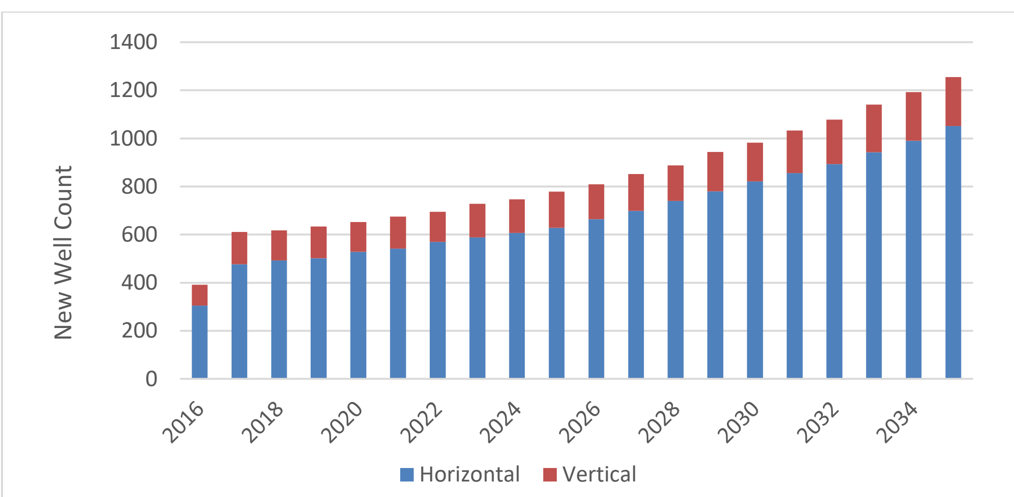
Canadian Crude Oil

Alberta

As in CERI Study 150, "Western Canada Crude Oil Forecasts and Impacts (2015-2035)", CERI uses historical licensing data along with oil price forecasts to develop a prediction for oil well drilling. CERI estimates 392 horizontal and vertical oil wells to be drilled in 2016, not including cold bitumen production (CBP) or in-situ thermal (Steam Assisted Gravity Drainage, [SAGD]) producing wells.

Longer term, CERI estimates oil well licensing and drilling activity to steadily increase from the current low levels of under 400 wells per year to approximately 1,300 wells per year in 2036. This is reflected in Figure 2.1.

Figure 2.1: Alberta New Oil Well Forecast

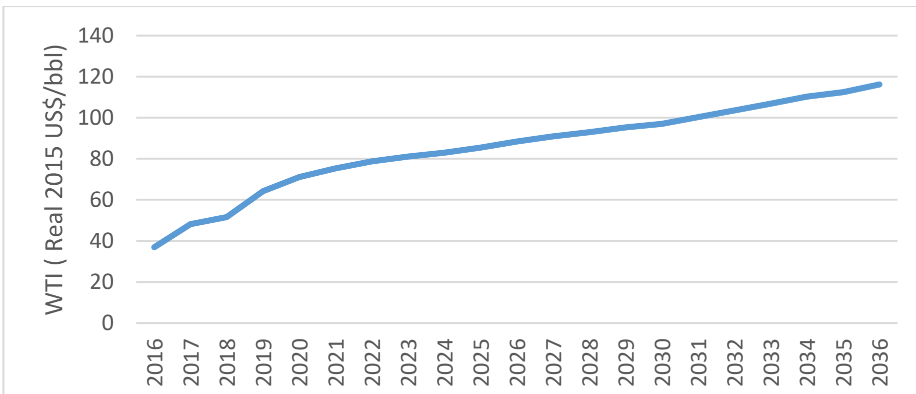


Source: CERI

As shown in Figure 2.1, a jump in drilling is expected to occur from 2016 to 2017 which can be attributed to an expected rise in the price of oil.

The new well forecast is developed based on well decline rates in addition to well supply costs and knowledge of drilling activity in pipeline activity areas, as well as the forecast for the price of crude oil. CERI uses information contained in the 2016 Well Cost Study from the Petroleum Services Association of Canada (PSAC) as well as from the Canadian Association of Petroleum Producers' (CAPP) Statistical Handbook. Reference wells are assigned to each area and formation under study and the well cost is calibrated to the average drill depth using true vertical depth for a vertical well and total drill depth for a horizontal well. A provision for infrastructure (field equipment) costs plus geological and geophysical costs are added to the well cost. The EIA's Reference Case forecast for WTI crude oil is used for all oil well forecasts done in this report and is shown in Figure 2.2.

Figure 2.2: WTI Crude Oil Price Forecast



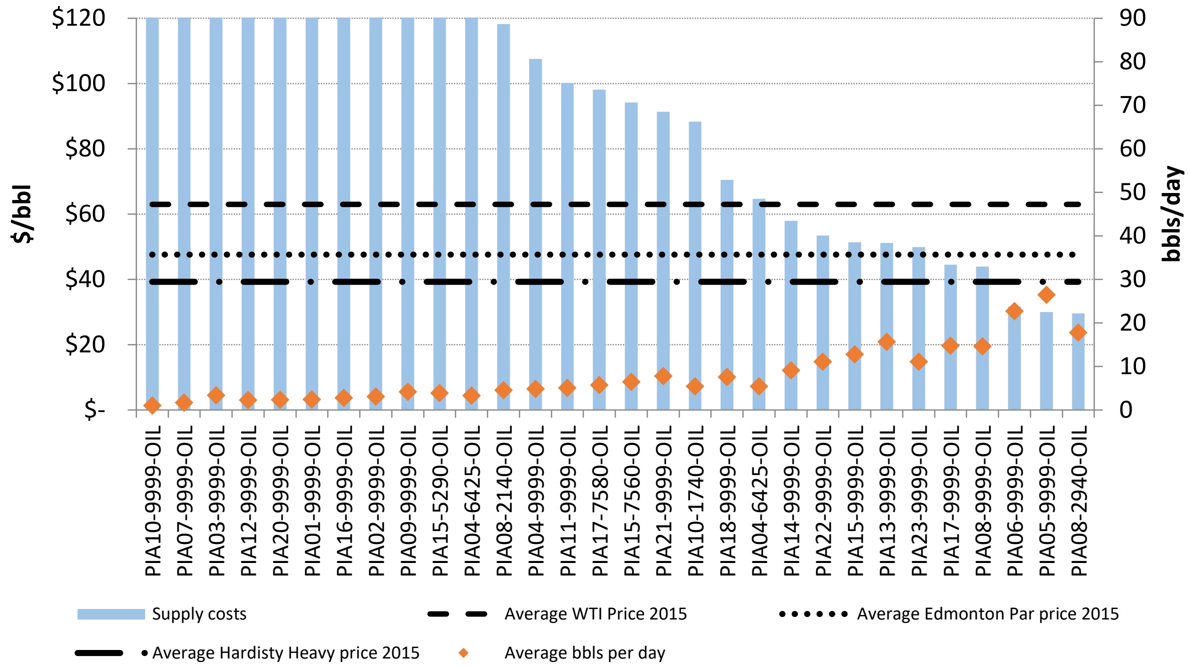
Source: EIA[1]

The EIA's Annual Energy Outlook 2016 predicts that in 2015 USD, the WTI price will rise to US$116/bbl by 2036 – significantly higher than the 2016 price of US$37/bbl.

The supply costs for specific pipeline areas are shown in Figures 2.3 and 2.4 with the average WTI price, Hardisty Heavy price and Edmonton Heavy par price overlaid for reference. The geographic locations of all well IDs listed in the following figures, as well as throughout the rest of this report, can be found in Appendix A.

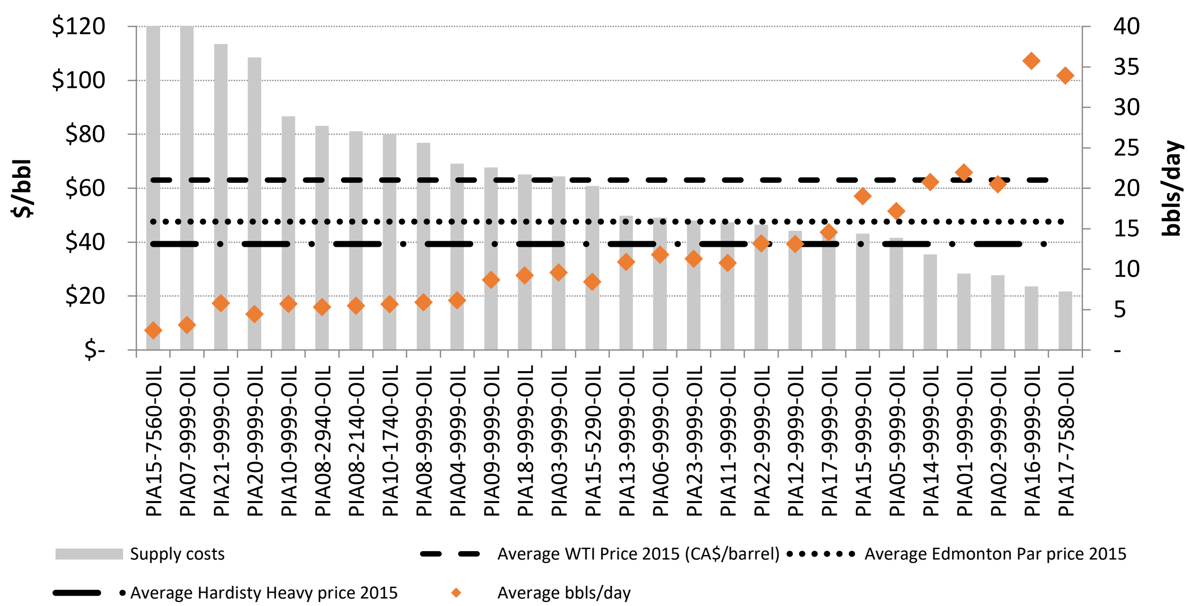
[1] U.S. Energy Information Administration, Annual Energy Outlook 2016, http://www.eia.gov/forecasts/aeo/data/browser/#/?id=1-AEO2016&region=0-0&cases=ref2016&start=2013&end=2040&f=A&linechart=ref2016-d032416a.3-1-AEO2016~&ctype=linechart&sourcekey=0, accessed July 5, 2016

Figure 2.3: Alberta Vertical Oil Well Supply Costs



Source: CERI, AER, PSAC, CAPP

Figure 2.4: Alberta Horizontal Oil Well Supply Costs

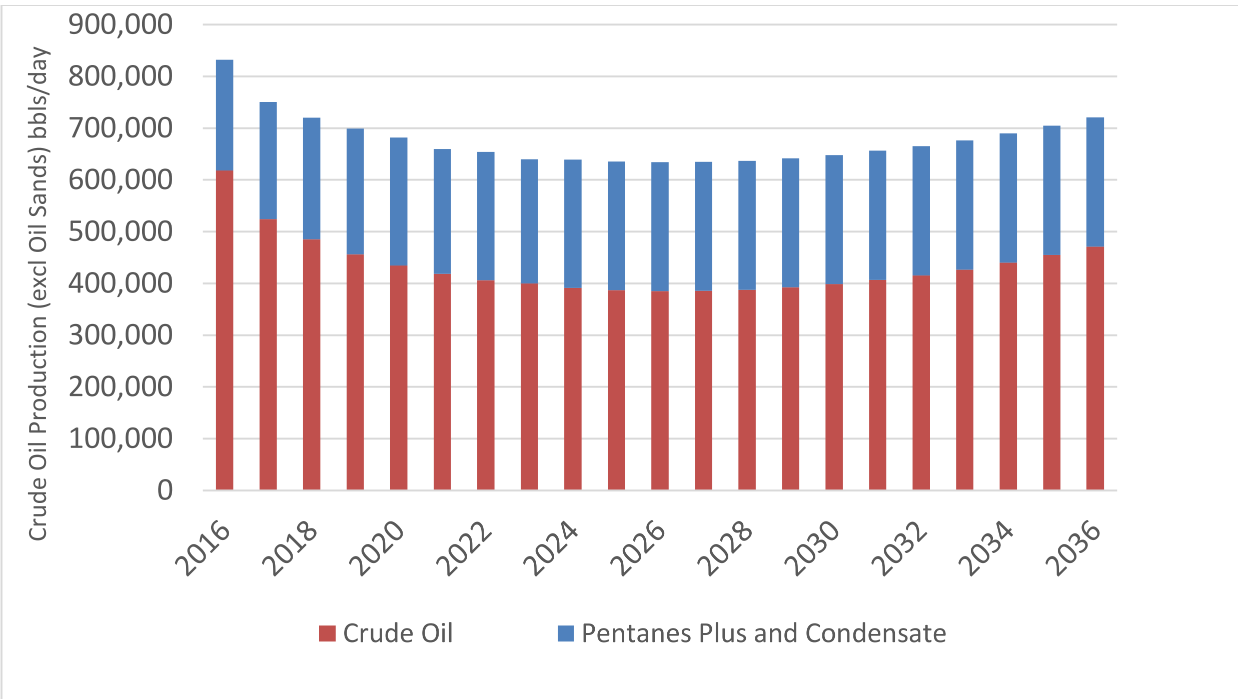


Source: CERI, AER, PSAC, CAPP

In looking at the supply cost results for oil wells in Alberta, the corridor to the east of the Rocky Mountains contains many of the pipeline influence areas at the lower end of both the horizontal and vertical supply cost curves, including PIAs 16, 17, 02, 01, 14, 05 and 15. The Montney, Duvernay and Bakken formations are, unsurprisingly, represented at the lower end of the supply cost curve. Going forward, it is expected that the majority of drilling will occur in these areas.

Given drilling expectations and known decline rates in the drilling areas, CERI developed a 20-year production forecast for oil production, not including oil sands production, in Alberta as shown in Figure 2.5.

Figure 2.5: Alberta Crude Oil Production Forecast



Source: CERI, AER, PSAC, CAPP

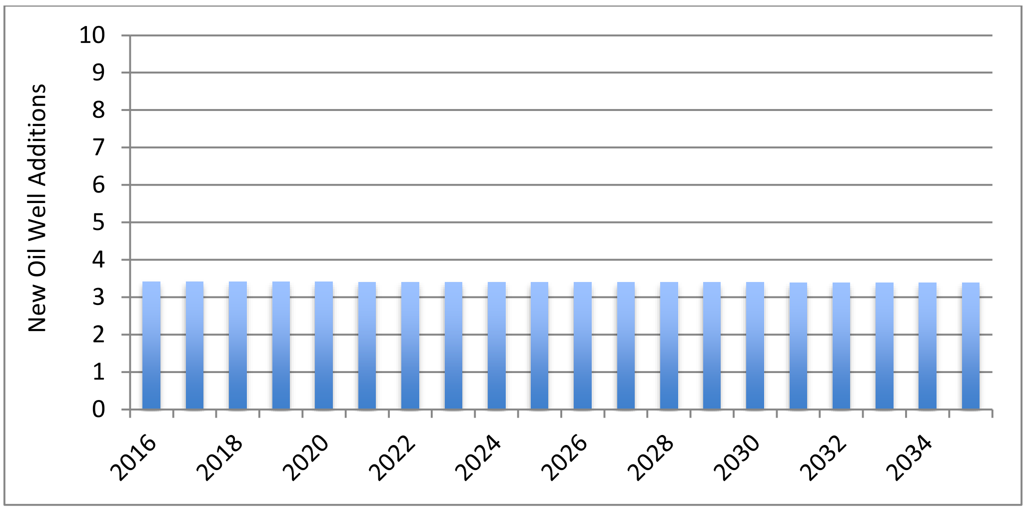
While Figure 2.1 showed continuously increasing drilling rates post-2016, the production shown in Figure 2.5 does not match this trend, with production decreases until 2027, after which increases slowly start. This can be attributed to a combination of well decline rates and drilling slowdowns that took place over 2015 and the first half of 2016. The increases in drilling shown in Figure 2.1 are not high enough to compensate for these factors which both lead to depressed production.

British Columbia

Historically, British Columbia has not contributed large amounts to Canada's total production of crude oil. Over the last ten years, British Columbia has produced approximately two percent of Canada's total crude.[2]

For British Columbia, as was done for the province of Alberta, CERI used historical well licensing data, supply costs and knowledge of drilling activity in pipeline influence areas to forecast drilling for new oil wells. CERI's forecast for conventional oil wells in BC is shown in Figure 2.6.

Figure 2.6: British Columbia New Oil Well Forecast



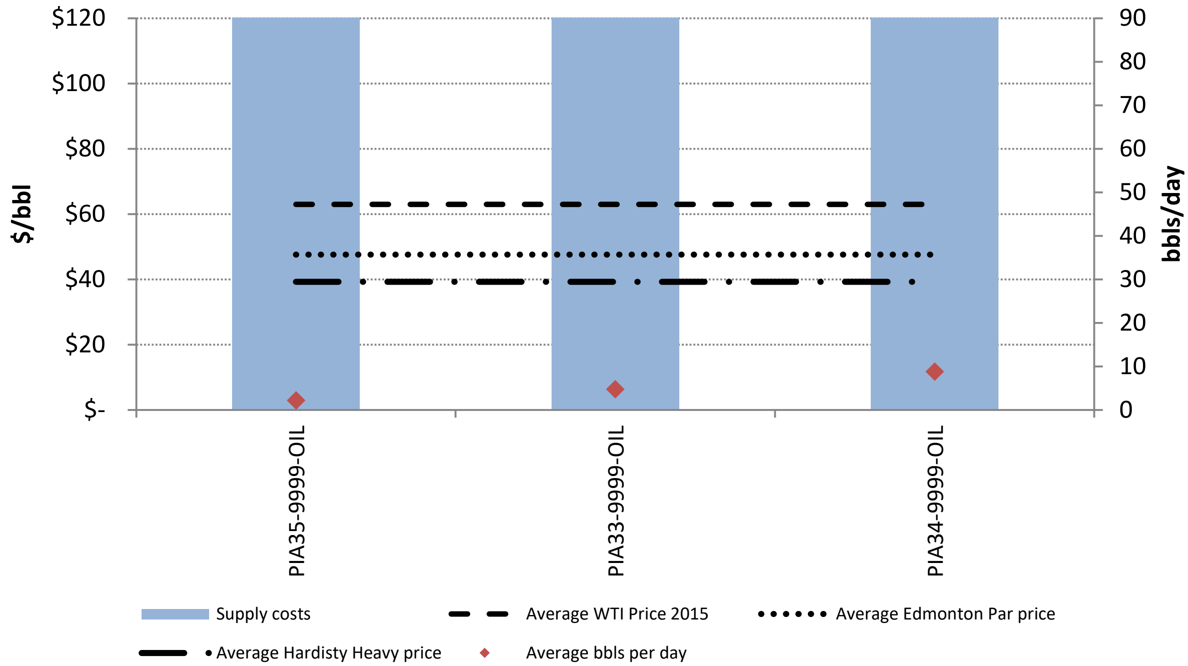
Source: CERI, BCOGC

CERI does not predict a significant drilling program targeting crude oil in British Columbia. The assumption is that the province will consistently add 3 new conventional oil wells per year over the study period.

The well costs for specific pipeline areas are shown in Figures 2.7 and 2.8, with the average WTI price, Hardisty Heavy price and Edmonton Heavy par price overlaid for reference.

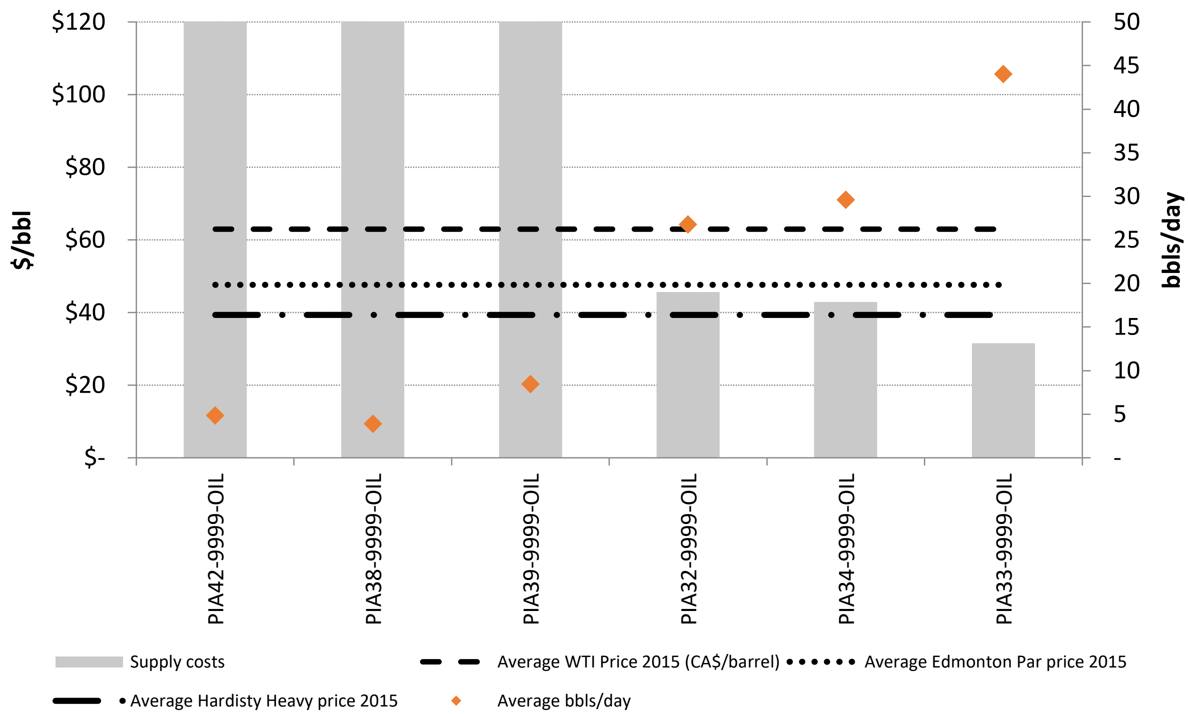
[2] Canadian Association of Petroleum Producers, 'Statistical Handbook for Canada's Upstream Petroleum Industry, May 2016, Table 3.7e.

Figure 2.7: British Columbia Vertical Oil Well Supply Costs



Source: CERI, BCOGC, PSAC, CAPP

Figure 2.8: British Columbia Horizontal Oil Well Supply Costs

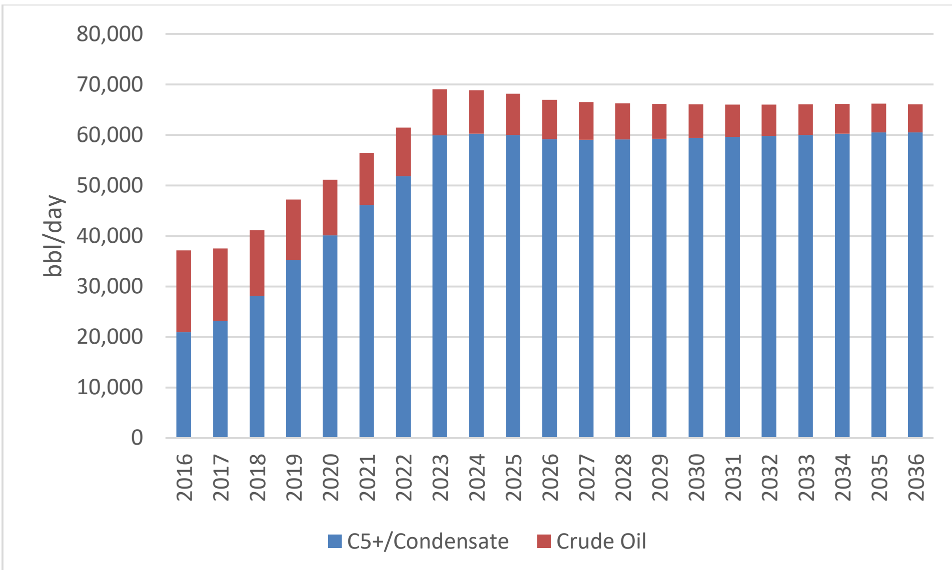


Source: CERI, BCOGC, PSAC, CAPP

The supply costs of horizontal wells are far less expensive than those of vertical wells, which is consistent with the trend towards drilling horizontal wells. The three areas shown in Figure 2.8 to have favourable average supply costs for horizontal drilling are all part of British Columbia's Montney formation. Future oil well drilling is expected to continue to be in this formation, concentrated in the three regions identified above.

Given drilling expectations and known decline rates in the drilling areas, CERI developed a 20-year production forecast for oil in British Columbia as shown in Figure 2.9.

Figure 2.9: British Columbia Crude Oil Production Forecast



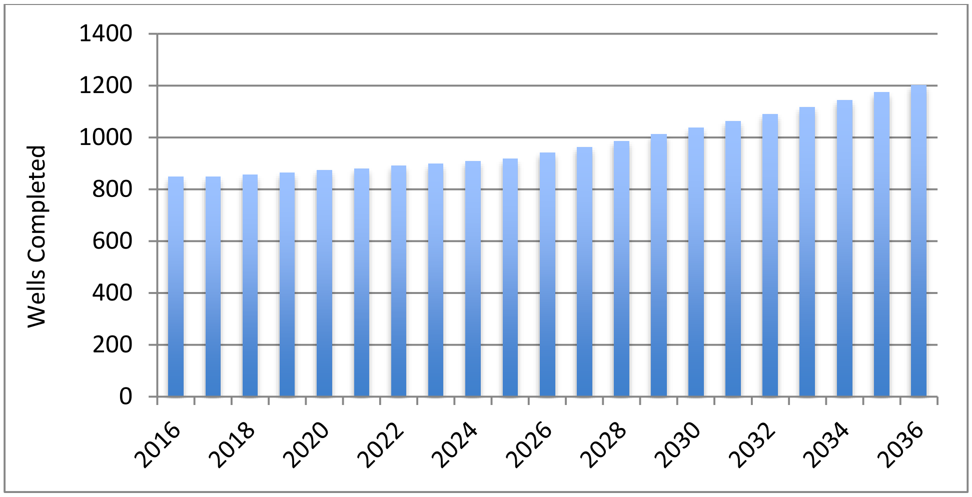
Source: CERI, BCOGC, PSAC, CAPP

CERI predicts continuously declining levels of crude production out of British Columbia owing to the generally unfavourable well supply costs and a preference for targeting natural gas rather than crude oil. Production of C5+/Condensate is expected to rise through 2023 and then remain stable. The C5+/Condensate production will come from the increased production of natural gas required to meet the demands from oncoming LNG plants.

Saskatchewan

As with Alberta and British Columbia, CERI uses historical well licensing data, supply costs and knowledge of drilling activity in pipeline influence areas to forecast drilling for new oil wells in the province of Saskatchewan. CERI's forecast for conventional oil wells in Saskatchewan is shown in Figure 2.10.

Figure 2.10: Saskatchewan New Oil Well Forecast

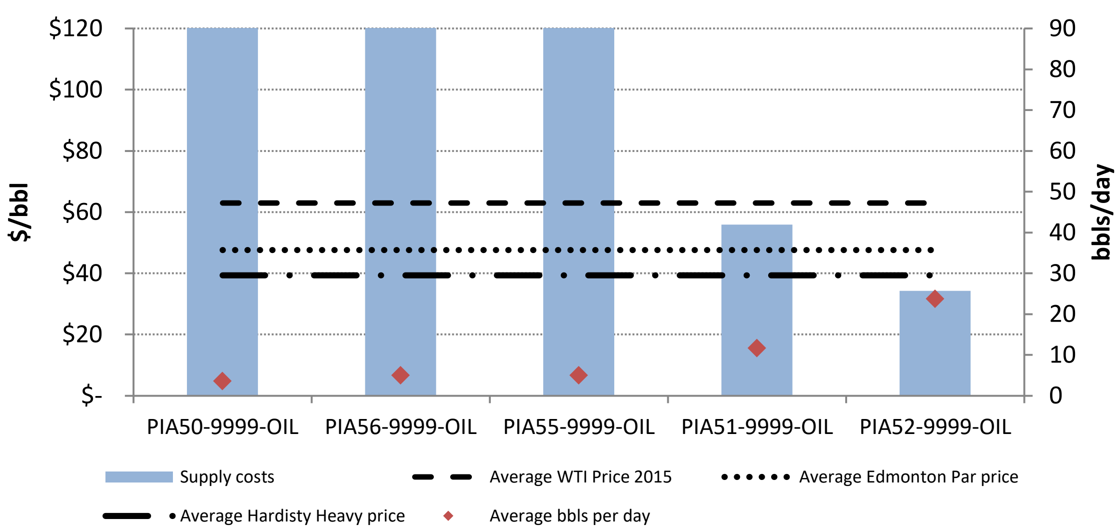


Source: CERI, Government of Saskatchewan, PSAC, CAPP

Drilling will consistently increase through the study period, with 2036 having approximately 50 percent more drilling than 2016. Most of the activity will fall within the tight oil formations within the WCSB, in Saskatchewan's portion of the Bakken.

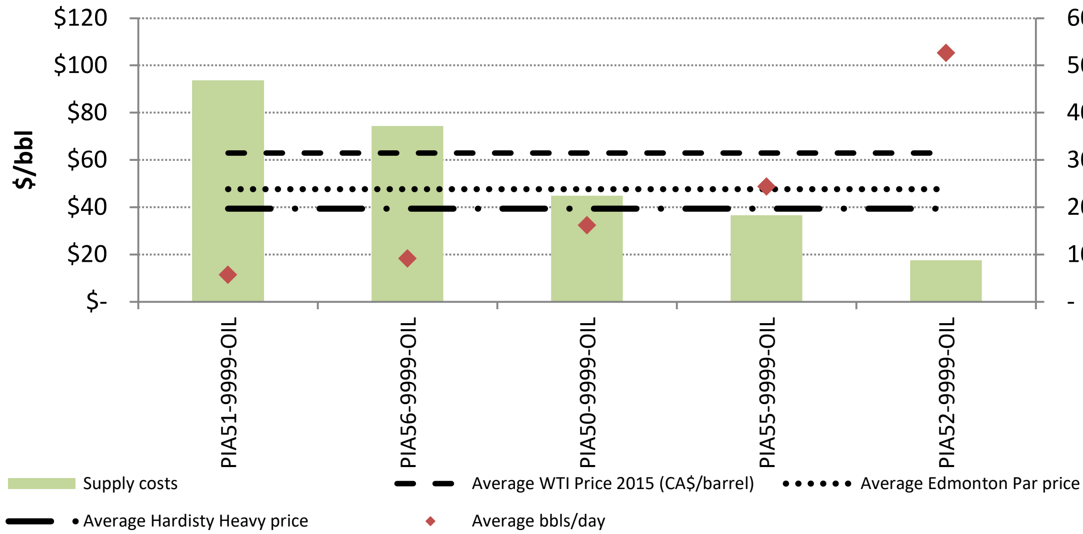
The average calculated well costs for specific pipeline areas are shown in Figures 2.11 and 2.12, with the average WTI price, Hardisty Heavy price and Edmonton Heavy par price overlaid for reference.

Figure 2.11: Saskatchewan Vertical Oil Well Supply Costs



Source: CERI, Government of Saskatchewan, PSAC, CAPP

Figure 2.12: Saskatchewan Horizontal Oil Well Supply Costs

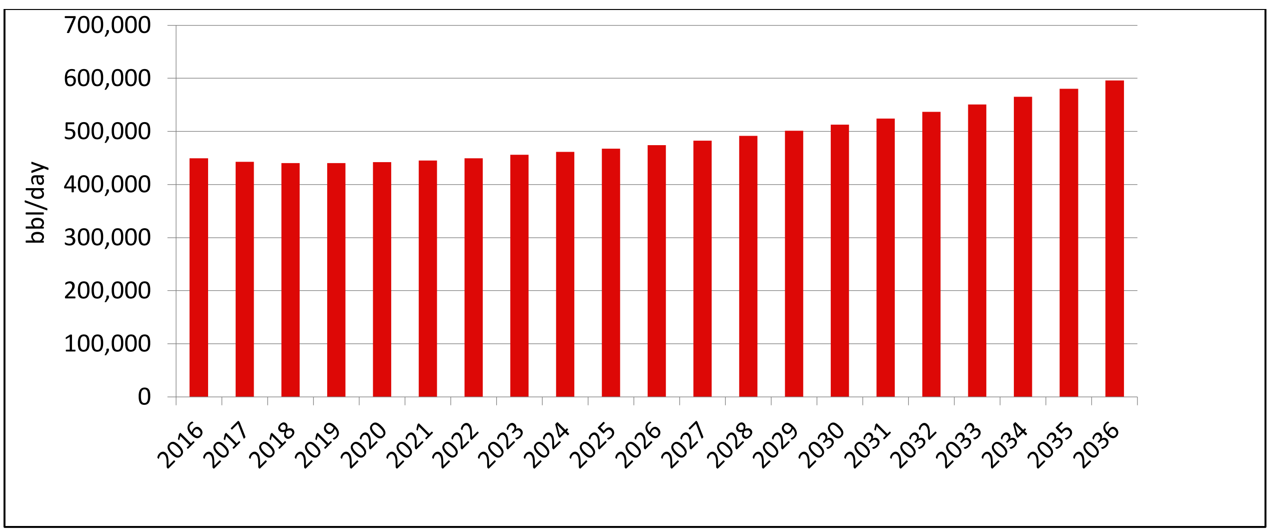


Source: CERI, Government of Saskatchewan, PSAC, CAPP

As with Alberta and British Columbia, the supply costs for horizontal wells are lower than those for vertical wells. Horizontal drilling is expected to make up higher percentages of total drilling in coming years.

Given drilling expectations and known decline rates in the drilling areas, CERI developed a 20-year production forecast for oil in Saskatchewan as shown in Figure 2.13.

Figure 2.13: Saskatchewan Crude Oil Production Forecast



Source: CERI, Government of Saskatchewan, PSAC, CAPP

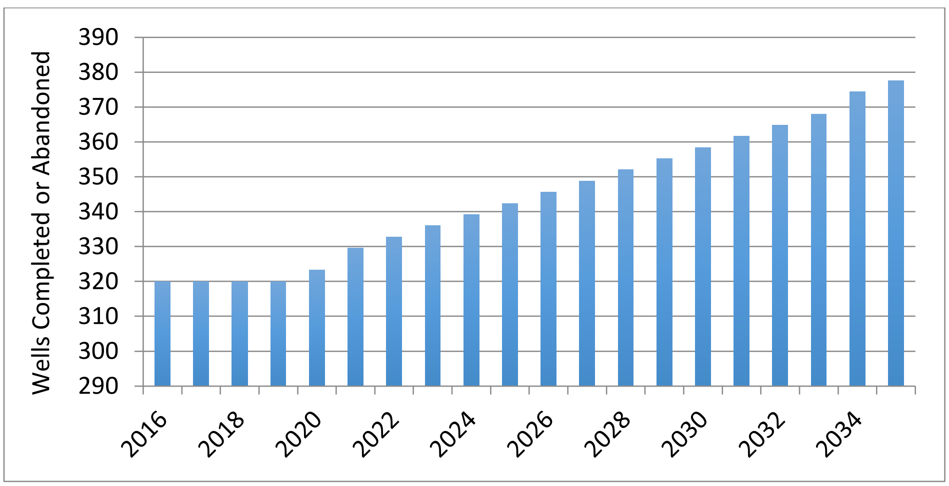
Saskatchewan's crude oil production forecast mirrors its increasing drilling forecast. CERI predicts that oil production will remain fairly constant until 2021, at which point it will increase throughout the remainder of the study period. 2036 will see approximately 150,000 more barrels per day of production than 2016 which is an increase of one-third.

Manitoba

While not a producer of natural gas, Manitoba has seen its production of crude oil more than double over the last decade, reaching a peak of four percent of total Canadian crude oil production in 2012.[3]

As with the other provinces in this study, CERI uses historical well licensing data, supply costs and knowledge of drilling activity in pipeline influence areas to forecast drilling for new oil wells in the province of Manitoba. CERI's forecast for conventional oil wells in Manitoba is shown in Figure 2.14.

Figure 2.14: Manitoba New Oil Well Forecast



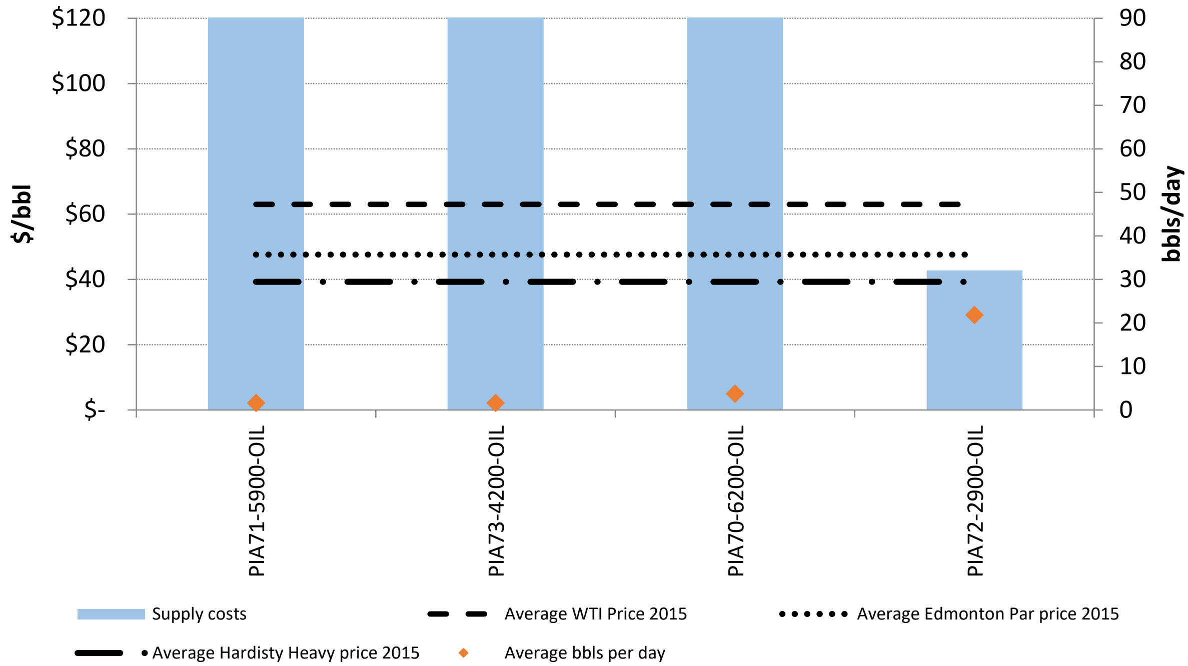
Source: CERI

CERI predicts linear growth in Manitoba's new oil wells after 2019, having more than 50 additional wells in 2036 than 2016.

The average calculated well costs for specific pipeline areas are shown in Figures 2.15 and 2.16, with the average WTI price, Hardisty Heavy price and Edmonton Heavy par price overlaid for reference.

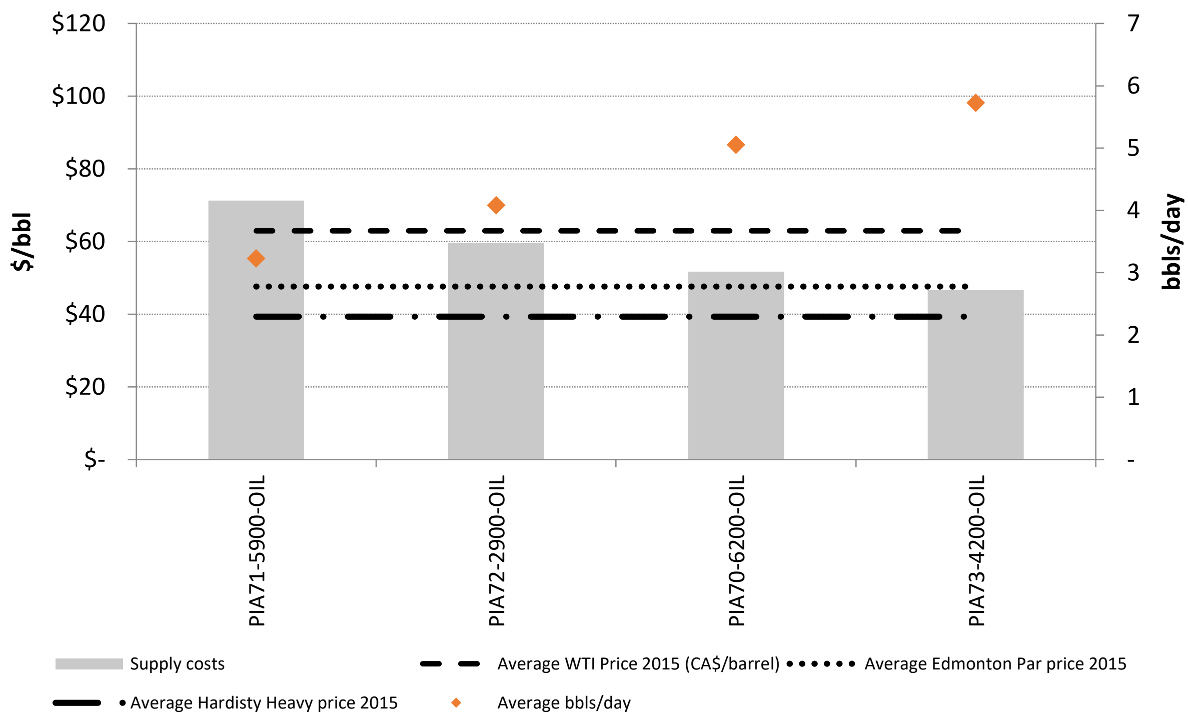
[3] Canadian Association of Petroleum Producers, 'Statistical Handbook for Canada's Upstream Petroleum Industry, May 2016, Table 3.7e.

Figure 2.15: Manitoba Vertical Oil Well Supply Costs



Source: CERI, Government of Manitoba, PSAC, CAPP

Figure 2.16: Manitoba Horizontal Oil Well Supply Costs

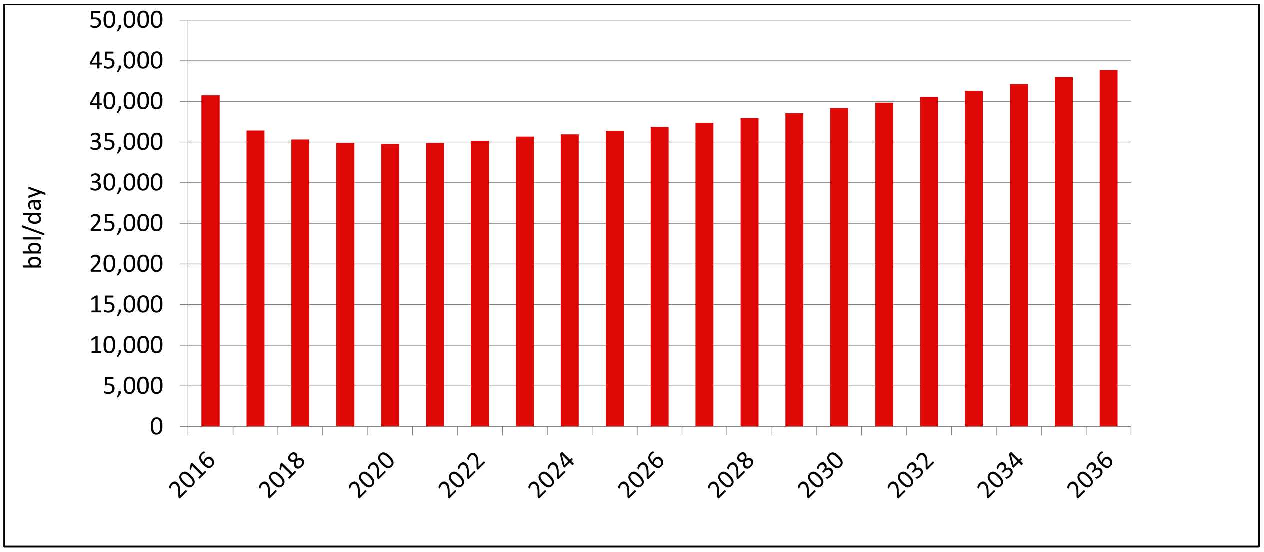


Source: CERI, Government of Manitoba, PSAC, CAPP

As with the other provinces in this study, the supply costs for horizontal wells are lower than those for vertical wells.

Given drilling expectations and known decline rates in the drilling areas, CERI developed a 20-year production forecast for oil in Manitoba as shown in Figure 2.17.

Figure 2.17: Manitoba Crude Oil Production Forecast



Source: CERI, Government of Manitoba, PSAC, CAPP

As drilling remains constant in the province over the next few years, CERI predicts declining production due to well decline rates. Production will increase with drilling after 2020, reaching almost 45,000 barrels per day by the end of the study period.

Newfoundland and Labrador

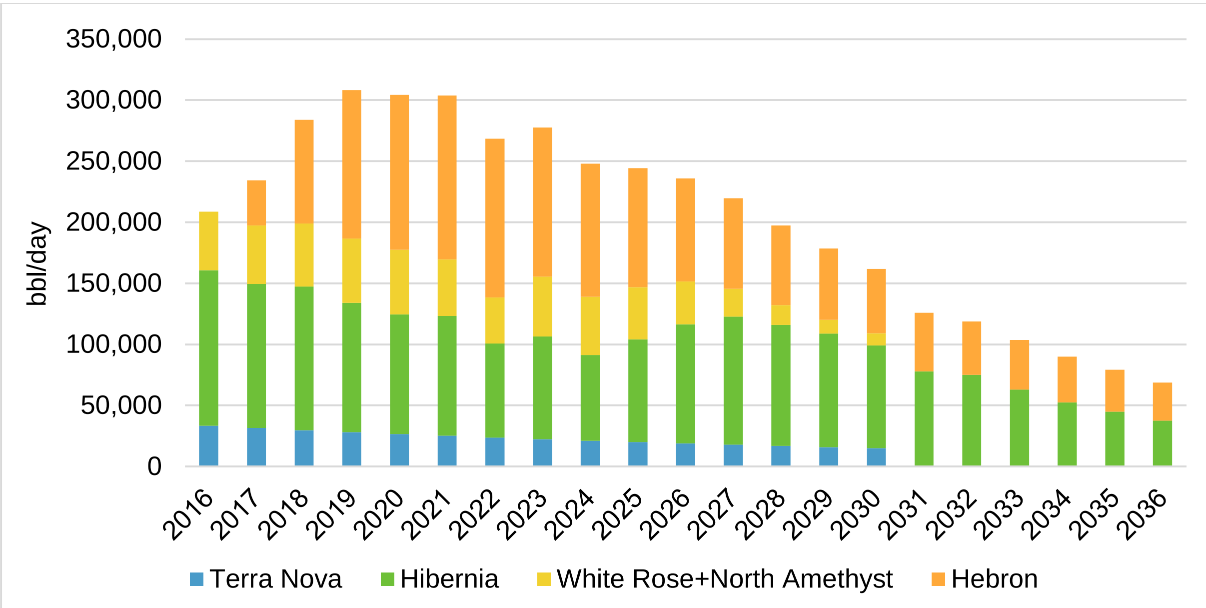
In 2015, Ontario produced 248,814 barrels and New Brunswick produced 12,617 barrels of crude oil, while East Coast Offshore produced 62,673,290 barrels with the vast majority being from Newfoundland and Labrador.[4] Over the past decade, Newfoundland and Labrador has produced over 20 percent of Canada's total crude oil per year, however in recent years it has dropped to 15 percent.[5] The offshore assets included in the analysis are Hibernia, Terra Nova, White Rose, and North Amethyst, including producing assets and officially approved project development extensions. The new asset – Hebron – to be commissioned in 2017 is also included in the analysis. Unlike the western Canadian provinces, CERI has assessed offshore Newfoundland on a per-asset basis rather than per-well. While Nova Scotia has offshore assets as well, it has historically

[4] Canadian Association of Petroleum Producers, 'Statistical Handbook for Canada's Upstream Petroleum Industry, May 2016, Table 3.1c.
[5] Canadian Association of Petroleum Producers, 'Statistical Handbook for Canada's Upstream Petroleum Industry, May 2016, Table 3.7e.

comprised less than one percent of total Canadian crude oil production and its production is not modeled by CERI for this report.

CERI used historical production information from the provincial regulator as well as information from project development plans, including recoverable reserves and project life in order to calculate production profiles for the 20-year study period. CERI's forecast for offshore Newfoundland crude oil production is shown in Figure 2.18.

Figure 2.18: Offshore Newfoundland Crude Oil Production Forecast



Source: CERI, CNLOPB, Various individual operators

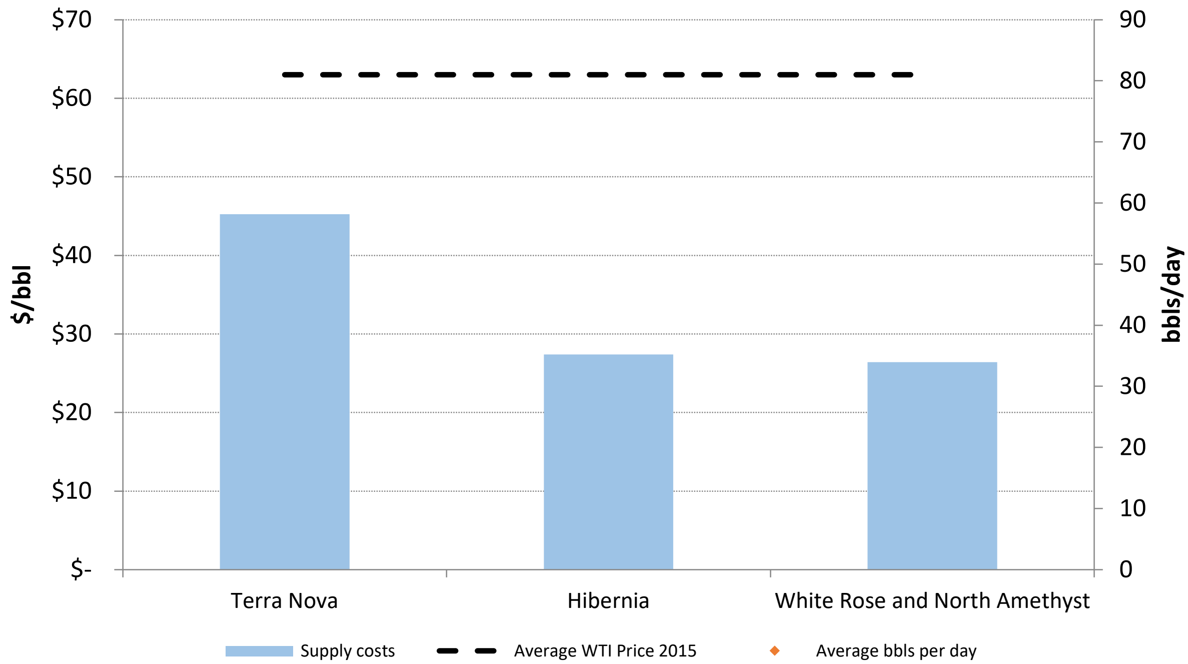
Total crude oil production will increase until 2019 as the Hebron asset is added and starts to produce. After 2019, Hebron's annual production is set to decline steadily throughout the length of the study period, with Terra Nova set to come offline in 2030.

While offshore Newfoundland sees significant volumes of natural gas recovered alongside the oil, this gas is not produced to be sold. Any solution gas that is produced is currently used as fuel for oil production, re-injected to maintain well pressure, enhanced oil recovery, or stored for potential future commercial use. In 2012, Ziff Energy Group calculated that the costs of producing offshore gas would be 4 to 5 times the North American domestic gas price,[6] making it economically unviable.

[6] Ziff Energy Group, Natural Gas as an Island Power Generation Option, October 30, 2012, http://muskratfalls.nalcorenergy.com/wp-content/uploads/2013/03/Natural-gas-as-an-island-power-generation-option.pdf, pp. 2

The average calculated well costs for the offshore oil assets are shown in Figure 2.19, with the average WTI price overlaid for reference.

Figure 2.19: Offshore Newfoundland Oil Well Supply Costs, 2015



Source: CERI, CNLOPB, PSAC, CAPP

As the supply costs for offshore Newfoundland oil drilling are more aggregated than those for the provinces in Western Canada, the results are more heavily impacted by the large amount of production that comes out of the offshore wells and the supply costs appear to be significantly lower. White Rose and North Amethyst and Hibernia show similar supply costs, while Terra Nova is just less than double, however still less than the reference oil prices.

As with the supply cost calculations for the western Canadian provinces, individual wells may show a wide range of costs. Oil production in Newfoundland and Labrador fell 21 percent in 2015 from 2014 levels,[7] highlighting that producers are sensitive to the drop in oil price. Differences in factors attributing to supply costs are also responsible for this drop. Offshore drilling has higher upfront capital costs than onshore drilling, discouraging new drilling when oil prices drop. Further, the higher capital cost encourages heavy rates of production out of existing wells, leading to high decline rates. When drilling is reduced, production will decline quickly.

[7] C-NLOPB, Production Data, Accessed July 21, 2016, http://www.cnlopb.ca/offshore/production.php

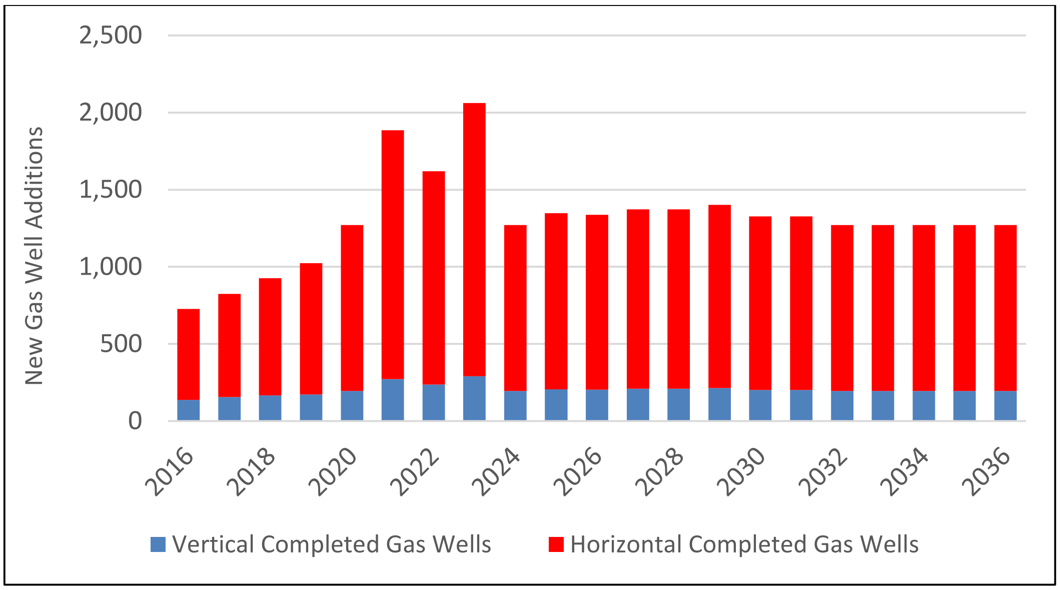
Natural Gas

Alberta

CERI Study 158, 'Canadian Natural Gas Market Review', published in June of 2016, forecasts drilling activity and production data and calculates well supply costs for vertical and horizontal conventional natural gas wells in the WCSB. The results of this study have been updated to include production data that had not been released at the time of modeling.

CERI developed the new gas well forecast based on well decline rates as well as well supply cost and knowledge of drilling activity in pipeline activity areas. Alberta natural gas well additions are shown in Figure 2.20.

Figure 2.20: Alberta New Gas Well Additions



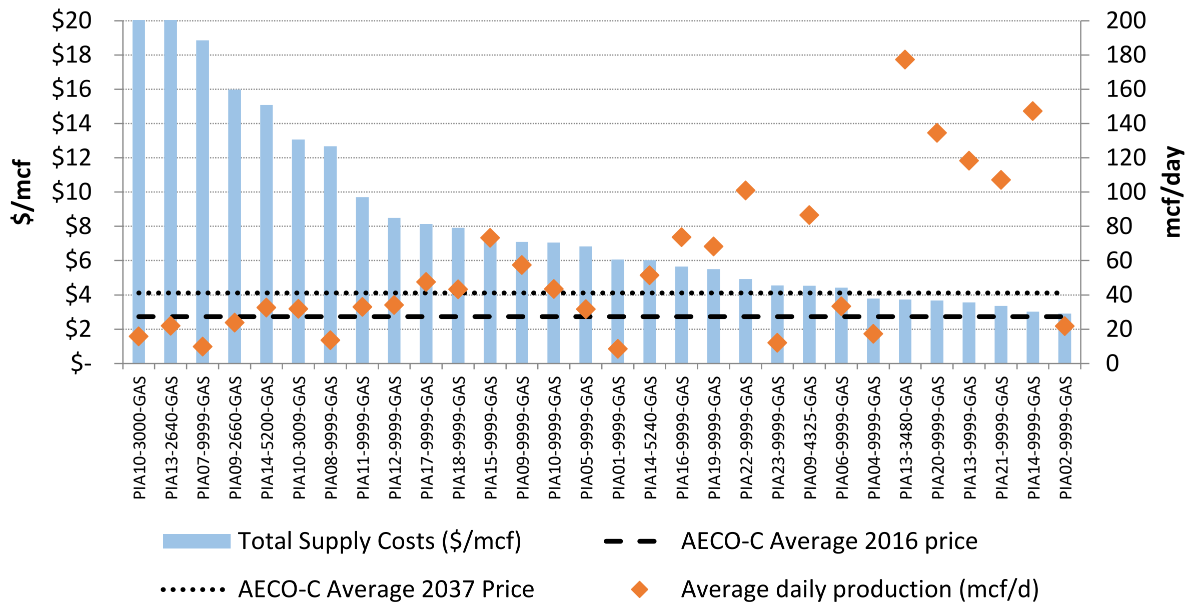
Source: CERI

As with new oil wells, natural gas drilling is expected to increase from the current low levels of activity of 726 wells in 2016 to 1,270 wells in 2036. Peaks in drilling are expected in the coming years to accommodate increased demand from LNG projects set to come online in British Columbia. CERI sees British Columbia's first LNG project coming online in 2022 and its second coming online in 2023. While the natural gas supplying these projects (5 Bcfd) will mostly come out of British Columbia, the volume of gas from British Columbia that is available to export to Alberta will be reduced. It is assumed that Alberta producers will step in to fill the gap. Horizontal wells consistently make up more than 80 percent of the new well additions in any given year in the study period.

As with oil, CERI uses information contained in the 2016 Well Cost Study from the Petroleum Services Association of Canada (PSAC) as well as from the Canadian Association of Petroleum Producers' (CAPP) Statistical Handbook in order to calculate the well supply costs. Reference wells are assigned to each area and formation under study and the well cost is calibrated to the average drill depth using true vertical depth for a vertical well and total drill depth for a horizontal well. A provision for connection infrastructure costs plus geological and geophysical costs are added to the well cost.

The supply costs for vertical and horizontal natural gas wells in Alberta are shown in Figures 2.21 and 2.22 against the average AECO-C prices for 2016 and 2037 (using the National Energy Board's references case[8] prediction of the price of natural gas at Henry Hub, with CERI assuming an AECO-C discount to Henry Hub of $1.22/Mcf).

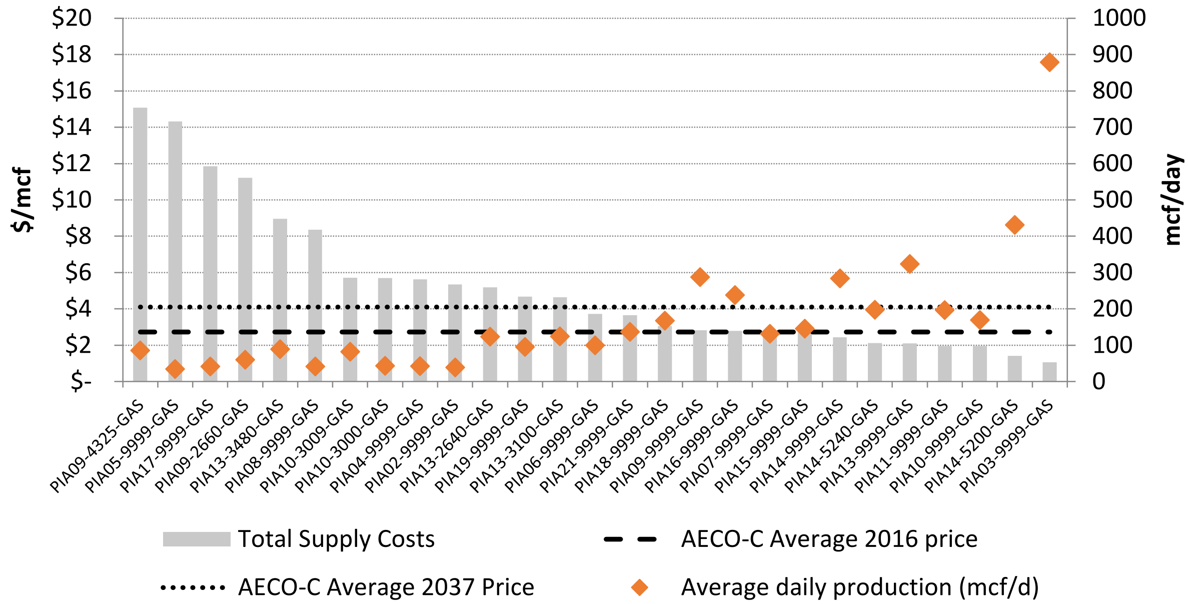
Figure 2.21: Alberta Vertical Natural Gas Well Supply Costs



Source: CERI, PSAC, CAPP, NEB

[8] National Energy Board, "Canada's Energy Future 2016", http://www.neb-one.gc.ca/nrg/ntgrtd/ftr/2016/2016nrgftr-eng.pdf, page 36, accessed July 5, 2016.

Figure 2.22: Alberta Horizontal Natural Gas Well Supply Costs



Source: CERI, PSAC, CAPP, NEB

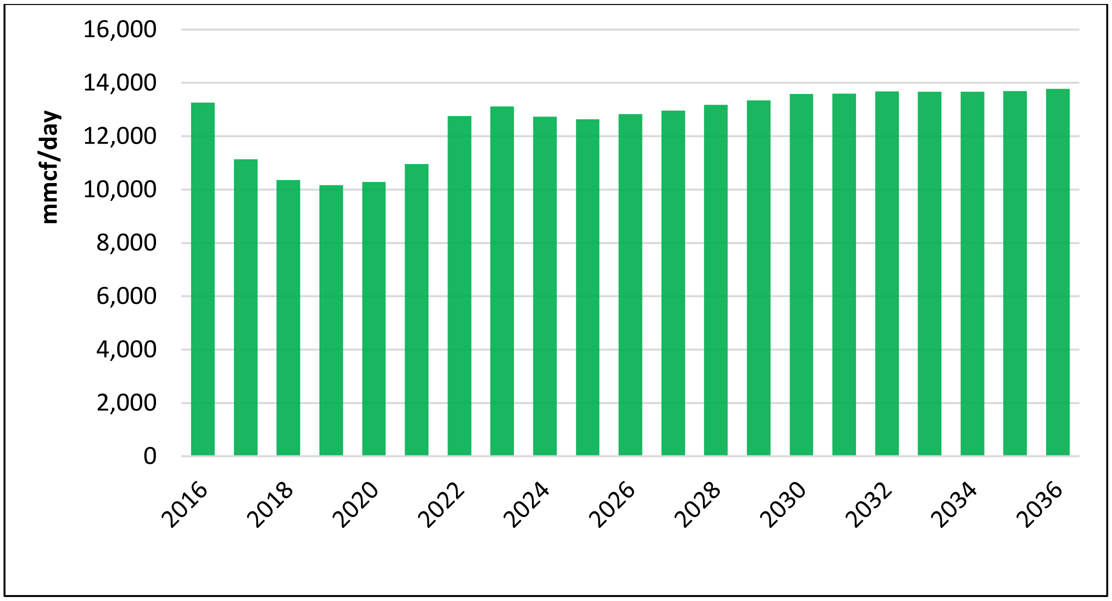
Horizontal wells are generally shown to have lesser supply costs, and have a larger number of pipeline influence areas whose supply costs fall below the 2016 and 2037 AECO-C prices, which is consistent with the forecast in Figure 2.20 showing the number of new horizontal wells vastly surpassing the number of new vertical wells.

Economies of scale are relevant to the calculations of an individual producer, as many well pads will contain multiple wells. The more prolific formations in Alberta have seen approximately 2 wells per pad over the same period of time.

When looking at drilling numbers in specific formations, the corridor to the east of the Rocky Mountains has collectively the highest concentration of activity. Formations include Alberta's Montney, Doig, Cardium, Banff, Glauconitic and Beaverhill as well as collective smaller pools. The weighted average supply cost of the ten Alberta areas in this region is $1.83/Mcf.

Given drilling expectations and known decline rates in the drilling areas, CERI developed a 20-year production forecast for natural gas in Alberta as shown in Figure 2.23.

Figure 2.23: Alberta Wellhead Natural Gas Production Forecast



Source: CERI, AER

While drilling activity is predicted to rise from current levels until 2023, the supply of natural gas from Alberta will dip from 2016, and reach current levels again in 2023. Natural gas supply will decrease until 2019, at which point it will rise until a peak in 2023. When looking at the drilling forecast for gas wells in Alberta, production lags drilling in the years until 2022. This is due to the preemptive drilling of wells meant to compensate for reduced flow from British Columbia as upcoming LNG projects increase its demand. These wells will not start to produce until 2022 when the first of the LNG projects is set to come online. Post-2024, natural gas production in Alberta remains fairly stable with slight increases to just below 14,000 mmcf/day through the duration of the study period. Solution gas, or associated gas, is not considered in the forecast for Alberta, nor the rest of the provinces in this study. It is worth noting that approximately 10 percent of the natural gas produced in the WCSB is solution gas.

British Columbia

British Columbia has been a more significant player in the production of natural gas over crude oil. In the past, British Columbia has produced approximately five percent of total Canadian production.[9]

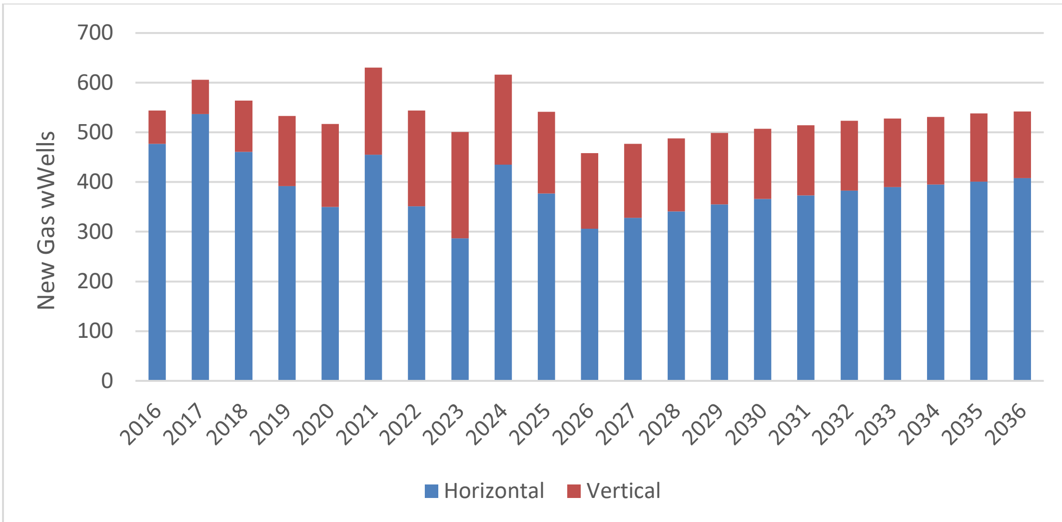
As with Alberta, drilling activity, production data and well supply costs have been updated from CERI's Study 158 for natural gas in British Columbia.

CERI uses historical monthly new natural gas well licenses to extrapolate a forecast through to the end of 2016. Through the remainder of the study period, the new well forecast is developed

[9] Canadian Association of Petroleum Producers, 'Statistical Handbook for Canada's Upstream Petroleum Industry, May 2016, Table 3.9c.

based on well decline rates as well as supply costs and knowledge of drilling activity in pipeline activity areas. British Columbia natural gas well additions are shown in Figure 2.24.

Figure 2.24: British Columbia New Gas Well Forecast

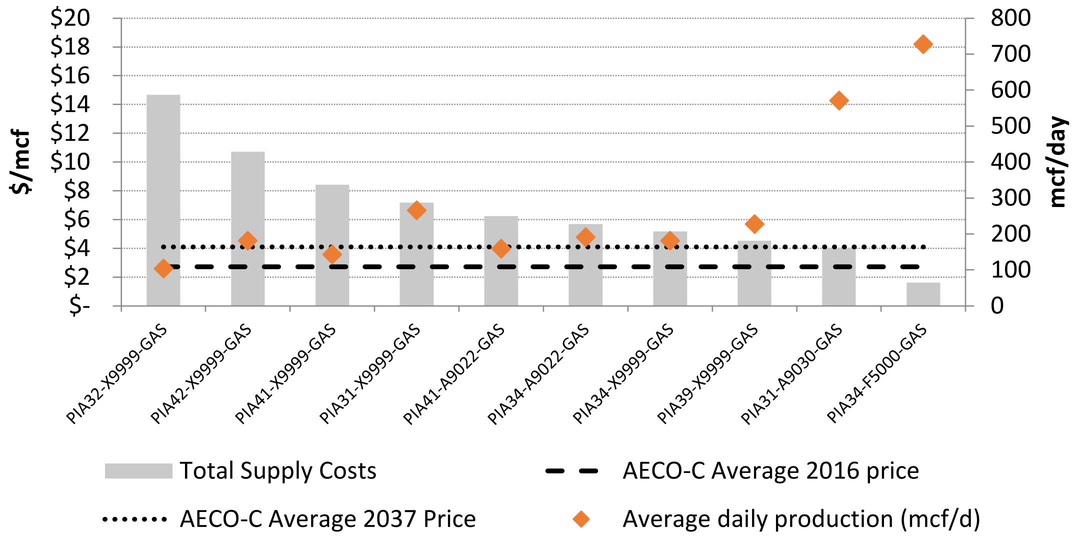


Source: CERI

The number of new well additions that CERI expects to see over the next five to six years is increased by expectations of LNG facilities being built in the province. In the year 2024, the new additions due to LNG are expected to drop off, and the province will see small but consistent growth through the remainder of the study period.

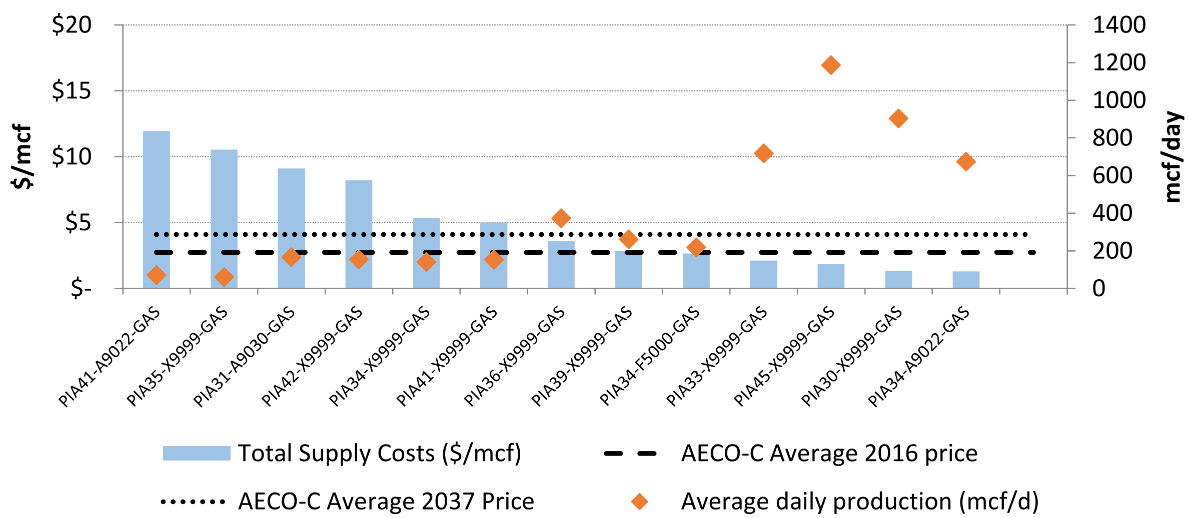
Supply costs for natural gas wells in British Columbia are calculated in the same manner that they are for Alberta's wells. The supply costs for natural gas wells, vertical and horizontal, are shown in Figures 2.25 and 2.26, respectively.

Figure 2.25: British Columbia Vertical Gas Well Supply Costs



Source: CERI, BCOGC, PSAC, CAPP

Figure 2.26: British Columbia Horizontal Gas Well Supply Costs



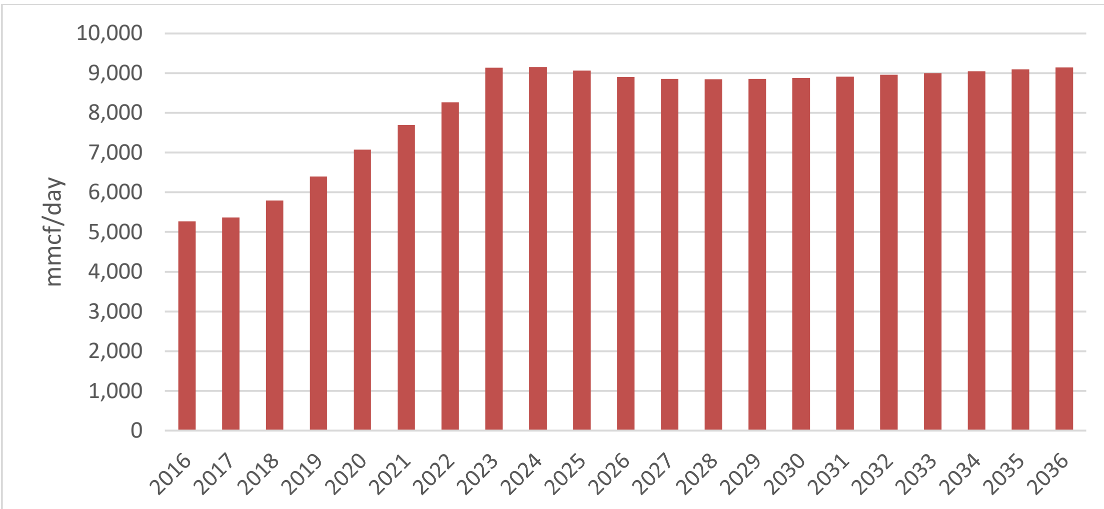
Source: CERI, BCOGC, PSAC, CAPP

In the WCSB, the most economically viable natural gas wells are in the province of British Columbia, particularly its Montney formation. The average supply cost of vertical wells in BC's Montney formation is $2.59/Mcf, proving its attractiveness to drillers. Since 2013, approximately 65 percent of the wells drilled in BC have been in its Montney formation. The remainder of the drilling has been split fairly evenly between the rest of BC's formations, with the next highest numbers coming out of its Jean Marie formation at 5 percent. The Montney has the overwhelmingly highest concentration of activity, and it is expected that this will remain the case throughout the study period due to its favorable well economics.

Economies of scale are relevant to the calculations of an individual producer, as many well pads will contain multiple wells. In looking at BC's drilling over the past year, the Montney formation has seen, on average, more than 6 wells per pad.

CERI's production forecast for natural gas in British Columbia is shown in Figure 2.27.

Figure 2.27: British Columbia Field Gate Natural Gas Production Forecast



Source: CERI, BCOGC, PSAC, CAPP

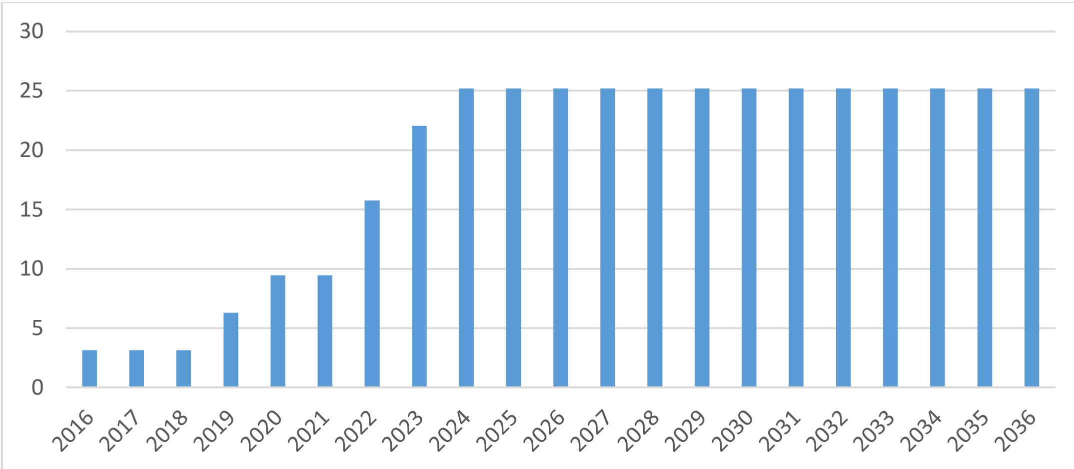
As with natural gas production in Alberta, British Columbia's production of natural gas accounts for an increase in demand of approximately 5 Bcf/d due to LNG projects coming online in 2022. Consistent increases in production are expected until 2023, at which point production will stabilize through the remainder of the study period at approximately 9,000 mmcf/day.

Saskatchewan

As with Alberta, drilling activity, production data and well supply costs have been updated from CERI's Study 158 for natural gas in Saskatchewan.

CERI uses historical monthly new natural gas well licenses to extrapolate a forecast through to the end of 2016. Through the remainder of the study period, the new well forecast is developed based on well decline rates as well as supply costs and knowledge of drilling activity in pipeline activity areas. Saskatchewan natural gas well additions are shown in Figure 2.28.

Figure 2.28: Saskatchewan New Gas Well Forecast

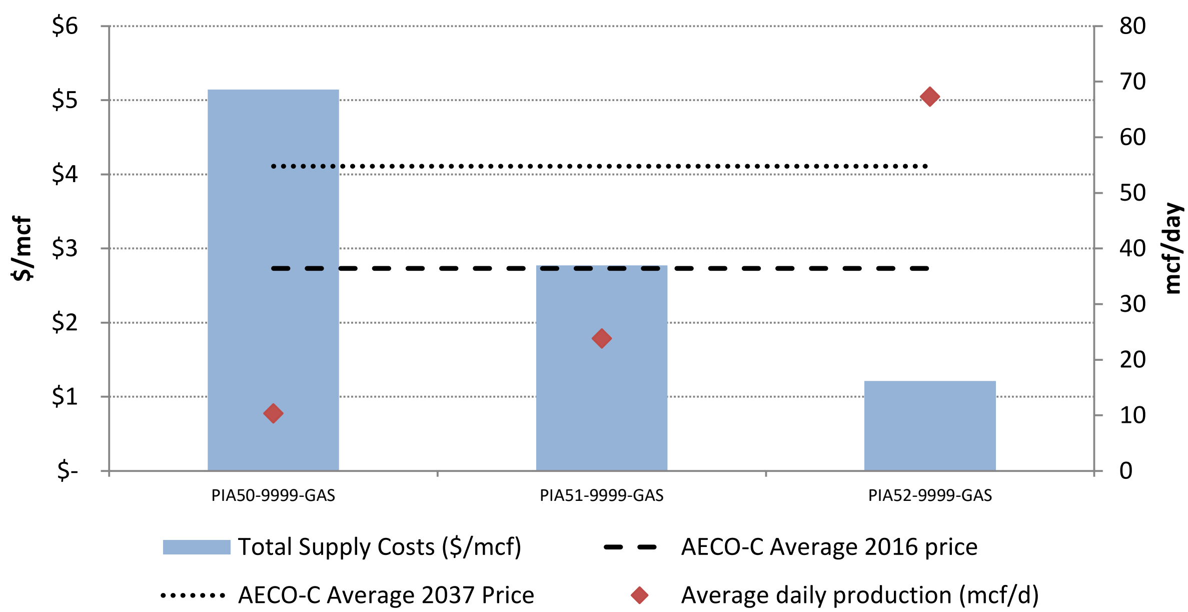


Source: CERI

Drilling of gas wells in Saskatchewan is expected to rise from current levels below 5 wells per year to 25 wells per year in 2024, and remain constant through the end of the study period.

Supply costs for natural gas wells in Saskatchewan are calculated in the same manner that they are for Alberta and British Columbia's wells. Insufficient data was available for the determination of Saskatchewan's horizontal well costs, however the supply costs for vertical wells are shown in Figure 2.29.

Figure 2.29: Saskatchewan Vertical Natural Gas Well Supply Costs

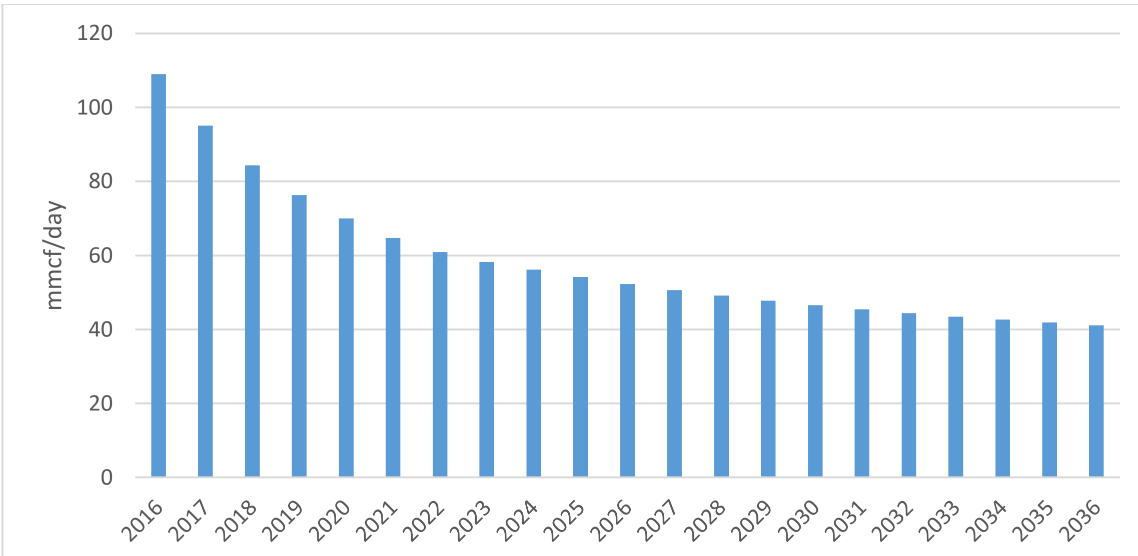


Source: CERI

Similar to the other provinces in the WCSB, it can be expected that the supply costs of horizontal wells in Saskatchewan will be less expensive than the vertical well supply costs. Horizontal wells will continue to make up a higher proportion of drilling throughout the 20-year study period.

CERI's 20-year production forecast for natural gas in Saskatchewan is shown in Figure 2.30.

Figure 2.30: Saskatchewan Natural Gas Production Forecast



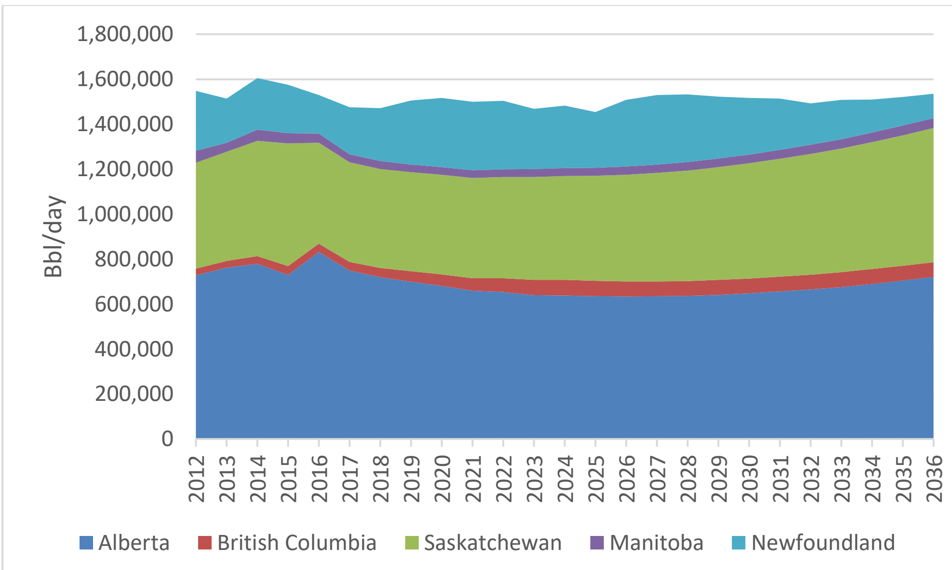
Source: CERI, Government of Saskatchewan, PSAC, CAPP

As with the previous provinces, due to drilling declines in 2015 and the first half of 2016 as well as well decline rates, natural gas production in Saskatchewan is expected to decline throughout the study period. The consistent addition of 25 new wells per year after 2024 is enough to sustain a consistent decline rate as shown in Figure 2.31.

Chapter 3: Canadian Oil and Gas Production and Royalties Outlook

Figure 3.1 shows total conventional crude oil that will be produced in Canada through 2036. It does not include production out of the territories, Ontario, New Brunswick or Nova Scotia as these volumes are negligible.

Figure 3.1: Total Canadian Conventional Crude Oil Production



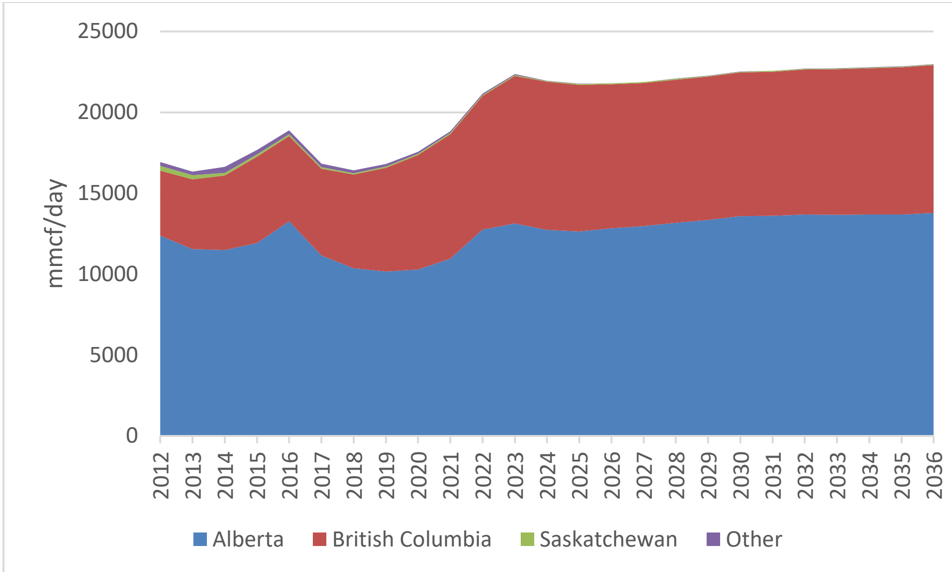
Source: CERI, BCOGC, AER, Government of Saskatchewan, Government of Manitoba, CNLOPB, PSAC, CAPP

Production levels are not expected to reach the highs seen in 2014 prior to the decline in oil price. Total production will remain fairly stable through the remainder of the study period, with slight growth in Western Canada being offset by the declines seen in offshore Newfoundland. The growth in crude oil production will be dominated by Saskatchewan as it is expected the province will be focusing on drilling their tight oil formation. In 2036, total conventional crude oil production is just above 1.5 MMbpd.

Figure 3.2 shows total natural gas production in Canada through 2036. Production out of Ontario, New Brunswick, Nova Scotia, the Yukon and Northwest Territories are included as "Other" and their values are from the National Energy Board's Energy Future January 2016.[36]

[36] National Energy Board, Canada's Energy Future 2016: Energy Supply and Demand Projections to 2040, January 2016, accessed July 2016.

Figure 3.2: Total Canadian Natural Gas Production



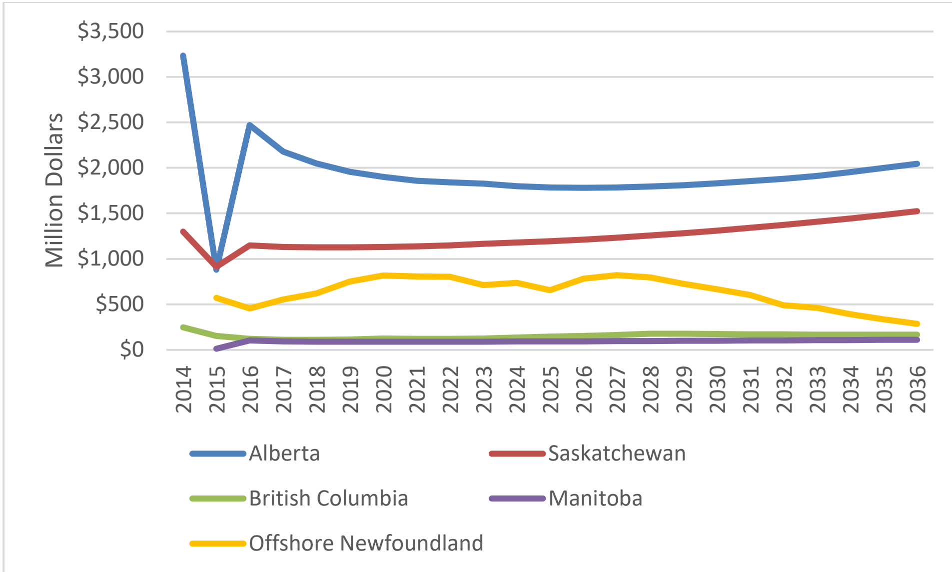
Source: CERI, NEB, BCOGC, AER, Government of Saskatchewan, PSAC, CAPP

The vast majority of natural gas production will continue to come out of British Columbia and Alberta. Both provinces will see declining natural gas production from 2016 through 2018 while the market adjusts to the reduction in drilling that has happened in the current low price environment. Both provinces will also see an uptick in production leading to the LNG projects, the first of which CERI predicts will come online in 2022. Once production has risen to accommodate the increase in demand that the LNG projects will cause, production remains fairly stable with marginal increases through the remainder of the study period. In 2036, production of natural gas will be slightly above 20 Bcf/day.

As part of the supply cost calculations for both oil and gas wells, CERI calculates royalty payments for each province, given expected production. CERI has separated the expected royalty receipts, by province, and they will be discussed below.

Figure 3.3 highlights CERI's estimates of royalty revenues that each province in question will earn throughout the study period. The 2014 values are from the various provincial budgets, while the values for 2015 through 2036 were calculated using the province's royalty calculations and CERI's production forecasts for oil and gas.

Figure 3.3: Royalty Revenues by Province



Source: CERI, Governments of Alberta, British Columbia, Saskatchewan, Manitoba and Newfoundland and Labrador

Consistent with production levels, royalty revenues are expected to drop from their highs in 2014. The drastic appearance in the drop in Alberta's royalty revenues can be attributed to the step changes built into the formula according to the price of oil. Alberta's new royalty framework differentiates between oil priced at $30, $50 and $100 per barrel.[37] The province of Saskatchewan also sees reduced revenues from 2014, however not as drastic as in Alberta. After 2016, the revenues are expected to rise continuously through the duration of the study period. The royalties from offshore Newfoundland's oil production are expected to rise as production ramps up due to Hebron's 2017 commissioning, and then ramp down as the projects come to the end of their producing lives.

[37] Department of Energy, Government of Alberta, "Alberta at a Crossroads: Royalty Review Advisory Panel Report", January 2016, accessed June 2016.

Chapter 4: Conclusions

The next 20 years will be characterized by slow growth at best for both oil and natural gas. Production costs for new wells are, in some cases, below the market price for both commodities but the majority of reference wells are not economic. Therefore, significant reductions in production costs would be needed for an expansion of oil and gas activity in Canada.

We note that horizontal wells sharing the same well pad will be the default choice for producers over the forecast period. As well, gas well economics improve with the presence of natural gas liquids.

The natural gas forecast has two major uncertainties. One is the timing and size of proposed LNG plants in British Columbia. If none are built, this could remove upwards of 5 Bcf/d of gas production. The second is the use of gas for electricity generation in Alberta. With the government's policy of moving away from coal-fired generation, natural gas demand would likely increase. It is uncertain when that additional demand would occur and by how much.

With respect to the oil market, price is the major uncertainty. Higher prices would put an upward pressure on the production forecast. Another uncertainty is market access. The new proposed oil pipelines, if approved, would provide alternate access to global markets, rather than relying solely on the United States. Additional access could also reduce the discount of western Canadian oil resulting from the current limited access. Tidewater access within Canada would bring a higher price for Western Canadian Select.

This latter uncertainty would not affect offshore Newfoundland crude, which already has ocean access for its production and does not experience the land-locked discount faced in Western Canada.

Appendix A: Natural Gas and Crude Oil Production Forecasts and Supply Cost Methodologies

Natural Gas Production Forecast and Supply Cost Methodology

The production forecast in this study is an update from that done in CERI Study 158, "Canadian Natural Gas Market Review", released in July 2016. CERI completed supply cost calculations, explained below, which informed the production forecast.

The supply cost calculations done in this study were also used in CERI Study No. 158. The supply cost method has not changed, and the assumptions have been updated to reflect their changes over time.

The WCSB supply costs represent the natural gas price (in real 2015 dollars) required to recover all capital expenditures, operating costs, royalties, taxes, and a specified return on investment for each well.

The supply cost is calculated with a cash flow model where net cash flow equals total revenue less any costs and other payments such as taxes and royalties.

The net cash flow is discounted back over the lifetime of the well (on average 25 years) to the first time period (2015) using a specified discount rate of 10 percent (real), thereby allowing the price of natural gas to vary and solve for the supply cost. The supply cost is the gas price that sets the Net Present Value (NPV) of the cash flows to zero.

The production of hydrocarbon fluids impacts supply cost with an assumption of a cut of 1 percent ethane, 90 percent propane, 99 percent butane and 99 percent pentane+. The hydrocarbons increase operating costs but also act as a further revenue stream.

Historical trends of the number of wells per pad are incorporated into the supply costs. Factors for economics of scale are used for areas where the average pad has seen multiple (in some cases more than 6) wells/pad.

Production Inputs

Historical well data was used to calculate the 2015 production inputs. Information was collected from the Alberta Energy Regulator (AER), the Government of Saskatchewan and the British Columbia Oil and Gas Commission (BCOGC) that details the historic production of hydrocarbon fluids as well as general well characteristics, such as completion date, initial production rate, total depth, true vertical depth and location.

Cost Inputs

- Drilling and completion costs were estimated from well-specific data provided by the Petroleum Services Association of Canada (PSAC).[38] Drilling and completion costs per metre drilled were estimated for each area and then applied to each area given the assumed well depth.
- Geological, geophysical, tie-in costs (infrastructure) and land costs were all derived from data sourced from the Canadian Association of Petroleum Producers (CAPP).[39]
- Operating costs were estimated from CAPP[40] at the provincial level.
- Royalties were derived for all wells consistent with the regulations for natural gas royalties across the three provinces.[41,42,43]
    - Alberta's 2015 Royalty Review is important to note. Royalties on new natural gas wells will be at 5 percent until cumulative revenues equal the well's Drilling and Completion Cost Allowance. This Drilling and Completion Cost Allowance is a function of the well's vertical depth and lateral length, giving credit for the higher cost associated with drilling deeper than a set threshold. Wells shallower than or equal to 2,000 metres are treated differently than wells deeper than 2,000 metres.[44]
- Within the supply cost model, federal corporate income tax rates were assumed constant at 15 percent. Alberta and Saskatchewan income tax rates were assumed to be constant at 12 percent and British Columbia income tax rates were assumed to be constant at 11 percent.

Other Economic Assumptions

- The inflation rate is assumed to be 2 percent per annum, which is within the Bank of Canada's target inflation of 1-3 percent.
- The results are presented in **Canadian dollars** in real terms in 2015 dollars. The Canadian dollar was assumed to grow from 79 cents/USD to 85 cents/USD over the next 20 years.
- **Supply costs are calculated as plant-gate costs,** that is, they do not include transportation or processing costs.

[38] PSAC, 2016 Well Cost Study Upcoming Winter Costs – Published November 3, 2015
[39] CAPP, Statistical Handbook for Canada's Upstream Petroleum Industry May 2016
[40] Ibid.
[41] Government of British Columbia website, Natural Gas Royalties, February 2016, http://www2.gov.bc.ca/gov/content/taxes/natural-resource-taxes/oil-natural-gas/oil-gas-royalty/understand/natural-gas#royalty-rate
[42] Alberta Energy website, Alberta Natural Gas Royalty Guidelines (2009), February 2016, http://www.energy.alberta.ca/NaturalGas/3109.asp
[43] Government of Saskatchewan website, Crown Royalty and Freehold Production Tax Rate Formula Factors and Royalty Rate Calculator, February 2016, http://www.economy.gov.sk.ca/royaltytaxfactors
[44] Alberta Energy, 'Modernized Royalty Framework: Formulas', accessed July 18, 2016, http://www.energy.alberta.ca/Org/pdfs/MRFCstar.pdf.

- Gas supply costs are presented as Canadian dollars per thousand cubic feet of natural gas ($/mcf). An exchange rate of 1USD = 1.279CAD was used, as per the Bank of Canada's 2015 average.[45]
- The natural gas price is assumed to increase at 2 percent per annum, consistent with the Energy Information Administration's annual average growth rate forecast (from 2014 to 2040) in the *Annual Energy Outlook 2015*.[46]

Crude Oil Production: Western Canada Forecast and Supply Cost Methodology

The production forecast in this study is an update from that done in CERI Study 150, "Western Canada Crude Oil Forecasts and Impacts (2015 – 2035)", released in July 2015. The province of Manitoba was added to the analysis.

The supply cost calculations done in this study were last done in CERI Study 135, "Conventional Oil Supply Costs in Western Canada", released in June 2013. Again, the province of Manitoba was added to the analysis. The methodologies for both supply forecast and supply cost calculations have not changed, and the assumptions used have been updated to reflect their changes over time.

The supply cost represents the oil price (in real 2015 dollars) required to recover all capital expenditures, operating costs, royalties, taxes, and a specified return on investment for each well.

The supply cost is calculated with a cash flow model where net cash flow equals total revenue less any costs and other payments such as taxes and royalties.

The net cash flow is discounted back over the lifetime of the well (on average 20 years) to the first time period (2015) using a specified discount rate of 10 percent (real), thereby allowing the price of oil to vary and solve for the supply cost. The supply cost is the oil price that sets the Net Present Value (NPV) of the cash flow to zero.

Each well is considered operational while production rates are 3 bbls/day or greater. If production falls below 3 bbls/day, the well is considered to be shut off and the economic evaluation is conducted for that time period only.

Companies may evaluate individual projects and investments using higher or lower discount rates than those used in this analysis. This would result in higher or lower supply costs than those presented here.

[45] Bank of Canada, 'Year Average of Exchange Rates', 2015, accessed May 2016, http://www.bankofcanada.ca/stats/assets/pdf/nraa-2015-en.pdf.
[46] EIA Annual Energy Outlook 2015, April 2015

The analysis has been undertaken for a number of study areas, and the results represent the supply cost for a "typical well" located in each area.

Production Inputs

Historical well data was used to calculate the 2015 production inputs. Information was collected from the AER, the Government of Saskatchewan, the British Columbia Oil and Gas Commission (BCOGC) and the Government of Manitoba that details the historic production of hydrocarbon fluids as well as general well characteristics, such as completion date, initial production rate, total depth, true vertical depth and location.

- The **initial production (IP)** rates for wells drilled in 2015 were derived from IP rates of wells that were drilled from the years 2005 through 2014.
- Production **decline** parameters were derived from historical monthly production rates from wells drilled between 2007 and 2014. A "type" curve was derived for each area and is used to establish the production decline profile for new wells that would come on stream in 2015.
- The **average depth** of new wells for each area was calculated from an average of the last ten years of wells drilled.

Cost Inputs

- **Drilling and completion costs** were estimated from data provided by the Petroleum Services Association of Canada (PSAC).[47] Drilling and completion costs per metre drilled were estimated for each area and then applied to each area given the assumed well depth.
- **Geological, geophysical, tie-in costs (infrastructure) and land costs** were all derived from data sourced from CAPP.[48] These were derived at the provincial level, so they do not vary between areas or wells.
- **Operating costs** were estimated from CAPP[49] at the provincial level and are assumed to be constant per barrel of oil produced.
- **Royalties** were derived for all wells consistent with the regulations for oil royalties across the four provinces.[50,51,52,53]

[47] PSAC, 2016 Well Cost Study Upcoming Winter Costs – Published November 3, 2015
[48] CAPP, Statistical Handbook for Canada's Upstream Petroleum Industry May 2016
[49] Ibid.
[50] Government of BC, Oil Royalties, http://www2.gov.bc.ca/gov/content/taxes/natural-resource-taxes/oil-natural-gas/oil-gas-royalty/understand/oil, accessed June 2016
[51] Government of Alberta, Alberta's Modernized Royalty Framework Overview, http://www.energy.alberta.ca/Org/pdfs/MRFFactsheet.pdf, accessed July 2016
[52] Government of Saskatchewan, Crude Oil Royalty/Tax Formulas, http://www.economy.gov.sk.ca/factor-circulars, accessed June 2016
[53] Government of Manitoba, Manitoba Petroleum Fiscal Regime, http://www.manitoba.ca/iem/petroleum/regime/index.html, accessed July 2016

  - As well-specific recovery methods are unknown, the *Enhanced Hydrocarbon Recovery Program*[54] was not considered in the royalty calculations.
- Within the supply cost model, federal corporate income tax rates were assumed constant at 15 percent. Alberta and Saskatchewan income tax rates were assumed to be constant at 12 percent, British Columbia income tax rates were assumed to be constant at 11 percent and Manitoba income tax rates were assumed to be constant at 12 percent.

Other Economic Assumptions

- Economic assumptions for the crude oil supply forecast and supply cost calculations were consistent with the assumptions used in the natural gas models.
- The **oil price** is assumed to increase at 1.22 percent per annum, consistent with the U.S. Energy Information Administration's annual average growth rate forecast in the *2015 Annual Energy Outlook.*[55]

Crude Oil Production: Offshore Newfoundland Forecast and Supply Cost Methodology

The production profile for the Newfoundland and Labrador offshore assets comprises aggregated profiles of:

a) producing assets: Hibernia, Terra Nova, White Rose, North Amethyst producing assets as well as all officially approved for development extensions of these projects

b) new asset - Hebron - to be commissioned in 2017

c) new perspective asset, which is likely to come online within the study period (Bay du Nord)

Production Profile Inputs

To establish per asset production profiles, the following inputs were used:

a) <u>Recoverable reserves.</u> For most assets, C-NLOPB latest reserves estimation (May 2016) were used. For the Hebron project, Operator estimation of reserves was used from Development Plan of 2011. For the perspective asset, an assumption of recoverable reserves had to be made based on best available information issued by Operator's in the public domain.

b) <u>Produced up to date reserves.</u> Historical production published by C-NLOPB was used.

c) <u>Project life.</u> Due to maturity of all producing assets and number of extension projects underway, a mix of data on project finish year was considered based on approved Development Plans and Amendments, C-NLOPB as well as estimations of Operator's representatives, usually presented at regional offshore conferences. An economic cut-off

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[54] Government of Alberta, Enhanced Hydrocarbon Recovery Program, accessed August 2016, http://www.energy.alberta.ca/About_Us/4232.asp

[55] U.S. Energy Information Administration, Annual Energy Outlook 2015 with projections to 2040, accessed May 2016, http://www.eia.gov/forecasts/aeo/pdf/0383(2015).pdf

level, used in Development plans or Amendments per project, was also taken into consideration while modelling a production profile.

d) Production profile from 2016 to project life finish. The general approach was to rely on the latest approved Development plan or Amendment (hereinafter referred to as Project file) per each asset to obtain a production profile (excluding perspective asset, which lacks such a file). In cases where current remaining reserves estimation or project life finish year was different compared to the latest Project file, appropriate adjustments were made to Operator latest production forecast, which would a) produce remaining reserves b) get to estimated project finish year and c) finish upon reaching economic cut-off. If no such adjustment were needed, as in the case with Hebron, the latest Operator's production forecast was used. For new perspective asset, due to lack of information, production profile, time to first oil after appraisal drilling finish, and project life were assumed based on closest analogues out of Newfoundland and Labrador producing assets.

Production Profile Assumptions

- Only one perspective asset was taken into aggregate production profile out of several discovered deposits in the jurisdiction of C-NLOPB, which has the most reserves and is most mature in its appraisal
- For the perspective asset, due to lack of information, recoverable reserves, production profile, time to first oil date after appraisal drilling finish, and project life were assumed based on available estimations of Operator in the public domain and closest analogues out of Newfoundland and Labrador producing assets
- No other extension projects for current producing assets were assumed besides those already approved in Development Plans and Amendments
- No gas production is modelled irrespective of presence of gas reserves for producing assets. The reasons behind this are that no Development Plan or Amendment currently contain approved gas project plans. Based on available data in C-NLOPB documents (decisions and staff analysis), some Operators will or already do explore potential commercial gas projects and technologies, including at the request of C-NLOPB, that this data be incorporated into perspective gas production forecasts only upon becoming available.
- The supply cost calculations for Newfoundland and Labrador's assets used the same methodology as those done for the western Canadian provinces. As the production data was aggregated per asset, so was the cost data. Information on number of wells per asset, as well as average depth per well was extrapolated using historical drilling over the past three years.
- Newfoundland and Labrador corporate income tax rates were assumed to be constant at 14 percent.

Appendix B: Study Supply Areas

Table B.1 describes the study areas used to estimate production and supply costs. Figures B.1-B.4 show the maps of drilling natural gas wells in British Columbia, Alberta, Saskatchewan and Manitoba. As the analysis for offshore Newfoundland was aggregated by asset, a map of the producing assets is shown in Figure B.5.

Table B.1: Supply Study Areas

Area ID	Province	Area Description
PIA01-9999	Alberta	Suffield Medicine Hat Area
PIA02-9999	Alberta	Bow Island Area
PIA03-9999	Alberta	Foothills Area west of Calgary
PIA04-9999	Alberta	Hussar to Princess Area
PIA05-9999	Alberta	Didsbury to Hussar Area
PIA06-9999	Alberta	Nevis and Ghostpine Area
PIA07-9999	Alberta	Bens Lake to Princess (North Lateral) Area
PIA08-9999	Alberta	Bens Lake to Canendish (East Lateral)
PIA09-9999	Alberta	Edson to Caroline (Plains Mainline)
PIA10-9999	Alberta	McLeod to Caroline (Foothills Mainline)
PIA11-9999	Alberta	Edmonton Area
PIA12-9999	Alberta	Bens Lake upstream to Calling Lake
PIA13-9999	Alberta	Gold Creek to Edson Area
PIA14-9999	Alberta	Vahalla to Gold Creek Area
PIA15-9999	Alberta	Judy Creek, Kaybon to Edson and McLeod
PIA16-9999	Alberta	Doe Creek to Teepee Creek Area
PIA17-9999	Alberta	Heart River Wolverine Creek Area

Area ID	Province	Area Description
PIA18-9999	Alberta	Darling Creek to Slave Lake Compressor
PIA19-9999	Alberta	Fort McMurray Area
PIA20-9999	Alberta	Owl Lake Area
PIA21-9999	Alberta	Thunder Creek to Tanghe Creek
PIA22-9999	Alberta	Zama Lake to Meikle Compressor
PIA23-9999	Alberta	Princess to Empress Mainline
PIA30-X9999	British Columbia	Pine River Lateral
PIA31-X9999	British Columbia	Tupper Creek/Noel Area
PIA32-X9999	British Columbia	Groundbirch Area
PIA33-X9999	British Columbia	Dawson Creek
PIA34-X9999	British Columbia	Fort St. John Area
PIA35-X9999	British Columbia	Chinchauga River
PIA36-X9999	British Columbia	Ring Area
PIA37-X9999	British Columbia	Kahntah Area
PIA38-X9999	British Columbia	Shekilie Area
PIA39-X9999	British Columbia	Peggo-Pesh Area
PIA40-X9999	British Columbia	Helmut North Area
PIA41-X9999	British Columbia	Fort Nelson to CS2
PIA42-X9999	British Columbia	Fort Nelson to NWT Border
PIA45-X9999	British Columbia	CS2 to Summit Lake Area
PIA50-9999	Saskatchewan	Southwest
PIA51-9999	Saskatchewan	Central West
PIA52-9999	Saskatchewan	Central Northwest
PIA70-6200	Manitoba	Bakken - Tourquay, Bakken
PIA71-5900	Manitoba	Lodgepole

PIA72-2900	Manitoba	Amaranth
PIA73-4200	Manitoba	Mission Canyon
PIA79-9999	Manitoba	Others

Source: CERI

Figure B.1: Map of British Columbia Study Areas

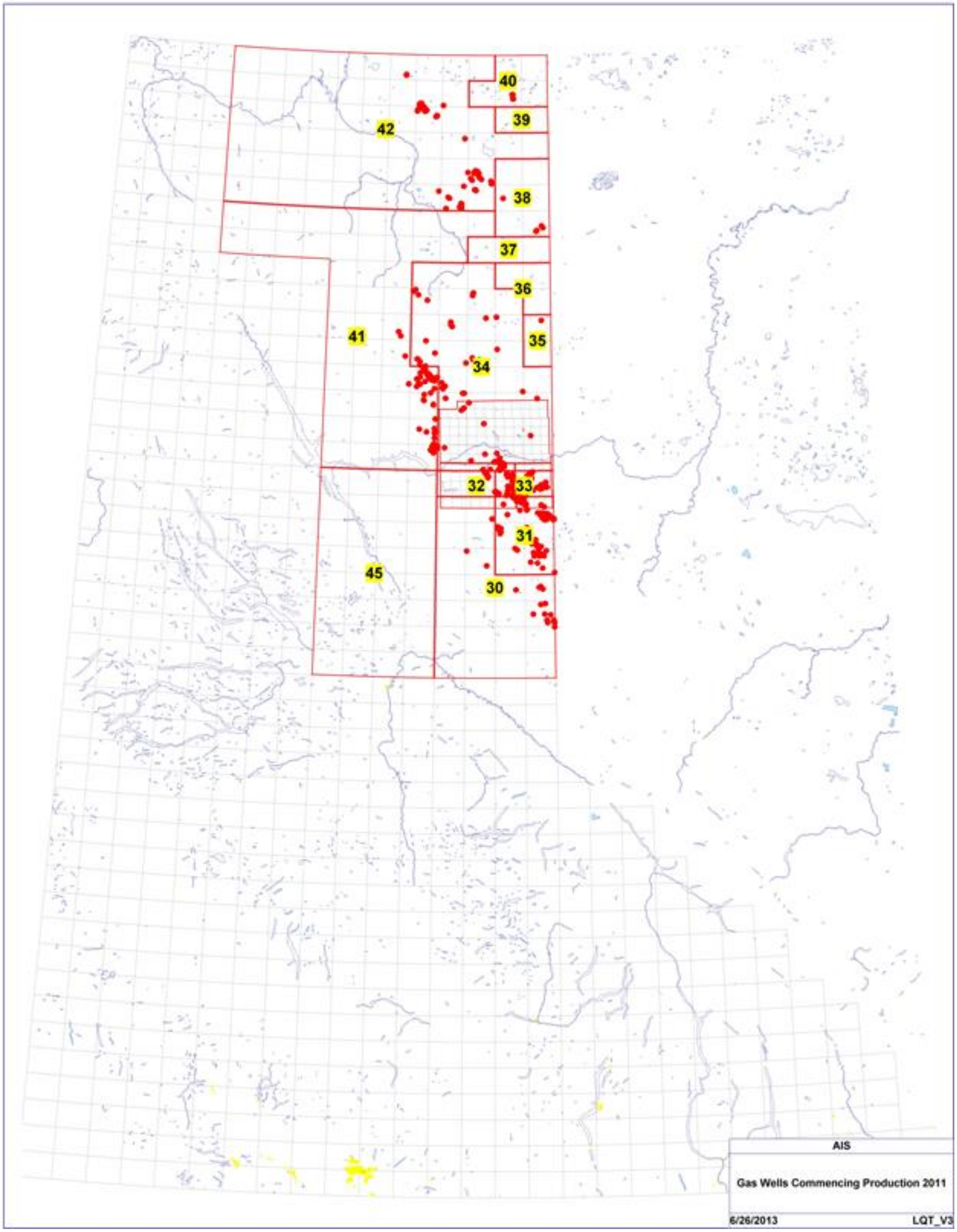


Figure B.2: Map of Alberta Study Areas

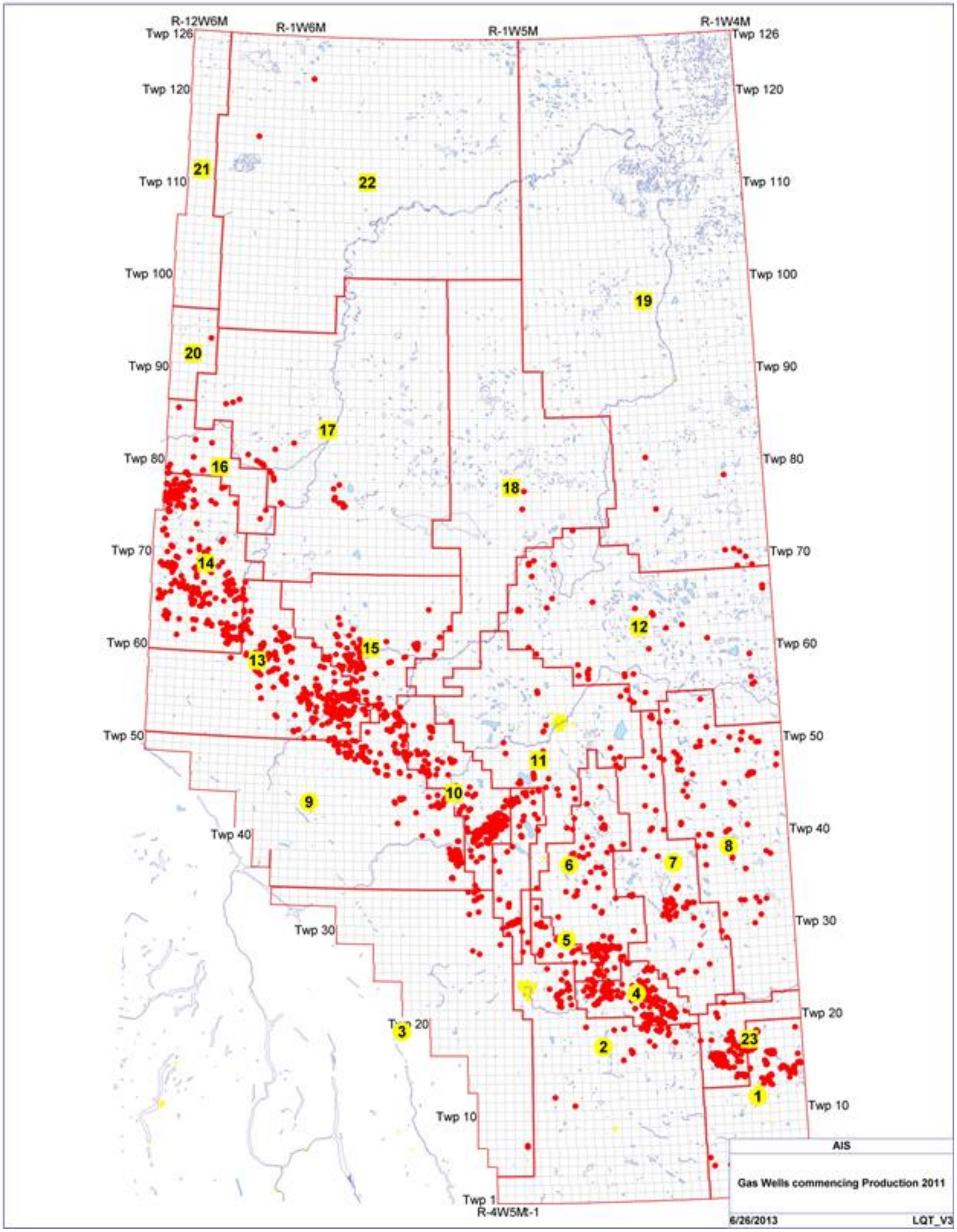


Figure B.3: Map of Saskatchewan Study Areas

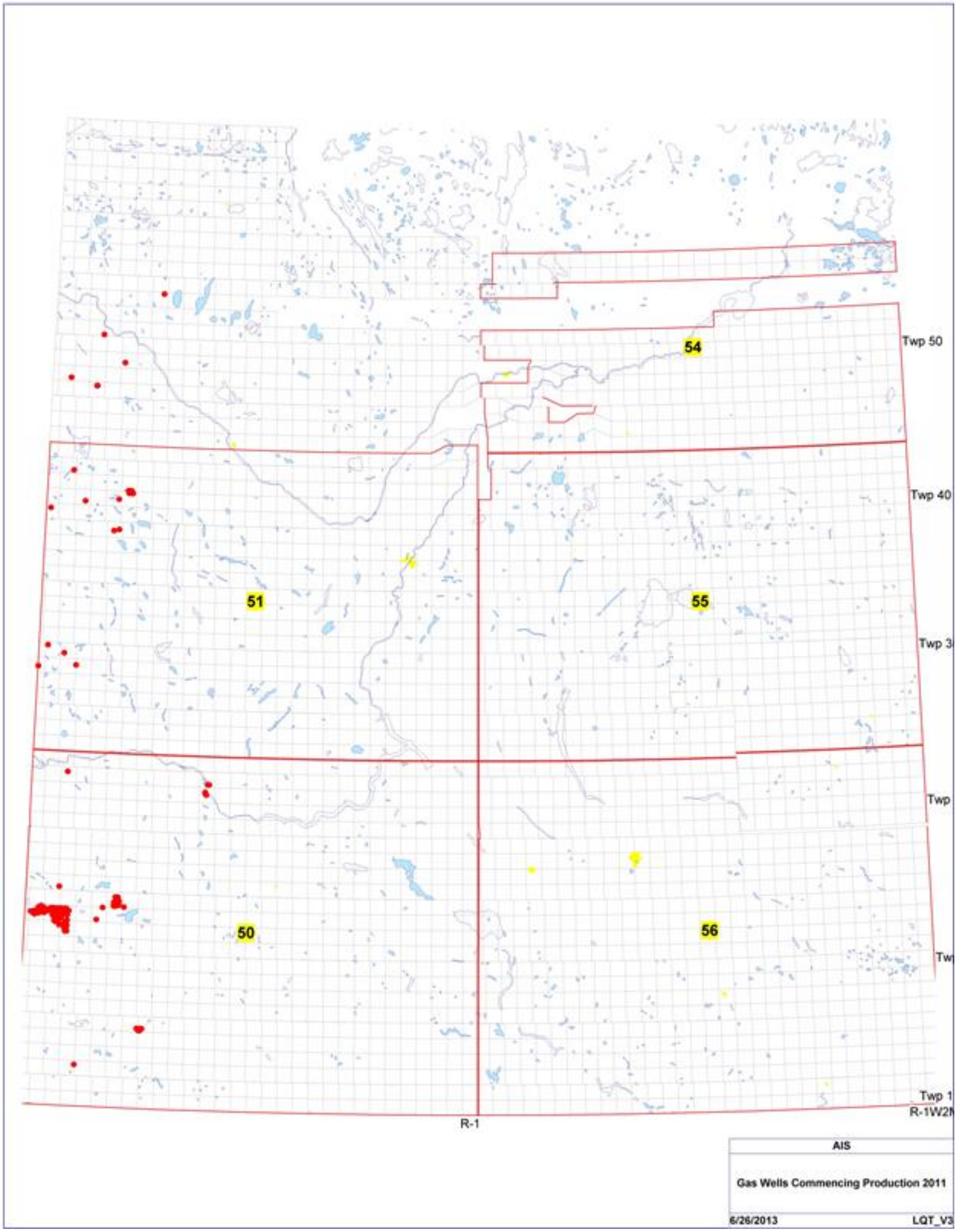


Figure B.4: Map of Manitoba Study Areas

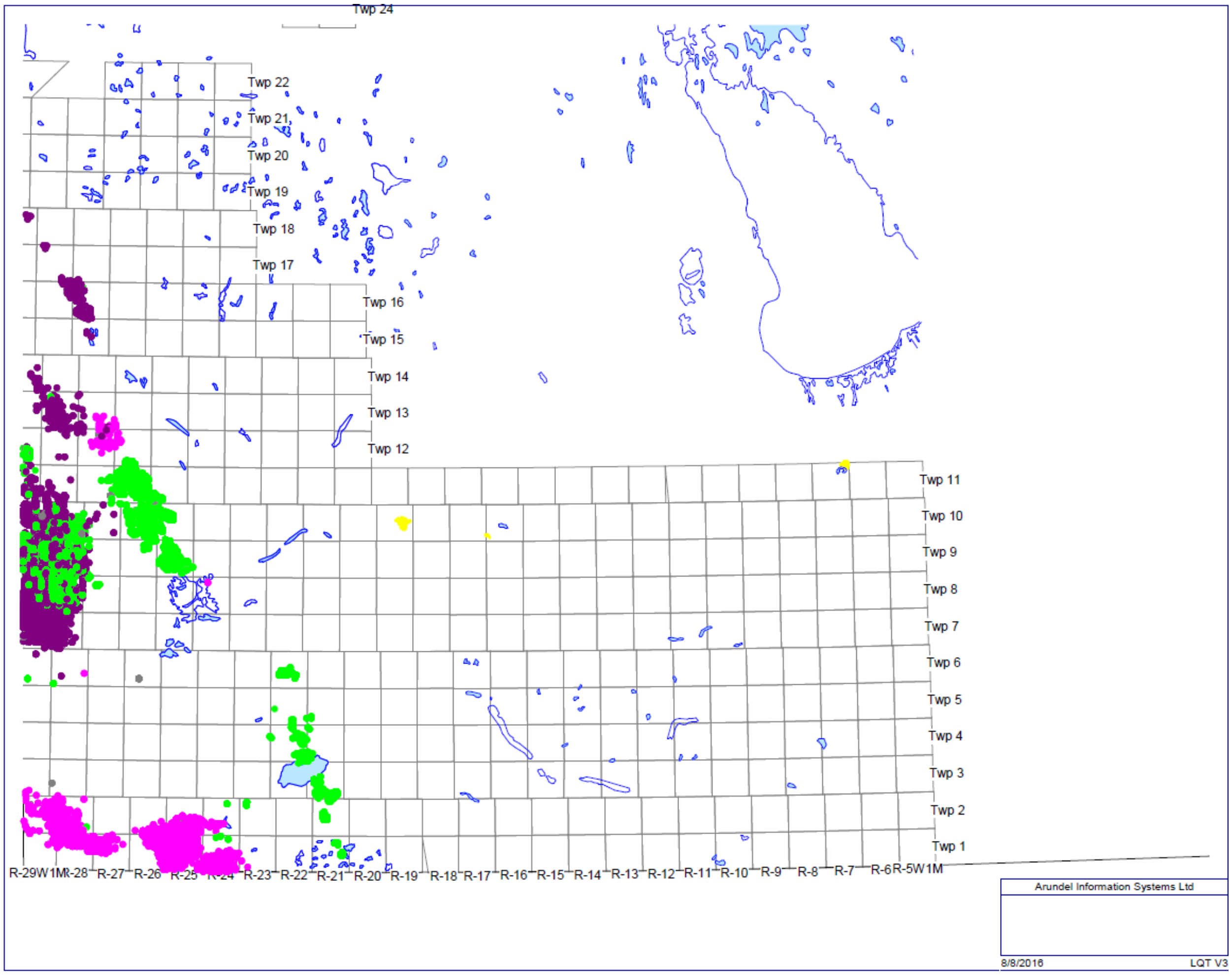
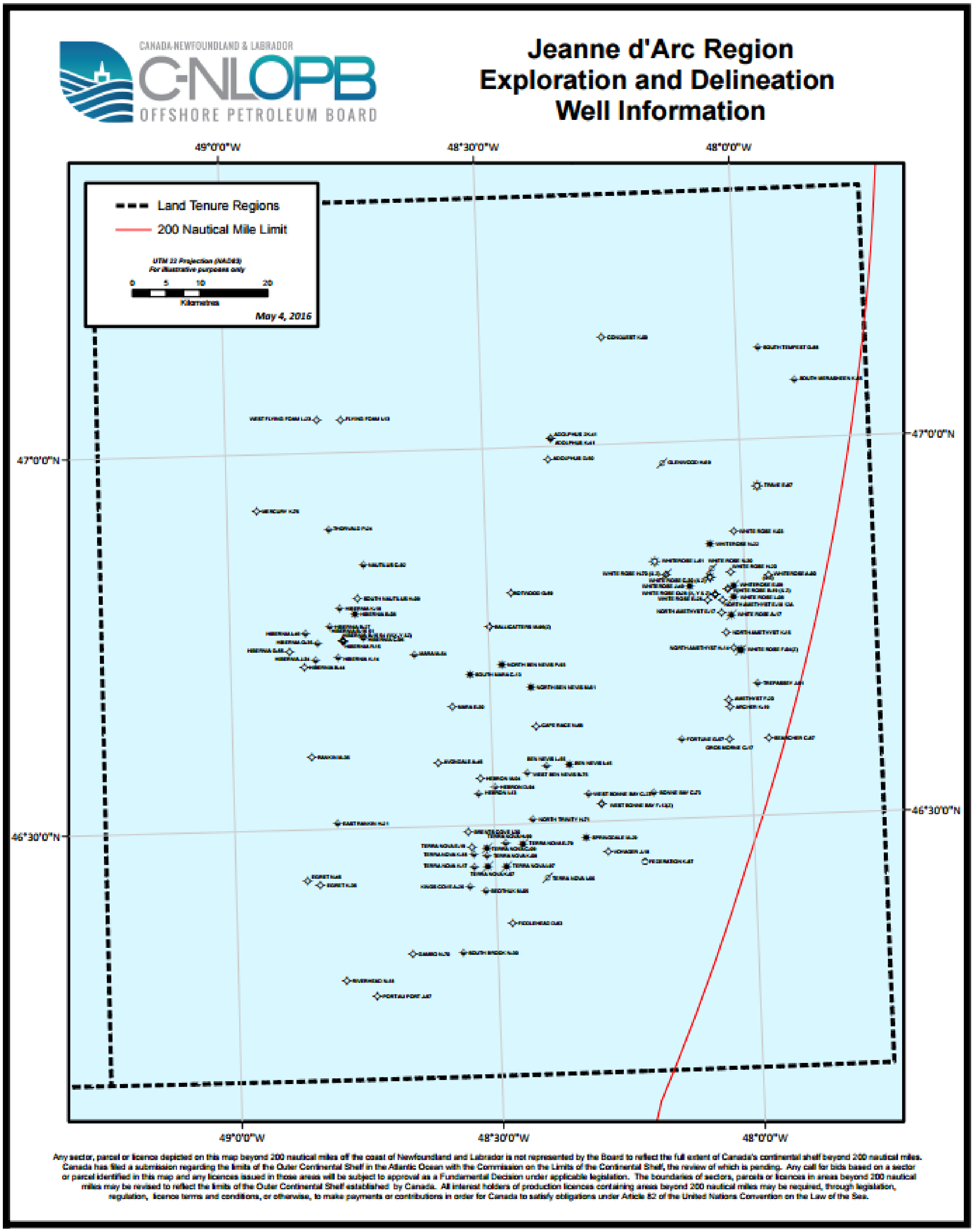


Figure B.5: Map of Newfoundland and Labrador Study Areas*



*Study areas are Terra Nova, Hibernia, White Rose and North Amethyst, Hebron assets

Source: CNLOPB